COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

EXHIBIT 18

Testimony of David A. Spainhoward

December 2007

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

DIRECT TESTIMONY OF DAVID A. SPAINHOWARD

ON BEHALF OF
APPLICANTS

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 (the "E.ON U.S. Parties").

I. INTRODUCTION

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

A. My testimony addresses three principal areas. First, in Section II, I address issues related to Big Rivers' and the E.ON U.S. Parties' contracts and relationship with the City of Henderson, and the City of Henderson Utility Commission, acting through Henderson Municipal Power & Light, (collectively, "Henderson"). Those contracts, specifically the Agreement and Amendments to Agreements among Henderson, Big Rivers and certain of the E.ON U.S. Parties (the "1998 Station Two Agreement"), require a consent from Henderson for an early termination of the 1998 Station Two Agreement. I describe the status of this process to obtain Henderson's consent and the related agreements in my testimony.

In Section III, I address Big Rivers' Rates, Rules and Administrative Regulations for Furnishing Electric Service (the "Tariff") and explain the proposed changes to the Tariff that are necessary to implement an unwind of the 1998 Lease Transaction (the "Unwind Transaction"). I also address some of the larger issues associated with changes to Big Rivers' Open Access Transmission Tariff ("OATT") made as part of the implementation of the Unwind Transaction, including new rates for transmission and ancillary services and other changes made to comply with Federal Energy Regulatory Commission ("FERC") changes in the standard terms and conditions of transmission and ancillary services that must be offered under an OATT in order to satisfy FERC's requirements.

In addition to the Tariff and OATT changes, in Section III I also discuss Big Rivers' proposal to reinitiate the Integrated Resource Plan ("IRP") process and propose an approach on how Big Rivers will implement its requirements after the Unwind Transaction is closed.

In Section IV, I discuss the reporting and other requirements imposed on Big Rivers as part of the 1998 Lease Transaction in connection with Big Rivers' request in the Application that it be relieved of these requirements.

Finally, in Section V, I 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.

II. HENDERSON STATION TWO ISSUES AND STATUS

Q. Please describe the contractual relationship between Henderson and Big Rivers with respect to Station Two prior to the Lease Transaction.

A. Under the terms of an August 1, 1970 Power Plant Construction and Operation Agreement between Henderson and Big Rivers ("Station Two Operating Agreement"), Big Rivers became responsible for operating and maintaining Henderson's Station Two units ("Station Two"). Big Rivers, in return, was entitled to the portion of Station Two's capacity that was surplus to Henderson's needs under an August 1, 1970 Power Sales Contract with the

City of Henderson (the "Station Two Power Sales Agreement"). Big Rivers and Henderson also entered into a third 1970 agreement relating to Station Two, the Joint Facilities Agreement. (Together, these three 1970 agreements are referred to as the "Station Two Contracts").

In 1998, prior to the closing of the Lease Transaction between Big Rivers and the E.ON U.S. Parties, Big Rivers and Henderson agreed upon amendments to the Station Two Contracts (the "1998 Station Two Contract Amendments"). The 1998 Station Two Contract Amendments established the foundation for Big Rivers to incorporate certain of its Station Two Contract obligations and benefits as part of the long-term Lease Transaction, and were implemented between Henderson and Big Rivers. Among other things, the 1998 Station Two Contract Amendments extended the terms of the Station Two Contracts for the operating life of Station Two.

Q. Please describe the relationship between Station Two and the existing Lease Transaction between Big Rivers and the E.ON U.S. Parties.

A. As part of the Lease Transaction, Big Rivers, Henderson, WKE Station Two, Inc. ("WKE Station Two"), LG&E Energy Marketing Inc. ("LEM"), and Western Kentucky Energy Corp. ("WKEC") (the last three E.ON U.S. Parties, of which WKEC is the remaining party) entered into a new multi-party agreement, the 1998 Station Two Agreement. The 1998 Station Two Agreement used the Station Two Contracts, as amended by the 1998 Station Two Contract Amendments, as the baseline for the deal between Henderson and Big Rivers and modified that deal to include WKE Station Two to perform certain obligations and obtain certain benefits for the term of the Lease Transaction.

