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October 9, 2008

Hon. Stephanie Stumbo
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: The Applications of Big Rivers Electric Corporation for: (1) 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 of E.ON U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing, Inc. for Approval of Transactions, PSC Case No. 2007-00455

Dear Ms. Stumbo:

Enclosed for filing on behalf of the Applicants are an original and ten copies of their motion to amend and supplement the application that was filed in this matter. I certify that this letter and the motion have been served on the attached service list.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej
Enclosures

cc: Michael H. Core
David Spainhoward
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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
OF E.ON U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING INC. FOR APPROVAL OF TRANSACTIONS	)	

MOTION TO AMEND AND SUPPLEMENT APPLICATION

The joint applicants ("Applicants") Big Rivers Electric Corporation ("Big Rivers"), E.ON U.S. LLC ("E.ON US"), Western Kentucky Energy Corp. ("WKEC"), and LG&E Energy Marketing, Inc. ("LEM," and collectively with E.ON US and WKEC, the "E.ON Parties") jointly move the Public Service Commission ("Commission") pursuant to 807 KAR 5:001 Section 3(5) for an order allowing them to amend and supplement the original application, as amended, in this matter (the "Application") as set forth herein. In summary form, the Applicants seek to amend and supplement the Application for the following purposes:

- The Applicants describe the terminations by Big Rivers of the leveraged leases entered into by Big Rivers in 2000[1] ("Leveraged Leases"), and the effect of the Leveraged Lease terminations on the Unwind Financial Model and the Application. With the exception of certain agreements concerning funding of the costs of the

[1] Approval to enter into the Leveraged Leases was granted by the Commission in its orders of November 24, 1999 and March 29, 2000 in Case No. 99-450, *In the Matter of Big Rivers Electric Corporation's Application for Approval of a Leverage Lease of Three Generating Units*.

Leveraged Lease terminations at the Unwind Transaction closing, no Commission approval was or is required for the Leveraged Lease terminations. This subject is discussed in more detail in paragraph numbers 4 through 13 of this motion.

- Big Rivers informs the Commission and the parties to this proceeding through the Third Supplemental Direct Testimony of C. William Blackburn (Exhibit 78, pages 12 through 22) of the changes Big Rivers has made in its financing plans since filing of the April 23, 2008 Motion to Amend and Supplement Application to include Big Rivers' plans for financing its operations following the closing of the Unwind Transaction. As is further described herein, those financing arrangements and documents are greatly simplified by the termination of the Leveraged Leases, as discussed below in paragraph number 9. Big Rivers also requests Commission approval of the proposed accounting treatment of the termination of the Leveraged Lease transactions, as described in paragraph number 12, below, and on page 14 of Exhibit 78.
- Big Rivers also seeks to file an updated version of its Unwind Financial Model, attached hereto as Exhibit 79, and to describe certain changes in assumptions and inputs that have occurred since the last iteration of the Unwind Financial Model provided to the Commission in June 2008 (the "June Model"). This subject is discussed in more detail in paragraph numbers 14 through 18 of this motion.
- The Applicants also seek to file a Third Amendment to Transaction Termination Agreement among Big Rivers, LEM and WKEC, attached hereto as Exhibit 80, which amends the original Transaction Termination Agreement filed as Exhibit 3 to the Application. This amendment supplements the terms of the Unwind Transaction

between the principal parties, and is described in detail in paragraph number 20 of this motion.

- Big Rivers further seeks to file revised versions of certain of the agreements between and among Big Rivers, Kenergy Corp., Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century," and collectively with Alcan, the "Smelters"), attached hereto as Exhibits 81 (clean) and 82 (redlined)(the "Smelter Agreements"). These document revisions are discussed in more detail in paragraph number 21 of this motion.
- Big Rivers also seeks approval to revise its general tariff ("Tariff"), attached hereto as Exhibits 83 (clean) and 84 (redlined), to delete the tariff language regarding the Member Discount Adjustment, which expired in August, and to make other revisions driven by changes in the Unwind Transaction and the Smelter Agreements as well as by the Commission's orders in Case Nos. 2007-00164 and 2007-00460. These changes are discussed in more detail in paragraph numbers 23 through 24 of this motion. Big Rivers also implements a change in its Member Rate Stability Mechanism preferred by its Members that applies funds from the Economic Reserve to mitigate rate shock from forecasted increases in costs. These changes are discussed in more detail in paragraph number 25.
- Big Rivers also seeks approval to revise and replace its Open Access Transmission Tariff ("OATT"), attached hereto as Exhibits 85 (clean) and 86 (redlined), to reflect changes in Federal Energy Regulatory Commission ("FERC") requirements. These changes are discussed in more detail in paragraph number 26 of this motion.

- Big Rivers also proposes to file draft agreements between Big Rivers and the City of Henderson, Kentucky and the City of Henderson, Utility Commission (collectively, "Henderson"), attached hereto as Exhibit 87. Big Rivers and Henderson have not reached agreement on the issues covered by the proposed agreements, and these proposed agreements have not been reviewed by or consented to by Henderson. These agreements, and the purpose for filing them, are discussed in more detail in paragraph numbers 27-29 of this motion.
- The information attached in support of this motion includes supplemental direct testimony from the following Applicants' witnesses:

  C. William Blackburn (Exhibit 78)

  Paul W. Thompson (Exhibit 91)

  Robert S. Mudge (Exhibit 98)

  David A. Spainhoward (Exhibit 99)

  Burns E. Mercer (Exhibit 101)

  Michael H. Core (Exhibit 102)

  William Steven Seelye (Exhibit 103)

  Mark A. Bailey (Exhibit 104)
- The Applicants propose a new procedural schedule, attached hereto as Exhibit 88. The dates proposed on the schedule respond to concerns about timing expressed by Commission staff on conference calls among the parties to this case, and by the Attorney General.

DISCUSSION

Big Rivers states as follows in support of this motion:

1. The Applicants have sought multiple amendments to the Application to supplement, revise or update information in the record, and to add requests for relief. To assist the Commission and the parties to this proceeding in reviewing these filings, the Applicants attach to this motion a revised and expanded "Table of Contents" to all exhibits. This table of contents lists all exhibits to the Application, including those first filed with this motion, and identifies the location of each exhibit in the record. It also states the location in the record of any earlier or superseded versions of an exhibit. Exhibits to this Motion are numbered beginning with Exhibit 78 to continue the exhibit numbering system from Big Rivers' Third Amendment and Supplement to Application, filed on or about April 23, 2008.

2. The Applicants further file with this motion a current schedule of all relief requested by the Applicants in this proceeding as Exhibit 89. This Exhibit 89 supersedes Exhibit 29 to the Application, the earlier version of that schedule.

3. The Applicants believe and represent that the documents included with this motion complete the documents required to support the relief sought by them in this proceeding. Accordingly, they file with this motion as Exhibit 88 a proposed amended procedural schedule to bring this proceeding to a conclusion within the time frame required to preserve and close the Unwind Transaction on February 26, 2009. The procedural schedule proposes time for additional data requests to the Applicants, supplemental intervenor testimony, and a hearing commencing on December 2, 2008. If the Commission then issues an order on or before January 23, 2009, the parties can close the Unwind Transaction on February 26, 2009.

Resolution of Ambac Issue

4. Big Rivers, with the assistance of the E.ON Parties, has resolved the so-called "Ambac Issue" by terminating the Leveraged Leases in which the issue arose in separate

transactions that closed on June 30, 2008, and on September 30, 2008. The Ambac Assurance Corporation ("Ambac") issue (the "Ambac Issue") arose out of the requirement in the agreements documenting Big Rivers' leveraged lease transactions, consummated by Big Rivers on April 18, 2000, that Big Rivers replace Ambac's credit support position in those Leveraged Leases with a suitable credit enhancer if Ambac ever failed to meet the minimum credit ratings requirements set forth in those agreements. That circumstance occurred on June 19, 2008, with the downgrade of Ambac by Moody's Investors Service to Aa3. The hearing in this matter previously scheduled to begin June 30, 2008, was postponed on the motion of the Applicants to give Big Rivers and the other parties with an interest time to resolve the Ambac Issue, and to define the impact of that resolution on the Unwind Transaction that is the subject of this proceeding.

5. The Leveraged Leases are described in detail in the Status Report dated August 29, 2008, filed by the Applicants in this proceeding, and which is refiled as Exhibit 90 to this motion, for convenience of the Commission and the parties. The Leveraged Leases, and the resolution of the Ambac Issue are also discussed in detail in the Third Supplemental Direct Testimony of C. William Blackburn, filed as Exhibit 78 to this motion, at pages 9 through 22, and in the Supplemental Testimony of Paul W. Thompson, filed as Exhibit 91 to this motion, at pages 4 through 7.

6. These commercial transactions are independent of and unrelated to the 1998 transactions approved by the Commission between E.ON US and its affiliates and Big Rivers[2]

[2] *In the Matter of: The Application of Big Rivers Electric Corporation, Louisville Gas and Electric Company, Western Kentucky Energy Corp., Western Kentucky Leasing Corp., and LG&E Station Two Inc. for Approval of Wholesale Rate Adjustment for Big Rivers Electric Corporation and for Approval of Transaction*, Case No. 97-204, Final Order (June 11, 1998); *In the Matter of: The Application of Big Rivers Electric Corporation for Approval of the 1998 Amendments to Station Two Contracts Between Big Rivers Electric Corporation and the City of Henderson, Kentucky and the Utility Commission of the City of Henderson*, Case No. 98-267, Final Order (July 14, 1998). See also, *In the Matter of: The Application of Big Rivers Electric Corporation, LG&E Energy Marketing*

that are proposed to be terminated in the Unwind Transaction that is the subject of this proceeding. Yet the potential significance of the Ambac Issue, and the contractual requirement that the issue be solved within 60 days following the downgrade of the Ambac rating, forced Big Rivers to give immediate attention to it.

7. The requirement in the Leveraged Leases that Big Rivers replace the Ambac credit enhancement was a duty owed by Big Rivers to Trisail Capital Corporation, which is controlled by Bank of America Leasing Corporation ("BoA"), and to Bluegrass Leasing, which is controlled by Philip Morris Capital Corporation ("PMCC"). After study and negotiations in each instance with the parties to the Leveraged Leases, as well as the Rural Utilities Service ("RUS"), Big Rivers determined that the likeliest favorable alternative of the several alternatives considered for solving the Ambac Issue as to each of BoA and PMCC was to terminate the Leveraged Leases of the respective party through a buyout (the "BoA Buyout" and the "PMCC Buyout"). *See* Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78, at pages 9 through 22; Affidavit of C. William Blackburn, Exhibit 92, *passim*.

8. The terms for the BoA Buyout and the PMCC Buyout are contained in documents that have been filed with the Commission on an informational basis regarding the BoA Buyout on June 11, 2008, and July 7, 2008, and regarding the PMCC Buyout on approximately October 1, 2008, and October 7, 2008. Except for the amount of the termination payment, the terms of the termination and the documents required for the termination closely mirror each other. The details of the cash flows for these two transactions are more fully described in the Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78, pages 9 through 11 and Exhibit CWB-9, and the effect of these transactions on the Unwind Financial Model is described

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Inc., Western Kentucky Energy Corp., WKE Station Two Inc. and WKE Corp. for Approval of Amendments to Transaction Documents, Case No. 2000-00118, Order (November 24, 1999).

in the Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78, pages 26 through 29.

9. The BoA Buyout and the PMCC Buyout terminate all of the Leveraged Leases entered into by Big Rivers in 2000. This eliminates from Big Rivers' current financing application a number of documents that were required only by reason of the existence of the leveraged leases between Big Rivers and PMCC and BoA. A full list of the financing documents previously filed in this case that are no longer required is presented as Exhibit 93 to the Application.

10. Big Rivers' financing plans stated in its filings on December 28, 2007, March 28, 2007, April 10, 2008 and April 23, 2008, change as a result of the termination of the Leveraged Leases to which Big Rivers was a party. At closing, Big Rivers will enter into an amended RUS note, the 2008 RUS Promissory Note, Series A (the "<u>RUS A Note</u>"). The amendment does not require Commission approval, but is attached hereto as Exhibit 94 for information purposes. Big Rivers anticipates it will need to reduce the RUS A Note principal balance by approximately \$140.2 million at closing of the Unwind Transaction, approximately an additional \$60.0 million in 2012 and approximately an additional \$200 million by no later than 2016. The details of these payments, which the Unwind Financial Model assumes will require financings, are more fully described in the Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78, pages 12 through 13.

11. Big Rivers seeks approval of the agreements it has entered into regarding funding of the terminations of the Leveraged Leases because they contain contingencies tied to the approval and closing of the Unwind Transaction. The funding agreements for the BoA Buyout are contained in a letter dated June 24, 2008, titled "Funding of Certain Amounts to be Paid to

The Bank of America" among Big Rivers, E.ON U.S., LLC, Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, and another letter dated June 24, 2008, titled "Payment Regarding the Buy-Out of the Bank of America" among Big Rivers and E.ON (the "BoA Letter Agreements"). The BoA Letter Agreements were filed with the Commission on or about July 8, 2008, and copies of them are attached hereto as Exhibit 95. Under the terms of the BoA Letter Agreements, E.ON U.S. funded the BoA Buyout. If the Unwind Transaction closes, Big Rivers and the Smelters will each reimburse E.ON $1 million. The funding agreement for the PMCC Buyout is incorporated into the Third Amendment to Transaction Termination Agreement, which is attached hereto as Exhibit 80 (the "PMCC Cost Share Agreement"). Big Rivers funded the PMCC Buyout. Under the PMCC Cost Share Agreement, if the Unwind Transaction closes, the E.ON Parties will pay Big Rivers one-half of the net amount paid to PMCC. Big Rivers will fund its remaining $60.9 million by reducing the amount it had anticipated prepaying to the Rural Utilities Service ("RUS") at the closing of the Unwind Transaction from $200 million to $140.2 million. The PMCC Cost Share Agreement is more fully described in the Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78 at page 10.

12. Big Rivers also seeks approval of certain accounting treatment relating to the PMCC Termination Agreement and the BoA Termination Agreement. This accounting treatment is described in the attached Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78 at page 24 and Exhibit CWB-11.

13. Big Rivers seeks approval of changes to the indenture and to certain other of the securities instruments attached hereto as Exhibit 96 to eliminate references to the parties involved in the BoA Leveraged Leases and in the PMCC Leveraged Leases. These changes are

detailed in the attached Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78 at pages 12 through 13.

Financial Effects of PMCC Buyout on Unwind Transaction

14. Big Rivers seeks approval to substitute the updated version of the Unwind Financial Model attached hereto as Exhibit 79 for the June Model. Big Rivers has used the updated Unwind Financial Model to isolate the financial effects of the PMCC Buyout and the BoA Buyout, and presents a comparison to show just the financial effects of the PMCC Buyout and the BoA Buyout. This comparison is shown as an attachment to the Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78, pages 40 through 41 and Exhibit CWB-12. This comparison estimates the weighted average effect of the PMCC Buyout and the Bank of America buyout to be $0.39/MWh on Non-Smelter Rates and $0.27/MWh on Smelter Rates.

Other Updated Financial Effects on Unwind Transaction

15. In addition to modeling the financial effects of the PMCC Buyout and the BoA Buyout, Big Rivers also has incorporated other known changes to the Unwind Financial Model since it was last supplied to the Commission. Some of the key changes to the Unwind Financial Model include incorporating, for modeling purposes, a new assumed Unwind Transaction closing date of December 31, 2008, rather than April 30, 2008, the use of new projected startup fuel prices, changes resulting from the federal Clean Air Interstate Rule ("CAIR") regulations being overturned, changes to certain known Big Rivers general and administrative costs and operations and maintenance costs, and other matters. Many of these changes are driven by the output of Big Rivers' Production Cost Model, which was updated in September 2008 and is provided hereto as Exhibit 97. The combined financial effects from the June Model to the updated Unwind Financial Model is presented as an attachment to the Third Supplemental Direct

Testimony of C. William Blackburn, Exhibit 78, pages 41 and 42 and Exhibit CWB-13. This comparison estimates the weighted average effect of all changes to be a $1.38/MWh increase in Non-Smelter Rates and a $1.49/MWh increase in Smelter Rates.

16. The various changes to the Unwind Financial Model, both those from the leveraged lease buyouts and otherwise, and the impact of those changes are discussed generally in the attached Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78, pages 26 through 40, while the Supplemental Direct Testimony of Robert S. Mudge, Exhibit 98 hereto, pages 3 through 9, discusses the actual implementation of these changes into the Unwind Financial Model. In addition, the Supplemental Direct Testimony of David A. Spainhoward, Exhibit 99 hereto, discusses the changes due to CAIR and the new emissions allowances pricing assumptions that modify inputs to the Unwind Financial Model. In addition, these changes have prompted Big Rivers to change the cost estimates in its limited Environmental Compliance Plan. However, as Mr. Spainhoward demonstrates, the changes to Big Rivers' limited Environmental Compliance Plan do not change the environmental surcharge structure. Supplemental Direct Testimony of David A. Spainhoward, Exhibit 99, pages 29 through 30.

17. Big Rivers also provides a comparison of Big Rivers' rates under the Unwind Transaction and Big Rivers' rates under the existing transaction as Exhibit 100 hereto, which is more fully discussed in the Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78 at pages 64 through 65.

18. Despite these increases in Big Rivers' rates produced by the Leveraged Lease buyouts and the other Unwind Financial Model updates, Big Rivers and its Members still support the Unwind Transaction. Supplemental Direct Testimony of Burns E. Mercer, Exhibit 101 at pages 4 through 5. Big Rivers' financial flexibility still will be increased, the benefits of

retaining the Smelters will remain the same, and Big Rivers will be economically stronger after closing of the Unwind Transaction. Big Rivers' continued belief in the benefits of the Unwind Transaction is provided in the Supplemental Direct Testimony of Michael H. Core, Exhibit 102 at pages 7, 11, and 15 through 16.

19. Big Rivers, in response to concerns of its Members about a rather dramatic rate increase shown in the June Model for 2013, which was echoed by Commission staff in a conference call among the parties on September 29, 2008, has developed a mechanism to "feather" the impact of those rate changes. Originally, as presented in the Application and described in the Direct Testimony of William Steven Seelye, Exhibit 25 at pages 27 through 32, the MRSM provided for the use of the Economic Reserve as a rate credit to offset in each month the total dollar amount of fuel adjustment charges ("FAC") and Environmental Surcharge costs billed to Members in that month to the extent such total dollar amounts were not already offset by the Unwind Surcredits and any Rebate Adjustments in that month. This proposed use of the MRSM left existing rates to the Non-Smelter Members effectively unchanged until exhaustion of the $157 million in the Economic Reserve. Big Rivers now proposes to change the MRSM to alter the speed at which the Economic Reserve will be drawn down in order to "feather" the effect of anticipated FAC and Environmental Surcharge Expenses on the Non-Smelter Member rates until the Economic Reserve is exhausted and the full amounts of the FAC and Environmental Surcharge are applied without credit. *See* Supplemental Direct Testimony of William Steven Seelye, Exhibit 103 at pages 3 through 10. This "feathering" will result in a gradual increase in rates between 2009 and 2013, as shown in Exhibit WSS-17. Absent some sort of rate smoothing, there potentially will be an abrupt rate transition at the time the Economic Reserve is exhausted and there is no offset to the FAC and Environmental Surcharge costs that

are then included in the Non-Smelter Member rates other than the Unwind Surcredit and any Rebate Adjustment in that month.

Amendments to Unwind Transaction Termination Agreement

20. Big Rivers seeks approval of the Third Amendment to Transaction Termination Agreement by and among Big Rivers Electric Corporation, LG&E Energy Marketing Inc., and Western Kentucky Energy Corp. attached hereto as Exhibit 80 (the "Third Amendment"). The Third Amendment amends the Transaction Termination Agreement dated March 26, 2007 (filed as Exhibit 3 to the Application and referred to herein as the "Termination Agreement"), which was previously amended by a First Amendment to Transaction Termination Agreement dated November 1, 2007 (filed as Exhibit 3 to the Application), clarified by a letter agreement dated December 4, 2007 (filed as Exhibit 3A to the Application), and amended by a Second Amendment to Transaction Termination Agreement dated June 11, 2008 (filed as Exhibit 1 to Big Rivers' Motion to Amend and Supplement Application dated June 10, 2008 (the "June 11 Motion"). The changes resulting from the Third Amendment are described in the Supplemental Testimony of Paul W. Thompson, attached hereto as Exhibit 91, at pages 3 through 9, and in the Supplemental Direct Testimony of David A. Spainhoward, attached as Exhibit 99, at pages 20 and 21.

Amendments to Smelter Agreements

21. Big Rivers seeks approval to substitute certain revised Smelter Agreements (a retail agreement for Alcan, a retail agreement for Century, a wholesale agreement for Alcan, and a wholesale agreement for Century, a lockbox agreement for Alcan, a lockbox agreement for Century, a guaranty for Alcan, a guaranty for Century, a coordination agreement for Alcan, and a coordination agreement for Century) attached hereto as Exhibit 81 (the "Smelter Agreements")

for the versions of those agreements filed as Exhibit 20 to the Application, which Big Rivers previously proposed to replace with the versions filed as Exhibit 2 to the June 11 Motion. A comparison of each of the revised agreements (except the guaranties) against the version of the agreements filed as Exhibit 2 to the June 11 Motion is attached hereto as Exhibit 82. Each of the Smelter Agreements has been revised (i) to remove the concept of a FAC Reserve for each Smelter because each Smelter has made separate arrangements with E.ON to offset anticipated future fuel costs resulting from the Unwind Transaction in lieu of the FAC Reserve; (ii) to reflect the elimination of the Member Discount Adjustment from Big Rivers' tariff; (iii) to clarify that transaction costs related to the Unwind Transaction will be excluded from the calculation of the TIER Adjustment Charge; (iv) to reduce each Smelter's monthly Surcharge by their *pro rata* share of $200,000 as part of an overall final settlement of various previously outstanding open items among the parties; and (v) to reflect Big Rivers' agreement that an amendment to Big Rivers' by-laws with respect to patronage allocation will bifurcate the patronage allocation in the year of the closing of the Unwind Transaction so that prior to the closing of the Unwind Transaction the patronage allocation will be computed in a manner consistent with the prior by-laws, while after the closing of the Unwind Transaction it will be computed based on the amended by-laws. The changes to the Smelter Agreements are more fully described in the attached Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78, at pages 49 through 54.

22. The Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 10, pages 66 and 67, mentions a disagreement between Big Rivers and the Smelters. Commission staff requested clarification about this disagreement in a conference call on September 29, 2008.

Mr. Blackburn addresses this issue in his Third Supplemental Direct Testimony, Exhibit 78, pages 59 through 60.

Changes to Big Rivers' Tariff

23. Big Rivers seeks approval to remove its Member Discount Adjustment (Rate Schedule 12) from its proposed Tariff, attached hereto as Exhibit 83, as that rate schedule expired in August 2008. A comparison of these changed Tariff terms to the previously submitted version of the Big Rivers' Tariff filed as Exhibit 22 to the Application on December 28, 2007 is presented as Exhibit 84. This change to Big Rivers' proposed Tariff is explained in the attached Supplemental Direct Testimony of David A. Spainhoward, Exhibit 99 at pages 13 through 14, and in the Third Supplemental Direct Testimony of C. William Blackburn, Exhibit 78 at pages 54 through 57.

24. As shown in Exhibits 83 and 84, Big Rivers also seeks approval to make certain other minor changes to its proposed Tariff from that filed as Exhibit 22 to the Application in this case on December 28, 2007 in order to implement Commission-ordered changes in those tariffs that have occurred since December 28, 2007 in Case Nos. 2007-00164 and 2007-00460. Big Rivers also adjusts the proposed Tariff to reflect the new Economic Reserve account contributions discussed in the June 11, 2008 filing with the Commission that resulted in an increase in the funding of that account from $75 million to $157 million. These changes are discussed in the attached Supplemental Direct Testimony of David A. Spainhoward, Exhibit 99 at pages 14 through 15 and in the Supplemental Direct Testimony of William Steven Seelye, Exhibit 103 at page 3.

