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December 28, 2007

RECEIVED

DEC 28 2007

PUBLIC SERVICE
COMMISSION

Hon. Elizabeth A. O'Donnell
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: *Application of Big Rivers Electric Corporation, E.ON U.S., LLC, Western Kentucky Energy Corp., and LG&E Energy Marketing Inc.*, P.S.C. No. 2007-00455; *The Application of Big Rivers Electric Corporation for Approval of Environmental Compliance Plan and Environmental Surcharge Tariff*, P.S.C. No. 2007-00460

Dear Ms. O'Donnell:

Enclosed for filing are the following documents, which seek a series of regulatory approvals required for Big Rivers Electric Corporation ("Big Rivers"), Western Kentucky Energy Corp., and LG&E Energy Marketing Inc. to consummate transaction between and among them that have become known as the "Unwind Transaction." More specifically, we enclose:

1. An original and ten copies of the Application of Big Rivers Electric Corporation, E.ON U.S., LLC, Western Kentucky Energy Corp., and LG&E Energy Marketing Inc., in a case predesignated as P.S.C. Case No. 2007-00455;

2. An original and ten copies of the Application of Big Rivers Electric Corporation for an environmental surcharge in a case predesignated as P.S.C. Case No. 2007-00460;

3. Petition of Western Kentucky Energy Corp. for Confidential Protection; and

4. Motion of Big Rivers Electric Corporation, E.ON U.S., LLC, Western Kentucky Energy Corp., and LG&E Energy Marketing Inc. for An informal conference on January 4, 2008.

I certify that a copy of this letter and each of the foregoing documents has been served on the Kentucky Attorney General, Rate Intervention Division, and the persons identified on the attached service list.

Please note that, in response to a request from Commission staff, the applicants have proposed a procedural schedule for this matter. A copy of that proposed procedural

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schedule is attached as Exhibit 4 to the Application, and for your convenience, an additional copy is attached to this letter. The procedural schedule contemplates an initial informal conference with Commission staff on Friday, January 4, 2008.

Sincerely yours,

James M. Miller

James M. Miller
Counsel for Big Rivers Electric Corporation

Enclosures
c: Mr. Michael H. Core
Mr. Paul W. Thompson
Hon. Allyson Sturgeon
Hon. Kendrick Riggs
Rural Utilities Service

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BIG RIVERS ELECTRIC CORPORATION
PSC CASE NOS. 2007-00455 AND 2007-00460

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PSC CASE NOS. 2007-00455 AND 2007-00460

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Big Rivers Electric Corporation for Approval of Environmental Compliance Plan and Environmental Surcharge Tariff	)))	Case No. 2007-00460

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of:

The Application of Big Rivers Electric Corporation)
for Approval of Environmental Compliance Plan)
and Environmental Surcharge Tariff) Case No. 2007-00460

APPLICATION AND MOTION FOR INCORPORATION BY REFERENCE

1. Big Rivers Electric Corporation ("Big Rivers"), by counsel, hereby submits this application ("Application") pursuant to KRS 278.183, 807 KAR 5:001, 807 KAR 5:011, and all other applicable statutes and regulations, seeking approval of an environmental compliance plan and environmental surcharge tariff.

2. Big Rivers is a rural electric cooperative corporation organized pursuant to KRS Chapter 279. Its mailing address is P.O. Box 24, 201 Third Street, Henderson, Kentucky 42419. 807 KAR 5:001 Section 8(1). Big Rivers owns electric generation facilities, and purchases, transmits and sells electricity at wholesale. It exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative members, which are: Kenergy Corp., Meade County Rural Electric Cooperative Corporation, and Jackson Purchase Energy Corporation (collectively, the "Members"). The Members in turn provide retail electric service to approximately 110,000 consumer/members located in 22 Western Kentucky counties, to wit: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union and Webster.

3. The articles of incorporation of Big Rivers, and all amendments thereto, are attached as Exhibit 1 to the Application of Big Rivers in *In the Matter of: Application of Big Rivers Electric Corporation, LG&E Energy Marketing Inc., Western Kentucky Energy Corp.,*

WKE Station Two Inc., and WKE Corp., Pursuant to the Public Service Commission Orders in Case Nos. 99-450 and 2000-095, for Approval of Amendments to Station Two Agreements, PSC Case No. 2005-00532, and are incorporated herein by reference. 807 KAR 5:001 Section 8(3).

4. This Application and the supporting exhibits, which are incorporated herein by reference, contain fully the facts on which the relief requested by Big Rivers is based. 807 KAR 5:001 Section 8(1).

5. This Application is being filed in conjunction with the application in Case Number 2007-00455 (the "Unwind Application"),[1] in which Big Rivers and other parties are seeking various approvals required by one or more of them to enter into a transaction (the "Unwind Transaction") to terminate the transaction (the "1998 Transactions") approved by the Kentucky Public Service Commission ("Commission") in Case Numbers 97-204 and 98-267.[2]

6. Prior to 1998, Big Rivers operated its generators in Western Kentucky known as Wilson Station, Coleman Station, Green Station, and Reid Station, and also operated, pursuant to contract with the City of Henderson, a generating plant that is owned by the City of Henderson ("HMP&L"), known as Station Two. The 1998 Transactions were part of an overall plan that resolved Big Rivers' reorganization under Chapter 11 of the United States Bankruptcy Code, and it involved Big Rivers leasing its generating units to subsidiaries or affiliates of LG&E Energy Corp. (the "LG&E Parties"), and assigning to the LG&E Parties Big Rivers' contractual rights and obligations relating to Station Two. Under the 1998 Transactions, Big Rivers contracted to

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[1] *In the Matter of: Joint Application of Big Rivers, E.ON, LG&E Energy Marketing, Inc., and Western Kentucky Energy Corporation for Approval to Unwind Lease and Power Purchase Transactions*, PSC Case No. 2007-00455.
[2] *See* Order dated April 30, 1998, in *In the Matter of: The Application of Big Rivers Electric Corporation, Louisville Gas and Electric Company, Western Kentucky Energy Corp., Western Kentucky Leasing Corp., and LG&E Station Two Inc. for Approval of Wholesale Rate Adjustment for Big Rivers Electric Corporation and for Approval of Transaction*, PSC Case No. 97-204; Order dated July 14, 1998, in *In the Matter of: The Application of Big Rivers Electric Corporation for Approval of the 1998 Amendments to Station Two Contracts between Big Rivers Electric Corporation and the City of Henderson, Kentucky and the Utility Commission of the City of Henderson*, PSC Case No. 98-267.

purchase power from the LG&E Parties in an amount sufficient to cover the anticipated needs of Big Rivers' Members, other than the amounts of power required by its Members to supply the retail requirements of two aluminum smelter customers located in Big Rivers' service area (the "Smelters"). *See* Unwind Application.

7. The Unwind Transaction essentially seeks to terminate the 1998 Transactions and to return to Big Rivers the control and operation and maintenance of its generating units and to assign back to Big Rivers its rights and obligations relating to Station Two. As part of the Unwind Transaction, Big Rivers will receive, subject to certain potential adjustments, \$301,500,000 in cash at closing plus other value totaling, in the aggregate, approximately \$623 million. This consideration will cause Big Rivers' equity to improve from a negative 13.6% before closing, to a positive 24.4% immediately after closing. The Unwind Transaction will restore Big Rivers' ability to finance system additions, power purchases, or other arrangements to meet growth associated with economic development, an ability Big Rivers has lacked since 1998. The Unwind Transaction will enable Big Rivers to provide for the power needs of the Smelters, whose loads total approximately 850 megawatts, under long-term contracts and at a cost acceptable to the Smelters, which the Smelters have said is critical to sustain their operations and the jobs and economic contributions they provide to Western Kentucky.[3] The daunting alternative would be for the Smelters to seek power on the potentially volatile open market when their current power contracts expire in 2010 and 2011. The Unwind Transaction will also enable the LG&E Parties, now affiliates or subsidiaries of E.ON U.S., to exit their unregulated business activities, including the transactions with Big Rivers, which had not proven advantageous to

[3] *See* Unwind Application; Smelter Comments filed June 8, 2005, in *In the Matter of: An Assessment of Kentucky's Electric Generation, Transmission and Distribution Needs*, PSC Case No. 2005-00090.

E.ON U.S., and to focus on their regulated activities rather than on wholesale generation. *See* Unwind Application.

8. Once Big Rivers regains control of its generating facilities, it will have to bear additional costs to comply with federal, state, and local environmental laws and regulations. In the instant proceeding, Big Rivers is seeking the Commission's approval, pursuant to KRS 278.183, of an environmental compliance plan and an environmental surcharge tariff. Big Rivers' environmental compliance plan ("Compliance Plan"), is set forth in the form of the prepared testimony of David A. Spainhoward ("Spainhoward Testimony"), attached hereto as Exhibit A and incorporated herein by reference, and the prepared testimony of William Steven Seelye ("Seelye Testimony"), attached hereto as Exhibit B and incorporated herein by reference. Big Rivers proposes to recover the environmental costs set forth in the Compliance Plan in accordance with KRS 278.183 and through its proposed Environmental Surcharge tariff ("Environmental Surcharge Tariff"), attached as Exhibit WSS-5 to the Seelye Testimony and incorporated herein by reference.

9. The Compliance Plan consists of three programs (a SO_2 compliance plan, a NOx compliance plan, and a SO_3 compliance plan) that Big Rivers will undertake in order to comply with the federal Clean Air Act, as amended, and with federal, state, and local environmental statutes and regulations that apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal. The only expenses Big Rivers is proposing to recover under the Compliance plan are the commodity costs of purchasing SO_2, NOx, and SO_3 reagents, and payments made to third-parties in connection with the disposal of wastes. Big Rivers is not proposing to recover any other operation and maintenance expenses related to SO_2, NOx, and SO_3 compliance, nor is it requesting a return on rate base or property taxes related to

any facilities at this time. The testimony of David A. Spainhoward and the exhibits thereto further describe the environmental projects included in the Compliance Plan; provide detailed projected compliance costs; describe the various federal, state, and local environmental laws and regulations that affect Big Rivers and how the Compliance Plan projects are measures aimed at complying with those environmental requirements; and otherwise support the reasonableness and cost-effectiveness of the Compliance Plan and the Environmental Surcharge Tariff.

10. The proposed Environmental Surcharge Tariff is a mandatory rider to all wholesale sales by Big Rivers to its Members. The Environmental Surcharge Tariff provides for monthly adjustments that will allow Big Rivers to recover the revenue requirements of the Compliance Plan. The testimony of William Steven Seelye further explains the mechanics of the Environmental Surcharge Tariff, the expenses that will be recovered through the Environmental Surcharge Tariff, how the monthly environmental surcharge factors will be calculated, and the monthly forms that Big Rivers will file with the Commission.

11. The Environmental Surcharge Tariff, and Big Rivers' ability to recover its environmental compliance costs through the Environmental Surcharge Tariff, are an integral part of the Unwind Transaction. As part of the Unwind Transaction, Big Rivers is proposing several new tariffs, including the Environmental Surcharge Tariff, a Member Rate Stability Mechanism ("MRSM"), a Fuel Adjustment Clause ("FAC"), an Unwind Surcredit, and a Rebate Adjustment. *See id.;* Seelye Testimony. These tariffs are critical to Big Rivers' efforts to unwind the 1998 Transactions, to provide wholesale electric power for service to the Smelters at rates that will enable the Smelters to remain economically viable businesses in Western Kentucky, to recover its prudently incurred costs, and to protect the interests of its Members. The combination of the revenue from the other tariffs proposed in the Unwind Application (the Unwind Surcredit,

Rebate Adjustment, and MRSM) is expected to have the effect of canceling out any impact of the Environmental Surcharge and the FAC for Big Rivers' non-Smelter rates to its Members for approximately five years after the Unwind Transaction. The testimony of C. William Blackburn ("Blackburn Testimony"), filed as Exhibit 10 to the Application in PSC Case Number 2007-00455, further explains how the proposed tariffs will work together. *See* Blackburn Testimony at pages 8-9, 78-80, 92-96; *see also* Seelye Testimony.

12. As noted in the Unwind Application, the Unwind Transaction is the result of thousands of hours of careful and extensive negotiations, research and drafting. The terms of the Unwind Transaction are very carefully balanced with the interests of the Smelters, Big Rivers, Big Rivers' Members, and the retail customers of Big Rivers' Members. For this reason, Big Rivers seeks approval of the Environmental Surcharge Tariff without alteration to maintain that critical and delicate balance. The parties to the Unwind Transaction may, of course, refuse to close if the Commission changes the terms of the transaction. *See* Unwind Application.

13. Big Rivers anticipates that each of its Members will implement their own tariffs in order to pass through the Big Rivers environmental surcharge. Each Member will file a separate application for approval of its tariff.

14. Big Rivers gave notice to the Commission of its intent to file this Application more than 30 days prior to filing it in accordance with KRS 278.183. Big Rivers also mailed a notice of the proposed new tariffs, including the Environmental Surcharge Tariff, to each of its Members prior to filing this Application. *See id.* Exhibit 31.

15. Big Rivers requests that the Commission accept and approve the Compliance Plan and the Environmental Surcharge Tariff, without change, to become effective with the closing of

the Unwind Transaction. The authority for this relief is found in KRS 278.183, and related sections. 807 KAR 5:001 Section 8(1).

16. Big Rivers further moves that the Unwind Application, specifically including Exhibit 10 (the Blackburn Testimony) and Exhibit 31 (the notice) to the Unwind Application, be made a part of the record in this case by reference only. The authority for this relief is found in 807 KAR 5:001 Section 5(5). 807 KAR 5:001 Section 8(1).

WHEREFORE, Big Rivers requests that the Commission enter its order accepting and approving, without change, Big Rivers' proposed Compliance Plan and Environmental Surcharge Tariff, incorporating the Unwind Application by reference, and granting all other relief to which it may appear entitled.

On this the 28th day of December, 2007.

SULLIVAN, MOUNTJOY, STAINBACK
& MILLER, P.S.C.

James M. Miller

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Tyson Kamuf
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(270) 926-4000
Counsel for Big Rivers Electric Corporation

Verification

I, David A. Spainhoward, Vice President External Relations & Interim Chief Production Officer for Big Rivers Electric Corporation, hereby state that I have read the foregoing Application and that the statements contained therein are true and correct to the best of my knowledge and belief, on this the 27th day of December, 2007.

David A. Spainhoward

David A. Spainhoward
Vice President External Relations & Interim Chief Production Officer
Big Rivers Electric Corporation

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

The foregoing verification statement was SUBSCRIBED AND SWORN to before me by David A. Spainhoward as Vice President External Relations & Interim Chief Production Officer for Big Rivers Electric Corporation, on this the 27th day of December, 2007.

Paula Mitchell

Notary Public, Ky., State at Large
My commission expires: 1-12-09

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00460

DIRECT TESTIMONY OF
DAVID A. SPAINHOWARD

ON BEHALF OF
BIG RIVERS ELECTRIC CORPORATION

DECEMBER 2007

DIRECT TESTIMONY OF
DAVID A. SPAINHOWARD

Q. Please state your name, your address, your position with Big Rivers Electric Corporation and your qualifications.

A. My name is David A. Spainhoward. My current business address is 201 Third Street, Henderson, Kentucky 42420. I have been an employee of Big Rivers Electric Corporation ("Big Rivers") since 1972. My current position is Vice President External Relations & Interim Chief Production Officer at Big Rivers. Before holding my current position, I held the position of Vice President Contract Administration and Regulatory Affairs. I have also held positions in the Big Rivers Corporate Planning, Real Estate, Accounting and Purchasing departments. I am a graduate of Oakland City University in Oakland City, Indiana with the degree of Bachelor of Science in Management. I also have a Master of Science in Management degree from Oakland City University. I am also a graduate of Lockyear College of Business in Evansville, Indiana with an Associate Degree in Data Process Management. In addition, I have a certificate of proficiency from the United States Department of Agriculture School in Bookkeeping and Accounting. I am currently Chairman of the Board of Commissioners of the Henderson County Water District in Henderson, Kentucky.

Q. Have you previously testified before this Commission?

A. Yes. I have previously submitted testimony and personally appeared before the Kentucky Public Service Commission in numerous other matters. I was one of Big Rivers' witnesses in the case approving Big Rivers' 1998 lease transaction ("Lease Transaction") with E.ON U.S., LLC and its affiliates.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present Big Rivers' Environmental Compliance Plan aimed at recovering through an environmental surcharge Big Rivers' costs related to reagent, net disposal and net allowances for sulfur dioxide ("SO_2"), nitrous oxide ("NOx"), and sulfur trioxide ("SO_3"). I present SO_2, NOx, and SO_3 as three separate environmental programs under the Environmental Compliance Plan, and I establish each program's compliance with the regulatory requirements for the recovery of environmental surcharges under KRS § 278.183. I also explain the derivation of the costs underlying each of these three programs and break them out by individual Big Rivers plant.

Q. Why is Big Rivers proposing to implement an Environmental Surcharge?

A. In PSC Case Number 2007-00455, Big Rivers is seeking various approvals to implement an unwind of the 1998 Lease Transaction (the "Unwind Transaction"), which will enable Big Rivers to regain operation and control of its generating units. Big Rivers has followed closely changes in environmental regulations regarding SO_2, NOx, and SO_3. We believe the Big Rivers facilities comply with current environmental requirements, and in this case, Big Rivers is seeking approval from the Commission to recover the variable O&M expenses associated with operating those facilities after the Unwind Transaction is closed. On a going-forward basis, Big Rivers proposes the Environmental Surcharge to recover these O&M costs, which are all costs resulting from federal and state environmental requirements and related to the generation of electricity from coal.

Q. What is the nature of Big Rivers' proposed Environmental Surcharge?

A. Big Rivers is asking for Commission approval to recover through a new Environmental Surcharge mechanism its environmental-related variable O&M costs (reagents, net disposals, and net allowances) associated with its SO_2 control technology equipment, its NOx control technology equipment, and its mitigation of SO_3 for opacity purposes.

Q. How does Big Rivers propose to recover the Environmental Surcharge?

A. Big Rivers will recover the Environmental Surcharge as a surcharge on all energy sold. The costs of the programs included in the Environmental Surcharge are allocated on a straight energy basis across all MWh taken on Big Rivers' system. This allocation, as well as the general operation of the Environmental Surcharge, is explained in greater detail in Exhibit B, the Testimony of William Steven Seelye.

Q. Is Big Rivers submitting an environmental compliance plan in connection with its request to utilize an Environmental Surcharge as part of this filing?

A. Yes, Big Rivers is submitting a limited Big Rivers Electric Corporation Environmental Compliance Plan ("Environmental Compliance Plan") with three separate programs (SO_2, NOx, and SO_3) as part of this filing in order to support its proposal to adopt an Environmental Surcharge. The Environmental Compliance Plan, attached as Exhibit DAS-1, is not a full environmental compliance plan treating all of the various environmental issues Big Rivers will face with respect to the operation of its units. Instead, the attached Environmental Compliance Plan is presented for Commission approval pursuant to the requirements of KRS 278.183 solely to support the recovery of the costs of these three programs, the costs of which will comprise Big Rivers' proposed Environmental Surcharge. Big Rivers is developing a more comprehensive and more global environmental compliance plan, of which the attached Environmental Compliance Plan would be only a portion.

Q. Please describe the various components of the three programs that will comprise the Environmental Compliance Plan submitted as Exhibit DAS-1.

A. Big Rivers is proposing that its Environmental Compliance Plan will be comprised of three separate programs: (1) an SO_2 program to recover the variable costs of reagents, sludge and ash disposal, and the sale of SO_2 allowances; (2) a NOx program to recover the variable costs of reagents and the sale of NOx allowances; and (3) an SO_3 program to recover the variable costs of reagents. I describe each of these three programs below in summary form. Exhibit DAS-1 describes each of these three programs in greater depth.

A. SO_2 Program

Q. Please describe the environmental requirements that obligate Big Rivers to control its emissions of SO_2.

A. Big Rivers' generation is subject to a number of different regulatory requirements relating to SO_2. These regulatory requirements vary from plant to plant. In general, however, SO_2 emissions are subject to regulation under a number of legislative provisions: (1) the Kentucky State Implementation Plan ("SIP") for emissions of all regulated pollutants; (2) amendments to the federal Clean Air Act; and (3) the provisions of the Clean Air Interstate Rule ("CAIR"). The specific application of each of these regulatory requirements to each of Big Rivers' plants is presented in the Environmental Compliance Plan in Exhibit DAS-1.