Notwithstanding this conveyance of rights and obligations, Big Rivers remained a party to the Station Two Contracts, as amended (albeit with the E.ON U.S. Parties agreeing to perform a substantial majority of Big Rivers' obligations during the term of the Lease Transaction) and also continued in its role as transmission provider to Henderson. In general terms, however, WKE Station Two and LEM succeeded to Big Rivers' rights to the surplus capacity and energy from Station Two in return for the lease payments made to Big Rivers in the Lease Transaction, and WKE Station Two assumed the generating plant operation and maintenance responsibilities of Big Rivers under these contracts. The full terms of this arrangement are set forth in the 1998 Station Two Agreement.

In 2005, both the 1998 Station Two Contract Amendments between Big Rivers and Henderson and the 1998 Station Two Agreement between Big Rivers, Henderson, and WKEC were amended to accommodate the building of selective catalytic reduction equipment ("SCR") on the two Station Two units. References to the 1998 Station Two Contract Amendments and to the 1998 Station Two Agreement in this testimony refer to those agreements as amended in 2005.

In order to unwind the Lease Transaction, Henderson must agree to an early expiration of the term of the Station Two Agreement in order to restore Big Rivers' and Henderson's relationship regarding Station Two to its status prior to the commencement of the Lease Transaction (*i.e.*, to the status set out in the Station Two Contracts as amended by the 1998 Station Two Contract Amendments).

Q. Does the 1998 Station Two Agreement make any provision for how Station Two issues will be dealt with upon a termination of the Lease Transaction?

A. Yes. Section 10.16 of the 1998 Station Two Agreement provides that at the expiration or termination of the 1998 Station Two Agreement, all rights and obligations under the Station Two Contracts, as amended by the 1998 Station Two Contract Amendments, assigned to and assumed by the E.ON U.S. Parties, will automatically revert to and be assigned to Big Rivers without any action on the part of any of the parties to the 1998 Station Two Agreement. By means of the 1998 Station Two Contract Amendments, Big Rivers and Henderson already had amended the terms of their arrangement to accommodate a termination of the 1998 Station Two Agreement. Section 10.16 further provides that none of the E.ON U.S. Parties thereafter shall retain any interest in the Station Two Contracts, and that Big Rivers will assume, pay and perform all obligations and liabilities relating to the Station Two Contracts going forward from the date of expiration or termination.

Q. Will Big Rivers have a new agreement amending the 1998 Station Two Agreement?

A. Yes, most likely. Under the 1998 Station Two Contract Amendments, Big Rivers and Henderson updated their arrangements to enable Big Rivers to operate Station Two after the termination of the Lease Transaction. Section 10.16 of the 1998 Station Two Agreement establishes that the intent of the parties was to restore Big Rivers and Henderson to a contractual status for Station Two closely resembling their status prior to the Lease Transaction and that no separate documentation is required for the status quo to be restored once the 1998 Station Two Agreement terminates. Provided Henderson gives its consent to the early termination of the 1998 Station Two Agreement, Big Rivers under the terms of the 1998 Station Two Contract

Amendments already has a contractual structure in place under which it can operate and maintain the Station Two units and receive the excess quantities of capacity and energy to which it is contractually entitled. However, because Henderson must provide its consent to the early termination of the 1998 Station Two Agreement and because certain additional issues between Henderson, Big Rivers and the E.ON Parties have yet to be resolved, Big Rivers anticipates that an amendment in one form or another may be required.