25. As described in paragraph number 19, above, Big Rivers proposes to change its tariff to "feather" the use of the Economic Reserve, and smooth the introduction of expected rate

increases to its Members. As described in more detail in the Supplemental Direct Testimony of William Steven Seelye, Exhibit 103 at pages 3 through 10, the Big Rivers Tariff Member Rate Stability Mechanism has been amended to conserve use of the Economic Reserve in a manner that will cause the anticipated increases in expenses recovered through Big Rivers' FAC and Environmental Surcharge to be smoothed over time rather than introduced suddenly, in which case, as shown in the June Model, the Economic Reserve is suddenly depleted.

Changes to Big Rivers' OATT

26. Big Rivers seeks approval to substitute the revised version of its OATT attached hereto as Exhibit 85 for the version filed as Exhibit 33 to the Application, which Big Rivers previously proposed to replace in its Motion to Amend Application dated January 30, 2008. These changes are necessary to reflect changes to the FERC's *pro forma* Order No. 890-B OATT, on which Big Rivers' OATT is modeled. A redlined comparison of the attached OATT against the January 30 version is attached hereto as Exhibit 86. The changes to Big Rivers' OATT are explained in the Supplemental Direct Testimony of David A. Spainhoward, attached hereto as Exhibit 99, at pages 15 through 20.

Revised Henderson Station Two Agreements

27. Big Rivers seeks approval of (i) the Amendments to Contracts Among Henderson, and Big Rivers (the "Amendments to Contracts," Exhibit 87, attached); (ii) Second Amendatory Agreement among Big Rivers, the E.ON Entities and Henderson (the "Second Amendatory Agreement," Exhibit 87, attached, and Exhibit PWT-7 to Supplemental Direct Testimony of Paul W. Thompson, attached as Exhibit 90); (iii) Station Two Termination and Release Agreement between Big Rivers and the E.ON Entities (the "Termination and Release," Exhibit 87, attached, and Exhibit PWT-8 to Supplemental Direct Testimony of Paul W. Thompson, attached as

Exhibit 90); (iv) the Station Two G&A Allocation Agreement between Big Rivers and Henderson (the "Station Two G&A Allocation Agreement," Exhibit 87, attached); and (v) Agreement for Assignment of Responsibility for Complying with Reliability Standards between Henderson and Big Rivers (the "Reliability Standards Agreement," Exhibit 87, attached).

28. The Amendments to Contracts proposes that Big Rivers pay Henderson $1.00 per MWh more for all Excess Henderson Energy and Energy Associated with Excess Henderson Capacity than is currently required under the 1970 Station Two Contracts with Henderson, as amended, and that Big Rivers commit to take and pay for all Excess Henderson Energy and Energy Associated with Excess Henderson Capacity that is available. The Amendments to Contracts, the Second Amendatory Agreement, the Termination and Release, the Station Two G&A Agreement, and the Reliability Standards Agreement are described in detail in the attached Supplemental Direct Testimony of David A. Spainhoward, Exhibit 99, at pages 7 through 12. Big Rivers' efforts to resolve the outstanding issues with HMP&L are described in the Supplemental Direct Testimony of Michael H. Core attached hereto as Exhibit 102, pages 13 through 15. The Second Amendatory Agreement and the Termination and Release are further described by Paul W. Thompson in his Supplemental Direct Testimony, Exhibit 91, at pages 11 through 14.

29. Big Rivers believes these agreements and amendments to agreements will be necessary to secure Henderson's consent to the Unwind Transaction. Although Henderson has not yet reviewed or approved these agreements and amendments, and has not agreed to the terms reflected in these documents, Big Rivers is comfortable that these are a reasonable basis for a resolution of the outstanding issues with Henderson. Big Rivers files these agreements for approval at this time in an effort to create a basis on which agreement can be reached with

Henderson without having to return to the Commission for further time-consuming proceedings. Big Rivers understands that should Henderson not accept these agreements as proposed, any material changes will require further Commission review and approval, and will likely delay the Unwind Transaction closing.

Due Diligence and Transition Readiness

30. Big Rivers updated the Commission and interested parties on September 19, 2008, regarding the status of Big Rivers' ongoing due diligence activities, and provided additional reports on the condition of the generating units. *See* Big Rivers' September 19, 2008 Supplemental Response to the Attorney General's Supplemental Request for Information, Item 88. A description of Big Rivers' continuing due diligence efforts is updated in the Supplemental Direct Testimony of Mark A. Bailey, Exhibit 104. In his testimony, Mr. Bailey also updates the Commission on Big Rivers' efforts to prepare for transition to resuming operational control of its generating facilities, and demonstrates that the arrangements it has in place will provide for a seamless transition after the Unwind Transaction closing. Supplemental Direct Testimony of Mark A. Bailey, Exhibit 104, pages 3 through 12. As part of this update, Mr. Bailey provides an update on the necessary arrangements for the provision of information technology services and generation dispatch services following the closing. Supplemental Direct Testimony of Mark A. Bailey, Exhibit 104, pages 9 through 12. Mr. Bailey also provides Big Rivers' Updated Production Work Plan (Exhibit 105) as part of his testimony.

Conclusion

31. The Applicants submit that the proposed agreements and amendments attached to this Motion are all in substantially final form, and that this case is ready to go to hearing based upon the procedural schedule provided.

WHEREFORE, the Applicants respectfully request that the Commission (i) authorize the Applicants to amend and supplement their Application as set forth herein; (ii) grant the approvals requested herein; and (iii) grant the Applicants all other relief to which it may appear entitled.

On this the 9th day of October, 2008.

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Kendrick Riggs by James M. Miller by permission

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ENERGY MARKETING, INC.

Verification

I, C. William Blackburn, Vice President and Chief Financial Officer for Big Rivers Electric Corporation, hereby state that I have read the foregoing Motion and that the statements contained therein are true and correct to the best of my knowledge and belief; and I verify, state, and affirm that my third supplemental testimony, which is attached to the Motion, is true and correct to the best of my knowledge and belief, on this the 9th day of October, 2008.

C. William Blackburn
C. William Blackburn
Vice President and Chief Financial Officer
Big Rivers Electric Corporation

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

The foregoing verification statement was SUBSCRIBED AND SWORN to before me by C. William Blackburn, as Vice President and Chief Financial Officer of Big Rivers Electric Corporation, on this the 9th day of October, 2008.

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

TABLE OF CONTENTS TO APPLICATION EXHIBITS AND APPENDICES

I. Exhibits and Appendices to December 28, 2007, Application

No.	Contents
1.	Articles of Incorporation of Western Kentucky Energy Corp and LG&E Energy Marketing, Inc., filed on or about December 28, 2007, as Exhibit 1 to the original Application.
2.	Chart of Regulatory Compliance Requirements Cross-Referenced to Application, filed on or about December 28, 2007, as Exhibit 2 to the original Application.
3.	Transaction Termination Agreement dated as of March 26, 2007, among Big Rivers Electric Corporation, LG&E Energy Marketing Inc. and Western Kentucky Energy Corp., and First Amendment to Transaction Termination Agreement, both filed on or about December 28, 2007, as Exhibit 3 to the original Application. *See also* Letter Agreement filed on or about December 28, 2007, as Exhibit 3A to the original Application (see Item 3A, below); Second Amendment to Transaction Termination Agreement filed as Exhibit 1 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application; Third Amendment to Transaction Termination Agreement filed October 9, 2008 (see Item 80, below); Big Rivers' February 14, 2008, Response to Item 3 of the Commission Staff's First Data Request.
3A.	Letter Agreement dated as of December 4, 2007, among Big Rivers Electric Corporation, LG&E Energy Marketing Inc. and Western Kentucky Energy Corp. filed on or about December 28, 2007, as Exhibit 3A to the original Application. *See also* Item 3, above.
4.	Proposed Procedural Schedule, replaced by Proposed Procedural Schedule filed October 9, 2008. *See* Item 88, below.
5.	Testimony of Mark A. Bailey, filed on or about December 28, 2007, as Exhibit 5 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing.
6.	Final orders dated April 30, 1998, in *The Application of Big Rivers Electric Corporation, Louisville Gas and Electric Company, Western Kentucky Energy Corp., Western Kentucky Leasing Corp., and LG&E Station Two Inc. for Approval of Wholesale Rate Adjustment for Big Rivers Electric Corporation and for Approval of Transaction*, PSC Case No. 97-204 (Final Order dated April 30, 1998), and July 14, 1998, in *The Application of Big Rivers Electric Corporation for Approval of the 1998 Amendments to Station Two Contracts Between Big Rivers Electric Corporation and the City of Henderson, Kentucky and the Utility Commission of the City of Henderson*, P.S.C. Case No. 98-267 (Final Order dated

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July 14, 1998), filed on or about December 28, 2007, as Exhibit 6 to the original Application.

7. Analysis of 1998 Transaction Document Termination Clauses and List of 1998 Transaction Documents Affected by Unwind Transaction in Response to May 2, 2007 Letter from Beth O'Donnell, filed on or about December 28, 2007, as Exhibit 7 to the original Application.

8. Unwind Financial Model dated as of December 22, 2007, filed on or about December 28, 2007, as Exhibit 8 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing. *See also* Unwind Financial Models filed in Big Rivers' February 14, 2008, Response to Items 10 and 12 of the Commission Staff's First Data Request; Unwind Financial Model, filed as Exhibit 75 to Big Rivers' Third Amendment and Supplement to Application on or about April 23, 2008 (see Item 75, below); Unwind Financial Model filed as Exhibit 8 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application; Unwind Financial Model filed October 9, 2008 (see Item 79, below).

9. Testimony of Robert S. Mudge, filed on or about December 28, 2007, as Exhibit 9 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing.

10. Testimony of C. William Blackburn, filed on or about December 28, 2007, as Exhibit 10 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing.

11. Summary and Analysis of Terms and Conditions of the Termination Agreement in Response to May 2, 2007 Letter from Beth O'Donnell, filed on or about December 28, 2007, as Exhibit 11 to the original Application.

12. Summary of Termination Agreement, filed on or about December 28, 2007, as Exhibit 12 to the original Application.

13. Identification of Amendments Required to Leveraged Lease Transaction by Unwind Transactions in Response to May 2, 2007 Letter from Beth O'Donnell, filed on or about December 28, 2007, as Exhibit 13 to the original Application.

14. Testimony of Michael H. Core, filed on or about December 28, 2007, as Exhibit 14 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing.

15. Testimony of Paul W. Thompson, filed on or about December 28, 2007, as Exhibit 15 to the original Application, and updated by E.ON's January 30, 2008, Errata to the Direct Testimony of Paul W. Thompson, and E.ON's June 11, 2008, Revisions to the Testimony of Paul W. Thompson.

No.	Contents
16.	Generation Dispatch Support Services Agreement dated as of December 1, 2007, filed on or about December 28, 2007, as Exhibit 16 to the original Application.
17.	Information Technology Support Services Agreement dated as of December 1, 2007, filed on or about December 28, 2007, as Exhibit 17 to the original Application.
18.	Testimony of David A. Spainhoward, filed on or about December 28, 2007, as Exhibit 18 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing.
19.	Summary of New Smelter Arrangements, filed on or about December 28, 2007, as Exhibit 19 to the original Application.
20.	Smelter Agreements (retail agreements, wholesale agreements, coordination agreements, and lockbox agreements) – coordination agreements replaced by Smelter Agreements filed as Exhibit 2 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application; all other agreements replaced by Smelter Agreements filed October 9, 2008 (see Item 81, below).
21.	Testimony of Mark W. Glotfelty, filed on or about December 28, 2007, as Exhibit 21 to the original Application.
22.	Current Tariff, filed on or about December 28, 2007, as Exhibit 22 to the original Application.
23.	Proposed Tariff filed on or about December 28, 2007, as Exhibit 23 to the original Application - replaced by Proposed Tariff filed October 9, 2008. *See* Item 83, below.
24.	Comparison of Current and Proposed Tariff, filed on or about December 28, 2007, as Exhibit 24 to the original Application - replaced by Comparison of Proposed Tariff against Tariff filed as Exhibit 23 to the original Application, filed October 9, 2008. *See* Item 84, below.
25.	Testimony of William Steven Seelye, filed on or about December 28, 2007, as Exhibit 25 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing.
26.	Testimony of Burns E. Mercer, filed on or about December 28, 2007, as Exhibit 26 to the original Application.

No.	Contents
27.	Amendments to Wholesale Power Contracts between Big Rivers and its Member Distribution Cooperatives, filed on or about December 28, 2007, as Exhibit 27 to the original Application.
28.	(i) Letter dated May 2, 2007, from Beth O'Donnell, Executive Secretary of KPSC, to Michael H. Core, and (ii) Response of Big Rivers to that letter, filed on or about December 28, 2007, as Exhibit 28 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing.
29.	Summary Chart of Approvals Requested – replaced by Summary Chart of Approvals Requested filed October 9, 2008. *See* Item 89, below.
30.	Notice to Commission of Proposed Filing for Approval of Unwind Transaction, filed on or about December 28, 2007, as Exhibit 30 to the original Application.
31.	Notice to Customers of Proposed Tariff Changes, filed on or about December 28, 2007, as Exhibit 31 to the original Application.
32.	Current Open Access Transmission Tariff (OATT), filed on or about December 28, 2007, as Exhibit 32 to the original Application.
33.	Proposed Open Access Transmission Tariff (OATT) – substituted by Proposed Open Access Transmission Tariff (OATT) filed as Exhibit A to Big Rivers' January 30, 2008, Motion to Amend Application, and replaced by Proposed Open Access Transmission Tariff (OATT) filed October 9, 2008. *See* Item 85, below.
34.	Comparison of Proposed OATT Against Current OATT – replaced by Comparison of Proposed OATT Against Current OATT filed as Exhibit B to Big Rivers' January 30, 2008, Motion to Amend Application, and supplemented by Comparison of Proposed OATT Against February OATT filed October 9, 2008. *See* Item 86, below.
35.	Testimony of Ralph L. Luciani, filed on or about December 28, 2007, as Exhibit 35 to the original Application.
36.	Certificate of good standing or certificate of authorization (Big Rivers), filed on or about December 28, 2007, as Exhibit 36 to the original Application.
37.	Independent Auditor's Annual Opinion Report, filed on or about December 28, 2007, as Exhibit 37 to the original Application. *See also* Big Rivers' February 14, 2008, Response to Item 11 of the Attorney General's Initial Request for Information to Joint Applicants; Big Rivers' May 30, 2008, Updated Responses to Data Requests, Tab 1 (Updated Response to Attorney General's Initial Request Item 11).

No.	Contents
38.	FERC Form 1 (Big Rivers), filed on or about December 28, 2007, as Exhibit 38 to the original Application.
39.	List of all computer software, programs and models used in the development of the filing, filed on or about December 28, 2007, as Exhibit 39 to the original Application.
40.	Prospectuses for the most recent stock or bond offerings, filed on or about December 28, 2007, as Exhibit 40 to the original Application.
41.	Annual report to members for 2005 & 2006, filed on or about December 28, 2007, as Exhibit 41 to the original Application.
42.	Fuel Contracts, filed on or about December 28, 2007, as Exhibit 42 to the original Application.
43.	System Map, filed on or about December 28, 2007, as Exhibit 43 to the original Application.
Appendix A.	1998 Transaction Documents and Amendments and Supplements, filed on or about December 28, 2007, as Appendix A to the original Application.
Appendix B.	Station Two Contracts and Amendments (other than Station Two Agreements from 1998 Transaction), filed on or about December 28, 2007, as Appendix B to the original Application.
Appendix C.	Defeased Sale/Leaseback Documents, filed on or about December 28, 2007, as Appendix C to the original Application.
Appendix D.	Most recent RUS Form 12, filed on or about December 28, 2007, as Appendix D to the original Application. *See also* Item 48, below. Supplemented by Exhibit 106 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.
Appendix E.	Smelter 2008 Tier 3 Contracts, filed on or about December 28, 2007, as Appendix E to the original Application.
Appendix F.	Miscellaneous Documents, filed on or about December 28, 2007, as Appendix F to the original Application:
	a. Orders dated November 24, 1999 and January 28, 2000, in *Big Rivers Electric Corporation's Application for Approval of a Leveraged Lease of Three Generating Units*, P.S.C. Case No. 99-450

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b. Order dated March 29, 2000 in *The Application of Big Rivers Electric Corporation, LG&E Energy Marketing Inc., Western Kentucky energy Corp., WKE Station Two Inc., and WKE Corp. for Approval of Amendments to Transactions Documents*, P.S.C. Case No. 2000-118

c. Orders dated November 28, 2000 and December 21, 2000 in *Big Rivers Electric Corporation's Application for Approval to Amend Evidences of Indebtedness*, P.S.C. Case No. 2001-486

d. Order dated November 15, 2001, in *Application of Big Rivers Electric Corporation, LG&E Energy Marketing Inc., Western Kentucky energy Corp., WKE Station Two Inc., and WKE Corp. for Approval of Amendments to Transactions Documents*, P.S.C. Case No. 2001-00305

e. Orders dated July 12, 2002 and October 30, 2002 in *Application of Big Rivers Electric Corporation, LG&E Energy Marketing Inc., Western Kentucky energy Corp., WKE Station Two Inc., and WKE Corp. for Approval of Amendments to Transactions Documents*, P.S.C. Case No. PSC Order 2002-000195

f. Order dated March 9, 2005 in *Application of Big Rivers Electric Corporation, LG&E Energy Marketing Inc., Western Kentucky energy Corp., WKE Station Two Inc., and WKE Corp. for Approval of Amendments to Transactions Documents*, P.S.C. Case No. 2005-00029.

II. Exhibits to Big Rivers' March 31, 2008, First Amendment and Supplement to Application

44. Summary of Fee Arrangements for Revolving Credit Agreements, filed as Exhibit 44 to Big Rivers' First Amendment and Supplement to Application on or about March 31, 2008.

45. Revolving Line of Credit Agreement dated as of _________, 2008, between Big Rivers Electric Corporation and National Rural Utilities Cooperative Finance Corporation, filed as Exhibit 45 to Big Rivers' First Amendment and Supplement to Application on or about March 31, 2008.

46. Revolving Credit Agreement dated as of _______, 2008, by and between Big Rivers Electric Corporation and CoBank ACB, including note dated as of

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_______, 2008, by and between Big Rivers Electric Corporation and CoBank ACB, filed as Exhibit 46 to Big Rivers' First Amendment and Supplement to Application on or about March 31, 2008.

47. Big Rivers' Description of Property, filed as Exhibit 47 to Big Rivers' First Amendment and Supplement to Application on or about March 31, 2008.

48. Big Rivers' Financial Exhibit, filed as Exhibit 48 to Big Rivers' First Amendment and Supplement to Application on or about March 31, 2008. *See also* Item Appendix D, above.

III. Exhibits to Big Rivers' April 11, 2008, Second Amendment and Supplement to Application

49. Indenture filed as Exhibit 49 to Big Rivers' Second Amendment and Supplement to Application on or about April 11, 2008 – replaced by Indenture filed October 9, 2008. *See* Item 96, below.

50. Facility Lessor (D) Secured Note (PBR-1) – no longer relevant.

51. Facility Lessor (E) Secured Note (PBR-1) – no longer relevant.

52. Ambac Credit Products Secured Note (PBR-1) – no longer relevant.

53. PCB Series 2001A Note dated as of _______, 2008, from Big Rivers Electric Corporation to the County of Ohio, Kentucky, filed as Exhibit 53 to Big Rivers' Second Amendment and Supplement to Application on or about April 11, 2008.

54. Ambac Municipal Bond Insurance Policy Series 1983 Note dated as of ________, 2008, from Big Rivers Electric Corporation to Ambac Assurance Corporation, filed as Exhibit 54 to Big Rivers' Second Amendment and Supplement to Application on or about April 11, 2008.

55. Standby Bond Purchase Agreement Note (Series 1983 Bonds), dated as of ________, 2008, from Big Rivers Electric Corporation to Dexia Credit Local, acting by and through its New York Branch, filed as Exhibit 55 to Big Rivers' Second Amendment and Supplement to Application on or about April 11, 2008.

56. Termination of Third Amended and Restated Subordination, Nondisturbance, Attornment and Intercreditor Agreement dated as of _________, 2008, among (a) Big Rivers Electric Corporation; (b) LG&E Energy Marketing Inc., and Western Kentucky Energy Corp.; (c) The United States of America, acting through the Administrator of the Rural Utilities Service; (d) Ambac Assurance Corporation; (e) National Rural Utilities Cooperative Finance Corporation; (e) Dexia Credit Local, New York Branch; (f) U.S. Bank Trust National Association, as trustee

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under the Trust Indenture dated as of August 1, 2001 (g) PBR-1 Statutory Trust; (h) PBR-2 Statutory Trust; (i) PBR-3 Statutory Trust; (j) FBR-1 Statutory Trust; (k) FBR-2 Statutory Trust; (l) PBR-1 OP Statutory Trust; (m) PBR-2 OP Statutory Trust; (n) PBR-3 OP Statutory Trust; (o) FBR-1 OP Statutory Trust; (p) FBR-2 OP Statutory Trust; (q) Bluegrass Leasing; (r) Bank of America Leasing Corporation; (s) AME Investments, LLC; (t) CoBank, ACB; and (u) Ambac Credit Products, LLC, filed as Exhibit 56 to Big Rivers' Second Amendment and Supplement to Application on or about April 11, 2008.

57. Termination of Third Restated Mortgage and Security Agreement dated _________, 2008, among (a) Big Rivers Electric Corporation; (b) The United States of America, acting through the Administrator of the Rural Utilities Service; (d) Ambac Assurance Corporation; (e) National Rural Utilities Cooperative Finance Corporation; (e) Dexia Credit Local, New York Branch; (f) U.S. Bank Trust National Association, as trustee under the Trust Indenture dated as of August 1, 2001 (g) PBR-1 Statutory Trust; (h) PBR-2 Statutory Trust; (i) PBR-3 Statutory Trust; (j) FBR-1 Statutory Trust; (k) FBR-2 Statutory Trust; and (v) Ambac Credit Products, LLC, filed as Exhibit 49 to Big Rivers' Second Amendment and Supplement to Application on or about April 11, 2008.

58. Amended and Restated Stock Pledge Agreement – no longer relevant.

59. Amended and Restated Funding Agreement Pledge Agreement (PBR-1) – no longer relevant.

60. Amended and Restated Payment Agreement Pledge Agreement (PBR-1) – no longer relevant.

61. Amended and Restated Government Securities Pledge Agreement (PBR-1) – no longer relevant.

62. Partial Termination of Funding Agreement Pledge Agreement (PBR-1) – no longer relevant.

63. Partial Termination of Payment Agreement Pledge Agreement (PBR-1) – no longer relevant.

64. Partial Termination of Government Securities Pledge Agreement (PBR-1) – no longer relevant.

IV. Exhibits to Big Rivers' April 23, 2008, Third Amendment and Supplement to Application

65. Intercreditor Agreement – no longer relevant.

No.	Contents
66.	Ambac Letter Agreement – no longer relevant.
67.	Bank of America Letter Agreement – no longer relevant.
68.	Creditor Consent, Termination and Release Agreement – replaced by Creditor Consent, Termination and Release Agreement filed October 9, 2008. *See* Item 96, below.
69.	First Amendment to ISDA Master Agreement (PBR-1) (Big Rivers Swap) – no longer relevant.
70.	Escrow Agreement (PBR-1) – no longer relevant.
71.	First Amendment to ISDA Master Agreement (PBR-1) – no longer relevant.
72.	Amended and Consolidated Loan Contract, dated as of ____________, 2008, between Big Rivers Electric Corporation and United States of America (No Commission approval sought), filed as Exhibit 72 to Big Rivers' Third Amendment and Supplement to Application on or about April 23, 2008.
73.	RUS 2008 Promissory Note, Series A – replaced by RUS 2008 Promissory Note, Series A filed October 9, 2008. *See* Item 94, below.
74.	RUS 2008 Promissory Note, Series B, dated as of ____________, 2008, between Big Rivers Electric Corporation and United States of America (No Commission approval sought), filed as Exhibit 74 to Big Rivers' Third Amendment and Supplement to Application on or about April 23, 2008.
75.	Unwind Financial Model, filed as Exhibit 75 to Big Rivers' Third Amendment and Supplement to Application on or about April 23, 2008. *See also* Unwind Financial Model filed on or about December 28, 2007, as Exhibit 8 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing (see Item 8, above); Unwind Financial Models filed in Big Rivers' February 14, 2008, Response to Items 10 and 12 of the Commission Staff's First Data Request; Unwind Financial Model filed as Exhibit 8 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application; Unwind Financial Model filed October 9, 2008 (see Item 79, below).
76.	Table of Contents to Application Exhibits Added by Financing Documents Filings, filed as Exhibit 76 to Big Rivers' Third Amendment and Supplement to Application on or about April 23, 2008. *See also* this Table of Contents to Application Exhibits and Appendices, filed October 9, 2008.