Q. Please describe the reagent costs which Big Rivers proposes to recover through the Environmental Surcharge.

A. The SO_2 reagent cost is comprised of the commodity cost of three separate types of reagent: lime, limestone, and di-basic acid or similar substitutes ("DBA"). No single Big Rivers unit incurs all three of these reagent costs. These reagents are used to treat the flue gas emitted from the plants. Depending on the plant concerned, either lime or limestone is used to treat flue gas, sometimes in tandem with DBA.

Q. What does Big Rivers propose to recover as the reagent cost for lime, limestone, and DBA as part of the Environmental Surcharge?

A. Attached as Attachment 1 to the Environmental Compliance Plan included as Exhibit DAS-1, Big Rivers provides the projected non-fuel variable O&M costs for a five-year period (2008-2012). For each Big Rivers generating station, this exhibit provides a projected reagent cost for lime, limestone, and DBA, as applicable. In each case, the amount included as the reagent cost is a pure commodity cost with no additional labor or handling added to the cost. For each unit, Big Rivers has estimated the projected requirement for lime, limestone and DBA and then multiplied that projected requirement by the expected price of that commodity for the year in question.

For the Coleman Station, the limestone costs are projected to begin at $2.463 million in 2008 (partial year), and to rise to $5.311 million in 2012. The Coleman Station projects no use of DBA.

For the Green Station, the lime costs are projected to begin at $5.494 million in 2008 (partial year), and to rise to $11.710 million in 2012. The Green Station projects no use of DBA.

For Henderson Station Two, the BREC share of lime costs are projected to begin at $1.865 million in 2008 (partial year), and to rise to $4.080 million in 2012. The Henderson Station Two projects no use of DBA.

For the Wilson Station, the limestone costs are projected at $2.112 million in 2008 (partial year), rising to a high of $3.281 million in 2010. The Wilson Station projects DBA costs of $0.750 million in 2008 (partial year), rising to a high of $1.223 million in 2012.

Q. Please describe the SO_2 disposal costs that will be incorporated into the Environmental Surcharge.

A. In addition to the costs of the reagents, Big Rivers also must incur costs to dispose of coal combustion by-products. The various units each produce quantities of fly ash, bottom ash, and SO_2 scrubber sludge as combustion by-products, and Big Rivers must dispose of these by-products consistent with environmental regulations. In addition, certain quantities of fixation lime are added as a reagent to these by-products as a stabilizing agent. The costs proposed by Big Rivers for inclusion in its Environmental Surcharge are comprised of the handling and hauling costs paid by Big Rivers to third-party contractors to remove and dispose of these combustion by-products, as well as the reagent cost for the fixation lime. No internal Big Rivers labor cost is allocated as a part of these costs.

Q. Are there any exceptions to this ordinary treatment of the costs of disposing of these combustion by-products?

A. Yes. Unlike the other generating units, Big Rivers' Coleman Station produces gypsum as part of the combustion by-products. The Coleman Station's scrubber waste is gypsum, a portion of which retains a value and can be sold and transported for reuse in other industries, and a portion of which must be disposed of as non-reusable ("off-spec gypsum"). Accordingly, Big Rivers offsets against the SO_2 disposal costs the amounts received from the sale of gypsum from the Coleman Station. These gypsum sales used as an offset are projected to be \$0.227 million in 2008 (partial year), rising to \$0.344 million in 2009 before declining to \$0.322 million in 2012. These costs are shown on Exhibit DAS-1, Attachment 1.

Q. What costs does Big Rivers project for fly ash, bottom ash, sludge, fixation lime, and off-spec gypsum disposal?

A. These costs also are shown on Exhibit DAS-1, Attachment 1. For the Coleman Station, fly ash disposal costs are projected to be \$1.024 million in

2008 (partial year), increasing to $1.033 million in 2012, and bottom ash disposal costs are projected to be $0.256 million in 2008 (partial year), increasing to $0.258 million in 2012. The Coleman Station has no ordinary sludge; instead its waste is either sold for production of gypsum or disposed of as off-spec gypsum waste. Off-spec gypsum disposal costs are projected to be $0.137 million in 2008 increasing to $0.138 million in 2012. The Coleman Station projects no costs for fixation lime.

For the Green Station, sludge disposal costs are projected to be $0.870 million in 2008 (partial year), rising to $1.567 million in 2012; fly ash disposal costs are projected to be $0.376 million in 2008, rising to $0.677 million in 2012; bottom ash disposal costs are projected to be $0.094 million in 2008, rising to $0.169 million in 2012; and fixation lime disposal costs are projected to be $0.437 million in 2008, rising to $0.731 million in 2012.

For Henderson Station Two, sludge disposal costs net of Henderson are projected to be $0.298 million in 2008 (partial year), rising to $0.551 million in 2012; fly ash disposal costs are projected to be $0.097 million in 2008, rising to $0.179 million in 2012; bottom ash disposal costs are projected to be $0.024 million in 2008, rising to $0.045 million in 2012; and fixation lime disposal costs are projected to be $0.138 million. rising to $0.244 million in 2012.

For the Wilson Station, sludge disposal costs are projected to be $0.357 million in 2008 (partial year), rising to $0.564 million in 2012; fly ash disposal costs are projected to be $0.098 million in 2008, rising to $0.182 million in 2012; bottom ash disposal costs are projected to be $0.024 million in 2008, rising to $0.045 million in 2012; and fixation lime disposal costs are projected to be $0.179 million in 2008, rising to $0.446 million in 2012.

Q. The final component of the Environmental Surcharge relating to SO_2 concerns the sale of SO_2 allowances. Could you please explain this component.

A. In each year, Big Rivers emits a quantity of SO_2, expressed in terms of tons of SO_2, and each year it receives from the United States Environmental Protection Agency ("EPA") a number of allowances, each of which permits it to emit one ton of SO_2. Big Rivers has projected the amount of SO_2 (expressed in thousand tons, or "ktons") that it will emit over the period 2008 to 2012. Big Rivers also has projected the SO_2 allowances it will receive from the EPA over the same period. Under the terms of agreements Big Rivers has with the City of Henderson to operate the City of Henderson's Station Two generating unit, portions of SO_2 allowances received from the EPA are retained by the City of Henderson. Attached as Attachment 2 to Exhibit DAS-1, Big Rivers presents its projected disposition of SO_2 allowances for the period 2008 to 2012. In each year, any SO_2 allowances that are excess to Big Rivers' needs will be sold as surplus, and the revenues received from these sales will be used as an offset to reduce the level of the Environmental Surcharge. Big Rivers projects that it will realize $14.487 million in revenues from the sale of excess 2008 SO_2 allowances, with this amount declining to $4.065 million for 2012 SO_2 allowances.

B. NOx Program

Q. Please describe the legal requirements that obligate Big Rivers to control its emissions of NOx.

A. Big Rivers' generation is subject to a number of different regulatory requirements relating to NOx. These requirements vary from plant to plant under each regulatory requirement. In general, however, NOx emissions are subject to regulation under four separate legislative provisions: (1) the Kentucky SIP for emissions of all regulated pollutants; (2) the provisions of various amendments to the federal Clean Air Act; (3) the U.S. Environmental Protection Agency's NOx SIP Call pursuant to Clean Air Act Section 126; and (4) the provisions of the CAIR. The specific application of each of these regulatory requirements to each of Big Rivers' plants is presented in the Environmental Compliance Plan in Exhibit DAS-1.

Q. Please describe the reagent costs which Big Rivers proposes to recover through the Environmental Surcharge.

A. The NOx reagent cost is comprised of the commodity cost of two separate types of reagent: sulfur and ammonia. Ammonia is used in the equipment called selective catalytic reduction ("SCR") equipment to convert NOx into nitrogen and water vapor. Sulfur is used to offset the negative impact of SCR equipment on other plant systems such as the flue gas desulfurization system.

Q. What does Big Rivers propose to recover as the reagent cost for sulfur and ammonia as part of the Environmental Surcharge?

A. In the attached Exhibit DAS-1, Big Rivers provides for each Big Rivers generating station a projected reagent cost for ammonia and sulfur. In each case, the amount included as the reagent cost is a pure commodity cost with no additional labor or handling added into the cost. For each unit, Big Rivers has estimated the projected requirement for ammonia and sulfur and then multiplied that projected amount by the expected price of that commodity for the year in question.

No ammonia or sulfur costs relating to NOx are projected for the Coleman Station, the Green Station, or the Reid unit.

For Henderson Station Two, the sulfur costs net of Henderson are projected to begin at $0.036 million in 2008 (partial year), and to rise to $0.091 million in 2012. The ammonia costs are projected to begin at $0.331 million, and to rise to $0.826 million in 2012.

For the Wilson Station, the sulfur costs are projected to begin at $0.023 million in 2008 (partial year), rising to a high of $0.037 million in 2012. The Wilson Station ammonia costs are projected to begin at $0.645 million in 2008, rising to $1.722 million in 2012.

Q. The final component of the Environmental Surcharge relating to NOx concerns the purchase of NOx allowances. Could you please explain this component.

A. In each year, Big Rivers emits a quantity of NOx, expressed in terms of tons of NOx, and each year it receives from the EPA a number of allowances, each of which permits it to emit one ton of NOx. Big Rivers has projected the amount of NOx (expressed in thousand tons, or "ktons") that it will emit over the period 2008 to 2012. Big Rivers also has projected the NOx allowances it will receive from the EPA over the same period. Under the terms of the agreements with Henderson, portions of any excess NOx allowances not necessary for Station Two to comply with NOx emissions requirements are retained by Henderson. Attachment 2 to Exhibit DAS-1 is Big Rivers' projected disposition of NOx allowances for the period 2008 to 2012. Big Rivers' allocated share of NOx emission allowances during the period 2008-2012 is less than Big Rivers' projected NOx emissions. Accordingly, Big Rivers will need to purchase NOx allowances to cover this gap. Big Rivers projects that it will incur $0.214 million to purchase NOx allowances for 2008, $7.226 million for 2009, $6.104 million in 2010, $3.974 million in 2011, and $3.648 million for 2012. All of these net costs will be flowed through the Environmental Surcharge.

C. SO_3 Program

Q. Please describe the legal requirements that obligate Big Rivers to control its emissions of SO_3.

A. Big Rivers incurs costs to control its SO_3 emissions in response to requirements from federal, state, and local environmental authorities. The Kentucky Public Service Commission ("KPSC") has found that SO_3 mitigation costs are made in response to requirements from federal, state, and local environmental authorities even though specific emission limits are not established for SO_3 emissions. *See* The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct a Selective Catalytic Reduction System and Approval of its 2006 Compliance Plan for Recovery by Environmental Surcharge, Case No. 2006-00206, final order dated December 21, 2006. These general requirements include: (1) the general duty to avoid harm to human health and the environment under KRS Chapter 224; (2) the general requirement under Kentucky state law not to create opacity (*e.g.*, 401 KAR 59:015; 401 KAR 60:005; 401 KAR 61:015); (3) the Kentucky SIP for emissions of all regulated pollutants; and (4) amendments to the federal Clean Air Act.

Q. Please describe the reagent costs for SO_3 which Big Rivers proposes to recover through the Environmental Surcharge.

A. The SO_3 reagent cost is comprised of the commodity cost of a single reagent, lime hydrate. Lime hydrate is blown into station ductwork in dry form and reacts with SO_3 to neutralize its effect on opacity.

Q. What does Big Rivers propose to recover as the reagent cost for lime hydrate as part of the Environmental Surcharge?

A. Exhibit DAS-1 shows the projected reagent cost for lime hydrate for the Wilson generating station. The amount included as the lime hydrate reagent cost is a pure commodity cost with no additional labor or handling added into the cost. For the Wilson unit, Big Rivers has estimated the projected requirement for lime hydrate and then multiplied that projected requirement by the expected price of the commodity for the year in question.

No SO_3 requirements for lime hydrate are expected for the Coleman Station, the Green Station, the Reid unit, or Henderson Station Two.
For the Wilson Station, the lime hydrate reagent cost is projected to be $0.421 million in 2008, rising to $1.123 million in 2012.

Q. Does this limited environmental compliance plan mean that Big Rivers is proposing to undercollect its environmental costs?

A. No. The global environmental compliance plan that Big Rivers will develop will simply be broader in time and scope.

Q. Does the submitted Environmental Compliance Plan demonstrate that the costs of the three programs are "costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes

and by-products from facilities utilized for production of energy from coal"?

A. Yes. Consistent with the requirements of KRS 278.183, I detail in my discussion above and in Exhibit DAS-1 the specific regulatory requirements applicable to each of the three submitted programs. I also describe the various costs which Big Rivers seeks to recover and explain how they relate to coal combustion wastes and by-products from facilities utilized for production of energy from coal.

Q. Do the costs proposed for the three submitted programs comprising the Environmental Compliance Plan include any construction or other capital expenses requiring Commission findings on rate of return?

A. No. As demonstrated above in the discussion of each of the three programs, none of the costs for which Big Rivers seeks recovery include any construction or other capital expenditures. Instead, the costs relate to commodity costs of various reagents, third-party contracts to handle and dispose of combustion wastes and by-products, and net proceeds relating to the sale and purchase of SO_2 and NOx allowances for Big Rivers' plants.

Q. Does Big Rivers propose any income taxes, property taxes, other applicable taxes, or depreciation expenses with respect to the three submitted programs in the Environmental Compliance Plan?

A. No.

Q. Could you please summarize the action you request the Commission to take regarding the Environmental Compliance Plan and Environmental Surcharge?

A. In connection with the Unwind Transaction and the restoration to Big Rivers' operation of the leased generation assets, Big Rivers will be incurring variable O&M environmental costs for reagents, net disposals, and net allowances associated with its SO_2 control technology equipment, its NOx control technology equipment, and its mitigation of SO_3 for opacity purposes. These variable costs will have an effect on Big Rivers' cost of service. As discussed in the testimony of William Steven Seelye, Exhibit B, Big Rivers has proposed to use an Environmental Surcharge to recover these costs.

In support of the use of this Environmental Surcharge, Big Rivers is filing an Environmental Compliance Plan which describes the legal and regulatory requirements for the variable costs involved and lists the projected costs by

Big Rivers plant. Big Rivers requests that the KPSC accept its Environmental Compliance Plan under KRS § 278.183 and permit the costs relating to this Environmental Compliance Plan to be recovered under the proposed Environmental Surcharge.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

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

David A. Spainhoward

David A. Spainhoward

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

Subscribed and sworn to before me by David A. Spainhoward on this the 27th day of December, 2007.

Paula Mitchell

Notary Public, Ky. State at Large
My commission expires: 1-12-09

Big Rivers Electric Corporation

Big Rivers Electric Corporation

Environmental Compliance Plan

A Touchstone Energy® Cooperative

Station Description, Air Emissions Regulations and Units' Design

Coleman Station

The Coleman Station is a multiple unit plant consisting of three coal-fired units designed to burn Illinois Basin coal. The units were commercialized in 1969, 1970 and 1972 respectively with a combined net output rating of 440 MW during Ozone Season and 443 MW during Non-Ozone Season.

The Coleman Station is regulated as an existing station and must comply with the requirements contained in the Kentucky State Implementation Plan (SIP) for emissions of all regulated pollutants. The station was originally equipped with high efficiency electrostatic precipitators to control particulate emissions.

Reid Station

The Robert Reid Station is a multiple unit plant consisting of one coal-fired unit designed to burn Illinois Basin coal and/or natural gas and one combustion turbine with the ability to burn either fuel oil or natural gas. The units were commercialized in 1966 and 1976 respectively with a combined net output rating of 130 MW. Reid Station is regulated as an existing station and must comply with the requirements contained in the Kentucky State Implementation Plan (SIP) for emissions of all regulated pollutants. The Reid unit #1 was originally equipped with mechanical ash separators and was retro-fitted with high efficiency electrostatic precipitators in the 1970's to control particulate emissions.

City of Henderson Station Two

The Station Two facility is a multiple unit plant owned by the City of Henderson and operated by Big Rivers and consists of two coal-fired units designed to burn Illinois Basin coal. The units were commercialized in 1973 and 1974 respectively with a combined net output rating of 310 MW during Ozone Season and 311 MW during Non-Ozone Season. The City of Henderson's Station Two is regulated as an existing station and must comply with the requirements contained in the Kentucky State Implementation Plan (SIP) for emissions of all regulated pollutants. The station was originally equipped with high efficiency electrostatic precipitators to control particulate emissions.

Robert D. Green Station

The Robert D. Green facility is a multiple unit plant consisting of two coal-fired units designed to burn Illinois Basin coal. The units were commercialized in 1979 and 1981 respectively with a combined net output rating of 454 MW during both Ozone Season and Non-Ozone Season. The Green Station is regulated as a new station and must comply with the requirements contained in the Kentucky State Implementation Plan (SIP) and in 40 CFR 60 Subpart D for emissions of all regulated pollutants. The station was originally equipped with high efficiency electrostatic precipitators to control particulate emissions, low-NOx burners and dual-module, magnesium-lime-based flue gas desulfurization (FGD) systems.

DB Wilson Station

The DB Wilson Station is a single coal-fired unit designed to burn Illinois Basin coal. The unit was commercialized in 1986 with a net output rating of 417 MW during Ozone Seaason and 419

MW during Non-Ozone Seaason. The DB Wilson Station is regulated as a new station and must comply with the requirements contained in the Kentucky State Implementation Plan (SIP) and in 40 CFR 60 Subpart D(a) for emissions of all regulated pollutants. The station was originally equipped with high efficiency electrostatic precipitators to control particulate emissions, low-NOx burners with over-fire air ports; and a four-module, limestone-based FGD systems.

Sulfur Dioxide

For emissions of sulfur dioxide (SO2) the current permit limit for each **Coleman** unit is 5.2 lbs SO2/mmBTU heat input. These limits may be achieved either through the use of a medium sulfur coal or by utilization of a post combustion process.

Additionally, the provisions of the Acid Rain Program (ARP) contained in the Clean Air Act Amendments of 1990 apply to the units at the Coleman Station (C-1, C-2, & C-3). During Phase I of the ARP the annual allowances allocated to the units were sufficient to balance against the emissions. However, with the beginning of Phase II the emissions exceeded the annual allowance allocations requiring the purchase of additional allowances. To mitigate this issue a Flue Gas Desulfurization (FGD) system was installed at the Coleman Station and achieved full operation in early 2006. This single module, limestone-based system treats the flue gas from all three units providing reductions in SO2 emissions of 98%. These emission reductions allow the allowance allocations to balance the emissions and provide some surplus allowances for use within the rest of the Big Rivers system or for sale in the market.

Coleman Station is also subject to the provisions of the Clean Air Interstate Rule (CAIR). The SO2 provisions of this rule will take effect beginning in 2010. During the Phase I of the rule (from 2010 – 2014) the allowance surrender ratio will be two allowances for each ton of emissions. Beginning in 2015 with Phase II of the rule, the surrender ratio will increase to 2.86 allowances for each ton of emissions. Results from the production cost model indicate that the allocated allowances for Coleman Station will be sufficient to balance against the emissions during both Phase I and Phase II. There will be allowances remaining to be used to balance emissions in the rest of the Big Rivers system during Phase I.

Under the SO2 program for Coleman the primary costs are limestone reagent purchases associated with operation of the FGD system. Coleman does not require any FGD additives such as di-basic acid (DBA).

For emissions of SO2 the current limit for **the Reid coal fired unit** is 5.2 lbs SO2/mmBTU heat input. This limit may be achieved either through the use of a medium sulfur coal or by utilization of a post combustion process.

Additionally, the provisions of the ARP contained in the Clean Air Act Amendments of 1990 apply to the coal fired unit at Reid Station (R-1). From the beginning of Phase I of the ARP the allowances allocated to the units were not sufficient to balance against the emissions. This situation continues through Phase II. To mitigate this issue surplus allowances from other units within the Big Rivers system are used to balance the Reid emissions above the Reid allocations.