Q. Is Big Rivers including a new amended agreement at this time as part of its filing?

A. No. Big Rivers, Henderson, and the E.ON U.S. Parties are still negotiating Station Two issues in connection with obtaining Henderson's consent to the early termination of the 1998 Station Two Agreement. In Big Rivers' discussions with Henderson, we have come to an agreement on a number of issues that were raised by Henderson, but other issues remain outstanding. Once these negotiations are completed consistent with the above general principles, Big Rivers will supplement its Application to include a new amended agreement with Henderson, if one is required.

III. DESCRIPTION OF BIG RIVERS' TARIFF CHANGES, PROPOSAL TO REINSTITUTE ITS IRP OBLIGATIONS

A. The Big Rivers Tariff

Q. Will Big Rivers be making any changes to its tariffs on file with the Kentucky Public Service Commission ("KPSC") in order to implement the Unwind Transaction?

A. Yes. Big Rivers is proposing to make changes both with respect to its existing Tariff as well as to its existing OATT.

Q. Has Big Rivers provided a description of the changes to the existing Big Rivers Tariff in its filing?

A. Yes. Big Rivers has attached as Exhibit 24 to its filing a comparison of Big Rivers' currently applicable Tariff to its proposed Tariff. Big Rivers has also provided its currently applicable Tariff as Exhibit 22. And Exhibit 23 presents the proposed Tariff.

Q. Mr. Spainhoward, could you please walk us through the changes to the Big Rivers Tariff?

A. Certainly. There are three reasons for the changes proposed to Big Rivers' Tariff: first, to reflect the reality that Big Rivers now will be generating electricity, rather than purchasing all of its needs; second, to reflect the fact that Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century") (collectively, the "Smelters") will be served under special contracts; and third, to promote general efficiency, as certain defunct or inapplicable provisions are amended or deleted to reflect current conditions.

Q. On Tariff Sheet No. 2, Big Rivers has deleted references to the Smelter delivery points. Can you explain the reasons for this change?

A. Yes. This change was necessary because Big Rivers will be providing wholesale power to Kenergy for the benefit of the Smelters under a special contract. Those special contracts are a part of this filing and will be discussed in detail in the testimony of Mr. Blackburn (Exhibit 10).

Q. Big Rivers has amended Section A(9) of its Tariff at page 10 to eliminate the use of a Billing Review Committee. Could you please explain why Big Rivers no longer intends to use this committee?

A. Big Rivers' existing Tariff provided that in billing periods where there was a potential special metering issue that a committee comprised of members of Energy Control, Engineering and Transmission, and Accounting would be employed to review demand and energy quantities. Although Big Rivers intends to perform the same tasks, Big Rivers no longer considers it necessary to employ a special committee to do so, and thus has eliminated this reference.

Q. Big Rivers in Section A(11) at page 12 has added language clarifying adjustments that may be made to its power factor calculation. Please explain this change.

A. Big Rivers' existing Tariff in Section A(11) requires that Big Rivers' three member distribution cooperatives ("Members") maintain a power factor at the time of maximum demand of not less than 90% leading or lagging. Big Rivers now proposes additional clarifying language that provides that Big Rivers will adjust the maximum metered demand in situations in which this specified 90% leading or lagging power factor is not met. In this way, Members will have a financial incentive to maintain the required power factor, and Big Rivers will be compensated for any failure to maintain this required level. Under the proposed adjustment, the maximum metered demand will be multiplied by 90% and then divided by the actual power factor percentage.

This will result in increases in the metered demand where the power factor is less than 90%.

Q. Big Rivers has modified its Transmission Emergency Control Program in Section A(15) of its Tariff. Please explain this change.

A. This section of Big Rivers' Tariff describes the actions that Big Rivers will take in an emergency to restore service. Big Rivers has made limited clarifying changes to this section. Because Big Rivers' OATT describes certain transmission priorities that must be maintained in the event of a transmission emergency requiring a curtailment, Big Rivers has added language to this section clarifying that Big Rivers will take measures to restore transmission service in a manner not inconsistent with its OATT. Big Rivers also has provided additional detail regarding some of the steps it will take to restore service in the wake of a transmission emergency.