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77. Supplemental Testimony of C. William Blackburn, filed as Exhibit 77 to Big Rivers' Third Amendment and Supplement to Application on or about April 23, 2008.

V. Exhibits to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application Not Included Above

A. Comparison of Revised Smelter Agreements against Smelter Agreements filed with Application, filed as Exhibit 3 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application – all Smelter Agreements except coordination agreements replaced by Smelter Agreements filed October 9, 2008. *See* Item 81, below.

B. Omnibus Termination Agreement among Big Rivers Electric Corporation, Big Rivers Leasing LLC, FBR-1 Statutory Trust, FBR-2 Statutory Trust, FBR-1 OP Statutory Trust, FBR-2 OP Statutory Trust, Trisail Capital Corporation, AME Investments, LLC, CoBank, ACB, AME Asset Funding, LLC, U.S. Bank National Association, AIG Matched Funding Corp., Ambac Credit Product, LLC, and Ambac Assurance Corporation, filed as Exhibit 4 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application.

C. Letter Agreement among Big Rivers Electric Corporation, E.ON U.S. LLC, Alcan Primary Product Corporation, and Century Aluminum of Kentucky General Partnership, filed as Exhibit 5 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application.

D. Amendment of Operating and Support Agreement among Big Rivers Electric Corporation, PBR-3 Statutory Trust, FBR-1 Statutory Trust, and FBR-2 Statutory Trust (D.B. Wilson Unit 1), filed as Exhibit 6 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application.

E. Second Supplemental Testimony of C. William Blackburn, filed as Exhibit 7 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application.

VI. Exhibits to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application

78. Third Supplemental Direct Testimony of C. William Blackburn, filed as Exhibit 78 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

79. Unwind Financial Model, filed as Exhibit 79 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Unwind Financial Model filed on or about December 28, 2007, as Exhibit 8 to the original Application, and updated by Big Rivers' January 30, 2008, Errata filing (see Item

No.	Contents
	8, above); Unwind Financial Models filed in Big Rivers' February 14, 2008, Response to Items 10 and 12 of the Commission Staff's First Data Request; Unwind Financial Model, filed as Exhibit 75 to Big Rivers' Third Amendment and Supplement to Application on or about April 23, 2008 (see Item 75, above); Unwind Financial Model filed as Exhibit 8 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application.
80.	Third Amendment to Transaction Termination Agreement, filed as Exhibit 80 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Transaction Termination Agreement and First Amendment to Transaction Termination Agreement, both filed on or about December 28, 2007, as Exhibit 3 to the original Application (see Item 3, above); Letter Agreement filed on or about December 28, 2007, as Exhibit 3A to the original Application (see Item 3A, above); Second Amendment to Transaction Termination Agreement filed as Exhibit 1 to Big Rivers' June 11, 2008, Motion to Amend and Supplement Application; Big Rivers' February 14, 2008, Response to Item 3 of the Commission Staff's First Data Request.
81.	Smelter Agreements, filed as Exhibit 81 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item 20, above. a. Alcan Retail Agreement b. Century Retail Agreement c. Alcan Wholesale Agreement d. Century Wholesale Agreement e. Alcan Security and Lockbox Agreement f. Century Security and Lockbox Agreement g. Alcan Guaranty h. Century Guaranty i. Alcan Coordination Agreement j. Century Coordination Agreement
82.	Comparison of Revised Smelter Agreements and Previously-Filed Smelter Agreements, filed as Exhibit 82 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item A, above.

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a. Comparison of Alcan Retail Agreement

b. Comparison of Century Retail Agreement

c. Comparison of Alcan Wholesale Agreement

d. Comparison of Century Wholesale Agreement

e. Comparison of Alcan Security and Lockbox Agreement

f. Comparison of Century Security and Lockbox Agreement

g. Comparison of Alcan Coordination Agreement

h. Comparison of Century Coordination Agreement

83. Proposed Tariff, filed as Exhibit 83 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item 23, above.

84. Comparison of Proposed Tariff against Tariff filed as Exhibit 23 to the original Application, filed as Exhibit 84 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item 24, above.

85. Proposed Open Access Transmission Tariff, filed as Exhibit 85 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item 33, above.

86. Comparison of Proposed OATT against OATT filed as Exhibit A to Big Rivers' January 30, 2008, Motion to Amend Application, filed as Exhibit 86 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item 34, above.

87. Station Two Agreements and Amendments, filed as Exhibit 87 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

a. Second Amendatory Agreement

b. Amendments to 1970 Station Two Power Sales Contract

c. Station Two Termination and Release Agreement

d. Station Two G&A Allocation Agreement

e. Agreement for Assignment of Responsibility for Complying with Reliability Standards

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88. Proposed Procedural Schedule, filed as Exhibit 88 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item 4, above.

89. Summary Chart of Approvals Requested, filed as Exhibit 89 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item 29, above.

90. August 29, 2008, Status Report, filed as Exhibit 90 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

91. Supplemental Direct Testimony of Paul W. Thompson, filed as Exhibit 91 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

92. Affidavit of C. William Blackburn, dated September 25, 2008, filed as Exhibit 92 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

93. List of Financing Documents No Longer Required, filed as Exhibit 93 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

94. RUS 2008 Promissory Note, Series A, filed as Exhibit 94 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Item 73, above.

95. Agreements regarding "Funding of Certain Amounts to be Paid to The Bank of America" between Big Rivers, E.ON U.S., LLC, Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership" dated as of June 24, 2008, and "Payment Regarding the Buy-Out of the Bank of America" among Big Rivers and E.ON dated as of June 24, 2008, filed as Exhibit 95 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

96. Other Indenture/Security Agreements, filed as Exhibit 96 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application. *See also* Items 49 and 68, above.

97. Updated Production Cost Model, filed as Exhibit 97 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

98. Supplemental Direct Testimony of Robert S. Mudge, filed as Exhibit 98 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

99. Supplemental Direct Testimony of David A. Spainhoward, filed as Exhibit 99 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.

No.	Contents
100.	Comparison of Rates under the Unwind Transaction and Rates under the Existing Transaction, filed as Exhibit 100 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.
101.	Supplemental Direct Testimony of Burns E. Mercer, filed as Exhibit 101 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.
102.	Supplemental Direct Testimony of Michael H. Core, filed as Exhibit 102 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.
103.	Supplemental Direct Testimony of William Steven Seelye, filed as Exhibit 103 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.
104.	Supplemental Direct Testimony of Mark A. Bailey, filed as Exhibit 104 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.
105.	Updated Big Rivers ProductionWork Plan, filed as Exhibit 105 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application.
106.	Big Rivers' RUS Form 12, filed as Exhibit 106 to Big Rivers' October 9, 2008, Motion to Amend and Supplement Application, supplementing Attachment D to the December 28, 2007 Application.

EXHIBIT 78

THIRD SUPPLEMENTAL DIRECT TESTIMONY OF C. WILLIAM BLACKBURN

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

THIRD SUPPLEMENTAL DIRECT TESTIMONY OF C. WILLIAM BLACKBURN

ON BEHALF OF
APPLICANTS

OCTOBER 2008

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THIRD SUPPLEMENTAL DIRECT TESTIMONY OF C. WILLIAM BLACKBURN

I. OVERVIEW OF TESTIMONY

Q. Please state your name and position.

A. My name is C. William Blackburn. I am employed by Big Rivers Electric Corporation ("Big Rivers") as its Vice President Financial Services, Chief Financial Officer ("CFO") and Interim Vice President Power Supply.

Q. Are you the same C. William Blackburn who earlier provided testimony in these proceedings?

A. I am. I filed my direct testimony as Exhibit 10 to the original Application filed on December 28, 2007, my rebuttal testimony on April 23, 2008, my first supplemental testimony on April 23, 2008, and my second supplemental testimony on June 11, 2008.

Q. Why is Big Rivers now supplementing its Application and presenting this Third Supplemental Direct Testimony?

A. The primary reason Big Rivers is supplementing its Application and submitting this Third Supplemental Direct Testimony is to present the Commission with the effects on the Unwind Financial Model of Big Rivers' recent termination of its leveraged lease transactions of undivided interests in Plants Green and Wilson with Bluegrass Leasing Corporation, a subsidiary of Philip Morris Capital Corporation ("PMCC"). This termination was precipitated by a downgrade in the claims-paying ability of Ambac Assurance Corporation ("Ambac") by Moody's Investors Services ("Moody's") on June 19, 2008 and by more recent turmoil in the financial markets. Absent the lease termination Big Rivers would have been exposed to adverse consequences under the contractual terms of the leveraged lease transactions with PMCC.

Q. Has Big Rivers previously supplied the other parties and the Commission with information regarding the termination of the PMCC Lease Transaction?

A. Yes. Prior to engaging in the termination of the PMCC Lease Transaction, on September 26, 2008 I presented for informational purposes an Affidavit (attached as Exhibit 92) detailing the history of the PMCC Lease Transaction and presenting the sequence of events that led to Big Rivers' determination to terminate that transaction. I describe the terms of the PMCC Buyout below as it was closed in order to explain the effects of the PMCC Buyout on the Unwind Financial Model. I direct the Commission's attention to my earlier Affidavit, as needed, for additional background on the circumstances surrounding Big Rivers' decision to enter into the PMCC Buyout.

Q. Please describe your testimony.

A. In the first part of the testimony below I describe the structure of the PMCC Buyout and the flow of payments affecting the Unwind Financial Model. I also present details regarding a parallel buyout of Big Rivers' leveraged leases of Plant Green with Bank of America Leasing ("BoA") which were bought out on June 30, 2008, as previously reported to the Commission on July 2, 2008 ("BoA Buyout"). In the supplement to the Application filed herein ("Application Supplement"), Big Rivers requests Commission approval of the proposed accounting treatment for both the BoA Buyout and the PMCC Buyout. The description of the BoA Buyout is provided for that purpose. In my testimony, I describe the proposed financial accounting for these buyouts for which Big Rivers is seeking approval in the Application Supplement.

Q. Does your testimony address any issues other than those surrounding the termination of the PMCC leases and the BoA leases?

A. Yes. Big Rivers recognizes that it first filed its Application more than nine months ago and that it has an ongoing obligation to update that Application to provide known changes. Accordingly, apart from simply documenting the changes to Big Rivers' financial status arising from the BoA Buyout and the PMCC Buyout, my testimony also provides a summary of all known significant financial changes that have occurred since Big Rivers updated its Unwind Financial Model in Big Rivers' June 11, 2008 Motion to Amend and Supplement Application (the "June Model"). The second portion of my testimony thus presents a new iteration of Big Rivers' Unwind Financial Model, which is attached as Exhibit 79. Although many of the changes to the Unwind Financial Model relate to the implementation of the buyouts, a number of other changes have been made since Big Rivers supplied the Commission with the June Model. The expected closing date of the Unwind Transaction has been moved from April 30, 2008 to December 31, 2008, and this change is now reflected in the Unwind Financial Model. In addition, Big Rivers' Production Cost Model has been updated to reflect current operating assumptions and cost inputs, and I describe these changes as well, particularly with respect to their effects on the Unwind Financial Model.

Separately from this update of the various inputs to the Big Rivers financial model, I also present the updated output of the Unwind Financial Model, including the expected rates, to provide the Commission with as complete and updated a picture of Big Rivers' projected operations post-closing as can be currently estimated. In order to provide the Commission with information by which the Commission separately can assess both the financial impact of the buyouts and the financial impact created by other changes now documented in the financial model, Big Rivers presents a breakdown of the relative effect of these two categories of changes as part of my testimony.

Big Rivers' resolution of the PMCC lease transaction and the change in the expected closing date of the Unwind Transaction also entail certain changes in the compensation from E.ON U.S., LLC ("E.ON") and its affiliates under the Unwind Transaction, so I also update previous exhibits provided to the Commission summarizing these payments.

Q. Does your testimony address any other issues?

A. Yes. A third significant area of my testimony addresses the specific changes to the Smelter contracts necessitated by the PMCC Buyout and for other reasons. Some of these changes address issues relating to the PMCC Buyout and the allocation of the costs resulting from that termination given that the Smelters did not feel that they participated in the initial benefits created by the leveraged leases. Other portions of the Smelter Agreements are revised for reasons explained in this section.

A fourth area of my testimony addresses the changes to Big Rivers' Tariffs proposed in the Application. The Big Rivers Member Discount Adjustment ("MDA") expired at the end of August of this year. I discuss in this testimony the reasons for allowing that tariff provision to expire. I also describe the effect of these tariff changes on the Economic Reserve, and describe why these changes still offer the Big Rivers Non-Smelter Members adequate protection and incentive to enter into this transaction.

A fifth area of my testimony addresses updates to my responses to previously submitted Data Responses in this proceeding in order to present known changes to certain of Big Rivers' previous answers. As part of this Section I provide a financial matrix (Exhibit CWB-17). Also, I provide additional testimony regarding Big Rivers' ability to remarket power should one or more of the Smelters depart the system. As part of this testimony, I provide analyses of regional market sizes and known future needs for power to demonstrate that a viable market exists in which Big Rivers will be able to sell any generation stranded by a Smelter departure. I also address concerns regarding whether the benefits of this transaction load too many of the Smelter benefits on the front end of the period covered by the Smelter Agreements. Finally, I provide an update regarding Big Rivers' request for a tax ruling from the Kentucky Department of Revenue.

II. <u>CHANGES IN BIG RIVERS' FINANCIAL STATUS</u>

A. THE PMCC BUYOUT

Q. When did Big Rivers close the PMCC Buyout?

A. Big Rivers closed the termination of the PMCC Lease Transaction on Tuesday, September 30, 2008.

Q. How much did Big Rivers pay PMCC on September 30 in connection with the PMCC Buyout?

A. Big Rivers paid PMCC $109 million in cash, and gave PMCC its unsecured note in the amount of $12.38 million loan at an 8.5% annual interest rate, payable at the earlier to occur of the date of closing of the Unwind Transaction or December 15, 2009.

Q. Has WKEC agreed to participate in the PMCC leases termination costs?

A. Yes. WKEC has agreed to reimburse Big Rivers one half of the $121.38 million paid to PMCC plus one half of a $332,868 shortfall payment made to Co-Bank in connection with the sale of certain financial securities that collateralized a portion of the PMCC debt, for a total E.ON payment to Big Rivers of approximately $60.9 million. WKEC's payment is due at the closing of the Unwind Transaction. WKEC's obligation to make this payment is memorialized in the Third Amendment to Transaction Termination Agreement, presented with the supplemental testimony of Paul W. Thompson as Exhibit PWT-5.

Q. What was the derivation of this payment?

A. Although the terms of the PMCC Lease Transaction liquidated damages provision specified a termination payment of approximately $221.5 million, PMCC in return for an earlier termination agreed to reduce the face amount to $214 million. The $7.5 million difference represents PMCC's contribution to the economic resolution of the lease transaction. Moreover, consistent with the terms of the PMCC Lease Termination, Big Rivers then used the proceeds from the redemption of its guaranteed investment contract ("GIC") funding agreement with American International Group, Inc. ("AIG") (the "AIG GIC") and the net proceeds from the sale of certain federal securities by Co-Bank to reduce this amount. The redemption of the AIG GIC yielded $92.62 million. However, the sale of federal securities by Co-Bank yielded an amount $332,868 less than the outstanding value of the Series B debt paid off by Co-Bank. Accordingly, Big Rivers owed a shortfall payment of $332,868 to Co-Bank with regard to the Series B debt. Big Rivers then settled its net termination value payment by paying PMCC the sum of $109 million in cash and borrowed an additional $12.38 million from PMCC on the terms described above. These calculations and the BoA lease termination payments are charted in the table attached as Exhibit CWB-9 to this supplemental testimony.

Q. How is the PMCC Buyout reflected in the Big Rivers Unwind Financial Model?

A. For purposes of financially modeling the PMCC Buyout, Big Rivers has modeled a total Big Rivers payment of $60.9 million. This amount is reflected in Big Rivers' Financial Model as discussed below in Section II(C) of my Third Supplemental Direct Testimony.

Q. Will Big Rivers' buyout of the PMCC Lease Transaction have an effect on the amount Big Rivers will pay down on its note to the United States Rural Utilities Service ("RUS") at the closing of the Unwind Transaction?

A. The PMCC Buyout will result in a reduction in the amount to be prepaid by Big Rivers to the RUS at closing to reduce the principal amount of the RUS note. Originally, Big Rivers had proposed a very substantial prepayment to the RUS at closing with a simultaneous public debt issuance. Now, Big Rivers and the RUS have agreed to a revised schedule of Maximum Allowed Principal Balances as part of a New RUS Note (Exhibit 94) that is to be implemented following the closing of the Unwind Transaction. I attach the revised Maximum Allowed Principal Balance schedule as Exhibit CWB-10 to this testimony. Big Rivers will prepay approximately $140.2 million at the closing of the Unwind Transaction. Big Rivers will then pay approximately an additional $60.0 million to the RUS in or before 2012. Finally, under the revised schedule, Big Rivers will pay approximately an additional $200 million by no later than January 2016.

Q. Does the PMCC Lease Transaction termination have any effect on the ARVP Note with the RUS?

A. No. It does not change the amount or terms of the ARVP Note.

Q. Did Ambac provide any financial contribution to the PMCC Buyout?

A. Ambac agreed to waive its fees and legal services payments in connection with actions necessary to implement the PMCC Buyout.

Q. Has Big Rivers provided the Commission a copy of the PMCC Lease Termination Transaction documents?

A. Yes. Big Rivers made an information filing of the PMCC Buyout documents on October 7, 2008.

Q. Turning to accounting issues, how does Big Rivers intend to account for the PMCC Buyout and the BoA Buyout?

A. Generally, Big Rivers intends to currently expense all costs associated with the termination of the five lease transactions with Bluegrass Leasing and the Bank of America Leasing on a "netted" basis. As of September 30, 2008, Big Rivers currently has recorded a net loss on its books of approximately $77.0 million to reflect the amounts received in 2000 from entering into these leveraged lease transactions and the buyout expenses. Big Rivers proposes to expense as a loss the amounts expended to terminate these five leasing transactions. Big Rivers thus will record a net loss on December 31, 2008 of $16.1 million on its books as a result of this proposed accounting treatment. *See* Exhibits CWB-9 and CWB-11. I believe this is a just and reasonable method of accounting for these terminations, and I believe the Commission should grant Big Rivers approval for this proposed accounting treatment as requested in the Application Supplement. Big Rivers has requested the RUS to approve this same accounting treatment as well.

Q. Have the Smelters been kept informed throughout the PMCC Buyout?

A. Yes. Big Rivers remained in contact with the Smelters to apprise them of the status of the negotiations. The Smelters have supported Big Rivers' decision to terminate the PMCC Lease Transaction, preferring the elimination of this potential uncertainty created by the Ambac credit downgrade.

Q. Please describe the economics of the PMCC Buyout as they relate to the Smelters in the Unwind Transaction scenario.

A. Big Rivers is funding a portion of its costs of buying out PMCC by reducing the payment it makes on the RUS debt at the closing of the Unwind Transaction. This increases Big Rivers' debt level since the amount of debt to be prepaid to the RUS will be smaller than originally modeled. The June Model shows Big Rivers making a $200 million prepayment to the RUS at closing, but the PMCC Buyout now provides for this amount to be decreased to approximately $140.2 million. With a reduced RUS prepayment, the RUS debt level will be higher. As discussed below in Section III, this will lead to an increase in Big Rivers' wholesale rates offered to the Member Distribution

Cooperatives for both their Smelter and non-Smelter customers. Because the Smelters pay approximately 70% of system costs, the Smelters objected to being forced to bear the brunt of the increased costs resulting from the PMCC Buyout, particularly because they were not system average cost customers during the period following the leveraged lease transactions and never received what they believed to be a fair share of the benefits of the PMCC Lease Transaction in the first place.

Q. How did Big Rivers and the Smelters resolve this issue regarding the PMCC Lease Transaction and its termination?

A. The Smelters had previously agreed to pay a substantial monthly surcharge that would ultimately be applied against the expenses that would otherwise be paid by the distribution Non-Smelter Members through the FAC and the Environmental Surcharge (*see, e.g*, Alcan Retail Contract, Section 4.11). In order to resolve the issue of responsibility for payment of the PMCC Buyout costs, Big Rivers and the Smelters have agreed to a $200,000 downward adjustment in the monthly Smelter Surcharge for the initial 96 months (eight years) of their agreements. In total, this amounts to a $19.2 million nominal benefit to the Smelters.

Q. Doesn't this reduction in the Smelter Surcharge result in a front-loading of benefits to the Smelters?

A. No, quite the contrary. The argument against front-loading of benefits to the Smelters is that it gives the Smelters more of their total economic benefit in the initial years and dilutes incentives for them to stay on Big Rivers' system in later years. The structure of the Smelter resolution in the PMCC Buyout cuts against that by spreading out the Smelters' value over eight years. The benefit is not frontloaded but, rather, evenly received over that period. Moreover, a Smelter loses entitlement to any unrealized benefit if it does take service under its retail agreement for the full eight years.

Q. Does the PMCC Buyout change the need for a new Big Rivers Indenture?

A. No. Big Rivers still requires replacement of the existing Third Restated Mortgage with the proposed new Indenture as a key component of the Unwind Transaction. The reason is simple: Big Rivers needs an Indenture so that it can take full advantage of all credit markets in the future. As I explained in depth in my Direct

Testimony at pages 110-23, restructuring Big Rivers' obligations in the manner provided in the new Indenture is one of the main benefits of the Unwind Transaction; it will provide Big Rivers with the financial flexibility to access credit markets to meet unexpected financial obligations and provide for future improvements and expansion in a way that is not available under a standard mortgage. As the Commission is aware, Big Rivers already anticipates the need to access capital markets following the closing of the Unwind Transaction, commencing with the tax-exempt market in 2009 and the taxable market in 2011. The existing Third Restated Mortgage is simply not an adequate security document for the type of organization which Big Rivers will become after the Unwind Transaction.

Q. Please review the evolution of Big Rivers' post-closing financing plans since the filing of this case.

A. At the time the Application was filed, Big Rivers had a general expectation that it would prepay approximately $440 million of its RUS debt at the Unwind Transaction closing. The sources of those funds were anticipated to be (i) $176 million from cash on hand at closing, and (ii) $264 million in proceeds from the issuance of public debt. This is described in my Direct Testimony, filed as Exhibit 10 to the Application, at page 127.

When Big Rivers filed the financing portion of its application dated March 28, 2008, the early evidence of distress in the financial markets had caused Big Rivers to abandon its plans to issue public debt at closing. At that point, Big Rivers expected it would pay down $200 million on the RUS debt at closing. This adjustment in plans is discussed in paragraph 19, on page 8, of Big Rivers' March 28, 2008, First Amendment and Supplement to Application, and at pages 3 through 5 of my Supplemental Testimony, which is filed as Exhibit 77 with the April 23, 2008, Motion to Amend and Supplement Application.

Now, as described earlier in my testimony, Big Rivers' agreement with RUS is that Big Rivers will pay a minimum of $125 million on the RUS note at the Unwind Transaction closing, plus all negotiated improvements in termination value and any amounts by which the value of the AIG GIC exceeds $67.0 million. Through improved concession from PMCC and an increased GIC value the amount to be paid to RUS at closing for application to the RUS debt is $140.2 million.