Reid Station is also subject to the provisions of the CAIR. The SO2 provisions of this rule will take effect beginning in 2010. During the Phase I of the rule (from 2010 – 2014) the allowance surrender ratio will be two allowances for each ton of emissions. Beginning in 2015 with Phase II of the rule, the surrender ratio will increase to 2.86 allowances for each ton of emissions. The deficiency of allowance allocations will continue and become more pronounced under the requirements of CAIR. Additionally, SO2 emissions from the Reid combustions turbine (R-CT) operation will also be subject to the CAIR. This unit has no SO2 allowance allocations so all Reid emissions will be balanced through Big Rivers intra-system transfers or market allowance purchases.

Under the SO2 program for the Reid Station the primary costs are costs that are related to the need to purchase additional allowances to offset emissions.

For emissions of SO2 the current limit for **each Station Two unit** is 5.2 lbs SO2/mmBTU heat input. These limits may be achieved either through the use of a medium sulfur coal or by utilization of a post combustion process.

Additionally, the provisions of the ARP contained in the Clean Air Act Amendments of 1990 apply to the units at Station Two (H-1 & H-2). During Phase I of the ARP the allowances allocated to the units were sufficient to balance against the emissions. However, with the beginning of Phase II the emissions were expected to exceed the allowance allocations requiring the purchase of additional allowances. To mitigate this issue a FGD system was installed at the Station during Phase I and achieved full operation in 1995. This single-module-per-unit, magnesium-lime-based system treats the flue gas from each unit providing reductions in SO2 emissions of approximately 94%. These emission reductions allow the allowance allocations to balance the emissions and provide some surplus allowances for use within the Big Rivers system or for sale in the market.

Station Two is also subject to the provisions of the CAIR. The SO2 provisions of this rule will take effect beginning in 2010. During the Phase I of the rule (from 2010 – 2014) the allowance surrender ratio will be two allowances for each ton of emissions. Beginning in 2015 with Phase II of the rule, the surrender ratio will increase to 2.86 allowances for each ton of emissions. Results from the production cost model indicate that the allocated allowances for Station Two will be sufficient to balance the emissions during both Phase I and Phase II. There will be allowances remaining to be used to balance emissions in the rest of the Big Rivers system during Phase I.

Under the SO2 program for Station Two the primary costs are lime reagent purchases associated with operation of the FGD system. Station Two does not require any FGD additives such as di-basic acid (DBA).

For emissions of SO2 the current limit for **each Green unit** is 0.8 lbs SO_2/mmBTU heat input. These limits may be achieved either through the use of a compliance coal or by utilization of a post combustion process.

Additionally, the provisions of the ARP contained in the Clean Air Act Amendments of 1990 apply to the units at Green Station (G-1 & G-2). During Phase I and Phase II of the ARP the allowances allocated to the units were sufficient to balance against the emissions. These dual-module magnesium-lime FGD systems treat the flue gas from each unit providing reductions in SO2 emissions of approximately 97%. These emission reductions allow the allowance allocations to balance the emissions and provide some surplus allowances for use within the Big Rivers system or for sale in the market.

Green Station is also subject to the provisions of the CAIR. The SO2 provisions of this rule will take effect beginning in 2010. During the Phase I of the rule (from 2010 – 2014) the allowance surrender ratio will be two allowances for each ton of emissions. Beginning in 2015 with Phase II of the rule, the surrender ratio will increase to 2.86 allowances for each ton of emissions. Results from the production cost model indicate that the allocated allowances for Green Station will be sufficient to balance the emissions during both Phase I and Phase II. There will be allowances remaining to be used to balance emissions in the rest of the Big Rivers system during Phase I.

Under the SO2 program for the Green Station the primary costs are lime reagent purchases associated with operation of the FGD system. Green Station does not require any FGD additives such as DBA.

For **Wilson** emissions of SO2 the current limit is 1.2 lbs SO_2/mmBTU heat input. Additionally, at this rate the scrubber must meet a SO2 reduction of 90%. The regulations require the installation and operation of an FGD system.

Additionally, the provisions of the ARP contained in the Clean Air Act Amendments of 1990 apply to the unit at Wilson Station (W-1). During Phase I and Phase II of the ARP the allowances allocated to the unit were sufficient to balance against the emissions. This four-module limestone FGD system treats the flue gas from each unit providing reductions in SO2 emissions of approximately 91%. These emission reductions allow the allowance allocations to balance the emissions and provide some surplus allowances for use within the Big Rivers system or for sale in the market.

Wilson Station is also subject to the provisions of the CAIR. The SO2 provisions of this rule will take effect beginning in 2010. During the Phase I of the rule (from 2010 – 2014) the allowance surrender ratio will be two allowances for each ton of emissions. Beginning in 2015 with Phase II of the rule, the surrender ratio will increase to 2.86 allowances for each ton of emissions. Results from the production cost model indicate that the allocated allowances for Wilson Station will no longer be sufficient to balance against the emissions with the current removal efficiency, requiring the use of either surplus allowances available from the rest of the Big Rivers system or the purchase of allowances from the market.

Under the SO2 program for Wilson Station the primary costs are limestone reagent purchases and enhancement chemicals such as DBA associated with operation of the FGD system.

Attached Exhibits 1 and 2 demonstrate there are sufficient SO2 allowances in the 2008-2012 time frame for the Big Rivers generating system to meet compliance without the need to purchase additional allowances. However, there may be costs that are related to the need to purchase additional allowances to offset emissions or credits related to having additional surplus allowances available for sale in the market should actual operations differ from the production cost modeling

Oxides of Nitrogen

The existing Kentucky SIP requirements for the emissions of NOx from **the Coleman Plant** show that there are no specific rate based limits (ie. in lbs/mmBTU).

Under the provisions for the ARP for NOx reductions, the Coleman Station units are a part of an overall system-wide averaging plan. As a part of this plan the Coleman units have an annual target limit of approximately 0.49 lbs NOx/mmBTU. To meet this requirement, low-NOx burners were retro-fitted to each Coleman unit in 1993 and 1994.

As a result of various state Clean Air Act Section 126 requests, the Environmental Protection Agency (EPA) issued the NOx SIP Call which provided specific limits on the number of tons of NOx which could be emitted from various states (including Kentucky) during the Ozone Season (May 1 through Sept 30 of each year).These state emissions budgets were then divided among the various sources within the state and NOx emission allowance allocations were made. The system wide control plan included modifications to the Coleman units to reduce NOx emissions through the installation of advanced over-fire air systems in 2002 & 2003; to be operated during the annual Ozone Season.

The provisions of the NOx portion of the Clean Air Interstate Rule begin in 2009 with the creation of two new allowance allocations, one based on annual requirements, the other based on the continuation of the Ozone Season. Once the CAIR requirements begin the limitations under the NOx SIP Call will expire. The control plan calls for the continued operation of the installed advanced over-fire air systems but on a year-round basis. The need for additional allowances to balance against station emissions is expected to continue.

Under the NOx program for Coleman Station the primary costs are related to the need to purchase additional allowances to offset emissions or credits related to having surplus allowances available for sale in the market

The existing Kentucky SIP requirements for the emissions of NOx from **Reid Station** show that there are no specific rate based limits (ie. in lbs/mmBTU)

Under the provisions for the ARP for NOx reductions. the Reid Station coal fired unit is a part of an overall system-wide averaging plan. As a part of this plan the unit has an annual target limit of approximately 0.9 lbs NOx/mmBTU

As a result of various state Clean Air Act Section 126 requests. the EPA issued the NOx SIP Call which provided specific limits on the number of tons of NOx which could be emitted from various states (including Kentucky) during the Ozone Season .These state emissions budgets were then divided among the various sources within the state and NOx emission allowance allocations were made. The system wide control plan included modifications to the Reid Station coal fired unit (R-1) to reduce NOx emissions through the replacement of half the unit's coal burners with natural gas burners; and through the installation of a flue gas recirculation systems in 2001; to be operated during the annual Ozone Season.. Although this has enabled the unit to reduce emissions, the levels are still greater than the allowance allocations requiring the use of either surplus allowances available from the rest of the Big Rivers system or the purchase of allowances from the market. Additionally, the Reid combustion turbine (R-CT) was equipped with dual-fuel burners in 2001 allowing use of either fuel oil or natural gas combustion.

The provisions of the NOx portion of the Clean Air Interstate Rule begin in 2009 with the creation of two new allowance allocations, one based on annual requirements, the other based on the continuation of the Ozone Season. Once the CAIR requirements begin the limitations under the NOx SIP Call will expire. The control plan calls for the continued operation of the installed Reid NOx control systems on a year-around basis. The need for additional allowances to balance against station emissions is expected to continue.

Under the NOx program for Reid Station the primary costs are related to the need to purchase additional allowances to offset emissions or credits related to having surplus allowances available for sale in the market

The existing Kentucky SIP requirements for the emissions of NOx from **Station Two** show that there are no specific rate based limits (ie. in lbs/mmBTU)

Under the provisions for the ARP for NOx reductions, the Station Two units are a part of an overall system-wide averaging plan. As a part of this plan the station units have an annual target limit of approximately 0.51 lbs NOx/mmBTU. To meet this requirement low-NOx burners were retro-fitted each Station Two unit in 1993 and 1994.

As a result of various state Clean Air Act Section 126 requests. the EPA issued the NOx SIP Call which provided specific limits on the number of tons of NOx which could be emitted from various states (including Kentucky) during the Ozone Season. These state emissions budgets were then divided among the various sources within the state and NOx emission allowance allocations were made. The system wide control plan included modifications to the Station Two units to reduce NOx emissions through the installation of Selective Catalytic Reduction (SCR) systems to be operated during the annual Ozone Season. This has enabled the units to reduce emissions to a level below the allowance allocations and make surplus allowances available for use throughout the Big Rivers system or for sale.

The provisions of the NOx portion of the Clean Air Interstate Rule begin in 2009 with the creation of two new allowance allocations, one based on annual requirements, the other based on the continuation of the Ozone Season. Once the CAIR requirements begin the limitations under the NOx SIP Call will expire. The control plan calls for the continued operation of the installed SCR systems but on a year-around basis.

Under the NOx program for Station Two the primary costs are anhydrous ammonia reagent purchases associated with operation of the SCR system. Costs for sulfur addition to the Station Two FGD are also a result to offset negative process impacts due to the SCRs.

The existing Kentucky SIP and 40 CFR 60, Subpart D requirements for the emissions of NOx from **Green Station** have a rate based limit of 0.7 lbs NOx /mmBTU heat input.

Under the provisions for the Acid Rain Program for NOx reductions, the Green Station units are a part of an overall system-wide averaging plan. As a part of this plan the station units have an annual target limit of approximately 0.45 lbs NOx/mmBTU.

As a result of various state Clean Air Act Section 126 requests, the EPA issued the NOx SIP Call which provided specific limits on the number of tons of NOx which could be emitted from various states (including Kentucky) during the Ozone Season. These state emissions budgets were then divided among the various sources within the state and NOx emission allowance allocations were made. The system wide control plan included modifications to the Green Station units to reduce NOx emissions through the installation of coal re-burn systems to be operated during the annual Ozone Season. This has enabled the units to reduce emissions to a level which provides for system compliance but the levels are still greater than the allowance allocations requiring the use of either surplus allowances available from the rest of the Big Rivers system or the purchase of allowances from the market.

The provisions of the NOx portion of the Clean Air Interstate Rule begin in 2009 with the creation of two new allowance allocations, one based on annual requirements, the other based on the continuation of the Ozone Season. Once the CAIR requirements begin the limitations under the NOx SIP Call will expire. The control plan calls for the continued operation of the installed coal re-burn systems but on a year-around basis. The need for additional allowances to balance against station emissions is expected to continue.

Under the NOx program for Green Station the primary costs are related to the need to purchase additional allowances to offset emissions or credits related to having surplus allowances available for sale in the market

The existing Kentucky SIP and 40 CFR 60. Subpart D requirements for the emissions of NOx from **Wilson Station** have a rate based limit of 0.6 lbs NOx /mmBTU heat input.

Under the provisions for the ARP for NOx reductions, the Wilson Station units are a part of an overall system-wide averaging plan. As a part of this plan the station units have an annual target limit of approximately 0.47 lbs NOx/mmBTU

As a result of various state Clean Air Act Section 126 requests, the EPA issued the NOx SIP Call which provided specific limits on the number of tons of NOx which could be emitted from various states (including Kentucky) during the Ozone Season. These state emissions budgets were then divided among the various sources within the state and NOx emission allowance allocations were made. The system wide control plan included modifications to the Wilson Station unit to reduce NOx emissions through the installation of a SCR system in 2003 & 2004; to be operated during the annual Ozone Season. This has enabled the unit to reduce emissions to a level below the allowance allocations and make surplus allowances available for use throughout the Big Rivers system or for sale.

The provisions of the NOx portion of the Clean Air Interstate Rule begin in 2009 with the creation of two new allowance allocations, one based on annual requirements, the other based on the continuation of the Ozone Season. Once the CAIR requirements begin the limitations under the NOx SIP Call will expire. The control plan calls for the continued operation of the installed SCR system but on a year-around basis.

Under the NOx program for Wilson Station the primary costs are anhydrous ammonia reagent purchases associated with operation of the SCR system. There are also costs for sulfur addition to the Wilson Station FGD. The sulfur is required to offset negative process impacts due to the SCRs.

Attached Exhibits 1 and 2 demonstrate there are insufficient NOx allowances in the 2008-2012 time frame for the Big Rivers generating system to meet compliance. Additional allowances will need to be purchased to meet compliance. However, there may be costs that are related to the need to purchase additional allowances to offset emissions or credits related to having additional surplus allowances available for sale in the market should actual operations differ from the production cost modeling

SO3 and Opacity Compliance

The current limit for each **Coleman** unit for emissions of particulate matter is 0.27 lbs /mmBTU heat input. In addition, emissions shall not exceed 40% opacity based on a six-minute average except that a maximum of 60% opacity is allowed for a period of not more than six minutes in any sixty minutes during certain operational procedures. Also, each unit has established, through testing, an opacity trigger limit that is related to the particulate emission standard. This trigger limit provides an alternate method of monitoring particulate emissions on a continuous basis. These limits are achieved through the use of a high efficiency electrostatic precipitator. Due to the FGD design, additional significant reductions are realized as a result of flue gas interaction with the FGD slurry in the spray tower.

For emissions of particulate matter the current limit for the coal fired **Reid** unit #1 is 0.28 lbs /mmBTU heat input. In addition, emissions shall not exceed 40% opacity based on a six-minute average except that a maximum of 60% opacity is allowed for a period of not more than six minutes in any sixty minutes during certain operational procedures. Also, the unit has established, through testing, an opacity trigger limit that is related to the particulate emission standard. This trigger limit provides an alternate method of monitoring particulate emissions on a continuous basis. This limit is achieved through the use of a high efficiency electrostatic precipitator.

For emissions of particulate matter the current limit for each **Station Two** unit is 0.21 lbs /mmBTU heat input. In addition, emissions shall not exceed 40% opacity based on a six-minute average except that a maximum of 60% opacity is allowed for a period of not more than six minutes in any sixty minutes during certain operational procedures. Also, each unit has established, through testing, an opacity trigger limit that is related to the particulate emission standard. This trigger limit provides an alternate method of monitoring particulate emissions on a continuous basis when the unit is utilizing the bypass stack. These limits are achieved through the use of a high efficiency electrostatic precipitator. Due to the FGD design, additional significant reductions are realized as a result of flue gas interaction with the FGD slurry in the spray tower. Under normal operation post-scrubber particulate emissions are directly monitored on a continuous basis using a particulate monitor in lieu of using opacity monitoring and trigger level values.

For emissions of particulate matter the current limit for each **Green** unit is 0.1 lbs /mmBTU heat input. In addition, emissions shall not exceed 20% opacity based on a six-minute average except that a maximum of 27% opacity is allowed for a period of not more than six minutes in any sixty minutes during certain operational procedures. Also, each unit has established, through testing, an opacity trigger limit that is related to the particulate emission standard. This trigger limit provides an alternate method of monitoring particulate emissions on a continuous basis. These limits are achieved through the use of a high efficiency electrostatic precipitator. Due to the FGD design, additional significant reductions are realized as a result of flue gas interaction with the FGD slurry in the spray tower.

For emissions of particulate matter the current limit for the **Wilson** unit is 0.03 lbs /mmBTU heat input. In addition, emissions shall not exceed 20% opacity based on a six-minute average except that a maximum of 27% opacity is allowed for a period of not more than six minutes in any sixty minutes during certain operational procedures. Also, each unit has established, through testing, an opacity trigger limit that is related to the particulate emission standard. This trigger limit provides an alternate method of monitoring particulate emissions on a continuous basis. These limits are achieved through the use of a high efficiency electrostatic precipitator. As a result of the operation of the SCR system, there has been an increase in the opacity of the W-1 stack plume. In order to maintain the opacity levels to those approximately equal to levels prior to the installation of the SCR, a hydrated lime duct injection system has been installed and is operated when the SCR system in utilized. The primary cost of this operation is the purchase of the reagent.

Scrubbers By-Products Disposal

At the **Coleman Station** there are three main sources of combustion by-products: fly ash, bottom ash and scrubber waste. Due to the nature of these materials they are categorized as special waste. Fly ash and bottom ash are currently sluiced to the north ash pond. These materials are then periodically removed from the pond for final disposal at other permitted facilities. Additionally, there are costs related to the disposal of any off-spec gypsum (marketable by-product of the Coleman FGD). Currently, costs associated with the disposal of this waste are incorporated into a third party contract for the handling, hauling and operation of the landfill. No fixation lime is presently required for stabilization of these wastes in the landfills. Beginning in 2009 these wastes will be disposed of in a new facility at the Coleman Station. Consequently disposal costs are anticipated to decrease (in real dollars).

Coleman is unique in the BREC system in that scrubber waste is gypsum which is sold and transported for reuse in other industries including wallboard and cement. The revenue from the sale of this gypsum is netted against the other Coleman disposal costs mentioned above.

At the **Reid Station** there are two main sources of combustion by-products; fly ash and bottom ash. Due to the nature of these materials they are categorized as special waste. The R-1 fly ash is used to blend with the FGD sludge from the Green and Station Two units along with fixation lime to help with stabilization for disposal before being placed in a permitted on-site landfill.

Bottom ash is currently sluiced to the station ash pond. This material is then periodically removed from the pond for final disposal at the on-site landfill. Currently, costs associated with the disposal of this waste are incorporated into a third party contract for the handling, hauling and operation of the landfill.

At the **Station Two** there are three main sources of combustion by-products; fly ash, bottom ash and scrubber waste. Due to the nature of these materials they are categorized as special waste. Bottom ash is currently sluiced to the station ash pond. This material is periodically removed from the pond for final disposal at the permitted on-site landfill. Currently, costs associated with the disposal of these wastes are incorporated into a third party contract for the handling, hauling and operation of the landfill. Additionally, there are costs that are related to disposal of FGD sludge. Fixation lime is required for stabilization of these wastes in the landfill. In approximately 2015 the on-site landfill will be full and these wastes are planned to be disposed of in an off-site landfill permitted for "special wastes"; consequently disposal costs are anticipated to increase (in real dollars).

At the **Green Station** there are three main sources of combustion by-products; fly ash, bottom ash and scrubber waste. Due to the nature of these materials they are categorized as special waste. Bottom ash is currently sluiced to the station ash pond. These materials are periodically removed from the pond for final disposal at other permitted facilities. Fly ash is currently handled with a dry system, allowing it to be directly incorporated into the scrubber waste stream or sold as market conditions allow. Scrubber waste is disposed in an on-site special waste landfill. Currently, costs associated with the disposal of these wastes are incorporated into a third party contract for the operation of the landfill.

Additionally, there are costs that are related to disposal of FGD sludge. Fixation lime is required for stabilization of these wastes in the landfill. In approximately 2015 the on-site landfill will be full and these wastes are planned to be disposed of in an off-site landfill permitted for "special wastes"; consequently disposal costs are anticipated to increase (in real dollars).

At the **Wilson Station** there are three main sources of combustion by-products; fly ash, bottom ash and scrubber waste. Due to the nature of these materials they are categorized as special waste. Bottom ash is currently handled in semi-dry condition using conventional material handling equipment and disposed in the on-site landfill. Fly ash is currently handled with a dry system, allowing it to be directly incorporated into the scrubber waste stream or sold as market conditions allow. Scrubber waste is disposed in an on-site special waste landfill. Currently, costs associated with the disposal of this waste are incorporated into a third party contract for the handling, hauling and operation of the landfill.