Q. Section A(16) of Big Rivers' Tariff sets out Big Rivers' Generation Deficiency Emergency Control Program. Does Big Rivers propose any modifications to this section?

A. Yes. References in the current Section A(16) to "purchased power" have been changed to "generation" to reflect that Big Rivers will now be operating its generation. In addition, certain clarifying language has been added to the sequential steps that will be taken by Big Rivers in the case of a generation deficiency.

Q. **Section A(17) of Big Rivers' Tariff sets out Big Rivers' Fuel Emergency Control Program. Does Big Rivers propose any modifications to this section?**

A. Yes. This new section sets forth how Big Rivers will operate should its coal inventory drop below certain levels.

Q. **Section C(3) of the Big Rivers Tariff currently sets forth the terms under which Big Rivers will provide services to its Members for use by the Smelters. Does Big Rivers plan to change this section?**

A. Yes. This section will be revised to provide that it is terminated effective with the date of the closing of the Unwind Transaction. On and after the closing date of the Unwind Transaction Big Rivers will commence serving Kenergy with the wholesale power used to serve Alcan and Century pursuant to special contracts, rather than as part of the Tariff.

Q. **Sections C(5) and C(6) of the Big Rivers Tariff currently describe the rates and terms under which Big Rivers will provide transmission and ancillary services to its Members for use by the Smelters. Does Big Rivers change these sections in the proposed Tariff?**

A. Yes. These sections are revised to provide that they are terminated effective with the date of closing of the Unwind Transaction. On and after the closing date of the Unwind Transaction, Big Rivers will commence serving Kenergy with the wholesale power used to serve the Smelters pursuant to special contracts rather than as part of the Tariff.

Q. **Does Big Rivers also propose changes to its Tariff, Exhibit 22, in order to implement new cost adjustment clauses to accommodate the lease unwind?**

A. Yes. Big Rivers is proposing five cost adjustment clauses, or "riders", to be implemented as part of its Tariff: (1) Rebate Adjustment (Tariff Section 15); (2) Environmental Surcharge (Tariff Section 16); (3) Fuel Adjustment Clause (Tariff Section 17); (4) Member Rate Stability Mechanism (Tariff Section 18) ; and (5) Unwind Surcredit (Tariff Section 19). These five riders are critical to Big Rivers' efforts to unwind and terminate the Lease Transaction and are the subject of the separate testimony of William Steven Seelye at Exhibit 25. Mr. Seelye fully describes the operation and explanation for these tariff changes.

Q. What other areas of the Tariff does Big Rivers propose to change?

A. As another consequence of the end of the Lease Transaction and the associated termination of power purchases from WKEC (as assignee of LEM) to meet Big Rivers' Member loads (exclusive of the Smelter loads) under the Power Purchase Agreement with WKEC ("Purchase Agreement"), Big Rivers also is revising the sections of its Tariff dealing with Cogeneration Rates to reflect Big Rivers' changed capacity resource avoided costs and purchased power options. Big Rivers has included revisions to two cogeneration tariffs. First, Big Rivers has revised its Cogeneration and Small Power Production Purchase Tariff for cogenerators with over 100 KW. Second, Big Rivers has revised its Cogeneration and Small Power Producer Sales Tariff for cogenerators with over 100 KW. Uniform changes to these two tariffs include removal of all references to the applicable E.ON U.S. Party (LEM) and to purchases from LEM under the Purchase Agreement. The sales tariff replaces fixed rates tied to LEM with rates tied to Big Rivers' effective tariff rates. In place of the prior references to the Purchase Agreement, Big Rivers incorporates new formulas to calculate capacity purchase rates and firm energy purchase rates in the purchase tariff. The purchase tariff will be based on a formula approach to the calculation of avoided costs.

B. Changes to Big Rivers' OATT

Q. Big Rivers is also changing its Open Access Transmission Tariff. Could you please provide background regarding Big Rivers' OATT?