Q. What are the beneficial effects of the PMCC Buyout on Big Rivers' financing plans?

A. One clear benefit of the PMCC Buyout is a simplification of the security arrangements involving Big Rivers' assets by elimination of certain property interests and contractual rights in the lease transactions. Previously, on April 23, 2008, Big Rivers provided as Exhibit 76 to the Third Amended and Supplemental Application a table of contents listing the various Big Rivers financing documents filed as part of this proceeding. I have updated that Exhibit 76 in the attached Exhibit 93, presenting the disposition of each of the Big Rivers financing documents no longer required as a result of the buyout of the PMCC leases. As can be seen from Exhibit 93, Big Rivers' financing documents and requested approvals are greatly streamlined by the completed PMCC Buyout. Removal of references to all the various parties to the various leases also requires modification of a number of the financing documents, which have been revised accordingly and are resubmitted as Exhibit 96 to the Application.

Q. So Big Rivers will still need to obtain an Investment Grade Credit Rating from the rating agencies?

A. Yes.

Q. Does the PMCC Buyout have a negative effect on Big Rivers' ability to obtain that Investment Grade Credit Rating?

A. No. After the PMCC Buyout, the key credit metrics of equity/assets, TIER, and ending cash balances remain comfortably within the boundaries necessary to obtain investment grade credit ratings. If anything, the termination of the BoA and PMCC leveraged leases will assist Big Rivers in obtaining the ratings it requires by simplifying Big Rivers' credit arrangements, making the remaining credit structure much easier to understand.

Q. What is the status of Big Rivers' efforts with respect to obtaining an Investment Grade Credit Rating from the rating agencies?

A. Big Rivers postponed its rating agency presentations until it could resolve the problems created by the Ambac credit downgrade, and determine the impact of the solutions of those problems on its financial position. Now that the PMCC Buyout has been completed, Big Rivers will recommence the actions required for it to obtain an investment grade credit rating no later than immediately after the conclusion of the hearing in this case.

Q. In connection with obtaining an Investment Grade Credit Rating, is it correct that Big Rivers still needs to construct the Phase 2 Transmission Project authorized in Case No. 2007-00177?

A. Yes. Big Rivers will still need to construct the Phase 2 Transmission Project for which a Certificate of Public Convenience and Necessity was issued in 2007. I provide an update of Big Rivers' plans with respect to the Phase 2 Transmission Project in Section VI of this testimony.

B. CHANGES TO THE PRODUCTION COST MODEL

Q. Has Big Rivers made any changes to the Production Cost Model you described in your December 2007 Direct Testimony?

A. Yes. My December 2007 Direct Testimony referenced the November 2007 Production Cost Model and described the various inputs to that model. Big Rivers and WKEC now have almost an additional year of operations data available to update that model as well as additional cost information caused by changes in current market conditions from those included in the previous iteration of the Production Cost Model. The Production Cost Model most recently was run in May 2008 in connection with the prior iteration of the Big Rivers Unwind Financial Model. In order now to provide the Commission with updated information, Big Rivers has conducted another run of the Production Cost Model in September 2008 to use to update the Unwind Financial Model, and has submitted that updated Production Cost Model as Exhibit 97, and its updated Unwind Financial Model as Exhibit 79.

Q. Please describe how the Production Cost Model has been updated from the version developed in November 2007.

A. Certainly. First, the price forecasts for fuel oil and natural gas have been updated to take into account generally prevailing increases in those costs. The updated forecasts used are provided by WKEC (fuel oil) and ACES (natural gas). Although Big Rivers incorporated updated solid fuel forecasts (for coal and petcoke) as part of the May 2008 financial model update, which incorporated a rerun of the Production Cost Model, Big Rivers did not then update the Production

Cost Model to reflect updated prices for fuel oil and natural gas. These changes in fuel oil and natural gas prices are reflected in higher unit startup costs and higher fuel operating costs in the updated Production Cost Model. One additional change since the May 2008 version of the Production Cost Model is implementation of these same fuel oil and natural gas price increases for the modeled generation units in our surrounding region, leading to increased costs for those areas and producing greater potential for Big Rivers to make off-system sales.

Second, the Production Cost Model has been revised to incorporate updated unit reagent and disposal prices. Prices for lime, limestone, DBA and reagent disposal all have increased significantly over those incorporated in the November 2007 Production Cost Model. These prices have been reflected in more recent WKEC supplier contracts, both in terms of automatic contract escalations built into existing terms and in higher rates for replacement contracts reflecting market prices as existing contracts expire.

Third, Big Rivers has incorporated revised SO_2 and NO_X forecasts into the Production Cost Model. We have used forecasts provided by ACES for 2009 and 2010 and by Global Insight, Inc. for the years thereafter.

The forecasts provided by ACES are new and apply for the period 2009 through 2010, while the later years continue to use the previously supplied Global Insight long-term forecasts.

Fourth, as described in the Second Supplemental Direct Testimony of David A. Spainhoward (Exhibit 99), there have been a number of changes to environmental requirements stemming from the federal court reversal of the Clean Air Interstate Rule ("CAIR") regulations. For purposes of the Production Cost Model, Big Rivers has removed the assumptions that CAIR will be implemented in 2009 for NO_x and 2010 for SO_2. Instead, Big Rivers' Production Cost Model now incorporates an assumption that CAIR-like regulations will be implemented for NO_X and SO_2 starting in 2011. Big Rivers believes this is a reasonable and conservative assumption.

Fifth, and finally, the September 2008 Production Cost Model has been revised to eliminate a formerly forecasted need for a ten-week, 50 MW maintenance derating in Wilson Unit 1 for the years 2010, 2011, and 2012. Big Rivers has determined that maintenance to correct concerns with respect to the Wilson Unit 1 can be completed without a derating.

C. CHANGES TO THE UNWIND FINANCIAL MODEL

1. Changes Related to the PMCC Buyout and the BoA Buyout

Q. Has Big Rivers made any changes to the Unwind Financial Model to reflect the PMCC Buyout?

A. Yes. Big Rivers has updated the Unwind Financial Model to reflect the financial effects of the PMCC Buyout.

Q. What changes did Big Rivers make regarding the cost to Big Rivers of terminating the PMCC Lease Transaction?

A. Big Rivers used the actual cost to Big Rivers of paying off the PMCC Lease Transaction of $60.9 million net in the revised model. For purposes of the model, Big Rivers assumes that the PMCC Buyout is funded with a reduced RUS prepayment of $140.2 million at closing, which is then to be followed by an approximate $60.0 million capital markets issuance to be made at roughly the end of year 2012. These calculations are reflected in the Unwind Financial Model.

Q. Does the financial model also reflect changes to the RUS note prepayment?

A. Yes. As discussed previously, Big Rivers agreed with the RUS to a change in the Maximum Allowed Principal balance schedule in connection with the RUS' consent to a reduction in the RUS loan prepayment. I attach this revised balance schedule as Exhibit CWB-10. Changes to that payment schedule are now reflected in the financial model. The financial model now reflects an approximate $60.0 million payment in RUS debt by the end of 2012 and approximately an additional $200 million payment by January 2016.

Q. What other changes have been made to the financial model in connection with the PMCC Buyout?

A. As noted earlier, another change that needs to be made in connection with the PMCC Buyout is a change in the Smelter Surcharge pursuant to Section 4.11(b) of the revised agreements to reflect a reduction in that surcharge of $200,000 a month for the ninety-six months after the closing of the Unwind Transaction. Because the Smelter Surcharge is applied as part of the MRSM, a reduction in the Smelter Surcharge results in a drawing down of the Economic Reserve funds more quickly than otherwise would be the case. However, this quicker draw down in the Economic Reserve is offset by a "feathering" of the Economic Reserve by constricting the maximum amount to be offset in a given year by the MRSM. *See* Supplemental Direct Testimony of William Steven Seelye, Exhibit 103, pages 2 through 10.

A second change to the financial model produced by the PMCC Buyout is the discontinuation of the CoBank patronage amounts. Removal of CoBank as part of the PMCC Lease Termination ends these patronage amounts, and they are discontinued in the revised Unwind Financial Model.

Q. Is the reimbursement from Big Rivers to E.ON with respect to the BoA Buyout reflected in the revised model?

A. Yes. That amount, $1.0 million, is reflected in the updated Unwind Financial Model, Exhibit 79, page 5, at line 116 and in more detail in Exhibit CWB-9.

Q. Are your proposed accounting treatments for the PMCC Buyout and the BoA Buyout reflected in the Updated Financial Model?

A. Yes. The proposed accounting treatments are reflected in Exhibit CWB-11.

2. Changes in Other Assumptions

Q. Did Big Rivers make other changes to the Unwind Financial Model in connection with the filing made in the Application Supplement apart from those connected to the PMCC Buyout and the BoA Buyout?

A. Yes. Big Rivers originally filed its model in connection with its Application made in December 2007. The Application used an April 30, 2008 closing date and was based on late 2007 fuel assumptions and the November 2007 Big Rivers Production Cost Model. Later, in June 2008, Big Rivers filed with the Commission another iteration of the Big Rivers financial model (Exhibit 75) to reflect the results of a new financial arrangement between Big Rivers and E.ON concerning known and anticipated increases in solid fuel costs differing from those used in the earlier financial model filed in December. That June 2008 update to the financial model continued to use an April 30, 2008 closing date and certain other earlier assumptions even as it implemented the new solid fuel forecasts in order to isolate the impact of higher solid fuel prices. Big Rivers has updated the Big Rivers Production Cost Model as well as the Unwind Financial Model to reflect a closing date of December 31, 2008. Additionally, a number of other factors have changed in a way that would have a measurable effect on the financial model. Accordingly, Big Rivers has rerun the model based on these changed assumptions.

Q. Please describe these changes to the Big Rivers financial model inputs.

A. As noted above, a principal change in the financial model is the change in the expected closing date. Given that it is now October 2008, it is no longer useful to continue to model a closing date of April 30, 2008 and to present all changes to the Unwind Financial Model while retaining that date. Given the likely procedural schedule, Big Rivers has based its financial model on a December 31, 2008 closing date.

Q. How does the new expected closing date change the output of the Unwind Financial Model?

A. One principal change of using an expected closing date of December 31, 2008 is the elimination of the partial year's results for 2008. Another consequence of the new closing date is a revision to the expected cash flow to reflect revised WKEC inventory values and other variable costs that will change based on that date.

Q. Are there other changes to the Unwind Financial Model to reflect modifications in key assumptions?

A. Yes. Previous iterations of the financial model assumed a continuation of the Member Discount Adjustment ("MDA"). As this Commission is aware, Big Rivers and its Member Distribution Cooperatives allowed the MDA to expire on August 31, 2008, and the Unwind Financial Model reflects this decision.

In addition, the Unwind Financial Model no longer incorporates a mandatory 2% Member rate increase in 2010. Previously, Section 4.75(a) of the Smelter Agreements required this 2% Member rate increase calculation, but that requirement has now been eliminated, and this change is reflected in the Unwind Financial Model.

Q. How else has the Unwind Financial Model been modified to reflect cost inputs or estimates that have changed since the most recent Unwind Financial Model was filed with the Commission in June 2008?

A. Another principal change to the Unwind Financial Model has been the incorporation of the revisions reflected between the November 2007 Production Cost Model and the more recent September 2008 update of the Production Cost Model, to the extent these changes were not previously updated as part of the June 2008 Unwind Financial Model. I have discussed these modifications globally above, but I discuss them specifically below.

Q. Please describe how the changes to the Production Cost Model are broken down for the revised Unwind Financial Model.

A. A first change results from market increases in the prices of fuel oil and natural gas. These fuel oil and natural gas price increases are reflected in the Unwind Financial Model as part unit start-up fuel costs and as part unit fuel operating costs. They also are reflected in increases in off-system sales revenues as these higher prices are reflected in market prices for wholesale power in neighboring regions.

A second set of changes in the September 2008 Production Cost Model concerns the SO_2 and NO_x allowance price forecasts. The most recent September 2008 Production Cost Model uses updated market forecasts for 2009 and 2010, and these are now incorporated into the Unwind Financial Model. The Unwind Financial Model continues to use Big Rivers' long-term allowance forecasts for other years, and these inputs are unchanged from those previously provided to the Commission. Moreover, as discussed above, the Unwind Financial Model also assumes that CAIR-like SO_2 and NO_x regulations will not resume until 2011. Previously, the financial model assumed a 2009 NO_x regulation commencement and a 2010 SO_2 commencement date. This change reflects Big Rivers' current expectations regarding the environmental regulations as presented in the supplemental testimony of David A. Spainhoward (Exhibit 99).

A third set of changes reflected in the September 2008 Production Cost Model concerns unit reagent and disposal prices. Lime, limestone, and DBA disposal prices have increased significantly through contract escalations and certain replacement contracts that incorporate current increased market prices for these reagents. The results are increases in non-fuel variable operating expenses.

A fourth change reflected in the financial model is the elimination of certain previously forecasted deratings of Wilson Unit 1 discussed above. An effect of this elimination of the unit derating is the availability of additional MWs of power for potential off-system sales.

Q. Does the revised Unwind Financial Model reflect the impact of the court ruling vacating the federal Clean Air Interstate Rule?

A. Yes. In his supplemental testimony, Exhibit 99, David Spainhoward describes the court's ruling and its immediate impact on Big Rivers. From a financial modeling standpoint, the court's rejection of CAIR results in an impact on the market price of emissions allowances, and also results in changes to the Production Cost Model due to changes in the variable costs associated with environmental compliance for such items as ammonia for NOx emission control devices and NOx disposal costs, among others.

For purposes of the financial model, Big Rivers has assumed that there will be no replacement for the CAIR until January 1, 2011, at the earliest. Accordingly, the revised financial model reflects a decrease in the market price of emissions allowances for the years 2009 and 2010. In addition, for that same two-year period, the revised financial model assumes that the surrender rate for SO_2 allowances will be one-to-one, rather than the two-to-one surrender rate under CAIR, and that the NOx emissions control requirement will apply only during five months of the year (May through September), rather than year-round as would have been the case under CAIR. The Production Cost Model has been updated to reflect these changes to variable costs associated with environmental compliance, and these revisions have, in turn, been reflected in the revised Unwind Financial Model.

Q. Apart from these Production Cost Model related changes, does the passage of time produce other changes in estimated costs?

A. Yes. A number of individual, unconnected cost estimates have changed from those previously included in the November 2007 model (as updated by the June 2008 filing). I discuss each of these cost changes below:

First, estimated non-labor administrative and general costs have been revised upwards by from $3.5 million to $4.5 million per year. These costs changes result from an inconsistency discovered in the accounting treatment of plant expenses between Big Rivers and WKEC. Prior versions of the model used actual plant expenses provided by WKEC to Big Rivers. In the course of preparing detailed monthly budgets for potential Big Rivers operation of the plants after a closing of the Unwind Transaction, Big Rivers learned that four categories of costs had not been included in the plant expenses information it had received from WKEC that were incorporated as inputs to the Unwind Financial Model. Upon investigation, Big Rivers determined that WKEC did not include expenses for security, procurement, environmental costs, and emissions fees as part of the individual plant expenses Big Rivers had been using. In order to include the impact of these categories, Big River is incorporating these costs as part of administrative and general costs.

Second, Big Rivers has updated its information technology costs. Pursuant to the Information Technology Support Services Agreement with E.ON, certain required information technology services will be provided to Big Rivers by E.ON for up to eighteen months following the Unwind Closing Date. By that time, Big Rivers is required to transition to its own long-term information technology solution. As described in the Supplemental Direct Testimony of Mark A. Bailey (Exhibit 104), Big Rivers conducted due diligence and has determined to purchase and implement various modules of Oracle e-Business Suite software. Big Rivers has negotiated an agreement with Oracle to purchase the software (at a cost of $1.4 million plus an annual maintenance fee of $0.3 million). Also, Big Rivers has finalized agreements with EDS to configure and implement the software ($7.3 million) and to provide certain information technology services (application management, help desk, desktop support, network, and data center) for a term of eight years ($2.3 million annually) following the Unwind Closing Date. These information technology costs are now included in the Unwind Financial Model.

Q. Do Big Rivers' projected labor costs change in any way?

A. Yes. Big Rivers' projected labor costs have been changed to include an updated payroll calculation based on September 2008 data regarding current salaries and projected employment. These costs are included in the Unwind Financial Model.

Q. Are there any other updates to the Big Rivers Unwind Financial Model?

A. Yes. Another change since the financial model was most recently updated in June 2008 is the incorporation of the Kentucky coal tax credit. Big Rivers now includes the Kentucky coal tax credit for 2010 and part of 2011 as a part of Big Rivers' Fuel Adjustment Charge.

Q. Does the updated Big Rivers Unwind Financial Model reflect a different assumed interest earning rate from that previously included?

A. Yes. The updated Big Rivers financial model lowers the assumed interest earnings rate from 4.38% to 4.00%. This reflects changes in financial markets.

Q. Does the updated Big Rivers Unwind Financial Model reflect a change in the Member Rate Stability Mechanism in order to "feather" the timing of the drawdown of the Economic Reserve to mitigate the rate impact that would otherwise occur when the Economic Reserve is completely depleted?

A. Yes. Originally, as presented in the Application and described in the Direct Testimony of Stephen Seelye, Exhibit 25 at pp. 27-32, the MRSM provided for the use of the Economic Reserve as a rate credit to offset in each month the total dollar amount of fuel adjustment charges ("FAC") and Environmental Surcharge costs billed to Members in that month to the extent such total dollar amounts were not already offset by the Unwind Surcredits and any Rebate Adjustments in that month. This proposed use of the MRSM left existing rates to the Non-Smelter Members effectively unchanged until exhaustion of the $157 million in the Economic Reserve. *Big Rivers now proposes to change the* MRSM to alter the speed at which the Economic Reserve will be drawn down in order to follow the gradualism principle with the effect of anticipated FAC and Environmental Surcharge costs on the Non-Smelter Member rates until the Economic Reserve is exhausted and the full amounts of the FAC and Environmental Surcharge costs are applied without credit. This incorporation of gradualism is explained in the Supplemental Direct Testimony of William Steven Seelye, Exhibit 103, pages 2 through 10 and its use in the Unwind Financial Model is presented in the Supplemental Direct Testimony of Robert S. Mudge, Exhibit 98, pages 8 through 9.

Q. Are there any other significant changes to the model now presented as compared to the version of the Unwind Financial Model most recently filed with the Commission in June of 2008?

A. Not to my knowledge.

III. EFFECTS OF THE UPDATED BIG RIVERS UNWIND FINANCIAL MODEL

A. THE EFFECT OF THE BUYOUTS ON BIG RIVERS' RATES

Q. Will you please provide an estimate of the effect of the BoA Buyout and the PMCC Buyout on Big Rivers' rates?

A. Yes. The financial effects of the BoA Buyout and the PMCC Buyout are relatively easy to isolate. The effect of the buyouts will be an increase in rates by an average over the 15 years modeled of $0.39 MWh and $0.27 MWh for the Non-Smelter Members and the Smelters, respectively (including the effect of the reduction in the Smelter Surcharge amounts for the 96 months provided). A table isolating the rate effects of the BoA Buyout and the PMCC Buyout is attached as Exhibit CWB-12.

The benefits, of course, of completing these buyouts are a huge simplification in the structure and documentation of Big Rivers' finances and the elimination of the enormous risk of credit-support collapse by third-parties.

B. THE EFFECT OF THE UPDATED FINANCIAL MODEL ON EXPECTED RATES

Q. Does Big Rivers' Unwind Financial Model provide a new projection for Big Rivers' expected rates that includes all changes incorporated into the Unwind Financial Model?

A. Yes. Based on modeling performed by Big Rivers, the key credit metrics of equity/assets, TIER, and ending cash balances are all impacted by these changes. In terms of the effect on expected rates, the new financial model indicates that expected rates will increase by an average over the 15 years of $1.38 MWh and $1.49 MWh for the Non-Smelter Members and the Smelters, respectively. This represents an increase of approximately 3% for the Non-Smelter Members and the

Smelters. The results of this new modeling are presented at Exhibit CWB-13.

Q. Has Big Rivers modeled its TIER in future years under the Unwind Transaction as updated in the new Unwind Financial Model?

A. Yes. As part of the Unwind Financial Model Big Rivers has determined the rate levels that would be necessary to maintain a contractual TIER of 1.24 over the period from closing on December 31, 2008 through December 31, 2023. The model demonstrates that a conventional TIER of 1.27 or greater will be achieved under the projected rates in all years.

Q. Has Big Rivers modeled its Debt Service Coverage ("DSC") over the period 2009 through 2023 as reflected in the new Unwind Financial Model?

A. Yes. Over the period 2009 through 2023, Big Rivers' Unwind Financial Model projects that Big Rivers will maintain a DSC at levels between 2.24 and 1.44. The high of 2.24 is achieved in 2009 and then gradually reduces, with some fluctuation, to the low of 1.44 in 2016, before thereafter rising to a range between 1.98 to 1.93 in the years 2021 to 2023.

Q. Does Big Rivers' new Unwind Financial Model estimate the effect of the Unwind Transaction on Big Rivers' days of operating cash on hand?

A. Yes. As I explained in my December 2007 Direct Testimony, Exhibit 10 at p. 22, the Unwind Financial Model continues to show days of operating cash on hand two separate ways: including Big Rivers' lines of credit and excluding those credit lines. When Big Rivers' funds available under its lines of credit are included in days of operating cash on hand, the new Unwind Financial Model projects that Big Rivers will have 171.3 days of operating cash on hand in 2009. This amount drops down to 110.8 days in 2013, and thereafter increases to 188.6 days in 2015. It then drops to a level between 108.8 days and 117.8 days during the years 2017 to 2023. When Big Rivers' line of credit is excluded from the days of operating cash on hand in order to present a more conservative estimate, the new Unwind Financial Model indicates that Big Rivers will have 102.4 days of operating cash on hand in 2009. This amount drops to 53.9 days in 2013 and then climbs back to 118.0 days as late as 2016. Thereafter, it ranges between 46.6 days and 55.3 days during the years 2017 to 2023.

Q. Mr. Blackburn, do you continue to believe that the Unwind Financial Model demonstrates that Big Rivers will be financially healthy on and after the closing date of the Unwind Transaction?

A. I do. The revised Unwind Financial Model indicates that Big Rivers still will achieve a conventional TIER of at least 1.27 in every year modeled. Big Rivers still will have sufficient revenues to more than cover its debt service in each year as shown by the modeled DSC amounts. And Big Rivers still will maintain a reasonable amount of cash on hand (whether including or excluding Big Rivers' line of credit) to permit it to continue operating in a financially strong manner.

C. CHANGES TO PREVIOUS FINANCIAL EXHIBITS

Q. Mr. Blackburn does Big Rivers have any updates to its proposed journal entries as a result of the new Unwind Financial Transaction?

A. Yes. In my December 2007 Direct Testimony I presented as Exhibit CWB-7 a summary of the various Termination Agreement provisions requiring accounting treatment and Big Rivers' proposed journal entries with respect to each. As part of my testimony now, I submit Exhibit CWB-14, which revises and replaces Exhibit CWB-7, presenting revised journal entries for the various Termination Agreement provisions requiring accounting treatment.

Q. Big Rivers filed as Appendix D to its December 2007 Application its most recent RUS Form 12. Is Big Rivers supplying updated RUS Form 12s?

A. Yes. Big Rivers' updated monthly RUS Form 12s for the period December 2007 through August 2008 are attached as Exhibit 106 to the Application Supplement. Exhibit 106 supplements Appendix D to the December 2007 Application.

Q. Mr. Blackburn, Exhibit CWB-2 to your Direct Testimony presented a chart summarizing Big Rivers' Transaction Benefits received from E.ON and comparing them to E.ON's valuation of the benefits. Have you had occasion to update this exhibit?

A. I have. In Exhibit CWB-15 I present an updated chart showing the information previously presented as Exhibit CWB-2.

Q. E.ON and Big Rivers appear to value the Unwind Transaction differently. Can you reconcile the difference in Paul W. Thompson's Revised Exhibit PWT-3 and your Exhibit CWB-15?

A. Yes. As I noted in my Direct Testimony in discussing Exhibit CWB-2, each company looks at the transaction from its own perspective and necessarily evaluates its cost and benefits differently. I will reconcile the major differences below in the same order as they appear in Revised Exhibit PWT-3.

1. Termination Payment -- Big Rivers' cash balance does not include the E.ON contribution to the PMCC Buyout of $61.0 million, resulting in a $61.0 million negative difference. However, Big Rivers' cash balance does include $4.0 million not included by E.ON resulting from the projected inventory balances being $51.0 million ($4.0 million below the Transaction Termination Agreement's established value of $55.0 million). This results in a $57.0 million difference.