Additionally, there are costs that are related to disposal of FGD sludge. Fixation lime is required for stabilization of these wastes in the landfill.

Coleman Station non-fuel variable O&M
(in nominal dollars)

Year	2008-model	2008-model	2009-model	2010-model	2011-model	2012-model
	OTAG-coal	Non-OTAG coal	OTAG-coal	OTAG-coal	OTAG-coal	OTAG-coal
Net Generation (MWhr)	1,356,812	887,713	3,405,000	3,396,000	3,372,000	3,190,000
Net Avg MW's						
Net Average Heat Rate (BTU/kWh)						
SO2 lb/mmBTU inlet						
Average Service Hours						
Percent SO2 removal						
Limestone						
TPY limestone	83,046	54,334	208,408	207,857	206,388	195,248
Cost per Ton of Reagent	$17.93	$17.93	$19.72	$21.69	$24.29	$27.20
Cost of Reagent	$1,489,007	$974,204	$4,109,802	$4,508,418	$5,013,165	$5,310,758
Gypsum sales						
Tons	109,663	71,749	275,206	274,479	272,539	257,829
Cost per Ton	($1.25)	($1.25)	($1.25)	($1.25)	($1.25)	($1.25)
Cost	($137,079)	($89,686)	($344,008)	($343,098)	($340,674)	($322,286)
Fly Ash						
Tons of Disposal	72,051	47,140	180,816	180,338	179,063	169,399
Cost per Ton of Disposal	$8.59	$8.59	$5.50	$5.69	$5.89	$6.10
Cost of Disposal	$618,917	$404,935	$994,487	$1,026,123	$1,054,684	$1,033,332
Bottom Ash						
Tons of Disposal	18,013	11,785	45,204	45,084	44,766	42,350
Cost per Ton of Disposal	$8.59	$8.59	$5.50	$5.69	$5.89	$6.10
Cost of Disposal	$154,729	$101,234	$248,622	$256,531	$263,671	$258,333
Off-Spec Gypsum disposal						
Tons of Disposal	9,633	6,303	24,175	24,111	23,940	22,648
Cost per Ton of Disposal	$8.59	$8.59	$5.50	$5.69	$5.89	$6.10
Cost of Disposal	$82,748	$54,139	$132,961	$137,190	$141,009	$138,154
Di-Basic Acid						
Pounds of Reagent	0	0	0	0	0	0
Cost per Pound of Reagent	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Di-Basic Acid	$0	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$1.63**	**$1.63**	**$1.51**	**$1.64**	**$1.82**	**$2.01**
Total /Year	$2,208,322	$1,444,825	$5,141,864	$5,585,163	$6,131,854	$6,418,290
Sulfur						
MWhr per Gals						
Gallons of Sulfur	0	0				
Cost/gallon of Sulfur	$0.00	$0.00				
Cost of Sulfur	$0	$0	$0	$0	$0	$0
Ammonia						
NH3 Lbs/ MWhr						
Tons of Ammonia	0	0				
Cost / Ton of Ammonia	$0.00	$0.00				
Cost of Ammonia	$0	$0	$0	$0	$0	$0
Lime Hydrate (for SO_3)						
TPD						
Tons of Lime Hydrate	0	0				
Cost/ton of Lime Hydrate	$0.00	$0.00				
Cost of Lime Hydrate	$0	$0	$0	$0	$0	$0
NOx Sub-Total	$0	$0	$0	$0	$0	$0
Total /Year	$2,208,322	$1,444,825	$5,141,864	$5,585,163	$6,131,854	$6,418,290
Total $/Mwhr	**$1.63**	**$1.63**	**$1.51**	**$1.64**	**$1.82**	**$2.01**

Green Station non-fuel variable O&M

(in nominal dollars)

Year	2008-model	2008-model	2009-model	2010-model	2011-model	2012-model
	OTAG-Pet coke	Non-OTAG pet coke	OTAG-pet coke	OTAG-coal	OTAG-coal	OTAG-coal
Net Generation (MWhr)	1,490,129	965,779	3,645,000	3,614,000	3,405,000	3,607,000
Net Avg MW's						
Net Average Heat Rate (BTU/kWh)						
SO2 lb/mmBTU inlet						
Average Service Hours						
Percent SO2 removal						
Lime						
TPY lime	49,972	32,388	122,236	119,052	112,167	118,821
Cost per Ton of Reagent	$66.72	$66.72	$70.29	$74.49	$87.86	$98.55
Cost of Reagent	$3,334,129	$2,160,908	$8,591,986	$8,868,152	$9,854,970	$11,709,808
Sludge Disposal						
Tons	198,559	128,690	485,695	473,041	445,684	472,124
Cost per Ton	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost	$528,167	$342,314	$1,398,801	$1,570,495	$1,479,672	$1,567,453
Fly Ash						
Tons of Disposal	85,723	55,559	209,687	204,224	192,413	203,828
Cost per Ton of Disposal	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost of Disposal	$228,023	$147,786	$603,898	$678,023	$638,813	$676,710
Bottom Ash						
Tons of Disposal	21,431	13,890	52,422	51,056	48,103	50,957
Cost per Ton of Disposal	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost of Disposal	$57,006	$36,946	$150,975	$169,506	$159,703	$169,177
Fixation Lime						
Tons of Disposal	4,549	2,948	11,126	10,836	10,210	10,815
Cost per Ton of Disposal	$58.25	$58.25	$60.37	$65.30	$67.61	$67.61
Cost of Disposal	$264,951	$171,719	$671,683	$707,606	$690,269	$731,219
Di-Basic Acid						
Pounds of Reagent	0	0	0	0	0	0
Cost per Pound of Reagent	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Di-Basic Acid	$0	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$2.96**	**$2.96**	**$3.13**	**$3.32**	**$3.77**	**$4.12**
Total /Year	$4,412,276	$2,859,674	$11,417,342	$11,993,782	$12,823,427	$14,854,367
Sulfur						
MWhr per Gals						
Gallons of Sulfur						
Cost/gallon of Sulfur						
Cost of Sulfur	$0	$0	$0	$0	$0	$0
Ammonia						
NH3 Lbs/ MWhr						
Tons of Ammonia						
Cost / Ton of Ammonia						
Cost of Ammonia	$0	$0	$0	$0	$0	$0
Lime Hydrate (for SO_3)						
TPD						
Tons of Lime Hydrate						
Cost/ton of Lime Hydrate						
Cost of Lime Hydrate	$0	$0	$0	$0	$0	$0
NOx Sub-Total	$0	$0	$0	$0	$0	$0
Total /Year	$4,412,276	$2,859,674	$11,417,342	$11,993,782	$12,823,427	$14,854,367
Total $/Mwhr	$2.96	$2.96	$3.13	$3.32	$3.77	$4.12

HMP&L Station non-fuel variable O&M
(in nominal dollars-net of City)

ATTACHMENT 1

Year	2008-model	2008-model	2009-model	2010-model	2011-model	2012-model
	OTAG-coal	Non-OTAG coal	OTAG-coal	OTAG-coal	OTAG-coal	OTAG-coal
Net Generation (MWhr)	725.684	368.505	1.761.389	1.751.397	1.666.323	1.611.275
Net Avg MW's						
Net Average Heat Rate (BTU/kWh)						
SO2 lb/mmBTU inlet						
Average Service Hours						
Percent SO2 removal						
Lime						
TPY lime	18.644	9.292	45.253	44.997	42.811	41.397
Cost per Ton of Reagent	$66.72	$66.72	$70.29	$74.49	$87.86	$98.55
Cost of Reagent	$1.243.940	$619.980	$3.180.860	$3.351.802	$3.761.371	$4.079.641
Sludge Disposal						
Tons	74.707	37.234	181.331	180.302	171.544	165.877
Cost per Ton	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost	$198.722	$99.043	$522.232	$598.603	$569.526	$550.711
Fly Ash						
Tons of Disposal	24.323	12.123	59.037	58.702	55.851	54.005
Cost per Ton of Disposal	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost of Disposal	$64.699	$32.246	$170.026	$194.891	$185.424	$179.298
Bottom Ash						
Tons of Disposal	6.081	3.031	14.759	14.675	13.963	13.501
Cost per Ton of Disposal	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost of Disposal	$16.175	$8.061	$42.507	$48.723	$46.356	$44.825
Fixation Lime						
Tons of Disposal	1.584	790	3.846	3.824	3.638	3.518
Cost per Ton of Disposal	$58.25	$58.25	$60.37	$65.30	$67.61	$69.47
Cost of Disposal	$92.296	$46.000	$232.176	$249.711	$245.986	$244.404
Di-Basic Acid						
Pounds of Reagent	0	0	0	0	0	0
Cost per Pound of Reagent	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Di-Basic Acid	$0	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$2.23**	**$2.19**	**$2.35**	**$2.54**	**$2.89**	**$3.16**
Total /Year	$1,615,832	$805,330	$4,147,801	$4,443,730	$4,808,663	$5,098,878
BREC generation share from Station II	73.17%	73.17%	73.76%	73.65%	72.67%	70.95%
Sulfur						
MWhr per Gals						
Gallons of Sulfur	127	0	309	307	292	283
Cost/ton of Sulfur	$286.00	$286.00	$294.58	$303.42	$312.52	$321.11
Cost of Sulfur	$36.418	$0	$91.047	$93.247	$91.378	$90.788
Ammonia						
NH3 Lbs/ MWhr						
Tons of Ammonia	643	0	1.561	1.552	1.476	1.428
Cost / Ton of Ammonia	$515.41	$515.41	$530.87	$546.80	$563.20	$578.69
Cost of Ammonia	$331.367	$0	$828.424	$848.442	$831.440	$826.085
Lime Hydrate (for SO_3)						
TPD						
Tons of Lime Hydrate	0	0	0	0	0	0
Cost/ton of Lime Hydrate	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Lime Hydrate	$0	$0	$0	$0	$0	$0
NOx Sub-Total	$367.786	$0	$919.471	$941.689	$922.819	$916.873
Total /Year	$1.983.617	$805.330	$5.067.272	$5.385,419	$5.731.482	$6.015.752
Total $/Mwhr	**$2.73**	**$2.19**	**$2.88**	**$3.07**	**$3.44**	**$3.73**

Wilson Station non-fuel variable O&M
(in nominal dollars)

Year	2008-model	2008-model	2009-model	2010-model	2011-model	1st half 2012-model	2nd half 2012-model
	OTAG-Pet coke	Non-OTAG pet coke	OTAG-pet coke	OTAG-pet coke	OTAG-petcoke	OTAG-petcoke	OTAG-coal
Net Generation (MWhr)	1,390,062	855,240	2,967,000	3,331,000	3,109,000	1,648,500	1,648,500
Net Avg MW's							
Net Average Heat Rate (BTU/kWh)							
SO2 lb/mmBTU inlet							
Average Service Hours							
Percent SO2 removal							
Limestone							
TPY limestone	94,361	57,025	201,407	226,116	211,046	111,904	97,064
Cost per Ton of Reagent	$13.95	$13.95	$14.37	$14.80	$15.24	$15.70	$15.70
Cost of Reagent	$1,316,332	$795,499	$2,894,220	$3,346,521	$3,216,347	$1,756,895	$1,523,898
Sludge Disposal							
Tons	168,737	101,973	360,159	404,345	377,396	200,109	173,730
Cost per Ton	$1.32	$1.32	$1.36	$1.40	$1.45	$1.51	$1.51
Cost	$222,733	$134,604	$489,817	$566,083	$547,225	$302,164	$262,333
Fly Ash							
Tons of Disposal	46,207	27,924	98,626	110,726	103,346	54,798	65,430
Cost per Ton of Disposal	$1.32	$1.32	$1.36	$1.40	$1.45	$1.51	$1.51
Cost of Disposal	$60,993	$36,860	$134,131	$155,016	$149,852	$82,745	$98,800
Bottom Ash							
Tons of Disposal	11,552	6,981	24,656	27,681	25,837	13,699	16,358
Cost per Ton of Disposal	$1.32	$1.32	$1.36	$1.40	$1.45	$1.51	$1.51
Cost of Disposal	$15,248	$9,215	$33,533	$38,754	$37,463	$20,686	$24,700
Fixation Lime							
Tons of Disposal	3,009	0	6,423	7,211	6,730	3,569	3,109
Cost per Ton of Disposal	$59.33	$59.33	$61.10	$62.94	$64.83	$66.77	$66.77
Cost of Disposal	$178,537	$0	$392,445	$453,859	$436,332	$238,281	$207,594
Di-Basic Acid							
Pounds of Reagent	793,239	499,946	1,693,118	1,900,835	1,774,150	940,716	940,716
Cost per Pound of Reagent	$0.58	$0.58	$0.59	$0.61	$0.63	$0.65	$0.65
Cost of Di-Basic Acid	$460,078	$289,969	$1,005,712	$1,159,509	$1,117,715	$611,466	$611,466
SO2 and ash $/Mwhr	**$1.62**	**$1.48**	**$1.67**	**$1.72**	**$1.77**	**$1.83**	**$1.66**
Total /Year	$2,253,923	$1,266,147	$4,949,857	$5,719,742	$5,504,933	$3,012,237	$2,728,790
Sulfur							
MWhr per Gals	190.69	190.69	190.69	190.69	190.69	190.69	190.69
Gallons of Sulfur	7,290	4,485	15,559	17,468	16,304	8,645	8,645
Cost/gallon of Sulfur	$1.93	$1.93	$1.98	$2.04	$2.10	$2.17	$2.17
Cost of Sulfur	$14,069	$8,656	$30,807	$35,635	$34,238	$18,759	$18,759
Ammonia							
NH3 Lbs/ MWhr	1.8337	0.0000	1.8337	1.8337	1.8337	1.8337	1.8337
Tons of Ammonia	1,274	0	2,720	3,054	2,850	1,511	1,511
Cost / Ton of Ammonia	$506.00	$506.00	$521.18	$536.82	$552.92	$569.51	$569.51
Cost of Ammonia	$644,886	$0	$1,417,763	$1,639,463	$1,576,091	$860,773	$860,773
Lime Hydrate (for SO_3)							
TPD	25.00	0.00	25.00	25.00	25.00	25.00	25.00
Tons of Lime Hydrate	3,448	0	7,359	8,261	7,711	4,089	4,089
Cost/ton of Lime Hydrate	$122.06	$122.06	$125.72	$129.50	$133.38	$137.38	$137.38
Cost of Lime Hydrate	$420,811	$0	$925,127	$1,069,852	$1,028,466	$561,684	$561,684
NOx Sub-Total	$1,079,766	$8,656	$2,373,697	$2,744,950	$2,638,798	$1,441,216	$1,441,216
Total /Year	$3,333,689	$1,274,803	$7,323,555	$8,464,692	$8,143,731	$4,453,453	$4,170,007
Total $/Mwhr	**$2.40**	**$1.49**	**$2.47**	**$2.54**	**$2.62**	**$2.70**	**$2.53**

Emissions Allowance Costs Summary

ATTACHMENT 2

Nominal dollars

	2008	2009	2010	2011	2012
SO2 Price	$ 778	$ 853	$ 441	$ 409	$ 396
Total SO2(ktons) - emitted	14.849	20.077	21.157	20.054	20.575
Total SO2(ktons) - REQUIRED for compliance	14.849	20.077	42.314	40.107	41.150
Total SO2 Allowances (ktons)	34.991	52.487	52.487	52.487	52.487
sub-total SO2 tons left	20.142	32.410	10.173	12.380	11.337
Excess H-1&2 Allowances Back to City (capacity take)	1.522	2.228	0.957	1.048	1.071
SO2 allowances (ktons) left for BREC	18.620	30.182	9.216	11.332	10.266
SO2 allowances Sales	$14,486,360	$25,745,246	$4,064,256	$4,634,788	$4,065,336

	2008	2009	2010	2011	2012
NOx Price	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]	$ [illegible]
Total NOx(ktons) - emitted	5.046	13.896	13.892	13.202	13.196
NOx Emissions Alloc to City (ktons)	0.114	0.286	0.286	0.287	0.301
net NOx(ktons) - emitted	4.932	13.610	13.606	12.915	12.895
Total NOx Allowances (ktons)	4.799	11.398	11.398	11.398	11.398
NOx Allowances Alloc to City (ktons)	0.148	0.326	0.326	0.327	0.341
Net NOx Allowances (ktons)	4.651	11.072	11.072	11.071	11.057
NOx allowances (ktons) left for BREC	[illegible]	[illegible]	[illegible]	(1.844)	[illegible]
NOx allowances Sales	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

NOx Tons emitted

(in thousands)			2008	2009	2010	2011	2012
Wilson #1			0.382	0.983	1.120	0.994	1.045
HMPL #1			0.200	0.505	0.546	0.471	0.550
HMPL#2			0.195	0.574	0.529	0.569	0.476
Coleman #1			0.682	2.052	2.049	1.945	2.054
Coleman #2			0.858	2.118	1.957	1.999	1.941
Coleman #3			0.870	1.982	2.106	2.006	1.667
Reid #1			0.000	0.023	0.004	0.070	0.000
Reid CT			0.002	0.003	0.003	0.005	0.006
Green #1			0.878	3.027	2.743	2.893	2.728
Green #2			0.979	2.629	2.835	2.252	2.729
System total			5.046	13.895	13.892	13.202	13.196

SO2 Tons emitted

(in thousands)			2008	2009	2010	2011	2012
Wilson #1			7.304	9.637	10.846	10.131	10.586
HMPL #1			1.436	2.006	2.150	1.854	2.169
HMPL#2			1.287	2.264	2.101	2.246	1.892
Coleman #1			0.422	0.726	0.725	0.692	0.730
Coleman #2			0.498	0.749	0.693	0.708	0.689
Coleman #3			0.509	0.745	0.742	0.749	0.618
Reid #1			0.699	0.001	0.000	0.002	0.000
Reid CT			0.000	0.000	0.000	0.000	0.000
Green #1			1.309	2.124	1.907	2.050	1.938
Green #2			1.385	1.874	1.990	1.621	1.952
System total			14.849	20.126	21.155	20.054	20.575

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

CASE NO. 2007-00455

AND

CASE NO. 2007-00460

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

ON BEHALF OF
APPLICANTS

DECEMBER 2007

DIRECT TESTIMONY OF

WILLIAM STEVEN SEELYE

Q. Please state your name and business address.

A. My name is William Steven Seelye, and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility regulatory analysis, revenue requirement support, cost of service, rate design and economic analysis.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor the following five cost adjustment clauses on behalf of Big Rivers Electric Corporation ("Big Rivers"): Fuel Adjustment Clause ("FAC"), Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism ("MRSM"). These adjustment clauses, both individually and working in concert with one another, are critical to Big Rivers' efforts to unwind and terminate the lease, purchase power and other arrangements with E.ON U.S. LLC and its affiliates (hereafter "E.ON"). More specifically, these clauses represent essential elements that must be in place to terminate the lease and purchase power arrangement with E.ON, to establish a framework for continuing to provide electric service to the aluminum smelters ("Smelters") indirectly served by Big Rivers (through one of its member systems, Kenergy Corp.) so that the Smelters can be economically viable businesses operating in Western Kentucky, and to establish ratemaking mechanisms which will allow Big Rivers to recover its prudently incurred costs, while at the same time fully considering the interests of its distribution cooperative members/owners ("distribution cooperative member systems" or simply "Member Systems").

The FAC and Environmental Surcharge are standard cost adjustment clauses used by other utilities in Kentucky and would be applicable for service to all members of Big Rivers, including service provided to the distribution cooperative member systems, large industrial customers served by the distribution cooperatives, and the two Smelters served by Kenergy. The Unwind Surcredit and Rebate Adjustment clauses are special purpose clauses designed to pass along credits applicable to Big Rivers' members' non-Smelter. The MRSM is another special purpose clause designed to distribute a finite amount of dollars from an Economic Reserve. The MRSM will be established to offset any net increase in revenue requirements applicable to the members' non-Smelter sales for a period of approximately five years due to the implementation of the FAC and Environmental Surcharge after considering credits received from the Unwind Surcredit and Rebate Adjustment.