A. Big Rivers introduced its OATT in 1998 as part of the Lease Transaction. The 1998 Lease Transaction left Big Rivers in control of its transmission system. Both the E.ON U.S. Parties and the Smelters required access to that transmission system (the E.ON U.S. Parties for off-system sales and the Smelters for imports of so-called Tier 3 service). The OATT served as the means to assess unbundled charges for transmission service and ancillary service.

Previously, in 1996, the Federal Energy Regulatory Commission ("FERC") had issued its Order No. 888 (*Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*). FERC's Order No. 888 required transmission-owning utilities subject to FERC's jurisdiction as public utilities under the Federal Power Act to unbundle the costs and services for transmission and ancillary services from wholesale sales of power. Although Big Rivers was not subject to that order, Order No. 888 did impose a reciprocity requirement that directed any user of a public utility's OATT to provide reciprocal access to that user's own transmission facilities on a comparable basis to the service provided to the owner and operator of those facilities. Because Big Rivers intended to use third-parties' OATTs, having a ready means of providing reciprocal access to transmission service for those third-parties was deemed advantageous.

Big Rivers thus implemented an OATT as part of the 1998 Lease Transaction. Big Rivers calculated a transmission cost of service and incorporated generation-based ancillary services rates that were direct pass-throughs of amounts to be charged Big Rivers by the E.ON U.S. Parties for the provision of required generation-based ancillary services. The OATT Big Rivers filed was based almost entirely on the *pro forma* Order No. 888 OATT published by FERC. Big Rivers' only substantive changes to the *pro forma* tariff were ones designed to reflect the fact that Big Rivers is a non-FERC-jurisdictional cooperative and one that did not operate generation assets.

Q. Why is Big Rivers filing its OATT with the Kentucky Public Service Commission?

A. Big Rivers is not regulated as a "public utility" by the FERC under Part II of the Federal Power Act. Accordingly, the rates, terms and conditions of Big Rivers' OATT are not subject to direct jurisdiction by FERC, although FERC did issue a declaratory order finding that Big Rivers' OATT satisfied FERC's reciprocity requirements. Because the Lease Transaction involved Big Rivers providing Tier 3 transmission service to the Smelters, Big Rivers and the Smelters requested that the KPSC take jurisdiction over Big Rivers' OATT in order to provide a forum for reviewing its rates, terms, and conditions. The KPSC agreed to do so to the extent not preempted from doing so and approved Big Rivers' OATT as part of its approval of the Lease Transaction. Accordingly, Big Rivers now is filing these changes to its OATT with the KPSC and asking the KPSC to exercise its jurisdiction and approve the revised OATT.

Q. Will Big Rivers also be filing the OATT with FERC?

A. Yes. Although Big Rivers is not required to file the OATT with FERC, Big Rivers will be seeking a declaratory order from FERC that the new OATT qualifies as a valid reciprocity tariff under FERC's Order No. 890 standards. Big Rivers intends to file this declaratory order in sufficient time to obtain a FERC order by the Unwind Transaction closing date.

Q. Why is Big Rivers changing its OATT as part of the Unwind Transaction?

A. Big Rivers is changing its OATT for two reasons. First, FERC in 2007 implemented a new rule significantly amending many of the provisions of the Order No. 888 OATT mechanism. In February 2007, FERC issued Order No. 890 (*Preventing Undue Discrimination and Preference in Transmission Services*) with a revised *pro forma* OATT. Having had more than ten years of experience operating under the Order No. 888 tariffs, FERC implemented a number of refinements throughout the new tariff to more closely align operations to the non-discriminatory system FERC envisioned. Order No. 890 continues to incorporate a reciprocity requirement, and Big Rivers saw the occasion of the Unwind Transaction as the ideal time in which to incorporate these FERC-driven OATT changes to reflect Order No. 890. Big Rivers would be making these changes irrespective of the changes it is making to reflect the Unwind Transaction.