2. Leveraged Leases – E.ON has only listed the value of the E.ON portion of the PMCC Buyout of $61.0 million in its Termination Payment, but has not included its expenses associated with the BoA Buyout, which are $4.0 million.

3. E.ON inventory balances are shown at the Transaction Termination Agreement value of $55.0 million, which is $4.0

million higher than the inventory balances contained in Big Rivers' Unwind Financial Model.

4. Remaining personal property is $9.0 million; Big Rivers is not obligated to reimburse E.ON for any of the additional personal property that does not qualify as part of the inventory values.

5. E.ON's Residual Value Payment for shared incremental and non-incremental capital shows a difference of $16.1 million, due in part to the E.ON numbers reflecting a 9/30/08 balance whereas Big Rivers' numbers are projections as of 12/31/08.

6. The Coleman scrubber total cost for E.ON is $1.4 million larger than Big Rivers will record due to the net effect of non-includable expenses and depreciation.

7. E.ON has listed construction work in progress balances as of 9/30/08 and projections for the balance of the year. Big Rivers has included what it believes to be the correct amount of capital asset value in its projected residual value payment forgiveness and therefore does not double account for the benefit of $29.2 million that E.ON has shown.

8. Transaction cost reimbursement to Big Rivers is limited to $22.0 million, and Big Rivers does not list this as a benefit of the Unwind Transaction.

9. Big Rivers does not include IT support as a benefit because Big Rivers will reimburse E.ON for the service pursuant to the terms of the Information Technology Support Services Agreement, resulting in a $5.9 million difference.

10. Wilson stack cleaning is an item brought to E.ON's attention by Big Rivers through its continued due diligence activities. Big Rivers and E.ON agreed that E.ON would be responsible for the repair for this issue. Thus, Big Rivers has not recorded the cost of this repair as a part of the consideration received by Big Rivers. This results in a difference of $1.0 million.

11. Big Rivers has deferred E.ON lease income on its books which will be recognized as income to Big Rivers on the day of closing of the Unwind Transaction ($11.2 million). It is not considered a cost in the E.ON calculation.

12. Big Rivers has an unamortized marketing payment to E.ON on its books that will be recognized as an expense on the Unwind Transaction Closing date ($15.1 million).

13. The Assurance Agreement Payment is an E.ON liability to the Smelters for which Big Rivers has agreed to be responsible ($1.5 million).

14. Minor differences in three separate items account for the remaining $0.4 million difference.

RECONCILIATION OF ESTIMATED TRANSACTION BENEFITS

Exhibit PWT-3	Total: $842.3
1	(57.0)
2	65.0
3	(4.0)
4	(9.0)
5	(16.1)
6	(1.4)
7	(29.2)
8	(22.0)
9	(5.9)
10	(1.0)
11	11.2
12	(15.1)
13	(1.5)
14	(0.4)
Exhibit CWB-15	Total $755.9

IV. REVISIONS TO SMELTER AGREEMENTS

Q. Have the Smelter Agreements been revised since they were last submitted to the Commission in June 2008?

A. Yes, there have been certain revisions to the Smelter Retail and Wholesale Agreements for service to Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky General Partnership ("Century") since these agreements were last submitted to the Commission. The revisions reflect relatively minor changes or clarifications of these agreements. Revised versions of these agreements are included as Exhibit 81, and included as Exhibit 82 are comparisons showing the changes between the agreements as filed in June 2008 and the agreements filed herewith. The changes to the Coordination Agreements and the Smelter Security and Lockbox Agreements are minor, and these revised agreements and comparisons also are included in Exhibits 81 and 82.

Q. Please describe the principal revisions to the Smelter Retail and Wholesale Agreements.

A. There are six principal changes or clarifications to these agreements.

First, the Smelter Retail and Wholesale Agreements for both Alcan and Century have been modified to reflect elimination of the concept of an FAC Reserve for each Smelter. As I explained in my Second Supplemental Direct Testimony dated June 10, 2008, the Smelter Retail and Wholesale Agreements had been revised to incorporate an FAC Reserve, which was intended to offset increased fuel costs to each Smelter resulting from the Unwind Transaction. Big Rivers has determined that establishment of new Smelter FAC Reserve accounts to hold this $7 million agreed upon payment introduces an unnecessary complication into the tariffs and the deal given the extremely short term over which this $7 million would be recovered. After considering the issue since June, Big Rivers and the Smelters have agreed that Big Rivers simply paying this $7 million to the Smelters at the closing of the Unwind Transaction is preferable. Accordingly, Big Rivers has agreed to make an aggregate cash payment of $7 million to the Smelters at closing of the Unwind Transaction ($3.031 million to Alcan and $3.969 million to Century), and the Smelter Retail and Wholesale Agreements have been revised to delete provisions establishing or referencing the FAC Reserve (*see, e.g.*, Section 4.13.5).

Q. What is the second principal revision to the Smelter Retail and Wholesale Agreements?

A. Section 4.7.5(a) of these agreements assumes that Big Rivers will increase the Non-Smelter Member Rates by specified amounts by specified dates. In addition, the Big Rivers financial model contemplates the termination of the Member Discount Adjustment Rider to Big Rivers' tariff, which would increase amounts otherwise due by the Non-Smelter Members to Big Rivers. Accordingly, Section 4.7.5(a) has been clarified to state that the expiration or termination of the Member Discount Adjustment Rider will be considered to constitute an increase in the Non-Smelter Member Rates, whether such expiration or termination occurs prior to, on or after the Effective Date of the Smelter Retail and Wholesale Agreements.

Q. Please describe the third principal revision to these agreements.

A. Section 4.7.6 of the Smelter Retail and Wholesale Agreements has been revised to clarify that transaction costs related to the Unwind Transaction will be treated as having been incurred prior to consummation of the Unwind Transaction, and thus will be excluded from calculation of the TIER Adjustment Charge. Absent this change, the Smelters could be responsible for paying all of Big Rivers' transaction costs associated with the Unwind Transaction through the TIER Adjustment Charge, and Big Rivers believes it would be inappropriate for the Smelters to bear those costs.

Q. What is the fourth revision to the Smelter Retail and Wholesale Agreements?

A. Section 4.11(d) of these agreements now provides for Big Rivers to reduce the monthly Surcharge to Alcan and Century by their *pro rata* shares of $200,000. Big Rivers agreed to this reduction in the Surcharge as part of an overall settlement of certain previously outstanding items among the parties, as explained above.

Q. What is the fifth revision to the Smelter Retail and Wholesale Agreements that you address in your testimony?

A. The amendment to Big Rivers' by-laws contained in Appendix B to the Smelter Wholesale Agreements has been revised to reflect a bifurcation of the year in which the Unwind Transaction occurs with respect to patronage net earnings allocation, so that prior to closing of the Unwind Transaction the patronage allocation shall be computed in a manner consistent with the prior by-laws, and after closing shall be computed in a manner consistent with the amended by-laws. The revision, incorporated in Section 2 of Appendix B, provides that the patronage net earnings attributable to that portion of 2008 ending on the last day of the month preceding the month in which the Unwind Transaction closes shall be determined and allocated in accordance with the by-laws as in effect on January 1, 2008. The patronage net earnings attributable to that portion of the Unwind Transaction year beginning on the first day of the month in which the Unwind Transaction closes shall be determined and allocated in accordance with the amended by-laws.

Q. What is the final revision to the Smelter Retail and Wholesale Agreements?

A. A final change in the Smelter Retail and Wholesale Agreements is the addition of a closing incentive payment from Big Rivers to the Smelters. As an inducement for the Smelters to sign onto the Unwind Transaction in the face of the cost increases reflected in the updated Unwind Financial Model as compared to the June 2008 Model, Big Rivers has agreed to make a closing incentive payment to the

Smelters. The incentive payment, as has already been explained, is based on the difference between the amount charged each Smelter for Tier 3 energy under their current contract with Kenergy during the period from October 6, 2008 through the date of the closing of the Unwind Transaction, and the amount that would be owed for a similar quantity of energy under the Unwind Transaction rates. This payment, designed as an inducement for the Smelters to agree to close the Unwind Transaction, will be paid as a single lump sum at closing. Should the Unwind Transaction not close, no payment will be owed to the Smelters.

Big Rivers currently estimates that the amount of this lump sum payment would be approximately $1,400,000 if the Unwind Transaction were to close on December 31, 2008. For each month the closing of the Unwind Transaction is delayed, Big Rivers estimates that this lump sum payment would increase by approximately $480,000.

V. CHANGES TO BIG RIVERS' TARIFFS

Q. Has Big Rivers updated its Tariffs to reflect changes in rates produced by changes in the Unwind Transaction?

A. Yes. The Supplemental Direct Testimony of David A. Spainhoward (Exhibit 99) describes the mechanics of these tariff changes and explains the various pages and provisions that change.

Q. One change in the Tariffs is the elimination of the Member Discount Adjustment. Could you please explain this change?

A. As I noted in my Direct Testimony (Exhibit 10, pages 100-03), the Member Discount Adjustment was originally implemented in 2000 to return to Members a sum that Big Rivers realized in debt service interest reduction resulting from a prepayment to the RUS made in connection with the PMCC Lease Transaction. Big Rivers originally proposed indefinitely maintaining this adjustment until its next general rate review. However, in light of the termination of the PMCC Lease Transaction, Big Rivers and its Member Distribution Cooperatives determined to allow this tariff provision to expire by its own terms on August 31, 2008. Accordingly, the MDA is removed from Big Rivers' Tariff.

Q. Another change in the Tariffs concerns the effect of the revised financial model on the Economic Reserve Account and the

Member Rate Stability Mechanism. Could you please describe the effect of the various changes in the Unwind Financial Model to the operation of the Economic Reserve Account and the amounts refunded by the Member Rate Stability Mechanism?

A. As I stated previously in my Direct Testimony (Exhibit 10, pages 76-80), the Economic Reserve Account represents an attempt on the part of the parties to the Unwind Transaction to establish a regulatory account that, in part, will help to cushion the effect of potential FAC and Environmental Surcharge increases to Big Rivers' member distribution cooperatives for service to their Non-Smelter Members. Originally, this account was to hold $75 million of the funds received at closing from the E.ON Parties. Later, in June 2008, Big Rivers updated the transaction terms to reflect known and anticipated increases in fuel prices. This update increased the amount in the Economic Reserve Account to be funded by revenues received from the E.ON Parties at closing to $157 million.

The PMCC Buyout does not increase the amount to be placed in the Economic Reserve Account. However, as shown above, one effect of the various changes to the Unwind Financial Model is that Big Rivers' revenue requirements from its Non-Smelter Member customers will be higher than previously was the case. Accordingly, by operation of the Member Rate Stability Mechanism, as amended to incorporate feathering, amounts in the Economic Reserve Account will now be drawn down differently than previously was reflected in my testimony.

Q. When does Big Rivers now forecast the amounts in the Economic Reserve to be fully drawn down?

A. Big Rivers' financial model projects these amounts will be fully drawn down during 2013.

Q. Could you please estimate the effect of the proposed revised Tariff on revenues for the first twelve months after the closing of the Unwind Transaction?

A. Yes. There will be no effect, as shown on Exhibit CWB-16, which replaces Exhibit CWB-8 filed with my Direct Testimony in Exhibit 10.

VI. UPDATES TO DATA RESPONSES

Q. Will you please provide an exhibit summarizing Big Rivers' financial condition – or matrix – in connection with the Unwind Transaction.

A. Yes. I provide Exhibit CWB-17 hereto as Big Rivers' financial matrix.

Q. Does the current Application Supplement have any effect on Big Rivers' Certificate of Public Convenience and Necessity issued on October 30, 2007 in Case No. 2007-00177 relating to the Phase 2 Transmission Project?

A. Yes. Although I noted in my Direct Testimony that Big Rivers' needs to construct the Phase 2 Transmission Project was contingent on the Unwind Transaction becoming effective, the terms of Big Rivers' Certificate of Public Convenience and Necessity that was issued in Case No. 2007-00177 on October 30, 2007 will expire on October 30, 2008 by operation of law if Big Rivers has not begun construction of that project. Accordingly, Big Rivers has begun efforts to commence construction on the Phase 2 Transmission Project by that date in order to maintain its Certificate of Public Convenience and Necessity in full effect, and to assure the timely availability of the transmission facilities.

Q. In your Direct Testimony dated December 28, 2007, filed as Exhibit 10 to the Application, at pages 66-67, you mention a disagreement between Big Rivers and the Smelters regarding the issue of Big Rivers' obligation to provide wholesale service to Kenergy for resale to the Smelters. Please explain that issue in more detail, including how that issue is handled by Big Rivers and the Smelters in the Unwind Transaction.

A. Big Rivers and the Smelters disagree about whether there is an obligation of Big Rivers to provide wholesale electricity to Kenergy for resale to the Smelters following July 15, 1998. Big Rivers and the Smelters determined that they did not need to resolve this issue in order to enter into the Smelter Agreements and close the Unwind Transaction, that the Smelter Agreements and Unwind Transaction should not "change the playing field" for either side and that subsequent events and the passage of time may resolve the issue or render the issue moot. As a result, Big Rivers and the Smelters have agreed that no resolution or action is required currently. The final position of the parties on the issue is represented in Section 3.5 of each Smelter Coordination Agreement, which states:

> 3.5 Plan of Reorganization. The Parties acknowledge and agree that nothing in the [Smelter] Retail Agreement, the [Smelter] Wholesale Agreement, this Agreement or any document or agreement relating thereto may be construed to amend, affirm, waive or otherwise alter the terms of Schedule 5.4(a) of the Big Rivers plan of reorganization, as modified June 1, 1998, or any document or agreement relating thereto regarding the obligation of Big Rivers to serve Kenergy for the benefit of [Smelter]; *provided,* that [Smelter] and Big Rivers disagree, notwithstanding the Unwind Transaction, as to the obligation of Big Rivers, in the absence of a new or amended contract, to serve Kenergy for the benefit of [Smelter] when the Existing [Smelter] Agreement terminates or when the [Smelter] Retail Agreement terminates. The Parties acknowledge that clarity on this issue is desired by both Parties so that necessary and appropriate capital planning and decision-making can be undertaken. The Parties agree to endeavor in good faith to resolve this disagreement prior to 2015.

Q. Turning to a different issue, does Big Rivers have any additional evidentiary support to offer relating to its view that an adequate market exists for the off-system resale of capacity now devoted to the Smelters should the Smelters depart Big Rivers' system?

A. Yes. Big Rivers is positioned so that it can access a number of very robust energy markets in which significant quantities of wholesale power are traded. As an illustration of the magnitude of the quantities transacted in nearby power markets, I attach Exhibit CWB-18. As shown, the numbers presented for the volume of market transactions in the 1st quarter of 2008 (taken from *Megawatt Daily's and Power Markets Week's Power Sales Analysis* dated July 21, 2008) indicate that the Midwest Independent Transmission System Operator, Inc. wholesale market made 216,110,511 MWh of wholesale power sales transactions, that the Southern Company system made 29,882,066 MWh of wholesale power sales transactions, that the Tennessee Valley Authority made 4,914,557 MWh of wholesale power sales transactions, and that PJM South (mostly Virginia) made 1,137,782 MWh in wholesale power sales transactions. Big Rivers has sold off-system power into all of these markets, and it would be able to access them should one or both of the Smelters depart the system. The Smelters' total quarterly MWh commitment would amount to 1,861,500 MWh, and thus any Big Rivers remarketing of that commitment would comprise less than 1% (approximately 0.77%) of the total 1st quarter 2008 market size of 252,044,916 MWh.

Moreover, Big Rivers need not remarket this entire commitment in a 7 day by 24 hour block as it now sells this power to the Smelters. Economically, Big Rivers need only sell a sufficient quantity of this power to provide it with the same or more revenues it now earns from the Smelters. Because it is highly likely that Big Rivers would be able to sell this power at a rate higher than is now offered to the Smelters as part of this transaction, Big Rivers economically could recoup these amounts in full even if it did not resell the entire amount. Big Rivers' Unwind Financial Model already indicates that in each future year the projected market prices in neighboring markets will be in excess of the rate charged to the Smelters. However, in order to provide an additional demonstration of the viability of these projections, I attach Exhibit CWB-19, which sets forth Platt's 2008 *Power Sale Analysis'* projections of the forward price of 7x24 blocks of power at the CinHub over the term of the transaction. Although these price forecasts are not identical to those used in the model (and in fact generally are higher on average), they indicate a healthy spread between the modeled Smelter rate and the projected future market prices in all years modeled. This Exhibit CWB-19 also presents the percentage of the stranded Smelter power that would need to be sold to keep Big Rivers revenue neutral. As can be seen, this amount ranges from 97% to 81% over the period modeled. Thus, Big Rivers likely would not even need to sell the full amount of Smelter power that could be available in order to break even.

Q. In Big Rivers' Rebuttal Testimony you responded to the concerns that the benefits of the Unwind Transaction to the Smelters were unfairly front-end loaded. Does the new

Unwind Financial Model change your response that Smelter benefits are not unfairly front-end loaded?

A. No. The concern regarding a front-end loading of the Smelter benefits is that they would receive excessive benefits during early years and then can terminate their service without having provided payments for service on which these benefits were predicated. I do not believe it is the case that these benefits are in fact front-end loaded, and I demonstrated in my April 2008 Rebuttal Testimony that the benefits and revenues received were closely aligned. Rebuttal Testimony of C. William Blackburn at p. 18. The change to the Smelter Surcharge to reflect a reduction of $200,000 a month does not disturb this conclusion. Although the Smelters will receive an additional nominal $19.2 million benefit from this reduction in payments, they do not receive this benefit if they depart the system earlier. The Smelter Surcharge reduction is structured to require the Smelters to remain on the system to receive an additional benefit each month. Thus, were the Smelters to depart at the end of 2012, the first date they are permitted to do so by their contracts, they would receive only 48 months of this benefit (assuming a closing on December 31, 2008). This would thus amount to only a $9.6 million nominal additional benefit. But it would come at the cost of the additional $9.6 million they would otherwise receive were they to remain for eight full years. Accordingly, I believe this provides additional incentive for the Smelters to stay on the system, thereby mitigating the concern expressed regarding front-loading.

Q. Following up on Commission Staff's First Request for Information, No. 22, you mentioned that the Production Cost Model has been updated as of September 2008 and incorporated into the current Unwind Financial Model. Is a copy of the updated September 2008 Production Cost Model included in this filing?

A. Yes. The updated Production Cost Model is included as Exhibit 97.

Q. Big Rivers provided a comparison of Big Rivers' wholesale rates under the Unwind Transaction with rates under the status quo. The comparison was developed in response to the Commission Staff's Second Supplemental Request for Information filed April 16, 2008, Item 13, and was further explained in Big Rivers' May 30, 2008 filing to update responses, Tab 18. Is an update of this information included in this filing?

A. Yes. A comparison of the status quo rates with rates under the updated Unwind Financial Model is included as Exhibit 100 using the same assumptions used in the previous data responses.

Q. Has Big Rivers sought and obtained a tax ruling by the Kentucky Department of Revenue relating to the tax effects of the termination of the power purchase agreement between Big Rivers and WKEC and Big Rivers' assumption of WKEC's *obligation to supply electric power to Kenergy Corporation?*

A. Yes. As part of the Commission's data requests, the Commission in its Supplemental Data Request, Item 4(b), requested Big Rivers to provide the current status of its February 7, 2008 ruling requests from the Kentucky Department of Revenue. In updated compliance with that directive, Big Rivers on February 7, 2008 requested a number of rulings from the Kentucky Department of Revenue regarding the Unwind Transaction. On February 25, 2008, the Kentucky Department of Revenue issued an order containing a series of rulings (attached as Exhibit CWB-20).

First, it ruled that the transaction will be treated and taxed for Kentucky corporation income tax purposes in the same manner as the transaction is treated and taxed for Federal income tax purposes, except for differences between Federal income tax law and Kentucky income tax law. Accordingly, unless specifically provided for to the contrary in the Kentucky Revised Statutes, the Kentucky Department of Revenue will generally follow the Federal income tax treatment.

Second, the Kentucky Department of Revenue confirmed that the operation of the Generating Facilities and the related assets for the generation of electricity constitutes manufacturing for the purposes of KRS Chapter 139. To the extent the assets in question are used directly within the manufacturing process as provided in KRS 139.710, the Kentucky Department of Revenue confirmed that Big Rivers will be considered a manufacturer of tangible personal property.

Third, the Kentucky Department of Revenue confirmed that the transfer by WKEC to Big Rivers of various intangibles (contract rights, intellectual property, permits and SO_2 and NO_x allowances, etc.) to Big Rivers will be exempt from the sales tax imposed under KRS 139.200 for retail sales of tangible personal property or the furnishing of certain services.

Fourth, the Kentucky Department of Revenue confirmed that the return of the LG&E Energy Marketing, Inc. transmission deposits will not be subject to Kentucky sales and use tax by virtue of not constituting a retail sale as defined in KRS 139.100.

Fifth, the Kentucky Department of Revenue confirmed that Big Rivers will be subject to *ad valorem* assessment and taxation as a public service corporation pursuant to KRS 136.115 through 136.180.

Sixth, the Kentucky Department of Revenue confirmed that all machinery and equipment actually engaged by Big Rivers in manufacturing will be subject to a state rate of $0.15/$100 pursuant to KRS 132.020(1)(i) and shall be exempt from local taxes under KRS 132.200(4).

Seventh, the Kentucky Department of Revenue confirmed that non-operating intangible property of Big Rivers will be exempt from or not subject to *ad valorem* taxation, beginning with the 2006 tax year.

And eighth, the Kentucky Department of Revenue confirmed that the limited liability entity tax imposed by KRS 141.0401(2) will not apply to Big Rivers as long as Big Rivers is a public service corporation subject to tax under KRS 136.120. It further confirmed that this exemption from the limited liability entity tax provided by KRS 141.0401(6)(i) also applies to the $175 minimum tax.

Q. Did the Kentucky Department of Revenue's February 25, 2008 decline to issue any of Big Rivers' requested tax rulings?

A. Yes. Big Rivers requested a ruling that neither the payment nor receipt of the termination value payment, nor WKEC's waiver of its right to the Residual Value Payment ("RVP"), would be subject to Kentucky sales and use tax. The Kentucky Department of Revenue determined that it could not rule on this request without reviewing the Participation Agreement and the Station Two Agreements. E.ON made this same request and was given the same answer. Nevertheless, Big Rivers continues to believe that the termination value payment and the RVP are not subject to sales and use tax because they constitute intangible property which is not subject to the sales and use tax.