Q. Please summarize your testimony.

A. Big Rivers is proposing to implement the following adjustment clauses in connection with its efforts to unwind and terminate the lease, purchase power, and other arrangements with E.ON ("Unwind Transaction"):

1) Fuel Adjustment Clause
2) Environmental Surcharge
3) Unwind Surcredit
4) Rebate Adjustment
5) Member Rate Stability Mechanism

Big Rivers and E.ON are in the process of unwinding the lease, purchased power, and other arrangements with E.ON that were put in place in 1998 ("1998 Transaction"). In 1998, Big Rivers agreed to lease its generating facilities to E.ON's predecessor and to purchase a fixed amount of power from E.ON's predecessor. Under this lease and purchased power arrangement, Big Rivers has been purchasing power pursuant to a fixed price contract subject to periodic rate adjustments. Consequently, it was not necessary for Big Rivers to have an FAC or Environmental Surcharge in place to adjust rates for changes in fuel and environmental costs. Under the arrangement between Big Rivers and E.ON, except under extraordinary circumstances, the rates charged by E.ON are currently not directly affected by changes in fuel and environmental costs, and, in fact, there have not been any adjustments to the purchased power rates charged by E.ON due to changes in fuel or environmental costs since the lease and purchased power arrangement was established in 1998.

Once the agreement with E.ON is terminated, these costs will have an effect on Big Rivers' cost of service. Therefore, it is now necessary for Big Rivers to have an FAC and Environmental Surcharge in place in order to transition back to a cooperative utility that operates, controls and is fully responsible for the cost of its generation assets. Furthermore, it is critically important for Big Rivers to have the FAC and Environmental Surcharge in place in order to restructure its debt under favorable terms and conditions. With proceeds provided by E.ON in connection with terminating the lease and purchase power arrangement, Big Rivers plans to buy down a portion of its debt to the United States Rural Utilities Service ("RUS"), to convert the RUS mortgage to an indenture, and to finance a portion of its remaining debt requirements with public debt. Because fuel adjustment clauses and environmental cost recovery mechanisms are viewed favorably by the investment community, having the FAC and Environmental Surcharge in place should help facilitate Big Rivers' efforts to restructure its debt.

The Unwind Surcredit would transfer funds paid by the two Smelters to the Members through the "Smelter Surcharges" set forth in the wholesale agreements with Kenergy to provide service to the Smelters ("Smelter Special Contracts"). The two Smelters – Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century ") – are making significant payments in order to ensure that they will continue to be served with wholesale purchased power provided by Big Rivers to Kenergy for resale to the Smelters and to mitigate the risk of the Unwind to the Members.

Subject to Commission approval, the Rebate Adjustment would return to the distribution member cooperatives any refunds authorized by Big Rivers' Board of Directors pursuant to the application of refund provisions set forth in the service agreements with the Smelters. The Rebate Adjustment would therefore return, subject to Commission approval under Subsection 1 of KRS 278.455, any rebate amounts authorized by the Big Rivers Board should Big Rivers' times interest earned ratio ("TIER") exceed the level set forth in the Smelter Special Contracts. The amounts returned to the Member Systems through the Rebate Adjustment would be paid to the members as a lump-sum credit on their power bills.

Big Rivers will establish an Economic Reserve which will be used for a period of time to offset fully the impact of the FAC and Environmental Surcharge after netting out the effects of the Unwind Surcredit and the Rebate Adjustment. Big Rivers is proposing to implement the MRSM to provide a credit to offset fully the effect on the monthly power bills to its Member Systems of any FAC charges and Environmental Surcharges during the month less the Unwind Surcredits and consideration of any rebates under the Rebate Adjustment. The MRSM will draw upon the Economic Reserve to fund the credit to members until the Economic Reserve is fully exhausted. It is anticipated that the Economic Reserve will not be fully drawn down until sometime around 2012 (or approximately five years after the implementation of the MRSM). The initial value of the

Economic Reserve, which will be funded from proceeds received at closing, is expected to be $75 million, although Big Rivers is able to add to this amount at closing.

Q. How will the adjustment clauses you are sponsoring work together to affect Big Rivers' rates?

A. Without considering the other three adjustment clauses, it is anticipated that the FAC and Environmental Surcharge will have the effect of increasing the overall price paid by Big Rivers' Members. However, the Unwind Surcredit, Rebate Adjustment and MRSM – as a group – will fully offset the effect of the FAC and Environmental Surcharge for a period of approximately five years. The Unwind Surcredit, Rebate Adjustment, and MRSM will thus have the effect of canceling out any impact of the FAC and Environmental Surcharge for non-Smelter member sales for approximately five years.

It is important to understand that Big Rivers' proposal, which was developed over a period of more than four years of detailed negotiations, was carefully worked out with the Smelters and with Big Rivers' distribution cooperative members to address their individual concerns. The special contracts with the two Smelters, which operate in concert with the five adjustment clauses addressed in my testimony, will help ensure that the Smelters have an opportunity to continue to operate successfully in Western Kentucky. Under Big Rivers' proposal, there will not be a billing impact on non-Smelter members sales from the FAC and Environmental Surcharge for approximately five years.

Big Rivers' proposal carefully and delicately balances the interests of the Smelters and distribution cooperative members, while allowing Big Rivers to successfully transition out of the lease and purchased power arrangement with E.ON.

Q. Why are you submitting identical testimony in two different cases with the Commission?

A. In Case No. 2007-0455, Big Rivers and E.ON are jointly filing an application for the approval of the unwind arrangement. In that proceeding, Big Rivers is requesting approval of four of the five adjustment clauses described in my testimony -- FAC, Unwind Credit, Rebate Adjustment, and MRSM. Big Rivers is requesting approval of the Environmental Surcharge in a separate proceeding – Case No. 2007-00460. As explained earlier, all five of these clauses are connected in terms of the Smelter Agreements and in terms of the operation of the MRSM. Big Rivers determined that describing the proposed clauses as a group would facilitate the understanding of what we are trying to accomplish with these mechanisms.

Q. How is your testimony organized?

A. My testimony is divided into the following sections: (I) Qualifications, (II) Fuel Adjustment Clause (FAC), (III) Environmental Surcharge, (IV) Unwind Surcredit, (V) Rebate Adjustment, and (VI) Member Rate Stability Mechanism (MRSM).

I. QUALIFICATIONS

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

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed cost of service and rate studies for over 130 investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. A more detailed description of my qualifications is included in Exhibit WSS-1.

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

A. Yes, on many occasions. A listing of my testimony is included in Exhibit WSS-1.

Q. Do you have experience with fuel adjustment clauses, environmental surcharges, and other cost recovery mechanisms?

A. Yes. I have developed or modified fuel adjustment clauses, purchased power adjustment clauses, and gas supply clauses for over 25 electric and gas utilities, including investor-owned utilities, municipal utilities, generation and transmission cooperatives, and distribution cooperatives. I recently sponsored testimony in support of fuel adjustment clauses proposed by Westar Energy, Kansas Gas and Electric Company, and Nova Scotia Power Company. I have assisted a number of utilities in the development of environmental cost recovery mechanisms, including those implemented by Louisville Gas and Electric Company, Westar Energy, and Kansas Gas and Electric Company. I have also developed or assisted in the development and implementation of other cost adjustment clauses – including transmission cost recovery mechanisms for Vectren Electric Company, Westar Energy Company, and Kansas Gas and Electric Company; performance-based ratemaking mechanisms for Louisville Gas and Electric Company, Westar Energy Company, and Kansas Gas and Electric Company; revenue stabilization-mechanisms for Delta Natural Gas and Electric Company and Mobile Gas Company; and demand-side management cost-recovery mechanisms for Louisville Gas and Electric Company, Delta Natural Gas Company, and Nova Scotia Power Company.

Q. Do you have any cost of service and rate experience with generation and transmission cooperatives?

A. Yes. I have performed cost of service and rate studies for numerous generation and transmission cooperatives, including Hoosier Energy, South Mississippi Electric Cooperative, Alabama Electric Cooperative, Corn Belt Electric Cooperative, Wabash Valley Electric Cooperative, Southern Illinois Electric Cooperative, East Kentucky Power Cooperative, and Dairyland Electric Cooperative.

II. FUEL ADJUSTMENT CLAUSE

Q. Please describe Big Rivers' proposed FAC.

A. In Case No. 2007-00455, Big Rivers is proposing to implement the standard FAC used by other utilities in Kentucky. The proposed clause, which is included in Exhibit WSS-2, fully conforms with the Commission's regulations governing the application of fuel adjustment clauses, as set forth in 807 KAR 5:056.

Under the proposed FAC, the monthly Adjustment Factor would be calculated as follows:

$$\text{Adjustment Factor} = F/S - 1.072\ ¢/\text{kWh}$$

where F represents the fuel expense in the second preceding month and S represents the sales in the second preceding month. Detailed definitions of fuel costs (F) and sales (S) are set forth in the proposed clause.

Q. To what rate schedules would the FAC apply?

A. The FAC would apply to all of Big Rivers' Tariff rates and to Base Energy sales under the Smelter Special Contracts. In particular, the FAC would apply to the Monthly Delivery Point Rate to Members as set forth in Section C, Item 4 of the Big Rivers' Rates Rules and Regulations ("Tariff"), to the Big Rivers Industrial Customer Rate as set forth in Section C, Item 7 of the Tariff, and to Base Energy sales in the Smelter Special Contracts. In other words, the FAC would apply to all rate schedules applicable to native load customers served by Big Rivers in its control area, except Supplemental and Backup sales to the Smelters. Consistent with the practice of other utilities in Kentucky, the FAC would not apply to off-system sales. Items 4 and 7 of Section C of Big Rivers' Proposed Tariff, which is included as Exhibit 23 of the Application in Case No. 2007-00455, have been modified to make it clear that the FAC would apply to these rate schedules. The special contracts with the Smelters include a provision specifying that the FAC would apply to sales made under those agreements. (See Section 4.8.1 of the Agreement with Alcan included as Exhibit 20 of the Application and of the Agreement with Century included as Exhibit 20 of the Application.)

Although the FAC will apply to both the Smelter and the non-Smelter rates, it is important to understand that the MSRM and other credit mechanisms, as proposed, will fully offset the FAC applicable to non-Smelter member sales until the Economic Reserve is drawn down. As mentioned earlier in my testimony, the Members should not see an impact of FAC adjustments on their bills related to non-Smelter member sales for approximately five years, which is when the Economic Reserve is expected to be exhausted as currently projected. Even after the Economic Reserve is fully depleted, the Unwind Surcredit will continue to offset the impact of billings under the FAC and Environmental Surcharge.

Q. What base fuel cost is Big Rivers proposing?

A. Big Rivers is proposing a base fuel cost of 1.072 ¢/kWh. In the FAC, base fuel cost is subtracted from the monthly unit fuel cost (Fm/Sm) to determine the monthly Adjustment Factor.

Q. How was the base fuel cost determined?

A. Big Rivers is proposing a base fuel cost that is representative of its 2007 unit fuel cost, as was projected in 2004. This unit cost was determined early on in discussions with the parties about unwinding the arrangement with E.ON. The base fuel cost estimate was developed largely for purposes of negotiating rate formulas under the power supply agreements with the Smelters. It was important to the settlement process with the Smelters and other parties to agree to a figure that should be used as a base fuel cost. The 1.072 ¢/kWh amount was derived on the basis of production cost modeling performed by ACES Power Marketing using fuel cost, heat rate, forced outage rates, power purchases and line-loss inputs provided by Big Rivers, E.ON, Global Insight, Inc. and by ACES Power Marketing itself.

Q. Does the 1.072 ¢/kWh base fuel represent the level of fuel cost currently included in base rates?

A. Yes, in the following important sense. A base fuel cost of 1.072 ¢/kWh represents a going-forward level of fuel costs reflected in base rates which will allow Big Rivers a fair, just and reasonable recovery of its costs and will permit Big Rivers to maintain a reasonable TIER level until base rates can be determined in a general rate case which will be filed with an effective date sometime after January 1, 2010. Big Rivers has committed to file a general rate case within three years from the date of the Commission's final Order in Case No. 2007-00455, with rates not going into effect prior to January 1, 2010. Because the MRSM and the other credit mechanisms proposed in this proceeding are designed to fully offset the FAC, the level of the base fuel cost utilized in the FAC will not directly affect the non-Smelter member rates until the Economic Reserve is drawn down fully.

However, the level of the base will affect the FAC amount actually paid by the Smelters. Importantly, a base fuel cost of 1.072 ¢/kWh was determined to represent current base fuel costs in negotiations with the Smelters. Furthermore, a base fuel cost of 1.072 ¢/kWh is used in the financial models performed in support of Big Rivers' efforts to refinance its debt.

Big Rivers' current base rates were established at a level that would provide for the recovery of purchased power costs from E.ON along with other costs. The purchase power rate from E.ON was developed through a competitive bidding process in Big Rivers' reorganization proceeding that did not reflect the actual fuel costs used to generate power. Consequently, it is not really possible to accurately determine the level of base fuel costs included in the purchase power price from E.ON. Based on Big Rivers' financial model and on negotiations with the Smelters, we do know, however, that a base fuel cost of 1.072 ¢/kWh will reasonably reflect on a going-forward basis a level of fuel costs adequate for Big Rivers to operate under its current rates and meet target TIER levels until new base rates can be established in a general rate case with an effective date sometime after January 1, 2010.

Q. During the first couple of months, Big Rivers will not have fuel cost experience upon which to establish an FAC Adjustment Factor. How will the Adjustment Factor be determined during those initial couple of months?

A. Because F(m)/S(m) is calculated based on fuel costs *F(m)* and sales *S(m)* for the second month preceding the month during which the FAC Adjustment Factor is billed, for the first two or three months after approval of the FAC, Big Rivers will not have historical fuel cost experience which can be used to compute the FAC Adjustment Factor. The financial model used to evaluate the unwind arrangement with E.ON, the agreements with the Smelters, and Big Rivers' financing plan are predicated on the immediate implementation of an FAC with a fuel cost of $0.01662 per kWh. The $0.01662 per kWh amount corresponds to the projected level of Big Rivers' fuel costs when the FAC is proposed to go into effect. With fuel costs expected to be higher than Big Rivers' base fuel cost when the FAC is initially implemented, not being able to charge the difference between this fuel cost and the 1.072 ¢/kWh base would have a detrimental effect on Big Rivers' coverage ratios during the first year of the unwind agreement. Therefore, it is very important for Big Rivers to begin charging an FAC immediately upon taking over cost responsibility for the facilities. Therefore, we are proposing that a monthly unit fuel cost *F(m)/S(m)* of $0.01662 per kWh be used to compute the FAC Adjustment Factor for the first two or three months after implementation of the FAC, until Big Rivers' has a *full month* of fuel cost information upon which to determine *F(m)/S(m)* based upon actual cost data for the second preceding month.

Q. What monthly forms would be filed with the Commission?

A. Big Rivers would file the standard FAC forms submitted by other utilities in Kentucky. Specifically, at least ten days before the beginning of the upcoming month, Big Rivers would submit the form included in Exhibit WSS-3. Within 45 days after the end of each expense month, Big Rivers would submit the form included in Exhibit WSS-4 providing historical sales and expense information for the prior month. These forms will be filed monthly with the Commission.

Q. Is Big Rivers submitting any other documents in connection with its proposal to implement an FAC?

A. Yes. Big Rivers is submitting its Fuel Procurement Policies and Procedures, which is included as an exhibit to the Direct Testimony of Mark A. Bailey in Case No. 2007-00455, Exhibit 5, and copies of its fuel contracts, which are included in confidential Exhibit 43 to Big Rivers' Application in Case No. 2007-00455.

III. ENVIRONMENTAL SURCHARGE

Q. Please describe Big Rivers' proposed Environmental Surcharge.

A. Big Rivers is proposing an Environmental Surcharge in Case No. 2007-00460 pursuant to KRS 278.183. Big Rivers' proposed Environmental Surcharge is included as Exhibit WSS-5. Under KRS 278.183, utilities in Kentucky are entitled to implement a surcharge mechanism to recover the costs of complying with the Federal Clean Air Act, as amended, and federal, state, or local environmental laws and regulations which apply to coal combustion wastes and by-products from electric generation facilities.

Big Rivers' proposed Environmental Surcharge clause would allow it to recover the revenue requirements of approved environmental programs. As proposed, revenue requirements would include operation and maintenance expenses associated with three environmental programs consisting of reagent and removal expenses, which are energy-related costs varying with the amount of power generated at Big Rivers' power stations. The revenue requirement would also include an over/under recovery component to account for the over- or under-collection of revenue requirements from the previous six-month period.

The Monthly Environmental Surcharge Factor (MESF) would be calculated as follows:

MESF = CESF – BESF

where CESF is the Current Environmental Surcharge Factor which is determined by dividing the net Jurisdictional portion of approved environmental plan revenue requirements for the second preceding month, E(m), by the kWh sales for the second preceding month, S(m), and where BESF is the Base Environmental Surcharge Factor. Jurisdictional sales, S(m), would include all member sales to which the Environmental Surcharge is applicable. Similar to the FAC, we are proposing that a monthly unit environmental cost *E(m)/S(m)* of $0.00049 per kWh be used to compute the CESF for the first two or three months after implementation of the Environmental Surcharge, until Big Rivers has a *full month* of cost information upon which to determine *E(m)/S(m)* based upon actual cost data for the second preceding month. The $0.00049 per kWh amount is the level for these expenses incorporated into the financial models used by Big Rivers to evaluate the feasibility of the Unwind Transaction.

Although other utilities in Kentucky have structured their environmental cost recovery surcharges as percentage-of-revenue factors, Big Rivers is proposing to structure its

Environmental Surcharge as an energy charge (*i.e.*, as a charge per kWh) similar in design to the FAC. In the agreements negotiated with the Smelters, the Purchased Power Adjustment and the Environmental Surcharge were both structured as energy charges; therefore, Big Rivers is proposing to assess the Environmental Charge as an energy charge, consistent with what was negotiated with the Smelters and consistent with the fact that the expenses to be recovered through the mechanism consist *entirely* of variable costs. Importantly, Big Rivers' proposal is not contravened by any provisions of KRS 278.183, which does not prescribe the type of charge that must be used in an environmental cost recovery mechanism. Although KRS 278.183 does not prescribe the type of charge that must be used in the mechanism, we recognize that Big Rivers' proposed methodology represents somewhat of a departure from the environmental cost recovery clauses used by other utilities in Kentucky. Because of the unique circumstances involved with unwinding the lease and purchase arrangement with E.ON, with developing long-term arrangements to provide power to the Smelters, and with developing a mechanism that will prevent Members from seeing increases from the FAC and Environmental Surcharge for approximately five years, we respectfully request that the Commission approve the Environmental Surcharge as proposed by Big Rivers without prejudice to other environmental cost recovery mechanisms in the state or to any future environmental plans which could possibly be submitted by Big Rivers in the future.

Q. What rate schedules would the Environmental Surcharge apply to?

A. The Environmental Surcharge would apply to all of Big Rivers' Tariff rates and to Base Energy sales under the Smelter Special Contracts. Specifically, Environmental Surcharge would apply to the Monthly Delivery Point Rate to Members, the Big Rivers Industrial Customer Rate, and the Base Energy Charges under the Smelter Special Contracts. Under the Smelter Special Contracts, the Smelters would pay amounts by reference to the Environmental Surcharge.

Q. What costs would be included in Big Rivers' proposed environmental plans?

A. As discussed in the Direct Testimony of David A. Spainhoward, Exhibit 18 in Case No. 2007-00455, Big Rivers is proposing to recover the cost of its Environmental Compliance Plan – specifically, an SO2 Compliance Program, an NOX Compliance Program, and an SO3 Compliance Program. For the SO2 Compliance Program, Big Rivers would recover the commodity cost of reagents used by the scrubbers (specifically, the commodity cost of purchasing lime, limestone, and dibasic acid, as applicable), and payments made to third-parties in connection with the disposal of wastes (specifically, scrubber sludge, fly ash, bottom ash, and fixation lime) and the purchase of SO2 allowances. Big Rivers would credit (refund to customers through the Environmental Surcharge) all proceeds from the sale of scrubber waste from the Coleman Generating Station for the production of gypsum and all net proceeds from the sale of SO2 allowances.