Second, as noted in the testimony of Ralph L. Luciani (Exhibit 35), Big Rivers' resumption of ownership and control of the generation facilities in place of the E.ON U.S. Parties eliminates the existing pass-through used for the determination of the generation-based ancillary services costs included in Big Rivers' OATT. Because Big Rivers did not have an OATT prior to the Lease Transaction, Big Rivers had never implemented generation-based ancillary services rates reflecting its own ancillary services costs. Consequently, Big Rivers engaged Ralph Luciani of CRA International, Inc. to develop new generation-based ancillary services rates based on Big Rivers' operation of the reverted generation assets to incorporate into Big Rivers' OATT in place of the pass-through of the E.ON U.S. Parties' rates. Mr. Luciani has also developed new transmission rates to update all of the rates in Big Rivers' OATT.

Q. Does Big Rivers provide a comparison of the changes in its revised OATT to its existing OATT in its filing?

A. Yes. Exhibit 34 contains a red-lined version of the Big Rivers OATT comparing the differences between the new Order No. 890 version of Big Rivers' OATT (attached as Exhibit 33) to the existing Order No. 888-based version of Big Rivers' OATT (attached as Exhibit 32). The changes between the two versions are significant. However, the overwhelming majority of these changes simply reflect FERC's restructuring of the tariff rather than changes initiated by Big Rivers. Apart from implementing the new Big Rivers focused generation-based ancillary services rates necessary as a result of the Unwind Transaction and updating Big Rivers' transmission rates, Big Rivers merely is implementing the revised terms of the Order No. 890 OATT in the proposed OATT. In certain limited respects, Big Rivers' OATT differs from the *pro forma* Order No. 890 OATT, but many of these differences already were reflected in Big Rivers' existing OATT.

Q. Would you please describe the ways in which Big Rivers' proposed OATT differs from the FERC *pro forma* Order No. 890 OATT?

A. Some changes to the OATT simply reflect the fact that Big Rivers is not regulated as a "public utility" by FERC and thus is not required to file rates, terms and conditions of its tariff with FERC. Sections of the OATT changed on this basis include: Section 3; Section 9; Section 11; Section 12.4; Section 12.5; Section 15.6; Section 26; Section 29.5; and Section 34.5. These changes parallel changes Big Rivers made at the time it filed its currently effective OATT.

In addition, Big Rivers has replaced the term "Transmission Provider" throughout the OATT with "Big Rivers." Big Rivers made this identical change in its Order No. 888 OATT.

Order No. 890 also creates an obligation to post certain information regarding the timing of system impact studies, and requires transmission providers to pay fines in situations where response times exceed certain amounts. Because Big Rivers is not subject to FERC's regulation and is not required to file this information, Big Rivers has not incorporated these sections of the *pro forma* OATT.

Q. How else does the Big Rivers OATT differ from the FERC Order No. 890 *pro forma* OATT?

A. The new OATT assesses penalties from entities that take unreserved ancillary service or transmission service. The FERC *pro forma* Order No. 890 OATT in a number of places (Sections 13.7(c); 14.5; 28.6; 30.4; and Schedule 9) specifically gives the transmission provider discretion to specify the rate treatment for the use of unreserved transmission and ancillary services. FERC elsewhere in Order No. 890 indicated that in general it will allow charges of up to 200% of the cost of service. Big Rivers has adopted this amount as its default penalty language. In addition, Order No. 890 requires transmission providers to specify an allocation method to rebate the penalty portion of these charges in appropriate circumstances. Big Rivers addresses this requirement in Section 15.8 of the new OATT in a straight-forward manner.