Q. Mr. Blackburn, does this conclude your testimony at this time?

A. Yes, it does.

LISTS OF EXHIBITS TO BILL BLACKBURN'S TESTIMONY

Exhibit CWB-9	PMCC and BoA Lease Cash Flow
Exhibit CWB-10	RUS Maximum Allowed Principal Balance Schedule From RUS
Exhibit CWB-11	Termination Accounting Treatment For Leveraged Leases
Exhibit CWB-12	Table Isolating Rate Effects Of The Buyouts Together By Year
Exhibit CWB-13	Costs Effects In Model Between June 2008 and October 2008
Exhibit CWB-14	Revision To CWB-7, Proposed Journal Entries
Exhibit CWB-15	Summary Of Transaction Benefits From E.ON, Updating CWB-2
Exhibit CWB-16	Effect Of Revisions On Rates, Replaces CWB-8
Exhibit CWB-17	Financial Matrix
Exhibit CWB-18	Chart Showing Liquidity Of Power Sales In Nearby Markets
Exhibit CWB-19	Cinergy Hub Price Projections
Exhibit CWB-20	Kentucky Revenue Cabinet Tax Ruling Request
Exhibit CWB-21	Reconciliation Of Leveraged Leases

BIG RIVERS ELECTRIC CORPORATION
PMCC AND BoA LEASE CASH FLOW
(000's)

	BofA	PMCC	Total
Terminal Value (Net)	($40,000)	($214,000)	($254,000)
GIC	$33,875	$92,620	$126,495
Net Impact of B-Loan Payoff	$0	($333)	($333)
Total Shortfall	**($6,125)**	**($121,713)**	**($127,838)**
Contribution (E.ON + Smelter)	$5,125	$60,856	$65,982
Net	**($1,000)**	**($60,856)**	**($61,856)**
Net Impact of B-Loan Payoff	$2,207	$0	$2,207
Net Cash Flow	**$1,207**	**($60,856)**	**($59,649)**

BIG RIVERS ELECTRIC CORPORATION
RUS MAXIMUM ALLOWED PRINCIPAL BALANCE SCHEDULE FROM RUS

DATE	UNWIND MAXIMUM ALLOWED PRINCIPAL BALANCE	EXISTING MAXIMUM ALLOWED PRINCIPAL BALANCE	DIFFERENCE
21-Nov-08	643,390,666.00	768,605,000.00	(125,214,334.00)
31-Dec-08	643,390,666.00	768,605,000.00	(125,214,334.00)
02-Jan-09	641,043,116.28	760,106,000.00	(119,062,883.72)
01-Apr-09	637,280,892.02	751,607,000.00	(114,326,107.98)
01-Jul-09	633,666,706.46	743,109,000.00	(109,442,293.54)
01-Oct-09	630,100,533.53	729,610,000.00	(99,509,466.47)
04-Jan-10	626,780,462.74	720,611,000.00	(93,830,537.26)
01-Apr-10	622,620,789.50	711,613,000.00	(88,992,210.50)
01-Jul-10	618,796,442.32	702,614,000.00	(83,817,557.68)
01-Oct-10	615,014,752.40	688,615,000.00	(73,600,247.60)
03-Jan-11	611,372,025.65	678,117,000.00	(66,744,974.35)
01-Apr-11	607,097,484.41	667,618,000.00	(60,520,515.59)
01-Jul-11	603,050,601.09	657,120,000.00	(54,069,398.91)
03-Oct-11	599,230,706.56	641,622,000.00	(42,391,293.44)
02-Jan-12	595,070,532.28	626,624,000.00	(31,553,467.72)
02-Apr-12	590,827,927.25	611,626,000.00	(20,798,072.75)
02-Jul-12	586,524,668.04	596,628,000.00	(10,103,331.96)
01-Oct-12	507,159,887.51	576,631,000.00	(69,471,112.49)
02-Jan-13	501,820,262.61	576,631,000.00	(74,810,737.39)
01-Apr-13	496,106,057.66	576,631,000.00	(80,524,942.34)
01-Jul-13	490,468,043.81	576,631,000.00	(86,162,956.19)
01-Oct-13	484,826,471.07	571,631,000.00	(86,804,528.93)
02-Jan-14	479,179,510.95	556,133,000.00	(76,953,489.05)
01-Apr-14	473,147,870.25	540,635,000.00	(67,487,129.75)
01-Jul-14	467,180,736.63	525,138,000.00	(57,957,263.37)
01-Oct-14	461,201,657.45	504,640,000.00	(43,438,342.55)
02-Jan-15	455,208,577.62	491,642,000.00	(36,433,422.38)
01-Apr-15	448,840,851.30	478,644,000.00	(29,803,148.70)
01-Jul-15	442,525,261.59	465,646,000.00	(23,120,738.41)
01-Oct-15	436,188,846.88	439,348,000.00	(3,159,153.12)
04-Jan-16	229,965,990.63	421,350,000.00	(191,384,009.37)
01-Apr-16	220,895,301.86	403,353,000.00	(182,457,698.14)
01-Jul-16	211,803,320.08	385,356,000.00	(173,552,679.92)
03-Oct-16	202,681,180.59	367,359,000.00	(164,677,819.41)
02-Jan-17	193,328,976.04	348,861,000.00	(155,532,023.96)
03-Apr-17	183,850,466.08	330,364,000.00	(146,513,533.92)
03-Jul-17	174,236,075.84	311,867,000.00	(137,630,924.16)
02-Oct-17	164,483,857.39	293,370,000.00	(128,886,142.61)
02-Jan-18	154,617,746.73	273,873,000.00	(119,255,253.27)
02-Apr-18	144,559,929.85	254,376,000.00	(109,816,070.15)
02-Jul-18	134,382,285.55	234,879,000.00	(100,496,714.45)
01-Oct-18	124,058,738.44	215,381,000.00	(91,322,261.56)
02-Jan-19	113,626,283.94	195,384,000.00	(81,757,716.06)
01-Apr-19	102,969,386.70	175,388,000.00	(72,418,613.30)
01-Jul-19	92,195,516.33	155,391,000.00	(63,195,483.67)
01-Oct-19	81,281,719.85	135,394,000.00	(54,112,280.15)
02-Jan-20	70,222,482.75	115,397,000.00	(45,174,517.25)
01-Apr-20	58,965,382.61	95,400,000.00	(36,434,617.39)
01-Jul-20	47,558,378.14	75,403,000.00	(27,844,621.86)
01-Oct-20	35,995,765.61	55,406,000.00	(19,410,234.39)
04-Jan-21	24,283,059.46	35,409,000.00	(11,125,940.54)
01-Apr-21	12,365,870.43	15,412,000.00	(3,046,129.57)
01-Jul-21	0.00	0.00	0.00

Date Prepared: 9/02/08

BIG RIVERS ELECTRIC CORPORATION
TERMINATION ACCOUNTING TREATMENT FOR LEVERAGED LEASES

			DR	CR	
	Journal Entry 4 - Record Termination of Leveraged Leases				
224.14500	Long-Term Debt Defeased S/L Obligation		189,745,311.32		Financial Model Line 251
253.04500	Net Deferred Credit Defeased S/L Gain		50,559,000.01		Financial Model Line 263
435.00000	Extraordinary Deductions		16,144,676.65		Financial Model Line 187
	128.045000	Other Special Funds Defeased S/L Investment		196,799,740.02	Financial Model Line 226
	131.100000	Cash General Fund		59,649,247.96	Financial Model Line 116
Total			256,448,987.98	256,448,987.98	

BIG RIVERS ELECTRIC CORPORATION
TABLE ISOLATING RATE EFFECTS OF THE BUYOUTS TOGETHER BY YEAR

			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate Impact Analysis ($/ MWh)																	
1. Non-Smelter Members																	
1	*December Close/ $60.9m PMCC Buyout*	47.49	35.45	37.42	39.29	41.26	44.14	47.01	47.49	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98
2	MRDA Continued	(0.89)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
3	GRA	0.47	-	-	0.45	0.45	0.45	0.45	0.45	0.44	0.61	0.61	0.61	0.61	0.61	0.61	0.56
4	Regulatory Account	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5																	
6	FAC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Environmental Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Surcharge Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Rebate Realized	0.02	0.00	0.09	0.25	(0.00)	-	(0.00)	0.00	(0.00)	(0.00)	0.00	(0.00)	(0.00)	0.00	0.00	0.00
10	Economic Reserve/ MRSM	0.00	-	*(0.09)*	*(0.25)*	-	*0.35*	-	-	-	-	-	-	-	-	-	-
11	*Net*	0.02	0.00	0.00	(0.00)	(0.00)	0.35	(0.00)	0.00	(0.00)	(0.00)	0.00	(0.00)	(0.00)	0.00	0.00	0.00
12																	
13	*Overall Change*	(0.39)	(1.05)	(1.03)	(0.56)	(0.53)	(0.16)	(0.49)	(0.47)	(0.45)	(0.26)	(0.24)	(0.23)	(0.21)	(0.19)	(0.18)	(0.21)
14	*December Close/ No BofA or PMCC Buyout*	47.09	34.40	36.39	38.73	40.73	43.99	46.52	47.02	47.19	49.68	50.30	50.61	52.46	52.69	53.40	53.77
2. Smelters																	
1	*December Close/ $60.9m PMCC Buyout*	51.42	43.20	44.61	47.46	52.33	53.92	46.67	48.42	48.44	54.47	50.77	55.05	54.30	56.77	56.32	58.53
2	MRDA Continued	(0.71)	(0.83)	(0.81)	(0.79)	(0.77)	(0.75)	(0.74)	(0.72)	(0.71)	(0.69)	(0.68)	(0.66)	(0.65)	(0.64)	(0.62)	(0.61)
3	GRA	0.36	0.00	(0.00)	0.35	0.35	0.35	0.35	0.35	0.35	0.48	0.48	0.48	0.48	0.48	0.48	0.45
4	TIER Adjustment	0.05	0.65	-	0.16	(0.18)	(0.00)	0.07	0.14	0.22	(0.00)	0.02	(0.07)	(0.04)	(0.10)	(0.06)	0.00
5	FAC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Smelter Economic Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Environmental Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Power Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	TIER Related Rebate	0.02	-	0.10	0.26	-	-	-	-	-	-	-	-	-	-	-	-
11	*Overall Change*	(0.27)	(0.18)	(0.71)	(0.03)	(0.60)	(0.41)	(0.32)	(0.23)	(0.14)	(0.21)	(0.17)	(0.25)	(0.21)	(0.26)	(0.20)	(0.16)
12	*December Close/ No BofA or PMCC Buyout*	51.15	43.02	43.90	47.43	51.73	53.51	46.35	48.19	48.31	54.26	50.60	54.80	54.09	56.52	56.13	58.37

BIG RIVERS ELECTRIC CORPORATION

COSTS EFFECTS IN MODEL BETWEEN JUNE 2008 AND OCTOBER 2008

			2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate Impact Analysis ($/ MWh)																	
1. Non-Smelter Members																	
1	*Filed Model (6/08)*	46.11	34.40	34.39	35.71	35.69	47.57	46.29	46.38	46.47	48.99	49.64	49.87	51.53	51.51	52.13	52.40
2	Discontinued MRDA	0.89	1.05	1.03	1.00	0.98	0.96	0.93	0.91	0.89	0.87	0.85	0.84	0.82	0.80	0.78	0.77
3	GRA	(0.79)	-	-	(0.71)	(0.71)	(0.71)	(0.71)	(0.89)	(0.89)	(0.99)	(0.99)	(0.99)	(0.99)	(0.99)	(0.99)	(0.87)
4	Regulatory Account	(0.18)	-	-	(0.72)	(0.70)	(0.68)	(0.74)	(0.73)	(0.71)	0.01	0.01	0.01	0.33	0.32	0.31	0.25
5																	
6	FAC	0.63	0.41	0.82	0.61	0.98	3.16	0.27	0.38	0.50	0.30	0.28	0.33	0.19	0.43	0.51	0.62
7	Environmental Surcharge	0.69	1.11	(0.05)	0.49	0.43	0.64	0.36	0.84	0.79	0.76	0.75	0.79	0.79	0.81	0.82	0.81
8	Surcharge Credit	0.31	0.69	0.67	0.65	0.64	0.62	0.61	0.60	0.58	-	-	-	-	-	-	-
9	Rebate Realized	0.08	0.63	1.41	(0.62)	0.00	-	0.00	(0.00)	(0.00)	0.00	0.00	-	-	-	(0.00)	-
10	Economic Reserve/ MRSM	(0.26)	(2.84)	(0.85)	2.87	3.95	(7.41)	-	-	-	-	-	-	-	-	-	-
11	*Net*	1.45	(0.00)	2.00	4.00	6.00	(2.99)	1.24	1.82	1.87	1.06	1.03	1.12	0.98	1.24	1.33	1.43
12																	
13	*Overall Change*	1.38	1.05	3.03	3.58	5.57	(3.43)	0.72	1.12	1.17	0.95	0.90	0.97	1.13	1.37	1.44	1.58
14	*December Close/ $60.9m Buyout*	47.49	35.45	37.42	39.29	41.26	44.14	47.01	47.49	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98
2. Smelters																	
1	*Filed Model (6/08)*	49.93	40.73	42.80	45.84	51.68	52.49	46.71	48.40	47.95	53.08	49.35	53.27	52.57	54.49	53.90	55.66
2	Discontinued MRDA	0.71	0.83	0.81	0.79	0.77	0.75	0.74	0.72	0.71	0.69	0.68	0.66	0.65	0.64	0.62	0.61
3	GRA	(0.56)	0.64	0.00	(0.56)	(0.56)	(0.56)	(0.56)	(0.70)	(0.70)	(0.79)	(0.79)	(0.79)	(0.79)	(0.79)	(0.79)	(0.69)
4	TIER Adjustment	0.20	(0.00)	-	1.73	(0.04)	(1.14)	(0.56)	(0.77)	(0.58)	0.00	0.16	0.52	0.75	0.76	1.06	1.18
5	FAC	0.65	0.41	0.82	0.61	0.98	3.16	0.27	0.38	0.50	0.30	0.28	0.33	0.19	0.43	0.51	0.62
6	*Smelter Economic Reserve*	0.07	0.45	0.46	0.15	-	-	-	-	-	-	-	-	-	-	-	-
7	Environmental Surcharge	0.68	1.11	(0.05)	0.49	0.43	0.64	0.36	0.84	0.79	0.76	0.75	0.79	0.79	0.81	0.82	0.81
8	Power Purchases	(0.14)	(0.64)	(1.34)	(0.63)	(0.61)	(1.09)	0.05	(0.12)	0.11	0.42	0.35	0.26	0.14	0.43	0.20	0.34
9	Surcharge	(0.18)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	(0.33)	-	-	-	-	-	-	-
10	TIER Related Rebate	0.05	-	1.44	(0.63)	-	-	-	-	-	-	-	-	-	-	-	-
11	*Overall Change*	1.49	2.47	1.82	1.62	0.65	1.43	(0.04)	0.02	0.49	1.39	1.43	1.78	1.73	2.28	2.43	2.87
12	*December Close/ $60.9m Buyout*	51.42	43.20	44.61	47.46	52.33	53.92	46.67	48.42	48.44	54.47	50.77	55.05	54.30	56.77	56.32	58.53

BIG RIVERS ELECTRIC CORPORATION
REVISION TO CWB-7, PROPOSED JOURNAL ENTRIES

Journal Entry 1 - Record Value Received from WKE Parties

Account	Description	DR	CR	Transaction Termination Agreement
131.10000	Cash General Fund	387,675,000.00		Section 3.3 (a)
253.20000	Deferred Credit - Lease Income	11,222,201.63		Exibit B, Section 2.1
253.25000	Deferred Credit - Cap Asset Residual Value	55,042,016.94		Exibit B, Section 2.1 & 2.4
253.25100	Deferred Credit - Incremental Residual Value	86,313,604.26		Exibit B, Section 2.1 & 2.4
224.14100	LEM Settlement Promissory Note	15,659,261.00		Exibit B, Section 2.1 & 2.4
101.0312C	Boiler Plant Equipment - Clean Air - Coleman	98,520,087.44		Exibit B, Section 2.1 & 2.4
101.0316_	Miscellaneous Power Plant Equipment (Personal Property)	5,745,000.00		Section 3.3 (a)
151.00000	Fuel Stock	31,444,000.00		Section 3.3 (a)
154.00000	Plant Materials and Operating Supplies	13,847,000.00		Section 3.3 (a)
174.10000	Miscellaneous Asset - Allowances Receivable	1,960,000.00		Section 8.2 (d)
186.50000	Deferred Debit - Marketing PMT/Settlement		15,068,000.00	Exibit B Section 2.1 & 2.4
232.00000	Accounts Payable - Smelter Payment - Assurances Agreement		1,525,000.00	Financial Model Line 167
253.00000	Deferred Credit - Member Economic Reserve		157,000,000.00	Financial Model Line 169
434.00000	Extraordinary Income		533,835,171.27	
Total		707,428,171.27	707,428,171.27	

Journal Entry 2 - Record Payment to the RUS and Smelters

Account	Description	DR	CR	
224.35000	RUS New Note	147,004,256.96		Financial Model Line 166
232.00000	Accounts Payable - Smelter Payment - Assurances Agreement	1,525,000.00		Coordination Agreements Section 3.3
253.35000	Deferred Credit - Century Excess Reactive Power	99,967.58		Financial Model Line167
253.36000	Deferred Credit - Alcan Excess Reactive Power	102,032.42		Financial Model Line167
435.00000	Extraordinary Deductions	7,000,000.00		Financial Model Line 170
131.10000	Cash General Fund		155,731,256.96	
Total		155,731,256.96	155,731,256.96	

Journal Entry 3 - Establish Special Funds and Recognize Tax Asset

Account	Description	DR	CR	
190.10000	Accumulated Deferred Income Taxes	1,336,386.78		Financial Model Line 167
128.70000	Other Special Funds - Member Economic Reserve	157,000,000.00		Wholesale Electric Agreements Section 1.1.34
128.80000	Other Special Funds - Member Transition Reserve	35,000,000.00		Wholesale Electric Agreements Section 1.1.119
131.10000	Cash General Fund		193,336,386.78	
Total		193,336,386.78	193,336,386.78	

BIG RIVERS ELECTRIC CORPORATION
SUMMARY OF TRANSACTION BENEFITS FROM E.ON, UPDATING CWB-2

	$ Millions
Cash	387.7
Residual Value Payment	141.4
LG&E Rental Income Advance	11.2
Fuel Inventory & Other	51.0
Settlement Promissory Note	15.7
Coleman Scrubber	98.5
SO2 Allowance & Other	2.0
Leveraged Leases	65.0
Expense Unamortized Marketing Payment	(15.1)
Assurances Agreement Payment	(1.5)
Total	755.9

BIG RIVERS ELECTRIC CORPORATION
EFFECT OF REVISIONS ON RATES, REPLACES CWB-8

	KW	kWh	Demand Revenue	Base Energy Revenue & Green Power	Power Factor Penalty	Member Discount Adjustment	Total Revenue
JACKSON PURCHASE RURALS	1,513,222	706,499,600	11,152,446	14,412,779		(796,533)	24,768,692
KENERGY RURALS	2,675,848	1,240,784,266	19,721,000	25,312,151		(1,398,368)	43,634,783
MEADE COUNTY RURALS	1,073,189	480,883,740	7,909,403	9,810,066		(552,694)	17,166,775
TOTAL RURALS	5,262,259	2,428,167,606	38,782,849	49,534,996	0	(2,747,595)	85,570,250
KI-ACCURIDE	68,548	25,359,570	695,762	347,807		(33,217)	1,010,352
KI-ALCOA	9,218	1,264,728	93,563	17,346	6,526	(3,817)	113,618
KI-ALERIS	340,288	190,580,810	3,453,923	2,613,816		(193,798)	5,873,941
KI-ALLIED	68,858	27,853,430	698,909	382,010		(34,085)	1,046,834
KI-ARMSTRONG	12,592	4,011,075	127,809	55,012	8,180	(5,284)	185,717
KI-CARDINAL RIVER	4,319	861,680	43,838	11,818		(2,105)	53,551
KI-DOMTAR PAPER CO.	320,000	206,393,679	3,248,000	2,830,689		(193,563)	5,885,126
KI-DOTIKI #3	8,510	5,855,117	86,377	80,303	914	(5,258)	162,336
KI-DYSON CREEK MINE	1,200	247,970	12,180	3,401		(491)	15,090
KI-HOPKINS CO. COAL	4,467	2,272,354	45,340	31,165		(2,481)	74,024
KI-KB ALLOYS, INC.	24,890	7,586,430	252,634	104,048		(11,338)	345,344
KI-KIMBERLY-CLARK	433,123	297,329,540	4,396,198	4,077,875		(269,998)	8,204,075
KI-KMMC, LLC	22,050	7,649,631	223,808	104,915	1,147	(11,498)	318,372
KI-MIDWAY MINE	5,649	1,078,459	57,337	14,791	3,994	(959)	75,163
KI-PATRIOT COAL, LP	62,254	26,935,855	631,878	369,425	30,440	(31,558)	1,000,185
KI-ROLL COATER	47,355	21,686,383	480,653	297,429		(24,747)	753,335
KI-TYSON FOODS	120,344	65,381,996	1,221,492	896,714	1,289	(66,838)	2,052,657
KI-VALLEY GRAIN	22,833	9,290,566	231,755	127,420	33,596	(11,331)	381,440
JPI-SHELL OIL	61,517	20,120,530	624,398	275,953		(30,039)	870,312
TOTAL INDUSTRIALS	1,638,015	921,759,803	16,625,854	12,641,937	86,086	(932,405)	28,421,472
GRAND TOTAL	6,900,274	3,349,927,409	55,408,703	62,176,933	86,086	(3,680,000)	113,991,722

BIG RIVERS ELECTRIC CORPORATION
EFFECT OF REVISIONS ON RATES, REPLACES CWB-8

	KW	kWh	Demand Revenue	Base Energy Revenue	Power Factor Penalty	Member Discount Adjustment	Fuel Adjustment Charge	Environmental Surcharge	Unwind Surcredit	Rebate Adjustment	Member Rate Stability Mechanism	Total Revenue
JACKSON PURCHASE RURALS	1,513,222	706,499,600	11,152,446	14,412,779	0	0	7,926,926	1,547,234	(2,317,319)	(70,650)	(7,086,191)	25,565,225
KENERGY RURALS	2,675,848	1,240,784,266	19,721,000	25,312,151	0	0	13,921,599	2,717,318	(4,069,772)	(124,078)	(12,445,067)	45,033,151
MEADE COUNTY RURALS	1,073,189	480,883,740	7,909,403	9,810,066	0	0	5,395,516	1,053,135	(1,577,299)	(48,088)	(4,823,264)	17,719,469
TOTAL RURALS	5,262,259	2,428,167,606	38,782,849	49,534,996	0	0	27,244,041	5,317,687	(7,964,390)	(242,816)	(24,354,522)	88,317,845
KI-ACCURIDE	68,548	25,359,570	695,762	347,807	0	0	284,534	55,537	(83,179)	(2,536)	(254,356)	1,043,569
KI-ALCOA	9,218	1,264,728	93,563	17,346	6,526	0	14,190	2,770	(4,148)	(126)	(12,686)	117,435
KI-ALERIS	340,288	190,580,810	3,453,923	2,613,816	0	0	2,138,317	417,372	(625,105)	(19,058)	(1,911,526)	6,067,739
KI-ALLIED	68,858	27,853,430	698,909	382,010	0	0	312,515	60,999	(91,359)	(2,785)	(279,370)	1,080,919
KI-ARMSTRONG	12,592	4,011,075	127,809	55,012	8,180	0	45,004	8,784	(13,156)	(401)	(40,231)	191,001
KI-CARDINAL RIVER	4,319	861,680	43,838	11,818	0	0	9,668	1,887	(2,826)	(86)	(8,643)	55,656
KI-DOMTAR PAPER CO.	320,000	206,393,679	3,248,000	2,830,689	0	0	2,315,737	452,002	(676,971)	(20,639)	(2,070,129)	6,078,689
KI-DOTIKI #3	8,510	5,855,117	86,377	80,303	914	0	65,694	12,823	(19,205)	(586)	(58,726)	167,594
KI-DYSON CREEK MINE	1,200	247,970	12,180	3,401	0	0	2,782	543	(813)	(25)	(2,487)	15,581
KI-HOPKINS CO. COAL	4,467	2,272,354	45,340	31,165	0	0	25,496	4,976	(7,453)	(227)	(22,792)	76,505
KI-KB ALLOYS, INC.	24,890	7,586,430	252,634	104,048	0	0	85,120	16,614	(24,883)	(759)	(76,092)	356,682
KI-KIMBERLY-CLARK	433,123	297,329,540	4,396,198	4,077,875	0	0	3,336,037	651,152	(975,241)	(29,733)	(2,982,215)	8,474,073
KI-KMMC, LLC	22,050	7,649,631	223,808	104,915	1,147	0	85,829	16,753	(25,091)	(765)	(76,726)	329,870
KI-MIDWAY MINE	5,649	1,078,459	57,337	14,791	3,994	0	12,100	2,362	(3,537)	(108)	(10,817)	76,122
KI-PATRIOT COAL, LP	62,254	26,935,855	631,878	369,425	30,440	0	302,220	58,990	(88,350)	(2,694)	(270,166)	1,031,743
KI-ROLL COATER	47,355	21,686,383	480,653	297,429	0	0	243,321	47,493	(71,131)	(2,169)	(217,514)	778,082
KI-TYSON FOODS	120,344	65,381,996	1,221,492	896,714	1,289	0	733,586	143,187	(214,453)	(6,538)	(655,782)	2,119,495
KI-VALLEY GRAIN	22,833	9,290,566	231,755	127,420	33,596	0	104,240	20,346	(30,473)	(929)	(93,184)	392,771
JPI-SHELL OIL	61,517	20,120,530	624,398	275,953	0	0	225,752	44,064	(65,995)	(2,012)	(201,809)	900,351
TOTAL INDUSTRIALS	1,638,015	921,759,803	16,625,854	12,641,937	86,086	0	10,342,142	2,018,654	(3,023,369)	(92,176)	(9,245,251)	29,353,877
GRAND TOTAL	6,900,274	3,349,927,409	55,408,703	62,176,933	86,086	0	37,586,183	7,336,341	(10,987,759)	(334,992)	(33,599,773)	117,671,722