For the NOX Compliance Program, Big Rivers would recover the commodity cost of reagents used in connection with NOX compliance (specifically, the commodity cost of purchasing ammonia and sulfur) and the purchase of NOX allowances. Big Rivers would credit all net proceeds from the sale of NOX allowances.

For the SO3 Compliance Program, Big Rivers would recover the commodity cost of reagents used in connection with SO3 compliance, specifically the purchased cost of hydrated lime.

In this Application in Case No. 2007-00460, the only expenses that Big Rivers is proposing to recover through the Environmental Surcharge are the commodity costs of purchasing SO2, NOX, and SO3 reagents, and payments made to third parties to dispose of scrubber and related waste products. Big Rivers is not proposing to recover any other operation and maintenance expenses related to SO2, NOX, and SO3 compliance, nor is it requesting a return on rate base or property taxes related to any facilities in this Application.

Q. Are these expenses and allowance sale proceeds currently included in base rates?

A. No. As mentioned earlier, Big Rivers' current base rates were set at a level sufficient to cover its costs within the context of the lease and purchased power arrangement with E.ON . With Big Rivers assuming responsibility for the operation and maintenance of its generating facilities, the base rates currently charged by Big Rivers are not sufficient to cover these environmental expenses. These expenses are therefore not included in current base rates. Consequently, the Base Environmental Surcharge Factor (BESF) will initially be set at zero cents per kWh.

Big Rivers has agreed not to increase base rates prior to January 1, 2010, but would bill these environmental expenses to the Smelters and would use the Economic Reserve to offset these Environmental Surcharges, along with any FAC charges, applicable to the non-Smelter member sales for a period of approximately five years. Both the distribution cooperative members and the Smelters have agreed to this approach. Big Rivers has also made a commitment to file a general rate case to establish rates that would go into effect within three years from the date of the Commission's final Order in Case No. 2007-00455. When base rates are reviewed in connection with a general rate case proceeding, the Commission will be able to have full assurance that Big Rivers' rates, including any charges recovered through the Environmental Surcharge or FAC, properly reflect the actual cost of providing service. Until that time, because of the Economic Reserve which will have been established to prevent the members from experiencing an increase applicable to non-Smelter sales as a result of these two mechanisms, the non-Smelter members will not see a price increase as a result of setting the BESF at zero.

Q. Have you prepared an exhibit showing the forms that will be filed by Big Rivers with the Commission?

A. Yes. Big Rivers will file the monthly forms included in Exhibit WSS-6 with the Commission. These forms have been modeled after the forms used by other utilities in the state.

Q. Have you prepared an exhibit showing the anticipated Environmental Surcharge factors resulting from the three plans?

A. Yes. Exhibit WSS-7 shows the average Environmental Surcharge factors for the years 2008 through 2012.

IV. UNWIND SURCREDIT

Q. Please describe Big Rivers' proposed Unwind Surcredit.

A. In order to establish well-defined, long-term power supply arrangements with Big Rivers, the Smelters have agreed to pay a Surcharge in addition to any other charges payable under the special contracts. Specifically, Alcan and Century have agreed to pay certain surcharges as set forth in Section 4.11 of the Smelter Special Contracts, consisting of both fixed and variable surcharges. These surcharge amounts would be passed along to the members through the application of the Unwind Surcredit. The Unwind Surcredit, which is included in Exhibit WSS-8, would compute the monthly Unwind Surcredit factor, US(m), applicable to all member non-Smelter kWh sales, as follows:

$$US(m) = \text{Surcredit} + \text{Actual Adjustment} + \text{Balance Adjustment}$$

where Surcredit represents the per kWh factor calculated by dividing (a) the estimated payments that Big Rivers would receive from the Smelters in accordance with Section 4.11 of the Smelter Special Contracts during an upcoming calendar year by (b) the member non-Smelter sales (NSS), including sales made under the Monthly Delivery Point Rate to Members and the Big Rivers Industrial Customer Rate, in the corresponding calendar year. The proposed Unwind Surcharge mechanism includes an Actual Adjustment and a Balance Adjustment to provide for any over- or under-crediting of Smelter surcharge amounts. Similar provisions are included in the Gas Supply Cost (GSC) adjustment mechanisms used by gas distribution companies in Kentucky. Because the Unwind Surcharge amounts to be received from the Smelters would not be subject to significant volatility, we are proposing that the Unwind Surcredit operate on an annual rather than a quarterly adjustment cycle, in contrast to the GSC mechanisms used in the state. Big Rivers is proposing the Unwind Surcredit in Case No. 2007-00455 pursuant to subsection 1 of KRS 278.455.

Q. To what rate schedules would the Unwind Surcredit apply?

A. The Unwind Surcredit would apply to all of Big Rivers' member non-Smelter rates; specifically, the Unwind Surcharge would apply to the Monthly Delivery Point Rate to Members and the Big Rivers Industrial Customer Rate. The Unwind Surcredit would not apply to the Smelters.

Q. Have you prepared an exhibit showing the estimated Surcredit factors that will be applicable to non-Smelter member sales over the next five years?

A. Exhibit WSS-9 shows the average projected Surcredit factors during the first five years of operation of the proposed clause.

Q. Have you prepared an exhibit showing the monthly form that will be filed by Big Rivers with the Commission?

A. Yes. Big Rivers will file the form included in Exhibit WSS-10 with the Commission.

V. REBATE ADJUSTMENT

Q. Please describe the proposed Rebate Adjustment?

A. In the event that there is a rebate to the Smelters under Section 4.9 of the Smelter Special Contracts during a fiscal year, then Big Rivers, subject to Board approval, may also request Commission authorization to provide a cash rebate to its members pursuant to subsection 1 of KRS 278.455. Such a rebate would be subject to the discretion of Big Rivers and its Board, and may not be provided if funds are needed to support capital projects, to increase members' equity, or for other reasons. Any rebate would be provided as a lump-sum credit to the members and would be credited to the power bills to members during a single month of the year. The rebate provided to each member will be computed by allocating the total rebate amount on the basis of total annual base rate revenues received from each member for non-Smelter sales during the fiscal year for which the rebate amount was established. Big Rivers will apply to the Commission for authorization to provide a rebate within six months after the end of the fiscal year. The rebate will then be provided to members upon receipt of Commission approval. The Rebate Adjustment clause is included in Exhibit WSS-11.

Q. What rate schedules would the Rebate Adjustment apply to?

A. The Rebate Adjustment would apply to all of Big Rivers' non-Smelter member Tariff rates; specifically, the Rebate Adjustment would apply to the Monthly Delivery Point Rate to Members and the Big Rivers Industrial Customer Rate. The Rebate Adjustment would not apply to the Smelters. A separate rebate mechanism is included in the Smelter Special Contracts. (See Section 4.9 of the Smelter Special Contracts.)

Q. Have you prepared an exhibit showing the form that will be filed by Big Rivers with the Commission in the event that a rebate is provided to members?

A. Yes. Big Rivers will file the form included in Exhibit WSS-12 with the Commission in the event that Big Rivers provides a rebate.

VI. MEMBER RATE STABILITY MECHANISM (MRSM)

Q. Please describe the Member Rate Stability Mechanism?

A. Big Rivers will establish an Economic Reserve of approximately $75 million which will be used to offset the impact of the FAC and Environmental Surcharge after taking into account the credits received from the Unwind Surcredit and the Rebate Adjustment. Big Rivers' proposed MRSM, which is included in Exhibit WSS-13, will draw on the Economic Reserve to offset the monthly impacts of the FAC and Environmental Surcharge on the members' non-Smelter bills, net of the credits received under the Unwind Surcredit and Rebate Adjustment. Big Rivers is proposing the MRSM in Case No. 2007-00455 pursuant to subsection 1 of KRS 278.455. The MRSM will simply offset the *total dollar impact* of billings under the FAC and Environmental Surcharge *less* the total dollar amounts received under the Unwind Surcredit and *less* a monthly pro-rated portion of any lump sum rebates provided under the Rebate Adjustment. Because rebates under the Rebate Adjustment would be provided as a lump-sum credit to members, the rebate amount will be pro-rated equally (1/12th each month) over 12 billing months (including the month during which the lump-sum rebate occurs) for purposes of calculating monthly credits under the MRSM. In other words, the amount of the MRSM credit provided to each Member System during a month will equal (i) the total dollar amount of FAC charges (or credits) billed to the member during the month, *plus* (ii) the total dollar amount of Environmental Surcharge billed to the member during the month, *less* (iii) the total dollar amount of Unwind Surcredits credited to the member during the month, *less* (iv) one-twelfth (1/12) of any rebates provided under the Rebate Adjustment during the current month or during any of the 11 preceding months; provided that the amounts subtracted in items (iii) and (iv) cannot exceed the total of items (i) and (ii), in which case the monthly MRSM adjustment would be zero. Under the MRSM, Big Rivers' members will not experience any net increase from the application of the FAC and Environmental Surcharge to non-Smelter sales during a 12-month period until the Economic Reserve is drawn down completely. If a rebate is provided under the Rebate Adjustment, then the total cash amounts actually received from the application of the MRSM, Unwind Surcredit and Rebate Adjustment will not match the FAC and Environmental Surcharge amounts during each month; however, the total credits received under the MRSM, Unwind Surcredit and Rebate Adjustment will match the total FAC and Environmental Surcharge amounts over the 12-month period.

Although Big Rivers' members will not experience an increase from the application of the FAC and Environmental Surcharge during the 12 month period, it would be possible for the FAC, Environmental Surcharge, Unwind Surcredit, and Rebate Mechanism to result in a net decrease in the price paid by the members. For example, it would be possible for the Unwind Surcredit to more than offset the FAC and Environmental Surcredit (especially if the FAC happened to be a credit). In that event, MRSM would be set at zero and the members would simply see a net credit to their bills from the application of the mechanisms. In other words, as proposed, the MRSM would never result in a charge to members.

Q. Could you provide an example of how the MRSM would work assuming that there is no rebate under the Rebate Adjustment from the prior fiscal year?

A. Yes. If there is no rebate from the prior fiscal year, then the MRSM will simply offset the net dollar amount billed for non-Smelter member sales during the month to each member under the FAC and Environmental Surcharge less the Unwind Surcredit. For example, suppose that (i) the FAC amount billed to a member for non-Smelter sales is $10,150, (ii) the Environmental Surcharge billed to a member for non-Smelter sales is $20,200, and (iii) the Unwind Surcredit received is $5,000. Then the member's MRSM adjustment for the month would be a credit of $25,350 (or $10,150 + $20,200 - $5,000 = $25,350). In other words, the MRSM of $25,350 would offset the FAC charge of $10,150, *plus* the Environment Surcharge of $20,200, *less* the Unwind Surcredit of $5,000. It should be pointed out that the figures used in this example were developed simply to illustrate how the MRSM will be determined and in no way represent amounts that will likely occur.

Q. Could you also provide an example of how the MRSM would work assuming that there is a rebate under the Rebate Adjustment?

A. Yes. If a rebate is provided under the Rebate Mechanism, then the rebate amount to the member would be prorated over a 12-month period for purposes of calculating the MRSM adjustment for the month. Using the same assumptions outlined in the prior example, assume further that the member was provided a $144,000 rebate under the Rebate Mechanism within the last 12 months. The member's MRSM adjustment for the month would then be a credit of \$13,350 (or \$10,150 + \$20,200 - \$5,000 – \$144,000/12 = \$13,350). In this instance, the MRSM of \$13,350 would offset the FAC charge of \$10,150, *plus* the Environment Surcharge of \$20,200, *less* the Unwind Surcredit of \$5,000 *less* 1/12th of the \$144,000 rebate amount that the member received. Note that the MRSM of \$13,350 would not fully offset the net effect of the FAC, Environmental Surcredit, Unwind Surcredit and the pro-ration of the rebate amount during the month; but, on a 12 month basis the sum of the amounts received under the Unwind Surcredit, Rebate Mechanism, and MRSM would exactly match and thus fully offset the sum of the FAC and Environmental Surcharge.

Q. What will happen when the Economic Reserve is almost completely drawn down and there is only enough left to partially offset the impact of the FAC and Environmental Surcharge after accounting for the Unwind Surcredit and Rebate Adjustment?

A. During the last month of the MRSM, the amount remaining in the Economic Reserve will be prorated to each member on the basis of the total FAC and Environmental Surcharge amounts applicable to non-Smelter sales less credits under the Unwind Surcredits and less monthly prorated amounts under the Rebate Adjustment.

Q. Will the Economic Reserve accrue interest?

A. Yes. The Economic Reserve will be established as a stand-alone investment account, separate from any of Big Rivers' other cash investments. Interest earned or other earnings on the investment account will accrue to the Economic Reserve and will be returned to the members through the normal application of the MRSM. After the fund is initially established at the closing of the unwind arrangement with E.ON, no additional principal amounts will be added to the Economic Reserve. After closing, only interest will be added to the Economic Reserve.

Q. Will the MRSM account for the effect of any FAC or Environmental Surcharge costs being "rolled in" to base rates?

A. Yes. At some point prior to the Economic Reserve being fully drawn down, the Commission may consider moving costs recovered through the FAC and Environmental Surcharge into base rates (resulting in a "roll in"), or, in the case of the FAC, the Commission may consider moving costs recovered through base rates back into the FAC (resulting in a "roll out" of costs from base rates), particularly if Big Rivers were expecting to incur fuel costs lower than base fuel cost subsequent to a two-year FAC review. If there is either a "roll in" of FAC or Environmental Surcharge costs into base rates, or there is a "roll out" of FAC costs from base rates into the FAC, the MRSM, while it is in place, will account for any such effect of the "roll in" or "roll out" so that the Members will not see any impact on their bills, either positive or negative, due to a roll-in. For example, if 0.200 ¢ /kWH of the charge recovered through the Environmental Surcharge is "rolled in" to base rates, then the MRSM will subsequently provide a credit to offset any Environmental Surcharge amounts billed to the Member System *plus* the amount billed to the Member corresponding to the 0.200 ¢ /kWH charge that was "rolled in" to base rates.

Q. What rate schedules would the MRSM apply to?

A. The MRSM would apply to all of Big Rivers' non-Smelter member Tariff rates; specifically, the MRSM would apply to the Monthly Delivery Point Rate to Members and the Big Rivers Industrial Customer Rate. The MRSM will not apply to the Smelters.

Q. Does Big Rivers propose to file a monthly report with the Commission showing the MRSM amounts credited to each non-Smelter member, the interest added to the Economic Reserve, and the balance remaining in the Economic Reserve at the end of the month?

A. Yes. Big Rivers will file the form included in Exhibit WSS-14 within 45 days after the end of the month.

VII. FILING REQUIREMENTS RELATED TO THE PROPOSED CREDIT MECHANISMS

Q. Have you prepared an analysis demonstrating that the proposed rate changes associated with the Unwind Surcredit, Rebate Adjustment and MRSM do not change the rate design currently in effect and demonstrating that the revenue change is to be

allocated to each class within each tariff on a proportional basis, as required by section 1, sub-paragraphs (5)(a) and (b) of 807 KAR 5:007?

A. Yes. Exhibit WSS-15, which is constructed from information supplied in Exhibit CWB-8 of the Direct Testimony of C. William Blackburn in Case No. 2007-00455, shows the effect on member billings of the five adjustment clauses described in my testimony. Specifically, this exhibit shows that the implementation of the FAC, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment and MRSM will not have an initial impact on the revenues collected from members. As can be seen from Exhibit WSS-15, the revenues shown in Column (7), which represents estimated billings prior to the application of the five adjustment clauses, equal the revenues shown in Column (14), which represents the estimated billing subsequent to the application of the five mechanisms. It is evident from this exhibit that the three credit mechanisms – Unwind Surcredit, Rebate Adjustment and MRSM – do not have an effect on Big Rivers' current rate design. Collectively, these three credit mechanism will have the effect of off-setting the impact of the FAC and Environmental Surcharge, thus leaving Big Rivers' rate design *fully* intact over a 12-month period. This exhibit also shows that the billing credits from these three mechanisms are allocated to each tariff on a proportional basis. As discussed earlier in my testimony, credits under the Unwind Surcredit are allocated proportionally on the basis of kWh sales; credits under the Rebate Adjustment are allocated proportionally on the basis of prior year base revenues; and credits under the MRSM are allocated proportionally on the basis of the net impact of the four other adjustment clauses.

Q Do these credit mechanisms apply to the wholesale power sold by Big Rivers to Kenergy for resale to the Smelters?

A. No. Wholesale power supply to the Smelters is provided to Kenergy by Big Rivers under Special Contracts that are treated by Big Rivers as third-party wholesale sales arrangements. Because those Special Contracts do not provide for the Smelters to receive the benefit of these credit mechanisms, it is my understanding that application of those credit mechanisms to the wholesale sales for resale to the Smelters is not allowed under KRS 278.455(3).

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

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

W. Steven Seelye

COMMONWEALTH OF KENTUCKY)
COUNTY OF OLDHAM)

Subscribed and sworn to before me by W. Steven Seelye on this the 17TH day of December, 2007.

Patsy W. Luttrell
Notary Public, Ky. State at Large
My Commission Expires: 12-02-10

Exhibit WSS-1

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.

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 Case 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 Case Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

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.

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.

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 on behalf of Sierra Pacific Power Company regarding cash working capital for its 2007 electric general rate case.

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.

Exhibit WSS-2

FUEL ADJUSTMENT CLAUSE

APPLICABILITY

To all Big Rivers Electric Corporation's ("Big Rivers") Members.

AVAILABILITY

The Fuel Adjustment Clause ("FAC") is a mandatory rider to all wholesale sales by Big Rivers to its Members, including Base Energy sales to the Smelters under the two Wholesale Electric Service Agreements each dated as of __________, 2008, between Big Rivers and Kenergy with respect to service by Kenergy to the Smelters, but excluding Supplemental and Back-Up Energy sales to the Smelters under those two Agreements.

(1) The FAC shall provide for periodic adjustment per kWh of sales when the unit cost of fuel [F(m)/S(m)] is above or below the base unit cost of $0.01072 per kWh [F(b)/S(b)]. The monthly charges shall be increased or decreased by the product of the kWh furnished during the month and the FAC Factor for the month where the FAC Factor is defined below:

$$\text{FAC Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where "F" is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods as defined in 807 KAR 5:056, all defined below:

(2) Fuel cost (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis and exclusive of energy purchases directly related to Supplemental and Back-Up Energy sales to the Smelters. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, also such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel, as denoted in (2)(a) above, recovered through inter-system sales, including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis, and the cost of fossil fuel recovered through Interruptible, Back-Up or Market Energy sales to the Smelters

(e) All fuel costs shall be based on weighted average inventory costing.

(3) Forced outages are all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of public enemy, the utility may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment.

(4) Sales (S) shall be kWh sold, excluding inter-system sales and Supplemental and Back-Up Energy sales to the Smelters. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in subsection (2)(d) above, less (vi) total system losses. Utility-used energy shall not be excluded in the determination of sales (S).

(5) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of the FERC Uniform System of Accounts for Public Utilities and Licenses.

(6) Current (m) period shall be the second month preceding the month in which the FAC factor is billed.

(7) Until Big Rivers has actual fuel cost experience for a full calendar month reflecting the operation of its generating facilities, F(m)/S(m) shall be equal to $0.01662 per kWh.

Exhibit WSS-3

BIG RIVERS ELECTRIC CORP

FUEL ADJUSTMENT CLAUSE SCHEDULE

Expense Month :

$$\frac{\text{Fuel "Fm" (Fuel Cost Schedule)}}{\text{Sales "Sm" (Sales Schedule)}} = \frac{\rule{3cm}{0.4pt}}{\text{KWH}} = (+) \qquad / \text{ KWH}$$

Proposed Base Fuel Component = (-) $ 0.01072 / KWH

FAC Factor (1) = ______ / KWH

Note: (1) Five decimal places in dollars for normal rounding.