Q. Are there other changes to the Big Rivers OATT as compared to the Order No. 890 *pro forma* OATT?

A. Yes. Big Rivers has made a number of small changes to the Order No. 890 *pro forma* tariff to more accurately reflect its operations. For example, Big Rivers has adjusted Section 7.1 of the OATT to incorporate Big Rivers' standard billing procedures and practices. And in Sections 7.2 and 17.3 Big Rivers replaces FERC's regulatory interest rate on payments with the U.S. Treasury Bill interest rate. This change mirrors the provisions of the existing Big Rivers OATT. Big Rivers refines the term "Native Load Customers" in Section 1.19 specifically to include its three member distribution cooperatives. And Big Rivers omits Section 5 of the *pro forma* OATT dealing with local furnishing bonds because they are inapplicable to Big Rivers. Big Rivers made an identical change in its existing OATT.

Q. Does the proposed Big Rivers OATT change any of the information included in the attachments to the FERC Order No. 890 *pro forma* OATT?

A. Yes. One of the principal reasons FERC issued Order No. 890 was FERC's concern that there was a lack of standardization in the technical issues surrounding transmission service (*e.g.*, calculation of available transmission, transmission planning and expansion methodologies, and treatment of parallel flows). As part of Order No. 890, FERC specified a new level of detail that transmission providers should include in certain of their attachments to their OATTs dealing with these technical transmission issues. However, with regard to some of these issues FERC is working to develop new standards that are not yet completed. Accordingly, Big Rivers has complied with these requirements to the extent possible and has altered a number of these attachments from those included in the existing Big Rivers OATT to reflect changes that have been put in place.

Big Rivers incorporates a revised Attachment C to reflect Big Rivers' current methodology to determine available transmission capability ("ATC"). As FERC further refines ATC requirements it may be necessary for Big Rivers either to supplement this Application or later revise the OATT.

Big Rivers also incorporates a revised Attachment D to reflect Big Rivers' current methodology used to process System Impact Studies. This is another area of focus of Order No. 890. As with Attachment C, it may become necessary to supplement or revise this attachment if FERC further specifies how these studies are to be performed.

Big Rivers incorporates a revised Attachment J to address issues related to parallel flows across its transmission system. In the submitted Attachment J Big Rivers details its operating practices under the Joint Reliability Coordination Agreement among the Tennessee Valley Authority ("TVA") and the Midwest Independent System Operator, Inc. Because TVA acts as the reliability coordinator for Big Rivers, TVA will address this parallel flow issue under that agreement in the manner specified in the revised Attachment J.

Finally, in Attachment K Big Rivers includes its Transmission Planning Procedures. Big Rivers intends to meet Order No. 890's regional transmission planning requirements through joint participation with TVA, East Kentucky Power Cooperative, and AECI in a planning entity to be known as the Central Public Power Participants ("CPPP"). CPPP will interface with other regional entities in MISO, PJM, and the southeast as applicable. A draft of the CPPP approach to meet Order No. 890's planning requirements is included at Attachment K. Big Rivers will revise this portion of the filing if and when Big Rivers develops a new transmission planning process.

Q. Are there any other changes to the Big Rivers OATT?

A. Yes. A final change to the submitted OATT is Big Rivers' inclusion of a new detailed creditworthiness procedure in Attachment L. FERC requires all transmission providers to include a detailed creditworthiness procedure that will give potential customers advance notice of the creditworthiness standards applicable to them. Big Rivers believes this creditworthiness procedure is fair towards third-parties and meets FERC's requirements for a creditworthiness proposal.

C. Integrated Resource Plan

Q. Please describe Big Rivers' current obligations with respect to the Integrated Resource Plan.

A. Kentucky Administrative Regulation 807 KAR 5:058 establishes an integrated resource planning process that requires the Commission to review the long-range resource plans of electric utilities subject to its jurisdiction. Big Rivers most recently filed its IRP with the Commission on November 29, 2005. Big Rivers later on January 11, 2006 filed a motion to hold the case (Case No. 2005-00485) in abeyance. On April 18, 2006, Big Rivers asked the Commission to continue to hold the case in abeyance, and the Commission continues to hold the IRP case in abeyance.