BIG RIVERS ELECTRIC CORPORATION
FINANCIAL MATRIX

Key Credit Metrics	Min.	T	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Equity/ Assets																	
Filed Case (6/08)	24%	24%	25%	26%	28%	29%	30%	31%	32%	33%	34%	36%	37%	38%	39%	41%	42%
December Close/ $60.9m Buyout	26%	26%	27%	28%	28%	31%	33%	34%	31%	37%	38%	39%	40%	42%	43%	44%	45%
Conventional TIER																	
Filed Case (6/08)	1.22	na	1.27	1.22	1.27	1.27	1.28	1.29	1.29	1.29	1.29	1.30	1.30	1.30	1.31	1.31	1.32
December Close/ $60.9m Buyout	1.27	na	1.27	1.27	1.27	1.27	1.29	1.29	1.29	1.30	1.30	1.31	1.31	1.32	1.32	1.33	1.34
Debt Service Coverage																	
Filed Case (6/08)	1.32	na	1.61	1.32	1.43	1.58	1.55	1.89	1.68	1.47	1.51	1.56	1.51	1.56	1.53	1.49	1.47
December Close/ $60.9m Buyout	1.44	na	2.24	1.97	1.45	1.77	1.45	1.61	1.46	1.44	1.57	1.61	1.56	1.65	1.98	1.96	1.93
Ending Cash Balances ($M; Unrestricted + Transition Reserve; Excluding Line of Credit)																	
Filed Case (6/08)	74	178	147	113	88	74	77	102	112	113	115	116	112	114	112	107	100
December Close/ $60.9m Buyout	73	160	137	142	162	104	86	89	282	77	73	96	85	83	90	96	97

BIG RIVERS ELECTRIC CORPORATION
CHART SHOWING LIQUIDITY OF POWER SALES IN NEARBY MARKETS

BIG RIVERS DELIVERY POINTS Q1 2008 VOLUME
(REF: "PLATTS POWER SALES ANALYSIS, JULY 21, 2008")

	MWh
MISO	216,110,511
SOCO	29,882,066
TVA	4,914,557
PJM South	1,137,782
Total	252,044,916

Smelter Volume for One Quarter — Smelter Demand, MW 850

1,861,500 MWh — 0.74% of Total

BIG RIVERS ELECTRIC CORPORATION
CINERGY HUB PRICE PROJECTIONS

Increase sales by 1.1% (Ref EIA: Annual Energy Outlook 2008, June 2008)
Effective Smelter Rate (Ref: October KPSC Filing)

Year	Smelter Volume % of Total Market	Effective Smelter Rate	7x24 Cin Hub Fwd Price	% of Smelter Power To Be Sold In Market To Maintain Revenue 7 x 24 Sale
2008	0.77%			
2009	0.76%	$43.11	$49.68	87%
2010	0.76%	$42.98	$51.71	83%
2011	0.75%	$49.19	$53.13	93%
2012	0.74%	$52.33	$55.00	95%
2013	0.73%	$53.92	$56.83	95%
2014	0.72%	$46.67	$57.34	81%
2015	0.72%	$48.42	$57.29	85%
2016	0.71%	$48.44	$55.78	87%
2017	0.70%	$54.47	$56.20	97%
2018	0.69%	$50.77	$58.15	87%
2019	0.69%	$55.05	$59.87	92%
2020	0.68%	$54.30	$62.92	86%
2021	0.67%	$56.77	$64.64	88%
2022	0.66%	$56.32	$66.04	85%
2023	0.66%	$58.53	$66.91	87%

BIG RIVERS ELECTRIC CORPORATION
CINERGY HUB PRICE PROJECTIONS

CIN HUB
Quote Date
10/6/2008
Forward Prices ($/MWh)

	Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7X24	Yearly On Peak (5x16)	Yearly 7X24
2	Jan-09	61.50	37.43	56.70	44.99	53.12		
3	Feb-09	60.00	37.92	56.70	44.75	53.44		
4	Mar-09	62.53	32.83	58.33	42.19	53.36		
5	Apr-09	52.47	36.00	49.69	40.76	47.82		
6	May-09	54.50	23.76	44.82	32.50	43.36		
7	Jun-09	61.00	27.21	48.17	34.50	49.17		
8	Jul-09	76.41	28.44	63.61	40.42	59.58		
9	Aug-09	76.09	24.72	62.70	39.62	57.33		
10	Sep-09	58.75	25.88	42.86	32.25	45.32		
11	Oct-09	48.36	25.22	45.76	32.76	41.32		
12	Nov-09	54.41	25.70	44.06	33.04	44.16		
13	Dec-09	59.98	27.55	46.00	34.32	48.18	60.50	49.68
14	Jan-10	67.23	25.68	63.68	41.45	54.06		
15	Feb-10	65.77	29.19	62.32	41.23	54.57		
16	Mar-10	59.16	32.22	55.49	40.14	50.81		
17	Apr-10	56.84	31.12	53.12	38.77	48.80		
18	May-10	59.75	26.36	49.74	36.07	46.47		
19	Jun-10	65.75	29.97	53.06	38.00	51.57		
20	Jul-10	80.16	26.87	67.17	42.68	60.74		
21	Aug-10	79.84	27.68	66.21	41.83	60.99		
22	Sep-10	61.00	29.49	48.82	36.74	49.23		
23	Oct-10	50.81	27.06	48.35	35.41	43.68		
24	Nov-10	57.17	28.56	47.62	35.71	47.66		
25	Dec-10	63.02	30.58	49.71	37.09	51.99	63.88	51.71
26	Jan-11	66.38	32.64	61.93	44.13	55.28		
27	Feb-11	64.94	34.35	60.59	43.89	55.05		
28	Mar-11	62.15	35.14	57.43	42.73	53.16		
29	Apr-11	59.72	32.94	55.18	41.28	50.63		
30	May-11	58.20	29.00	52.95	38.40	47.84		
31	Jun-11	66.90	31.91	56.48	40.46	54.20		
32	Jul-11	82.74	26.93	71.50	45.43	62.34		
33	Aug-11	82.40	31.14	70.48	44.53	64.26		
34	Sep-11	60.44	31.39	51.97	39.11	50.05		
35	Oct-11	49.66	32.20	46.20	37.69	43.85		
36	Nov-11	57.56	30.40	50.69	38.01	48.91		
37	Dec-11	63.47	30.82	52.92	39.49	51.97	64.55	53.13
38	Jan-12	67.85	37.12	63.17	47.34	57.66		
39	Feb-12	66.77	38.81	62.08	47.09	57.66		
40	Mar-12	64.57	37.86	59.57	45.84	55.47		

BIG RIVERS ELECTRIC CORPORATION
CINERGY HUB PRICE PROJECTIONS

1	Apr-12	61.70	36.79	56.76	44.28	53.05		
2	May-12	59.84	33.37	54.66	41.19	50.43		
3	Jun-12	67.84	33.08	60.59	43.40	55.31		
4	Jul-12	84.10	30.69	76.70	48.73	65.27		
5	Aug-12	82.48	33.63	75.16	47.77	65.45		
6	Sep-12	61.56	31.83	55.75	41.95	50.71		
7	Oct-12	52.58	35.87	49.26	40.43	47.50		
8	Nov-12	57.37	33.30	53.23	40.78	49.35		
9	Dec-12	63.46	32.13	56.76	42.36	52.13	65.84	55.00
10	Jan-13	72.82	38.26	66.62	48.68	60.67		
11	Feb-13	71.99	38.49	65.78	48.42	60.17		
12	Mar-13	70.58	36.06	64.30	47.13	58.11		
13	Apr-13	66.11	37.77	60.08	45.53	55.90		
14	May-13	63.31	33.65	57.34	42.35	52.45		
15	Jun-13	70.18	32.84	62.30	44.62	56.13		
16	Jul-13	87.39	33.41	78.87	50.11	67.90		
17	Aug-13	84.23	33.56	75.90	49.12	65.78		
18	Sep-13	64.30	33.68	57.33	43.14	52.61		
19	Oct-13	57.06	36.42	51.55	41.57	49.34		
20	Nov-13	58.80	34.60	52.92	41.93	49.43		
21	Dec-13	65.46	34.00	58.37	43.55	53.45	69.35	56.83
22	Jan-14	76.93	39.73	69.24	50.57	63.04		
23	Feb-14	75.75	40.24	68.17	50.40	62.47		
24	Mar-14	74.32	37.49	66.88	49.01	60.44		
25	Apr-14	68.28	39.62	61.45	47.22	57.52		
26	May-14	64.54	34.88	58.09	43.98	53.27		
27	Jun-14	70.47	34.36	62.93	45.07	56.92		
28	Jul-14	87.51	33.04	78.00	49.56	67.51		
29	Aug-14	83.61	32.75	75.25	49.41	64.86		
30	Sep-14	63.88	36.11	57.49	44.13	53.35		
31	Oct-14	56.64	35.99	50.98	41.09	48.78		
32	Nov-14	57.97	31.84	52.18	40.45	47.85		
33	Dec-14	64.34	32.98	55.08	41.10	52.09	70.35	57.34
34	Jan-15	84.73	29.04	73.15	46.34	63.68		
35	Feb-15	83.43	30.24	75.09	46.55	64.11		
36	Mar-15	81.87	34.69	61.64	44.59	62.23		
37	Apr-15	75.25	33.83	57.75	42.15	58.33		
38	May-15	71.17	28.23	53.27	38.62	52.62		
39	Jun-15	77.76	30.30	53.63	38.41	57.65		
40	Jul-15	96.64	29.21	65.33	41.51	68.78		
41	Aug-15	92.43	25.42	64.47	40.74	64.08		
42	Sep-15	70.70	28.45	47.11	35.45	51.90		
43	Oct-15	62.77	24.81	46.29	32.70	46.92		
44	Nov-15	64.33	24.86	42.62	31.96	46.35		
45	Dec-15	71.50	25.97	43.37	32.36	50.88	77.71	57.29
46	Jan-16	87.63	21.70	58.12	36.82	58.67		

BIG RIVERS ELECTRIC CORPORATION
CINERGY HUB PRICE PROJECTIONS

1	Feb-16	86.28	23.53	60.35	36.62	60.59		
2	Mar-16	84.66	28.61	49.28	35.65	59.89		
3	Apr-16	77.82	26.79	47.18	34.44	54.68		
4	May-16	73.60	24.20	44.18	32.03	50.80		
5	Jun-16	80.41	26.62	47.12	33.75	56.56		
6	Jul-16	99.94	22.46	59.65	37.90	64.58		
7	Aug-16	95.58	25.98	58.80	37.15	66.05		
8	Sep-16	73.11	26.19	43.36	32.63	51.52		
9	Oct-16	64.91	23.01	44.52	31.44	46.56		
10	Nov-16	66.53	25.37	42.29	31.71	47.96		
11	Dec-16	73.95	25.71	44.15	32.94	51.46	80.37	55.78
12	Jan-17	88.10	23.38	58.90	37.31	60.25		
13	Feb-17	86.74	23.37	61.16	37.11	60.74		
14	Mar-17	85.12	29.00	49.94	36.13	60.36		
15	Apr-17	78.24	26.29	47.81	34.90	54.16		
16	May-17	73.99	25.32	44.77	32.46	52.11		
17	Jun-17	80.84	26.98	47.75	34.20	57.00		
18	Jul-17	100.48	22.77	60.45	38.41	65.10		
19	Aug-17	96.09	26.33	59.59	37.65	66.56		
20	Sep-17	73.51	25.82	43.94	33.07	51.04		
21	Oct-17	65.26	24.17	45.11	31.87	47.66		
22	Nov-17	66.88	25.71	42.86	32.14	48.35		
23	Dec-17	74.34	25.33	44.74	33.38	51.00	80 80	56.20
24	Jan-18	90.15	26.08	61.99	39.27	63.34		
25	Feb-18	88.76	24.60	64.37	39.06	62.73		
26	Mar-18	87.10	29.58	52.57	38.03	61.24		
27	Apr-18	80.06	28.58	50.33	36.73	56.95		
28	May-18	75.71	26.65	47.12	34.17	53.82		
29	Jun-18	82.73	27.44	50.26	36.00	57.81		
30	Jul-18	102.82	25.46	63.63	40.43	68.60		
31	Aug-18	98.33	27.71	62.72	39.63	68.67		
32	Sep-18	75.22	26.41	46.25	34.80	51.87		
33	Oct-18	66.78	26.34	47.48	33.54	49.98		
34	Nov-18	68.44	27.06	45.11	33.83	49.98		
35	Dec-18	76.08	26.66	47.09	35.14	52.75	82 68	58 15
36	Jan-19	92.05	27.29	64.89	41.11	65.21		
37	Feb-19	90.63	25.75	67.38	40.89	64.58		
38	Mar-19	88.94	29.98	55.02	39.80	61.99		
39	Apr-19	81.75	30.86	52.68	38.45	59.62		
40	May-19	77.31	27.89	49.32	35.76	55.42		
41	Jun-19	84.47	27.73	52.61	37.68	58.48		
42	Jul-19	104.98	28.22	66.60	42.32	71.97		
43	Aug-19	100.41	27.44	65.65	41.48	69.36		
44	Sep-19	76.80	28.44	48.41	36.43	54.37		
45	Oct-19	68.18	27.57	49.70	35.11	51.47		

BIG RIVERS ELECTRIC CORPORATION
CINERGY HUB PRICE PROJECTIONS

1	Nov-19	69.89	27.53	47.22	35.41	50.73		
2	Dec-19	77.68	28.71	49.29	36.78	55.25	84.42	59.87
3	Jan-20	96.33	28.72	68.28	43.26	68.37		
4	Feb-20	94.85	25.72	70.90	43.02	66.85		
5	Mar-20	93.08	32.58	57.90	41.88	66.10		
6	Apr-20	85.55	32.47	55.43	40.46	62.50		
7	May-20	80.91	27.51	51.90	37.64	56.25		
8	Jun-20	88.40	31.28	55.36	39.65	63.49		
9	Jul-20	109.87	31.34	70.09	44.53	76.85		
10	Aug-20	105.08	27.24	69.08	43.65	71.39		
11	Sep-20	80.38	30.77	50.95	38.34	57.96		
12	Oct-20	71.36	28.03	52.30	36.94	53.23		
13	Nov-20	73.14	28.97	49.69	37.26	53.21		
14	Dec-20	81.29	31.06	51.87	38.70	58.85	88.35	62.92
15	Jan-21	98.63	26.44	70.83	44.87	67.99		
16	Feb-21	97.12	28.11	73.55	44.63	69.62		
17	Mar-21	95.30	34.87	60.06	43.45	69.09		
18	Apr-21	87.59	33.69	57.50	41.97	64.27		
19	May-21	82.84	28.54	53.84	39.04	57.88		
20	Jun-21	90.51	32.44	57.43	41.13	65.27		
21	Jul-21	112.49	29.09	72.70	46.19	76.13		
22	Aug-21	107.59	29.96	71.66	45.28	74.76		
23	Sep-21	82.30	31.92	52.85	39.77	59.61		
24	Oct-21	73.06	28.04	54.25	38.32	54.01		
25	Nov-21	74.88	30.92	51.54	38.65	55.56		
26	Dec-21	83.23	33.10	53.80	40.15	61.46	90.46	64.64
27	Jan-22	100.16	29.15	73.44	46.52	70.74		
28	Feb-22	98.62	29.14	76.25	46.27	71.20		
29	Mar-22	96.77	36.15	62.27	45.04	70.63		
30	Apr-22	88.95	33.85	59.61	43.51	64.71		
31	May-22	84.12	30.57	55.82	40.47	60.18		
32	Jun-22	91.91	33.64	59.54	42.65	66.73		
33	Jul-22	114.23	28.38	75.37	47.89	76.42		
34	Aug-22	109.25	32.82	74.29	46.94	77.76		
35	Sep-22	83.57	33.09	54.79	41.23	60.99		
36	Oct-22	74.19	29.07	56.25	39.73	55.29		
37	Nov-22	76.04	32.05	53.43	40.07	56.86		
38	Dec-22	84.52	32.49	55.78	41.62	61.00	91.86	66.04
39	Jan-23	100.25	30.32	76.37	48.37	71.80		
40	Feb-23	98.71	30.30	79.29	48.12	72.21		
41	Mar-23	96.86	37.60	64.75	46.84	71.58		
42	Apr-23	89.03	34.08	61.99	45.25	64.71		
43	May-23	84.20	32.82	58.05	42.09	62.01		
44	Jun-23	91.99	34.98	61.92	44.35	67.64		
45	Jul-23	114.34	29.52	78.38	49.80	77.56		
46	Aug-23	109.35	34.13	77.26	48.81	78.76		

BIG RIVERS ELECTRIC CORPORATION
CINERGY HUB PRICE PROJECTIONS

1	Sep-23	83.65	33.47	56.98	42.87	60.99		
2	Oct-23	74.26	31.34	58.49	41.32	56.90		
3	Nov-23	76.11	33.33	55.57	41.67	57.74		
4	Dec-23	84.60	32.84	58.01	43.28	61.05	91 94	66 91
5	Jul-41	168.84	88.15	151.34	112.93	138.18		
6	Aug-41	168.84	88.15	151.34	112.93	138.18		
7	Sep-41	168.84	88.15	151.34	112.93	138.18		
8	Oct-41	168.84	88.15	151.34	112.93	138.18		
9	Nov-41	168.84	88.15	151.34	112.93	138.18		
10	Dec-41	168.84	88.15	151.34	112.93	138.18		
11	Jan-42	168.84	88.15	151.34	112.93	138.18		
12	Feb-42	168.84	88.15	151.34	112.93	138.18		
13	Mar-42	168.84	88.15	151.34	112.93	138.18		
14	Apr-42	168.84	88.15	151.34	112.93	138.18		
15	May-42	168.84	88.15	151.34	112.93	138.18		
16	Jun-42	168.84	88.15	151.34	112.93	138.18		
17	Jul-42	168.84	88.15	151.34	112.93	138.18		
18	Aug-42	168.84	88.15	151.34	112.93	138.18		
19	Sep-42	168.84	88.15	151.34	112.93	138.18		
20	Oct-42	168.84	88.15	151.34	112.93	138.18		
21	Nov-42	168.84	88.15	151.34	112.93	138.18		
22	Dec-42	168.84	88.15	151.34	112.93	138.18		
23	Jan-43	168.84	88.15	151.34	112.93	138.18		
24	Feb-43	168.84	88.15	151.34	112.93	138.18		
25	Mar-43	168.84	88.15	151.34	112.93	138.18		
26	Apr-43	168.84	88.15	151.34	112.93	138.18		
27	May-43	168.84	88.15	151.34	112.93	138.18		
28	Jun-43	168.84	88.15	151.34	112.93	138.18		
29	Jul-43	168.84	88.15	151.34	112.93	138.18		
30	Aug-43	168.84	88.15	151.34	112.93	138.18		
31	Sep-43	168.84	88.15	151.34	112.93	138.18		
32	Oct-43	168.84	88.15	151.34	112.93	138.18		
33	Nov-43	168.84	88.15	151.34	112.93	138.18		
34	Dec-43	168.84	88.15	151.34	112.93	138.18		
35	Jan-44	168.84	88.15	151.34	112.93	138.18		
36	Feb-44	168.84	88.15	151.34	112.93	138.18		
37	Mar-44	168.84	88.15	151.34	112.93	138.18		
38	Apr-44	168.84	88.15	151.34	112.93	138.18		
39	May-44	168.84	88.15	151.34	112.93	138.18		
40	Jun-44	168.84	88.15	151.34	112.93	138.18		
41	Jul-44	168.84	88.15	151.34	112.93	138.18		
42	Aug-44	168.84	88.15	151.34	112.93	138.18		
43	Sep-44	168.84	88.15	151.34	112.93	138.18		
44	Oct-44	168.84	88.15	151.34	112.93	138.18		
45	Nov-44	168.84	88.15	151.34	112.93	138.18		
46	Dec-44	168.84	88.15	151.34	112.93	138.18		

BIG RIVERS ELECTRIC CORPORATION
CINERGY HUB PRICE PROJECTIONS

Jan-45	168.84	88.15	151.34	112.93	138.18
Feb-45	168.84	88.15	151.34	112.93	138.18
Mar-45	168.84	88.15	151.34	112.93	138.18
Apr-45	168.84	88.15	151.34	112.93	138.18
May-45	168.84	88.15	151.34	112.93	138.18
Jun-45	168.84	88.15	151.34	112.93	138.18
Jul-45	168.84	88.15	151.34	112.93	138.18
Aug-45	168.84	88.15	151.34	112.93	138.18
Sep-45	168.84	88.15	151.34	112.93	138.18
Oct-45	168.84	88.15	151.34	112.93	138.18
Nov-45	168.84	88.15	151.34	112.93	138.18
Dec-45	168.84	88.15	151.34	112.93	138.18
Jan-46	168.84	88.15	151.34	112.93	138.18
Feb-46	168.84	88.15	151.34	112.93	138.18
Mar-46	168.84	88.15	151.34	112.93	138.18
Apr-46	168.84	88.15	151.34	112.93	138.18
May-46	168.84	88.15	151.34	112.93	138.18
Jun-46	168.84	88.15	151.34	112.93	138.18

STEVEN L. BESHEAR
Governor

FINANCE AND ADMINISTRATION CABINET
DEPARTMENT OF REVENUE

501 HIGH STREET
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JONATHAN MILLER
Secretary

WILLIAM M. COX, SR.
Commissioner

February 25, 2008

Jesse T. Mountjoy
Mark W. Starnes
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
100 St Ann Building
P O Box 727
Owensboro, Kentucky 42302-0727

RE: Request for Ruling -Big Rivers Electric Corporation

Dear Mr. Mountjoy and Mr Starns:

The Department of Revenue has reviewed your February 6, 2008 ruling requests on the termination of the power purchase agreement between Big Rivers Electric Corporation, E.On U.S. LLC and Western Kentucky Energy (WKEC) and the assumption by Big Rivers of WKEC's obligation to supply electric power to Kenergy Corporation (collectively the "Transaction").

We are construing your request as one for written advice under the terms of KRS 131.081(6). Its efficacy will therefore depend on whether that request has fully described the relevant specific facts and circumstances and will be subject to the other terms and conditions set forth in that statutory provision. It should be noted that the advice rendered below does not necessarily mean that the Department is endorsing all of the arguments or reasoning contained in the request.

<u>1. Corporation Income Tax Ruling</u>

A ruling is requested that the "Transaction" as well as Big Rivers' operation of the electrical generating facilities immediately following the Transaction will be treated and taxed for Kentucky corporation income tax purposes in the same manner as the Transaction is treated and taxed for Federal income tax purposes.

The Transaction will be treated and taxed for Kentucky corporation income tax purposes in the same manner as the transaction is treated and taxed for Federal income tax purposes, except for differences between federal income tax law and Kentucky income tax law. If the Kentucky tax treatment of a particular item of income or a deduction is not expressly prescribed in the Kentucky Revised Statutes, then the Department of Revenue will generally follow the federal income tax treatment. KRS 141.050(1) states:

> "Except to the extent required by differences between this chapter and its application and the federal income tax law and its application, the administrative and judicial interpretations of the federal income tax law, computations of gross income and deductions therefrom, accounting methods, and accounting procedures, for purposes of this chapter shall be as nearly as practicable identical with those required for federal income tax purposes. Changes to federal income tax law made after the Internal Revenue Code reference date contained in KRS 141.010(3) shall not apply for purposes of this chapter unless adopted by the General Assembly."