Effective Date for Billing:

Submitted by ______________________________

Title:

BIG RIVERS ELECTRIC CORP
FUEL COST SCHEDULE

Expense Month:

(A)	Company Generation		
	Coal Burned	(+)	
	Oil Burned	(+)	
	Gas Burned	(+)	
	Fuel (assigned cost during Forced Outage)	(+)	
	Fuel (substitute cost for Forced Outage)	(-)	
	SUB-TOTAL		
(B)	Purchases		
	Net energy cost - economy purchases	(+)	
	Identifiable fuel cost - other purchases	(+)	
	Identifiable fuel cost (substitute for Forced Outage)	(-)	
	Less Purchases Above Highest Cost Units	(-)	
	Internal Economy	(+)	
	Internal Replacement	(+)	
	SUB-TOTAL		
(C)	Inter-System Sales		
	Including Interchange-out	(+)	
	Internal Economy	(+)	
	Internal Replacement	(+)	
	Supplemental Sales to Smelters	(+)	
	Backup Sales to Smelters	(+)	
	Dollars Assigned to Inter-System Sales Losses	(+)	
	SUB-TOTAL		
(D)	Over or (Under) Recovery		
	From Page 4, Line 13		
	TOTAL FUEL RECOVERY (A+B-C-D) =		

BIG RIVERS ELECTRIC CORP

SALES SCHEDULE (KWH)

Expense Month:

(A)	Generation (Net)	(+)	
	Purchases including interchange-in	(+)	
	Internal Economy	(+)	
	Internal Replacement	(+)	
	SUB-TOTAL		

(B)	Inter-system Sales including interchange-out	(+)	
	Internal Economy	(+)	
	Internal Replacement	(+)	
	Supplemental Sales to Smelters	(+)	
	Backup Sales to Smelters	(+)	
	System Losses (KWH times)	(+)	
	SUB-TOTAL		

TOTAL SALES (A-B)

BIG RIVERS ELECTRIC CORP

FUEL ADJUSTMENT CLAUSE
OVER OR (UNDER) RECOVERY SCHEDULE

Expense Month:

1.	Last FAC Rate Billed		
2.	KWH Billed at Above Rate		______
3.	FAC Revenue/(Refund)	(Line 1 x Line 2)	______
4.	KWH Used to Determine Last FAC Rate		
5.	Non-Jurisdictional KWH (Included in Line 4)		______
6.	Kentucky Jurisdictional KWH	(Line 4 - Line 5)	______
7.	Revised FAC Rate Billed, if prior period adjustment is needed (See Note 1)		
8.	Recoverable FAC Revenue/(Refund)	(Line 1 x Line 6)	______
9.	Over or (Under) Recovery	(Line 3 - Line 8)	______
10.	Total Sales "Sm" (From Page 3 of 5)		______
11.	Kentucky Jurisdictional Sales		______
12.	Total Sales Divided by Kentucky Jurisdictional Sales	(Line 10 / Line 11)	______
13	Total Company Over or (Under) Recovery	(Line 9 x Line 12)	______ To Page 2, Line D

Note: An over/under recovery adjustment will not be calculated until the FAC Factor billed is determined using Big Rivers' actual fuel costs and sales.

Exhibit WSS-4

Company: Big Rivers Electric Corp

FUEL INVENTORY SCHEDULE

Plant:

Month Ended:

Fuel Coal

Plant A

	Amount	MMBTU	Per Unit	Tons	Per Unit
Beginning Inventory			¢		
Purchases			¢		
Adjustments					
Sub-Total			¢		
Less Fuel Burned			¢		
Ending Inventory			¢		

Plant B

	Amount	MMBTU	Per Unit	Tons	Per Unit
Beginning Inventory			¢		
Purchases			¢		
Adjustments					
Sub-Total			¢		
Less Fuel Burned			¢		
Ending Inventory			¢		

Coal In Transit

	Amount	MMBTU	Per Unit	Tons	Per Unit
Coal In Transit (1)			¢		
Total Combined Inventory			¢		

Company:........................ Big Rivers Electric Corp

FUEL INVENTORY SCHEDULE

Plant:...

Month Ended:.................................

Fuel No. 2 Fuel Oil

Plant A

	Units (Gal.)	Amount	Amount Per Unit
Beginning Inventory			¢
Less Fuel Burned (1)			¢
Other Uses (2)			¢
Ending Inventory			¢

Plant B

	Units (Gal.)	Amount	Amount Per Unit
Beginning Inventory			¢
Purchases			
Sub-Total			¢
Less Fuel Burned-Jurisdictional			¢
Non-Jurisdictional			¢
Ending Inventory			¢
Total Combined Inventory			¢

Company:................ Big Rivers Electric Corp

FUEL INVENTORY SCHEDULE

Plant:......................................

Month Ended:....................................

Fuel Natural Gas

Plant A

	Units (MCF)	Amount	Amount Per Unit
Beginning Inventory			
Purchases			¢
Sub-Total			¢
Less Fuel Burned			¢
Ending Inventory			

Plant B

	Units (MCF)	Amount	Amount Per Unit
Beginning Inventory			¢
Purchases			¢
Sub-Total			¢
Less Fuel Burned			¢
Ending Inventory			¢
Total Combined Inventory			¢

Big Rivers Electric Corp

POWER TRANSACTION SCHEDULE

Month Ended:

	Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
<u>Company</u>						
<u>Purchases</u>						
SUB-TOTAL						
LESS: PURCHASED FOR SUPPLEMENAL OR BACKUP SALES						
TOTAL						
<u>Sales</u>						
SUBTOTAL						
LOSSES ACROSS OTHER SYSTEMS (NOT BILLED)						
TOTAL						

BIG RIVERS ELECTRIC CORP
ANALYSIS OF OTHER FUEL PURCHASES
FOR THE MONTH OF

Fuel & Supplier (a)	PBDU (b)	P0CN (c)	MT (d)	Station Name (e)	Gal. or MCF Purchased (f)	BTU Per Unit (g)	Delivered Cost ($) (h)	Cents Per MMBTU (i)	% Sulfur (j)
Oil									
Natural Gas									
Total Natural Gas									

(b) Designated by Symbol
- P = Producer
- B = Broker
- D = Distributor
- U = Utility

(c) POCN = Purchase Order or Contract Number

(d) MT = Mode of Transportation Designated by Symbol
- R = Rail
- B = Barge
- T = Truck
- P = Pipeline

Company Name: Big Rivers Electric Corp

Station Name - Unit Number:

For the Month of:

Line No.	Item Description	Unit # 1	Unit # 2	Unit # 3	Total Station
1.	Unit Performance:				
	a. Capacity (name plate rating) (MW)				
	b. Capacity (average load) (L2c/L3a) (MW)				
	c. Net Demonstrated Capability (MW)				
	d. Net Capability Factor (L1b/L1c) (%)				
2.	Heat Rate:				
	a. BTU Consumed (MMBTU)				
	b. Gross Generation (MWH)				
	c. Net Generation (MWH)				
	d. Heat Rate (L2a/L2c) (BTU/KWH)				
3.	Operation Availability:				
	a. Hours Unit Operated				
	b. Hours Available				
	c. Hours During the Period				
	d. Availability Factor (L3b/L3c) (%)				
4.	Cost per KWH:				
	a. Gross Generation - FAC Basis (cents/KWH)				
	b. Net Generation - FAC Basis (cents/KWH)				
5.	Inventory Analysis:				
	a. Number of Days Supply based on actual burn at the station (1)				

Exhibit WSS-5

ENVIRONMENTAL SURCHARGE

APPLICABILITY

To all Big Rivers Electric Corporation's ("Big Rivers") Members.

AVAILABILITY

The Environmental Surcharge ("ES") is a mandatory rider to all sales by Big Rivers to its Members, including Base Energy sales to the Smelters under the two Wholesale Electric Service Agreements each dated as of __________, 2008, between Big Rivers and Kenergy with respect to service by Kenergy to the Smelters, but excluding Supplemental and Back-Up Energy sales to the Smelters under those two Agreements.

RATE

The ES shall provide for monthly adjustments based on a charge per kWh equal to the difference between the environmental compliance costs in the base period and in the current period based on the following formula:

CESF = Net E(m)/S(m)

MESF = CESF – BESF

MESF = Monthly Environmental Surcharge Factor
CESF = Current Environmental Surcharge Factor
BESF = Base Environmental Surcharge Factor of $0.00000/kWh

Where E(m) is the total of each approved environmental compliance plan revenue requirement of environmental costs for the current expense month and S(m) is the kWh sales for the current expense month as set forth below.

DEFINITIONS

(1) E(m) = OE – BAS + (Over)Under Recovery

Where:

(a) OE represents the Monthly Pollution Control Operating Expenses, defined as the operating and maintenance expense and emission allowance expense of approved environmental compliance plans;

(b) BAS is the net proceeds from By-Products and Emission Allowance Sales, and;

(c) (Over) or Under recovery amount as amortized from prior six-month period.

(2) Total E(m) is multiplied by the Jurisdictional System Allocation Ratio to arrive at Net E(m). The Jurisdictional System Allocation Ratio is the ratio of the kWh sales to Member Systems to which the Surcharge will be applied, ending with the current expense month, divided by the kWh sales related to jurisdictional sales, off-system sales, and Supplemental or Back-Up sales to the Smelters supplied from Big Rivers' generation resources during the month.

(3) Jurisdictional sales S(m) is the kWh sales for Big Rivers for the current expense month.

(4) The current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

(5) Until Big Rivers has actual cost experience for a full calendar month reflecting the operation of its generating facilities, E(m)/S(m) shall be equal to $0.00049 per kWh.

Exhibit WSS-6

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Monthly Billed Environmental Surcharge Factor - MESF
For the Expense Month

MESF = CESF - BESF

Where:

CESF	=	Current Environmental Surcharge Factor
BESF	=	Base Environmental Surcharge Factor

Calculation of MESF:

CESF, from ES Form 1.10	=
BESF	=
MESF	=

Effective Date for Billing:

Submitted by: ______________________

Title:

Date Submitted: ______________________

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT

Calculation of Total E(m) and
Jurisdictional Surcharge Billing Factor

For the Expense Month

Calculation of Total E(m)

E(m) = OE - BAS, where

OE	=	Pollution Control Operating Expenses for Expense Month
BAS	=	Total Proceeds from By-Product and Allowance Sales

		Environmental Compliance Plans
OE	=	
BAS	=	
E(m)	=	

Calculation of Jurisdictional Environmental Surcharge Billing Factor

Jurisdictional Allocation Ratio for Expense Month	=	
Jurisdictional E(m) = E(m) x Jurisdictional Allocation Ratio	=	
Adjustment for Monthly True-up (from Form 2.00)	=	
Adjustment for Under-collection,	=	
Prior Period Adjustment (if necessary)	=	
Net Jurisdictional E(m) = Jurisdictional E(m) minus Adjustment for Monthly True-up plus/minus Prior Period Adjustment	=	
Jurisdictional S(m) = Monthly Jurisdictional Kwh Sales for the Month	=	
Jurisdictional Environmental Surcharge Billing Factor: Net Jurisdictional E(m) / Jurisdictional S(m) ; Per Kwh	=	

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Revenue Requirements of Environmental Compliance Costs
For the Expense Month

Determination of Pollution Control Operating Expenses

	Enviromental Compliance Plan
Operations & Maintenance Expense for Expense Month	
Emission Allowance Expense for Expense Month from ES Form 2.31, 2.32 and 2.33	
Total Pollution Control Operations Expense for Expense Month	

Proceeds From By-Product and Allowance Sales

	Total Proceeds
Allowance Sales	
Scrubber By-Products Sales	
Total Proceeds from Sales	

True-up Adjustment: Over/Under Recovery of Monthly Surcharge Due to Timing Differences

A. MESF for two months prior to Expense Month	
B. Net Jurisdictional E(m) for two months prior to Expense Month	
C. Environmental Surcharge Revenue, current month (from ES Form 3.00)	
D. E(m) recovered through base rates	
E. Over/(Under) Recovery due to Timing Differences ((D + C) - B)	
Over-recoveries will be deducted from the Jurisdictional E(m); under-recoveries will be added to the Jurisdictional E(m)	

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances

For the Month Ended:

Vintage Year	Number of Allowances			Total Dollar Value Of Vintage Year			Comments and Explanations
	SO_2	NOx Annual	NOx Ozone Season	SO_2	NOx Annual	NOx Ozone Season	
Current Year							
2008							
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027 - 2036							

In the "Comments and Explanation" Column, describe any allowance inventory adjustment other than the assignment of allowances by EPA. Inventory adjustments include, but are not limited to, purchases, allowances acquired as part of other purchases, and the sale of allowances.

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (SO_2) - Current Vintage Year

For the Expense Month

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From Big Rivers							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
***Inventory of Emission* Allowances (NOx) - Ozone Season Allowance Allocation**

For the Expense Month

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity							
Dollars							
$/Allowance							
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity							
Dollars							
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity							
Dollars							
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity							
Dollars							
$/Allowance							
From Big Rivers:							
Quantity							
Dollars							
$/Allowance							

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Inventory of Emission Allowances (NOx) - Annual Allowance Allocation

For the Expense Month

	Beginning Inventory	Allocations/ Purchases	Utilized (Coal Fuel)	Utilized (Other Fuels)	Sold	Ending Inventory	Allocation, Purchase, or Sale Date & Vintage Years
TOTAL EMISSION ALLOWANCES IN INVENTORY, ALL CLASSIFICATIONS							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
ALLOCATED ALLOWANCES FROM EPA: COAL FUEL							
Quantity	-	-	-	-	-	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
ALLOCATED ALLOWANCES FROM EPA: OTHER FUELS							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
ALLOWANCES FROM PURCHASES:							
From Market:							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	
From Big Rivers:							
Quantity	0	0	0	0	0	0	
Dollars	$ -	$ -	$ -	$ -	$ -	$ -	
$/Allowance	$ -	$ -	$ -	$ -	$ -	$ -	

Emission Allowance Expense for Other Power Generation is excluded from expense reported on Form 2.00 for recovery through the monthly billing factor.

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Pollution Control - Operations & Maintenance Expenses
For the Month Ended:

O&M Expense Account	Generating Station	Generating Station	Generating Station	**Total All Stations**
Nox Plan				
Individual Expense Account Items				
Individual Expense Account Items				
Individual Expense Account Items				
Total NOx Plan O&M Expenses				
S02 Plan				
Individual Expense Account Items				
Individual Expense Account Items				
Individual Expense Account Items				
Total S02 Plan O&M Expenses				
S03 Plan				
Individual Expense Account Items				
Individual Expense Account Items				
Individual Expense Account Items				
Total S02 Plan O&M Expenses				

Current Month O&M Expense for All Plans				

BIG RIVERS ELECTRIC CORP
ENVIRONMENTAL SURCHARGE REPORT
Kwh Sales Computation of S (m)

For the Expense Month:

(1)	Member Sales (kWh)	
(2)	Base Energy Sales to Smelters (kWh)	
(3)	Subtotal Jurisdictional Sales (kWh)	
(4)	Off-System Sales (kWh)	
(5)	Supplemental and Backup Sales to Smelters Supplied from Big Rivers' Generation Resources (kWh)	
(6)	Total	
(7)	Jurisdictional Allocation Percentage for Current Month Expense Month Kentucky Jurisdictional kWhs dividded by Expense Month Total kWh Sales [(3)/(6)]	

Note: Off-System Sales excludes brokered sales
Total for Month = ____________________

Exhibit WSS-7

Big Rivers Electric Cooperative, Inc.
Estimate of
Monthly Environmental Surcharge Factor
2008 - 2012

	May - Dec 2008	2009	2010	2011	2012
NOX Plan					
HMPL Station Two (BREC Share)					
Sulfur	$ 36,418	$ 91,042	$ 93,243	$ 91,378	$ 90,794
Ammonia	331,366	828,379	848,411	831,442	826,138
HMPL Total	$ 367,784	$ 919,421	$ 941,654	$ 922,820	$ 916,932
Wilson					
Sulfur	$ 22,731	$ 30,807	$ 35,635	$ 34,238	$ 37,519
Ammonia	645,165	1,417,763	1,639,463	1,576,091	1,721,546
Wilson Total	$ 667,896	$ 1,448,570	$ 1,675,098	$ 1,610,329	$ 1,759,065
Nox Subtotal	$ 1,035,680	$ 2,367,991	$ 2,616,752	$ 2,533,149	$ 2,675,997
Allowances Costs	$ 214,723	$ 7,226,338	$ 6,104,003	$ 3,974,074	$ 3,647,901
Nox Grand Total	$ 1,250,403	$ 9,594,329	$ 8,720,755	$ 6,507,224	$ 6,323,898

Big Rivers Electric Cooperative, Inc.
Estimate of
Monthly Environmental Surcharge Factor
2008 - 2012

	May - Dec 2008	2009	2010	2011	2012
SO2 Plan					
Coleman Station					
Limestone	$ 2,463,212	$ 4,109,802	$ 4,508,418	$ 5,013,165	$ 5,310,758
Fly Ash	1,023,852	994,487	1,026,123	1,054,684	1,033,332
Bottom Ash	255,963	248,622	256,531	263,671	258,333
Gypsum Disposal	136,887	132,961	137,190	141,009	138,154
Di-Basic Acid	-	-	-	-	-
Coleman Total	$ 3,879,914	$ 5,485,872	$ 5,928,261	$ 6,472,529	$ 6,740,577
Green Station					
Lime	$ 5,494,432	$ 8,591,986	$ 8,868,152	$ 9,854,970	$ 11,709,808
Sludge Disposal	870,386	1,398,801	1,570,495	1,479,672	1,567,453
Fly Ash	375,768	603,898	678,023	638,813	676,710
Bottom Ash	93,942	150,975	169,506	159,703	169,177
Fixation Lime	436,622	671,683	707,606	690,269	731,219
Di-Basic Acid	-	-	-	-	-
Coleman Total	$ 7,271,150	$ 11,417,342	$ 11,993,782	$ 12,823,427	$ 14,854,367
HMPL Station (BREC Portion)					
Lime	$ 1,865,183	$ 3,180,689	$ 3,351,677	$ 3,761,377	$ 4,079,903
Sludge Disposal	297,966	522,204	598,580	569,527	550,746
Fly Ash	97,011	170,017	194,883	185,424	179,310
Bottom Ash	24,253	42,504	48,721	46,356	44,827
Fixation Lime	138,390	232,163	249,702	245,987	244,419
Di-Basic Acid	-	-	-	-	-
Coleman Total	$ 2,422,803	$ 4,147,578	$ 4,443,564	$ 4,808,671	$ 5,099,206
Reid					
Limestone	$ -	$ -	$ -	$ -	$ -
Sludge Disposal	-	-	-	-	-
Fly Ash	-	-	-	-	-
Bottom Ash	3,685	-	-	-	-
Fixation Lime	-	-	-	-	-
Di-Basic Acid	-	-	-	-	-
Coleman Total	$ 3,685	$ -	$ -	$ -	$ -
Wilson Station					
Limestone	$ 2,112,400	$ 2,894,220	$ 3,346,521	$ 3,216,347	$ 3,280,793
Sludge Disposal	357,434	489,817	566,083	547,225	564,497
Fly Ash	97,880	134,131	155,016	149,852	181,545
Bottom Ash	24,470	33,533	38,754	37,463	45,386
Fixation Lime	178,614	392,445	453,859	436,332	445,876
Di-Basic Acid	750,246	1,005,712	1,159,509	1,117,715	1,222,931
Coleman Total	$ 3,521,044	$ 4,949,857	$ 5,719,742	$ 5,504,933	$ 5,741,028
Sale of byproducts (Gypsum)	(226,765)	(344,008)	(343,098)	(340,674)	(322,286)
Net Allowance (Sales) Cost	(14,486,822)	(25,742,816)	(4,059,765)	(4,636,491)	(4,063,132)
S02 Grand Total	$ 2,385,009	$ (86,174)	$ 23,682,486	$ 24,632,395	$ 28,049,759

Big Rivers Electric Cooperative, Inc.
Estimate of
Monthly Environmental Surcharge Factor
2008 - 2012

	May - Dec 2008	2009	2010	2011	2012
SO3 Plan					
Wilson					
Lime Hydrate (for SO3)	$ 420,993	$ 925,127	$ 1,069,852	$ 1,028,468	$ 1,123,368
Wilson Total	420,993	925,127	1,069,852	1,028,468	1,123,368
S03 Grand Total	$ 420,993	$ 925,127	$ 1,069,852	$ 1,028,468	$ 1,123,368
Nox, S02 & SO3 Grand Total	$ 4,056,405	$ 10,433,282	$ 33,473,093	$ 32,168,087	$ 35,497,025

Big Rivers
Average Revenue Computation
In Millions of Dollars

Year	Member Twh	Smelter Twh	Subtotal Twh	Off-System Twh	Total Twh	Jurisdictional Allocation Percentage
2008	3.409	7.317	10.726	1.691	12.417	86.38%
2009	3.501	7.297	10.798	1.715	12.512	86.30%
2010	3.584	7.297	10.881	1.420	12.302	88.45%
2011	3.674	7.297	10.971	1.445	12.416	88.36%
2012	3.760	7.317	11.077	1.091	12.168	91.03%

Big Rivers
Estimate of Environmental Surcharge Factor

	May - Dec 2008	2009	2010	2011	2012
Net Pollution Control Operating Expenses	4,056,405	10,433,282	33,473,093	32,168,087	35,497,025
Jurisdictional Allocation Ratio	86.38%	86.30%	88.45%	88.36%	91.03%
Jurisdictional Expenses	3,504,034	9,003,600	29,608,363	28,425,021	32,314,523
Jurisdictional Sales (Twh) (8/12 of 2008)	7.150	10.798	10.881	10.971	11.077
Jurisdictional Environmental Surcharge Per kWh	$ 0.0005	$ 0.0008	$ 0.0027	$ 0.0026	$ 0.0029

Exhibit WSS-8

UNWIND SURCREDIT

APPLICABILITY

To all sales under Big Rivers Electric Corporation's ("Big Rivers'") Monthly Delivery Point Rate to Members as set forth in Section C.4 and Big Rivers Industrial Customer Rate as set forth in Section C.7 of Big Rivers' Rate, Rules and Regulations.