Q. How does Big Rivers propose to meet its IRP obligations after the Unwind Transaction is closed?

A. Big Rivers requests in the Application that the Commission terminate Case No. 2005-00485 which has been held in abeyance for the past two years. Big Rivers commits to file its next IRP no later than November 2010.

Q. Why does Big Rivers propose to wait until November 2010 to file an IRP?

A. The current IRP filed in November 2005 was not based on circumstances in which Big Rivers operated its generation. Accordingly, it is appropriate to terminate Case No. 2005-00485. Big Rivers is scheduled to conduct a new load forecast in 2009. This new forecast will be the basis for the development of its IRP. Big Rivers believes that a postponement of the filing of its IRP until 2010 is appropriate and will allow a presentation based on the best information available.

IV. <u>RELIEF FROM 1998 LEASE TRANSACTION REPORTING AND OTHER REQUIREMENTS</u>

Q. Did the Commission impose any reporting and other requirements on Big Rivers in connection with its approval of the 1998 Lease Transaction?

A. Yes. The Commission approved the 1998 Lease Transaction in orders dated April 30, 1998 in P.S.C. Case No. 97-204 and July 14, 1998 in P.S.C. Case No. 98-267 (the "1998 Orders"). The 1998 Orders are attached as Exhibit 6 to the Application.

In the 1998 Orders, the Commission included a number of reporting and information requirements on Big Rivers which Big Rivers now desires the Commission to terminate. Specifically, the Commission set forth the following requirements: (i) ordering paragraph 3 of P.S.C. Case No. 98-267 required Big Rivers to adopt a 50/50 sharing methodology for the reporting and recovery of unforeseen changes in transmission costs due to the Smelters' load; (ii) ordering paragraph 5 of P.S.C. Case No. 98-267 required Big Rivers annually to file and update its financial model; and (iii) ordering paragraph 20 of P.S.C. Case No. 97-204 required Big Rivers to file a report of its arbitrage sales and other sales every six months (which requirement later was incorporated into the annual filing of the financial model).

In addition, ordering paragraph 15 of P.S.C. Case No. 97-204 required Big Rivers to file a new depreciation study for Commission approval. As part of that later filing, the Commission sought assurances that Big Rivers' generating units would be operated for the period implicit in the new depreciation rates used in the depreciation study. In approving the depreciation study required by Case No. 97-204, the Commission, by letter issued October 7, 1999, also imposed a requirement that Big Rivers file an annual report describing the previous year's plant maintenance as well as major maintenance projects scheduled for the future year.

Q. What does Big Rivers propose with respect to these reporting and other requirements?

A. With the closing of the Unwind Transaction there no longer will be a need for these reporting and other requirements that were imposed on Big Rivers in the 1998 Orders. These requirements related only to the circumstances involved in the 1998 Lease Transaction and will have no further relevance upon its termination. Big Rivers thus proposes that the Commission's order in the Application expressly relieve Big Rivers of these requirements.

V. ENVIRONMENTAL COMPLIANCE PLAN AND ENVIRONMENTAL SURCHARGE

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

A. Big Rivers and WKEC have 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 are 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. In Case No. 2007-0455, Big Rivers is requesting approval for its Unwind Transaction, which incorporates the use of the new Environmental Surcharge. Separately, in Case No. 2007-00460, Big Rivers is requesting approval of the Environmental Surcharge. Accordingly, I include this section of my testimony describing the Environmental Surcharge in both proceedings.

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 25, 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 the agreements with Henderson, portions of SO_2 allowances received from the EPA are retained by 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 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 25, 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 20th day of December, 2007.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires: 1-19-09

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 disppsal						
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)

ATTACHMENT 1

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	$1,028,468	$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

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	$ 763	$ 2,847	$ 2,409	$ 2,155	$ 1,985
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	(0.281)	(2.538)	(2.534)	(1.844)	(1.838)
NOx allowances Sales	($214,403)	($7,225,686)	($6,104,406)	($3,973,820)	($3,648,430)

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