AVAILABILITY

This Unwind Surcredit (US) schedule is a rider for application to non-Smelter wholesale sales by Big Rivers Electric Corporation (Big Rivers) under Section C.4 and Section C.7. The funding for the Unwind Surcredit is made available through the Surcharge provisions of the Smelter Agreements at Sections 4.11.

DEFINITIONS

"Members" are Jackson Purchase Energy Corporation, Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation.

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

"Smelter Agreements" are the two Wholesale Electric Service Agreements each dated as of __________, 2008, between Big Rivers and Kenergy with respect to service by Kenergy to a Smelter.

DETERMINATION OF THE US

(1) The billing amount computed for all non-smelter wholesale sales to which this US is applicable shall be decreased at a rate per kWh in accordance with the following formula:

US = Surcredit + Actual Adjustment + Balance Adjustment

Where

Surcredit is the per kWh factor calculated by dividing (a) the estimated Surcharge value for the upcoming calendar year (or for remaining months in the current calendar year for the initial implementation of this Unwind Surcredit) by (b) Big Rivers' estimated non-smelter sales (NSS) to its Members for the corresponding calendar year. The Surcredit factor shall be re-determined annually with an effective date of January 1 of each calendar year.

Actual Adjustment is an adjustment which compensates for the difference between (a) the amount returned to Members through the application of the Surcredit factor and (b) the Surcharge amounts paid by the Smelters during the preceding calendar year as adjusted for any over- or under-recoveries as specified in the Smelter Agreements. The Actual Adjustment factor shall be re-determined annually with an effective date of April 1 of each calendar year.

Balance Adjustment is an adjustment that compensates for any over- or under-recoveries through application of the previous Actual Adjustment and previous Balance Adjustments. The Balance Adjustment factor shall be re-determined annually with an effective date of July 1 of each calendar year.

(2) The estimated Surcharge value is the annual payments that Big Rivers expects to receive from the Smelters during the upcoming calendar year in accordance with the Wholesale Smelter Agreements at Sections 4.11.

(3) Non-Smelter Sales (NSS) shall be the estimated kilowatt-hour sales for the upcoming calendar year made at wholesale by Big Rivers to its Members under Section C.4 and Section C.7, including the Large Industrial Rate, for resale to Kentucky ratepayers specifically excluding all sales for resale to the Smelters.

(4) The applicability of the US shall terminate when the funds provided under Sections 4.11 of the Wholesale Smelter Agreements are exhausted.

Exhibit WSS-9

Big Rivers
Estimate of Unwind Surcredits

	May - Dec 2008	2009	2010	2011	2012
Estimated Unwind Surcredits	9,300,000	10,330,000	13,870,000	13,870,000	16,080,000
Non-Smelter Member Sales (Twh) (8/12 of 2008)	2.323	3.501	3.584	3.674	3.760
Estimated Unwind Surcredit Per kWh	$ 0.0040	$ 0.0030	$ 0.0039	$ 0.0038	$ 0.0043

Exhibit WSS-10

BIG RIVERS ELECTRIC CORP

UNWIND SURCREDIT SCHEDULE

Current Month :

US Factor (1) =

$$\frac{\text{Surcharges "Surcharge(m)" (Surcharge Schedule)}}{\text{Non-Smelter Sales "NSS(m)" (Sales Schedule)}} = \frac{\qquad\qquad}{\text{KWH}} = (+) \qquad\qquad /\text{KWH}$$

Note: (1) Five decimal places in dollars for normal rounding.

Effective Date for Billing:

Submitted by ________________________________

Title:

BIG RIVERS ELECTRIC CORP
UNWIND SURCHARGES

Current Month:

Surcharges Collected From Smelters Under Smelter Agreements

Section 4.11(a)

Section 4.11(b)

Section 4.11(c)

Total Surcharges Collected From Smelters "Surcharge(m)"

BIG RIVERS ELECTRIC CORP

NON-SMELTER SALES SCHEDULE (KWH)

Current Month:

Non-Smelter Sales to Members

Kenergy	
Meade County	
Jackson Purchase	
Total Non-Smelter Sales "NSS(m)")	

Exhibit WSS-11

REBATE ADJUSTMENT

APPLICABILITY:

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

AVAILABILITY:

Available pursuant to Section A.7. of this tariff for electric service provided by Big Rivers to its Member Rural Electric Cooperatives for all Rural Delivery Points and Large Industrial Customer Delivery Points, served under Rate Schedule C.4.d. and Rate Schedule C.7., respectively.

DEFINITIONS

"Members" are Jackson Purchase Energy Corporation, Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation.

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

"Smelter Agreements" are the two Wholesale Electric Service Agreements each dated as of __________, 2008, between Big Rivers and Kenergy with respect to service by Kenergy to a Smelter.

REBATE ADJUSTMENT

In the event that there is a Rebate to the Smelters during a fiscal year under Section 4.9 of the Smelter Agreements, then Big Rivers, subject to approval from its Board of Directors, may request Kentucky Public Service Commission ("Commission") authorization to provide a cash rebate to its members pursuant to subsection 1 of KRS 278.455. The amount of a Rebate Adjustment, if any, will be the amount approved by order of the Commission. The Rebate Adjustment will be provided as a lump-sum credit to Members. Any rebate would be credited to the power bills to Members during a single month of the year. Rebates to Members shall be computed by allocating the total rebate amount to each Member system on the basis of total annual unadjusted billing Revenues received from each Member during the fiscal year for which the rebate amount was established. Big Rivers will apply to the Commission for authorization to provide a rebate to Members within six months after the end of the fiscal year. The rebate would then be provided to Members upon receipt of Commission approval.

Exhibit WSS-12

BIG RIVERS ELECTRIC CORP

REBATE ADJUSTMENT

Total Rebate Amount to be Credited on Members' Bills	$ -

(1) Member System	(2) Non-Smelter Fiscal Year Base Rate Revenue	(3) Percentage of Total	(4) Rebate Amount Allocated to Members	(5) Rebate to Members to be Included on Bills	(6) Rebate Amount Pro-rated Monthly For MRSM
			(3) x Rebate Amount	= (4)	(5) ÷ 12 months
Kenergy					
Meade County					
Jackson Purchase					
Total		100%			

Exhibit WSS-13

MEMBER RATE STABILITY MECHANISM (MRSM)

APPLICABILITY:

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

AVAILABILITY:

Available pursuant to Section A.7. of this tariff for electric service provided by Big Rivers to its Member Rural Electric Cooperatives for all Rural Delivery Points and Large Industrial Customer Delivery Points, served under Rate Schedule C.4.d. and Rate Schedule C.7., respectively.

DEFINITIONS

"Members" are Jackson Purchase Energy Corporation, Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation.

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

"Smelter Agreements" are the two Wholesale Electric Service Agreements each dated as of __________, 2008, between Big Rivers and Kenergy with respect to service by Kenergy to a Smelter.

MEMBER RATE STABILITY MECHANISM (MRSM)

Big Rivers will establish an Economic Reserve of $75 million, plus any additional amounts added at the time of closing the unwind arrangement with E.ON, which will be used to offset the effect of billing the FAC and Environmental Surcharge to non-Smelter sales, after taking into account the credits received from the Unwind Surcredit and the Rebate Adjustment. The Economic Reserve will be established as a stand-alone investment account, accruing interest. The MRSM will draw on the Economic Reserve to offset the monthly impacts of the FAC and Environmental Surcharge on each non-Smelter bill, net of the credits received under the Unwind Surcredit and Rebate Adjustment. The MRSM will offset the *total dollar impact* of billings under the FAC and Environmental Surcharge *less* the total dollar amounts received under the Unwind Surcredit and *less* a monthly pro-rata portion of any lump sum rebates provided under the Rebate Adjustment.

The amount of the MRSM credit provided to each member system during a month will each equal (i) the total dollar amount of FAC charges billed to the member during the month, *plus* (ii) the total dollar amount of Environmental charges billed to the member during the month, *less* (iii) the total dollar amount of Unwind Surcredits credited to the member during the month, *less* (iv) one-twelfth (1/12) of any rebates provided under the Rebate Adjustment during the current month or during any of the 11 preceding months; provided that the amounts subtracted in items (iii) and (iv) cannot exceed the total of items (i) and (ii), in which case the monthly MRSM adjustment would be zero.

If any portion of FAC or Environmental Surcharge costs are transferred to base rates, or if any portion of the FAC costs are transferred from base rates to the FAC, then the MRSM will account for any effect of the such transfers so that the Members will not see any impact on their bills, either positive or negative, of such transfers.

The MRSM shall be no longer applicable and shall be withdrawn once the Economic Reserve is exhausted. During the last month of the MRSM, the amount remaining in the Economic Reserve will be prorated to each member on the basis of the total FAC and Environmental Surcharge charges applicable to non-Smelter sales less credits under the Unwind Surcredits and less monthly prorated amounts under the Rebate Adjustment.

Exhibit WSS-14

BIG RIVERS ELECTRIC CORP

MEMBER RATE STABILITY SCHEDULE

Current Month :

(1)	(2)	(3)	(4)	(5)	(6)
Member System	**Non-Smelter FAC Applied During Month**	**Non-Smelter Environmental Surcharge Applied During Month**	**Unwind Surcredit Applied During Month**	**Non-Smelter Rebates Applied During Month**	**MRSM Credited During Month (2) + (3) - (4) - (5)**
Kenergy					
Meade County					
Jackson Purchase					
Total					

Notes: Rebate amounts applied during month represents 1/12 of any rebates provided pursuant to the Rebate Adjustment *during current or previous 11 months.*

During the last month of the MRSM, the remaining balance of the Economic Reserve will be pro-rated to the Members *on the basis of columns* (2) plus (3) less (4) & (5)

BIG RIVERS ELECTRIC CORP

ECONOMIC RESERVE

Current Month :

Economic Reserve at Beginning of Month	
Less: MRSM Amount Credited During Month (from Page 1)	
Plus: Interest Accrued During Month	
Economic Reserve at End of Month	

Exhibit WSS-15

Big Rivers Electric Corporation
Present Rates
Actual for 12 Months Ending October 2007

	KW	kWh	Demand Revenue	Base Energy Revenue	Power Factor Penalty	Member Discount Adjustment	Total Revenue
JACKSON PURCHASE RURALS	1,493,544	692,062,515	11,005,271 *	14,118,075		(781,793)	24,341,553
KENERGY RURALS	2,680,466	1,231,720,814	19,755,034	25,127,105		(1,401,803)	43,480,336
MEADE COUNTY RURALS	1,079,325	471,228,700	7,954,625	9,613,065		(551,707)	17,015,983
TOTAL RURALS	5,253,335	2,395,012,029	38,714,930	48,858,245	0	(2,735,303)	84,837,872
KI-ACCURIDE	70,423	28,061,478	714,793	384,863		(35,403)	1,064,253
KI-ALCOA	25,377	1,124,020	306,901 **	15,416	(11,459)	(5,962)	304,896
KI-ALERIS	339,402	187,601,720	3,444,930	2,572,958		(191,830)	5,826,058
KI-ALLIED	63,005	24,617,468	639,501	337,629		(30,820)	946,310
KI-ARMSTRONG	10,299	3,420,400	104,535	46,911	32,530	(5,860)	178,116
KI-CARDINAL RIVER	8,022	2,040,170	81,423	27,981	1,533	(3,430)	107,507
KI-DOMTAR PAPER CO.	325,000	215,731,279	3,298,750	2,958,754		(200,171)	6,057,333
KI-DOTIKI #3	8,296	5,772,110	84,204	79,164	1,056	(5,206)	159,218
KI-DYSON CREEK MINE	6,600	195,270	66,990	2,678		(2,587)	67,081
KI-HOPKINS CO. COAL	4,304	2,471,384	43,686	33,895	1,472	(2,605)	76,448
KI-KB ALLOYS, INC.	26,898	8,758,200	273,015	120,119		(12,655)	380,479
KI-KIMBERLY-CLARK	424,095	292,427,100	4,304,564	4,010,638		(264,889)	8,050,313
KI-KMMC, LLC	41,883	14,473,910	425,112	198,510		(20,132)	603,490
KI-PATRIOT COAL, LP	60,035	24,453,320	609,355	335,377	13,894	(30,150)	928,476
KI-ROLL COATER	48,165	22,967,080	488,875	314,994		(25,701)	778,168
KI-TYSON FOODS	119,477	63,561,090	1,212,692	871,740	1,289	(66,347)	2,019,374
KI-VALLEY GRAIN	22,456	8,961,092	227,928	122,901	35,506	(11,256)	375,079
JPI-SHELL OIL	61,775	22,902,180	627,016	314,103		(29,693)	911,426
TOTAL INDUSTRIALS	1,665,512	929,539,271	16,954,270	12,748,631	75,821	(944,697)	28,834,025
GRAND TOTAL	6,918,847	3,324,551,300	55,669,200	61,606,876	75,821	(3,680,000)	113,671,897

* Includes an adjustment of $2,149 given to JP due to an under billing during the period of May 2006-August 20
corrected in accordance with the Kentucky Administrative Regulations Title 807, Chapter 5, Section 10.

** 2006 - October 2006.
The under billing has been corrected in accordance with the Kentucky Administrative Regulations Title 807.
In addition, the power factor penalty reflects an adjustment related to the under billing.

Big Rivers Electric Corporation
Initial Impact of Five Adjustment Clauses

	(1) KW	(2) kWh	(3) Demand Revenue	(4) Base Energy Revenue	(5) Power Factor Penalty	(6) Member Discount Adjustment	(7) Sub-Total Revenues	(8) Fuel Adjustment Charge	(9) Environmental Surcharge	(10) Unwind Surcredit	(11) Rebate Adjustment	(12) Member Rate Stability Mechanism	(13) Sub-Total of Five Adjustment Clauses	(14) Total Revenue	(15) Percentage Impact of Five Adjustment Mechanisms
JACKSON PURCHASE RURALS	1,493,544	692,062,515	11,005,271	14,118,075		(781,793)	24,341,553	4,083,169	339,111	(2,768,250)	(173,016)	(1,481,014)	0	24,341,553	0.00%
KENERGY RURALS	2,680,466	1,231,720,814	19,755,034	25,127,105		(1,401,803)	43,480,336	7,267,153	603,543	(4,926,883)	(307,930)	(2,635,883)	0	43,480,336	0.00%
MEADE COUNTY RURALS	1,079,325	471,228,700	7,954,625	9,613,065		(551,707)	17,015,983	2,780,249	230,902	(1,884,915)	(117,807)	(1,008,429)	0	17,015,983	0.00%
TOTAL RURALS	5,253,335	2,395,012,029	38,714,930	48,858,245	0	(2,735,303)	84,837,872	14,130,571	1,173,556	(9,580,048)	(598,753)	(5,125,326)	0	84,837,872	0.00%
KI-ACCURIDE	70,423	28,061,478	714,793	384,863		(35,403)	1,064,253	165,563	13,750	(112,246)	(7,015)	(60,052)	0	1,064,253	0.00%
KI-ALCOA	25,377	1,124,020	306,901	15,416	(11,459)	(5,962)	304,896	6,632	551	(4,496)	(281)	(2,406)	0	304,896	0.00%
KI-ALERIS	339,402	187,601,720	3,444,930	2,572,958		(191,830)	5,826,058	1,106,850	91,925	(750,407)	(46,900)	(401,468)	0	5,826,058	0.00%
KI-ALLIED	63,005	24,617,468	639,501	337,629		(30,820)	946,310	145,243	12,063	(98,470)	(6,154)	(52,682)	0	946,310	0.00%
KI-ARMSTRONG	10,299	3,420,400	104,535	46,911	32,530	(5,860)	178,116	20,180	1,676	(13,682)	(855)	(7,319)	0	178,116	0.00%
KI-CARDINAL RIVER	8,022	2,040,170	81,423	27,981	1,533	(3,430)	107,507	12,037	1,000	(8,161)	(510)	(4,366)	0	107,507	0.00%
KI-DOMTAR PAPER CO.	325,000	215,731,279	3,298,750	2,958,754		(200,171)	6,057,333	1,272,815	105,708	(862,925)	(53,933)	(461,665)	0	6,057,333	0.00%
KI-DOTIKI #3	8,296	5,772,110	84,204	79,164	1,056	(5,206)	159,218	34,055	2,828	(23,088)	(1,443)	(12,352)	0	159,218	0.00%
KI-DYSON CREEK MINE	6,600	195,270	66,990	2,678		(2,587)	67,081	1,152	96	(781)	(49)	(418)	0	67,081	0.00%
KI-HOPKINS CO. COAL	4,304	2,471,384	43,686	33,895	1,472	(2,605)	76,448	14,581	1,211	(9,886)	(618)	(5,288)	0	76,448	0.00%
KI-KB ALLOYS, INC.	26,898	8,758,200	273,015	120,119		(12,655)	380,479	51,673	4,292	(35,033)	(2,190)	(18,742)	0	380,479	0.00%
KI-KIMBERLY-CLARK	424,095	292,427,100	4,304,564	4,010,638		(264,889)	8,050,313	1,725,320	143,289	(1,169,708)	(73,107)	(625,794)	0	8,050,313	0.00%
KI-KMMC, LLC	41,883	14,473,910	425,112	198,510		(20,132)	603,490	85,396	7,092	(57,896)	(3,618)	(30,974)	0	603,490	0.00%
KI-PATRIOT COAL, LP	60,035	24,453,320	609,355	335,377	13,894	(30,150)	928,476	144,275	11,982	(97,813)	(6,113)	(52,331)	0	928,476	0.00%
KI-ROLL COATER	48,165	22,967,080	488,875	314,994		(25,701)	778,168	135,506	11,254	(91,868)	(5,742)	(49,150)	0	778,168	0.00%
KI-TYSON FOODS	119,477	63,561,090	1,212,692	871,740	1,289	(66,347)	2,019,374	375,010	31,145	(254,244)	(15,890)	(136,021)	0	2,019,374	0.00%
KI-VALLEY GRAIN	22,456	8,961,092	227,928	122,901	35,506	(11,256)	375,079	52,870	4,391	(35,844)	(2,240)	(19,177)	0	375,079	0.00%
JPI-SHELL OIL	61,775	22,902,180	627,016	314,103		(29,693)	911,426	135,123	11,222	(91,609)	(5,726)	(49,010)	0	911,426	0.00%
TOTAL INDUSTRIALS	1,665,512	929,539,271	16,954,270	12,748,631	75,821	(944,697)	28,834,025	5,484,281	455,475	(3,718,157)	(232,384)	(1,989,215)	0	28,834,025	0.00%
GRAND TOTAL	6,918,847	3,324,551,300	55,669,200	61,606,876	75,821	(3,680,000)	113,671,897	19,614,852	1,629,031	(13,298,205)	(831,137)	(7,114,541)	0	113,671,897	0.00%