__2. Sales and Use Tax__

A. A ruling is requested that Big Rivers' operation of the generating facilities and the related assets for the purpose of generating electricity immediately after the Transaction will constitute the manufacturing of electricity under Kentucky law, and that Big Rivers accordingly will be treated as a manufacturer of tangible personal property for purposes of KRS Chapter 139.

The Department confirms that the operation of the Generating Facilities and related assets for the generation of electricity constitutes manufacturing for the purposes of KRS Chapter 139. To the extent that the assets in question are used directly within the manufacturing process as provided in KRS 139.170, Big River's will be considered a manufacturer of tangible personal property. If the assets remain incorporated within the same plant facility after the Transaction, then the assets are eligible for the same provisions under KRS Chapter 139 as they were entitled to prior to the Transaction.

B. A ruling is requested that neither (i) the payment or receipt of the termination payment, nor (ii) WKEC's waiver and release of its future right to receive the Residual Value Payment (as defined in the Participation Agreement) from Big Rivers (by virtue of the Termination and Release and the Station Two Termination and Release), will be subject to Kentucky sales and use tax or other tax consequence that may be adverse to Big Rivers. Likewise, a ruling is requested that the relinquishment of WKEC's rights under or pursuant to the Station Two Agreement is exempt from Kentucky sales and use tax upon the transfer of these rights to Big Rivers at closing as such rights also constitute intangible properties.

The Department cannot provide definitive advice on this issue without access to the Participation and Station Two Agreements. If these agreements are submitted for consideration, the Department will be glad to review the material and provide appropriate advice regarding the intangible nature of the transactions and the applicability of sales and use tax.

C. A ruling is requested that the transfer of the various intangibles (contract rights, intellectual property, permits and SO2 and NOx allowances, etc.) to Big Rivers will be exempt from Kentucky sales and use taxes as intangible personal property.

The Department concurs that any payments or receipts explicitly for the transfer of intangible property (contract rights, intellectual property, permits, and SO_2 and NO_x allowances, etc.) by WKEC to Big Rivers within the Unwind Transaction are not subject to the sales tax imposed under KRS 139.200 for retail sales of tangible personal property or the furnishing of certain specified services. This advice is expressly based upon your representations that these items are intangible property.

D. A ruling is requested that the return of the Transmission Deposits will not be subject to Kentucky sales and use tax.

Information provided indicates that these Transmission Deposits were originally paid by LG&E Energy Marketing, Inc. to Big Rivers to secure transmission services on the TVA and Big Rivers' transmission systems and for payment of costs associated with the use of these transmission systems. Therefore, Big Rivers' return of these Deposits along with interest accrued thereon forfeits any previous rights to firm transmission and access rights on these systems. Based upon this description, the return of the Deposits and accrued interest does not constitute a retail sale as defined in KRS 139.100 and would not be subject to Kentucky sales and use tax.

<u>3. Property Taxes</u>

A. A ruling is requested that Big Rivers will be subject to KRS 136.120 and taxed as a public service corporation thereunder.

Big Rivers will be subject to ad valorem assessment and taxation as a public service corporation pursuant to KRS 136.115 to 136.180.

B. A ruling is requested that all taxable tangible property to be used by Big Rivers in the electrical manufacturing process will be classified as machinery and equipment actually engaged in manufacturing by a manufacturer subject to the tax in KRS 136.120 (applicable to public service corporations), and accordingly will be taxable as "operating property" at the rate provided in KRS 132.020(1), and will be exempt from local property taxation pursuant to KRS 132.200(4).

All machinery and equipment actually engaged in manufacturing shall be subject to a state tax rate of $.15/100 pursuant to KRS 132.020(1)(i) and shall be exempt from local taxes under KRS 132.200(4),

C. A ruling is requested that any non-operating intangible property of Big Rivers will be exempt from state and local property taxation, due to the repeal of the Kentucky intangible property tax.

Non-operating intangible property of Big Rivers will be exempt from or not subject to ad valorem taxation, beginning with the 2006 tax year (KY Acts 2005, Ch. 168, §§ 55, 57, 171).

__4. Kentucky Limited Liability Entity Tax__

A. A ruling is requested that Big Rivers, as a public service corporation subject to taxation under KRS 136.120, will be exempt from the limited liability entity tax pursuant to KRS 141.0401(6)(i).

The limited liability entity tax imposed by KRS 141.0401(2) will not apply to Big Rivers Electric Corporation as long as Big Rivers is a public service corporation subject to tax under KRS 136.120. The exemption from the limited liability entity tax is provided by KRS 141.0401(6)(i) and also applies to the $175 minimum tax.

If you should require further assistance regarding these matters, please do not hesitate to contact my office for follow up.

Very Truly Yours,

William M. Cox, Sr.

William M. Cox, Sr.
Commissioner
Department of Revenue

C: Jeff Mosley
Jason Snyder
Doug Dowell

BIG RIVERS ELECTRIC CORPORATION
RECONCILIATION OF LEVERAGED LEASES

BoA	$	(14.588)	Unamortized Gain
		0.386	Loss on Buy Out
	$	(14.202)	Net Gain as of 9/30/08
PMCC	$	(36.705)	Unamortized Gain
		127.908	Loss on Buy Out
	$	91.203	Net Loss as of 9/30/08
Combined	$	77.001	Net Loss as of 9/30/08
		(1.000)	Amortization for October - December
		1.000	Big Rivers payment to E.ON for BoA
		(60.856)	E.ON payment to Big Rivers for PMCC
	$	16.145	Net Loss recorded on December 31, 2008

VERIFICATION

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

C. William Blackburn

C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 7th day of October, 2008.

Vikki G. King

Notary Public, Ky. State at Large
My Commission Expires March 3, 2010.

EXHIBIT 79

UNWIND FINANCIAL MODEL

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October 2008

Pro Forma

<<Return to Table of Contents

Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			12/31/2008	
1. Sales (TWH)																				
Rural	2.23	2.41	2.40	-		2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
Large Industrial	0.96	0.92	0.95	-		1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
Century	-	-	-	-		4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14
Alcan	-	-	-	-		3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16
Market	2.06	2.84	1.66	-		1.55	1.83	1.38	1.36	1.41	1.32	1.29	1.24	1.05	1.12	0.87	0.89	0.87	0.85	0.78
Total Sales	5.25	6.16	5.01	-		12.35	12.71	12.35	12.44	12.56	12.56	12.62	12.68	12.56	12.72	12.57	12.70	12.77	12.83	12.87

Pro Forma

Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			12/31/2008	
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)																				
General Rate Adjustment (%)	0.00%	0.00%	0.00%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	9.74%	0.00%	0.00%	0.00%	0.00%	0.00%	0.31%
FAC ($/ MWH)						11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
FAC Roll-In ($/MWh)																				
PPA ($/ MWH)						0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
Environmental Surcharge Adjustment ($/ MWH)																				
Rural						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Large Industrial						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Smelters						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Rural																				
Load Factor (%)	61.6%	63.3%	62.5%			60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
Demand ($/ KW-mo.)	7.37	7.37	7.37			7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	8.09	8.09	8.09	8.09	8.09	8.09	8.11
Energy ($/ MWH)	20.40	20.40	20.40			20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	22.39	22.39	22.39	22.39	22.39	22.39	22.46
Base	36.79	36.36	36.55			37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
MRDA	(1.20)	(1.14)	(1.14)			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Account Charge						-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
GRA	-	-	-			-	-	-	-	-	-	-	-	3.60	3.60	3.60	3.60	3.60	3.59	3.72
FAC	-	-	-			11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Environmental Surcharge	-	-	-			2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcredit	-	-	-			(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Non-Smelter Member Economic Reserve	-	-	-			(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
Net	-	-	-			-	2.09	5.69	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
Pre TIER Rebate Total	35.58	35.22	35.41			37.22	39.29	42.75	43.04	45.92	48.80	49.28	49.42	51.90	52.50	52.80	54.61	54.84	55.52	55.93
TIER Related Rebate	-	-	-			(0.10)	(1.79)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	35.58	35.22	35.41			37.12	37.49	42.75	43.04	45.92	48.80	49.28	49.42	51.90	52.50	52.80	54.61	54.84	55.52	55.93
Large Industrial																				
Load Factor (%)	78.1%	76.5%	77.7%			78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
Demand ($/ KW-mo.)	10.15	10.15	10.15			10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	11.14	11.14	11.14	11.14	11.14	11.14	11.17
Energy ($/ MWH)	13.72	13.72	13.72			13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	15.05	15.05	15.05	15.05	15.05	15.05	15.10
Base	31.51	31.90	31.61			31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
Power Factor Penalty/ Demand Cr. (Lrg.	0.19	0.08	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MRDA	(1.04)	(1.02)	(0.98)			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regulatory Account Charge						-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
GRA	-	-	-			-	-	-	-	-	-	-	-	3.06	3.06	3.06	3.06	3.06	3.06	3.16
FAC	-	-	-			11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
Environmental Surcharge	-	-	-			2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
Surcredit	-	-	-			(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Non-Smelter Member Economic Reserve	-	-	-			(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
Net	-	-	-			-	2.09	5.69	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
Pre TIER Rebate Total	30.67	30.96	30.62			31.39	33.49	36.98	37.30	40.20	43.10	43.60	43.79	45.73	46.35	46.67	48.54	48.75	49.46	49.87
TIER Related Rebate	-	-	-			(0.09)	(1.59)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	30.67	30.96	30.62			31.31	31.90	36.98	37.30	40.20	43.10	43.60	43.79	45.73	46.35	46.67	48.54	48.75	49.46	49.87

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
69	Non-Smelter Member Blend																				
72	Base	35.26	35.15	35.14			35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	(1.15)	(1.11)	(1.10)			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Regulatory Account Charge						-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
75	GRA	-	-	-			-	-	-	-	-	-	-	-	3.43	3.43	3.43	3.43	3.42	3.42	3.54
76																					
77	FAC	-	-	-			11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
78	Environmental Surcharge						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
79	Surcredit	-	-	-			(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
80	Non-Smelter Member Economic Reserve	-	-	-			(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
81	Net						-	2.09	5.69	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
82																					
83	Pre TIER Rebate Total	34.11	34.04	34.04			35.45	37.51	40.98	41.26	44.14	47.01	47.49	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98
84	TIER Related Rebate	-	-	-			(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	34.11	34.04	34.04			35.36	35.78	40.98	41.26	44.14	47.01	47.49	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98
86																					
87	Smelters																				
88	Base Rate	-	-	-			28.15	28.15	28.15	28.11	28.15	28.15	28.15	28.11	30.87	30.87	30.87	30.83	30.87	30.87	30.96
89	TIER Adjustment	-	-	-			-	-	1.79	2.25	1.59	1.64	2.78	2.59	3.55	0.54	3.67	2.97	4.30	3.53	4.75
90	Smelter Rate Subject to Price Cap	-	-	-			28.15	28.15	29.95	30.36	29.75	29.79	30.93	30.70	34.42	31.41	34.54	33.80	35.17	34.40	35.71
91	FAC						11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
92	PPA	-	-	-			0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
93	Environmental Surcharge						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
94	Surcharge 1	-	-	-			0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
95	Surcharge 2						0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	1.20	1.20	1.20	1.20	1.20	1.20	1.20
96	Smelter FAC Reserve						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
97	TIER Related Rebate	-	-	-			(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Effective Rate	-	-	-			43.11	42.98	49.19	52.33	53.92	46.67	48.42	48.44	54.47	50.77	55.05	54.30	56.77	56.32	58.53
99																					
100	Market	40.45	52.68	48.74			60.94	59.20	63.59	66.81	70.55	62.13	63.43	63.52	64.53	66.02	68.95	67.21	67.69	69.01	69.79
101																					
102	Overall Blend	36.60	42.62	38.92			43.15	43.29	48.35	50.57	52.79	48.41	49.66	49.66	53.79	52.03	54.53	54.62	56.12	56.15	57.52
103																					

#	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
104	**III. Cash Flows (M$)**																				
105																					
106	Operating Receipts																				
107	Rural	79.4	84.8	84.8	-	0.0	90.8	97.5	104.2	111.7	121.8	131.9	136.1	139.3	149.4	154.1	158.3	167.0	171.1	176.6	181.3
108	Large Industrial	29.3	28.5	29.2	-	0.0	33.4	36.6	40.1	43.5	48.3	53.2	55.3	57.0	61.2	63.6	65.7	69.9	72.0	74.7	77.0
109	Smelters	-	-	-	-	-	315.3	325.6	346.3	382.9	393.5	340.6	353.3	354.5	397.5	370.5	401.7	397.3	414.3	411.0	427.1
110	Offsystem	83.4	149.4	81.1	-	-	94.3	108.5	87.7	90.9	99.4	82.2	82.1	78.8	67.6	73.6	59.7	59.5	59.1	58.4	54.7
111	WKEC Lease	47.9	50.8	47.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Transmission	6.0	6.3	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Smelter - Tier 3 Transmission	1.7	1.7	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
114	Gain on Sale of Allowances	-	-	-	-	-	3.8	3.0	(0.6)	(0.4)	(0.2)	(1.9)	(16.3)	(15.1)	(14.5)	(15.6)	(14.2)	(15.5)	(15.6)	(16.0)	(16.5)
115	Cobank Patronage Capital & Other	0.6	0.6	0.6	-	-	-	-	-	0.7	1.6	1.5	-	-	-	-	-	-	-	-	-
116	Lease Buyout					(59.6)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
117	Interest Earnings	3.7	6.8	5.0	-	0.0	6.4	5.5	5.7	5.7	4.1	3.4	3.6	3.3	3.1	2.9	3.8	3.4	3.3	3.6	3.8
118	Total Receipts	252.0	328.9	255.3	-	(59.6)	543.9	576.7	583.4	635.0	668.4	611.0	614.2	617.8	664.3	649.2	675.0	681.6	704.1	708.2	727.4
119																					
120	Operating Disbursements																				
121	PPA	98.0	96.3	95.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122	Fuel Costs	-	-	-	-	0.0	270.6	304.9	307.9	344.6	370.3	259.1	259.3	262.0	261.0	267.6	268.7	275.7	277.5	286.7	285.8
123	SEPA & Other Purchases	11.4	68.0	11.6	-	0.0	23.1	17.9	28.1	25.7	29.7	25.8	28.2	30.1	48.9	34.0	45.0	37.4	49.3	45.3	55.8
124	Carbon Tax					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
125	Carbon Allowance Cost					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
126	Environmental	0.4	0.5	0.6	-	(0.0)	30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
127	Fixed O&M	-	-	-	-	0.0	101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
128	Transmission O&M	6.6	7.1	7.4	-	0.0	8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
129	APM, L/C, Cogen, CW & TVA Trans	4.7	8.8	5.9	-	0.0	6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
130	A&G	13.8	15.6	17.2	-	0.0	29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
131	Property Taxes & Insurance	2.4	2.3	2.2	-	0.0	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
132	Working Capital	6.8	4.6	(4.9)	-	0.0	(31.5)	(1.1)	(0.2)	(2.0)	(1.5)	9.1	0.2	0.3	(0.5)	1.4	(0.9)	0.1	(0.8)	0.3	(0.6)
133	PCB Restructuring	-	-	-	-	-	7.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
134	Other	2.3	1.9	2.0	-	(0.0)	(0.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
135	Total Disbursements	146.3	205.1	137.5	-	0.0	451.6	498.3	530.3	565.8	599.3	494.2	508.1	512.7	552.8	534.5	561.6	561.7	587.9	592.7	614.0
136																					
137	Operating Receipts less Disbursements	105.7	123.8	117.8	-	(59.6)	92.4	78.4	53.1	69.2	69.0	116.7	106.1	105.1	111.5	114.7	113.4	119.9	116.2	115.5	113.4
138																					

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
139																					
140	Operating Receipts less Disbursements	105.7	123.8	117.8	-	(59.6)	92.4	78.4	53.1	69.2	69.0	116.7	106.1	105.1	111.5	114.7	113.4	119.9	116.2	115.5	113.4
141																					
142	Capital Expenditures																				
143	Generation	6.4	6.6	6.7	-	(0.0)	36.2	20.6	31.5	23.4	38.5	32.8	33.8	34.8	35.9	36.9	38.1	39.2	40.4	41.6	42.8
144	Transmission	5.9	9.6	18.4	-	-	10.3	5.3	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
145	Transmission Upgrades	-	4.1	-	-	-	5.6	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-
146	A&G	0.9	1.3	1.3	-	0.0	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
147	Extraordinary Generation	-	-	-	-	-	28.7	17.4	25.4	10.7	8.8	5.2	4.4	2.3	2.8	2.4	7.0	3.4	3.1	2.7	3.3
148	Other (HQ Building, IP)	-	-	-	-	0.0	11.4	1.0	0.9	0.8	0.8	1.0	0.8	0.8	1.0	0.9	0.9	1.1	0.9	0.9	1.2
149	Total Capital Expenditures	13.2	21.6	26.4	-	0.0	93.5	51.3	63.7	42.2	50.1	40.9	41.2	41.1	44.1	45.3	51.2	49.1	49.9	50.9	53.3
150																					
151	*Income Taxes from Operations*	0.4	0.2	0.4	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
152																					
153	Net Pre-Finance Cash Flow	92.1	102.0	91.0	-	(59.6)	(1.1)	27.1	(10.6)	26.9	18.9	75.6	64.6	63.6	67.0	68.9	61.8	70.4	65.8	64.1	59.7
154																					
155	Financing																				
156	Principal (Net)	26.4	13.3	41.8	-	-	13.3	15.1	(42.5)	79.4	31.6	33.5	(171.5)	233.5	38.2	15.8	42.8	45.3	34.0	35.9	38.2
157	Interest	36.9	36.9	51.5	-	0.0	43.2	42.5	41.6	43.7	40.2	38.3	36.2	34.2	32.3	30.1	29.2	26.7	24.1	22.2	19.9
158	Financing Fees					-	-	-	1.0	-	-	-	7.0	-	-	-	-	-	-	-	-
159	Line of Credit	-	-	-	-	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
160	*Aggregate Debt Service (incl. Line of (*	63.4	50.2	93.3	-	0.0	57.0	58.0	0.6	123.6	72.3	72.3	(127.7)	268.2	71.0	46.4	72.5	72.5	58.6	58.6	58.6
161																					
162	Post-Finance Cash Flow	28.7	51.9	(2.3)	-	(59.6)	(58.1)	(31.0)	(11.2)	(96.6)	(53.4)	3.3	192.3	(204.6)	(4.0)	22.6	(10.7)	(2.2)	7.2	5.5	1.1
163																					
164	Unwind Transaction																				
165	Cash Proceeds	-			387.7																
166	Debt Reduction	-			(147.0)																
167	Misc. Transaction				(3.1)																
168	Net Before Member Reserves				237.6																
169	*Non-Smelter Member Economic Reserv*	-			(157.0)	-	35.5	36.1	30.8	38.3	35.7	-	-	-	-	-	-	-	-	-	-
170	Smelter Fuel Payment				(7.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
171																					
172	Net Before Transition Reserve				73.6	-	35.5	36.1	30.8	38.3	35.7	-	-	-	-	-	-	-	-	-	-
173																					
174	Ending Cash Balances (Incl. Transition	96.5	148.3	146.0	219.6	160.0	137.3	142.5	162.1	103.7	86.1	89.3	281.7	77.1	73.1	95.6	84.9	82.8	90.0	95.5	96.6
175	Reserve)																				

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
176	**IV. Income Statement (M$)**																				
177																					
178	Revenues																				
179	Rural	79.4	84.76	84.8	-	0.0	90.5	93.2	108.7	111.7	121.8	131.9	136.1	139.3	149.4	154.1	158.3	167.0	171.1	176.6	181.3
180	Large Industrial	29.3	28.53	29.2	-	-	33.3	35.0	41.8	43.5	48.3	53.2	55.3	57.0	61.2	63.6	65.7	69.9	72.0	74.7	77.0
181	Smelters	-	-	-	-	-	314.6	313.6	359.0	382.9	393.5	340.6	353.3	354.5	397.5	370.5	401.7	397.3	414.3	411.0	427.1
182	Off-System	83.4	149.38	81.1	-	-	94.3	108.5	87.7	90.9	99.4	82.2	82.1	78.8	67.6	73.6	59.7	59.5	59.1	58.4	54.7
183	Transmission	6.0	6.29	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
184	Smelter - Tier 3 Transmission	1.8	1.80	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
185	Gain on Sale of Allowances	-	-	-	-	-	3.8	3.0	(0.6)	(0.4)	(0.2)	(1.9)	(16.3)	(15.1)	(14.5)	(15.6)	(14.2)	(15.5)	(15.6)	(16.0)	(16.5)
186	WKEC Lease (Net)	52.3	52.33	52.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Lease Buyout				-	(16.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
188	Interest Earnings	3.7	6.83	5.0	-	0.0	6.4	5.5	5.7	5.7	4.1	3.4	3.6	3.3	3.1	2.9	3.8	3.4	3.3	3.6	3.8
189	Total Revenues	255.9	329.92	259.4	-	(16.1)	542.9	558.9	602.2	634.3	666.8	609.5	614.2	617.8	664.3	649.2	675.0	681.6	704.1	708.2	727.4
190																					
191	Expenses																				
192	PPA	98.0	96.29	95.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
193	Fuel Costs	-	-	-	-	(0.0)	270.8	301.0	305.8	339.5	366.4	276.1	259.3	261.7	260.2	267.6	268.0	275.4	277.0	285.9	285.5
194	SEPA & Other Purchases	11.4	68.01	11.61	-	0.0	22.8	19.3	25.9	24.3	27.1	26.5	28.1	29.4	41.7	31.9	38.8	39.1	46.6	44.0	51.3
195	Carbon Tax					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
196	Carbon Allowance Cost					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
197	Non-Fuel Variable Production O&M	0.4	0.48	0.6	-	(0.0)	30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
198	Fixed Production O&M	-	-	-	-	0.0	101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
199	Transmission O&M	6.6	7.07	7.4	-	0.0	8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
200	APM, L/C, Cogen, CW & TVA Trans	4.7	8.78	5.9	-	0.0	6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
201	A&G	13.8	15.62	17.2	-	0.0	29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
202	Property Taxes & Insurance	2.4	2.32	2.2	-	0.0	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
203	Depreciation & Amortization	32.8	32.15	32.5	-	0.0	34.4	35.6	44.6	46.0	46.1	46.4	48.0	49.5	63.6	64.9	66.3	67.8	69.2	70.6	72.2
204	Income Tax	-	-	-	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
205	Interest Expense (Incl. Financing Fees)	60.7	60.90	59.9	-	0.0	53.1	48.9	48.4	51.0	47.9	46.4	44.8	43.5	42.0	40.4	40.1	38.4	36.9	35.2	33.7
206	RUS Note & PCB Restructuring Charge	-	-	-	-	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
207	Net Sale-Leaseback	(2.6)	(2.56)	(3.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Other - Net	(6.0)	(6.32)	(6.6)	-	(0.0)	(0.3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Total Expenses	222.3	282.74	222.9	-	(0.0)	564.1	581.7	619.8	658.7	689.3	596.6	601.5	605.4	652.2	637.4	663.2	670.1	692.9	697.4	716.8
210																					
211	Unwind Transaction	-	-	-	690.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212																					
213	Non-Smelter Member Economic Reserve	-	-	-	(157.0)	-	35.5	36.1	30.8	38.3	35.7	-	-	-	-	-	-	-	-	-	-
214																					
215	Smelter FAC Payment	-	-	-	(7.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216																					
217	Net Margin	33.7	47.18	36.5	526.8	(16.1)	14.3	13.3	13.2	13.9	13.2	12.9	12.6	12.4	12.1	11.8	11.8	11.5	11.2	10.9	10.6

Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			12/31/2008	
V. Balance Sheet (MS)																				
Assets																				
Property																				
Total Utility Plant in Service	1,731.2	1,749.9	1,783.8	1,882.3	1,882.3	1,986.7	2,038.8	2,103.3	2,146.4	2,197.3	2,239.1	2,281.1	2,323.1	2,368.1	2,414.3	2,466.3	2,516.3	2,567.1	2,618.8	2,673.0
Construction in Progress	13.1	15.1	15.1	15.1	15.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Depreciation & Amortization	827.5	854.1	886.6	886.6	886.6	921.0	956.5	1,001.2	1,047.2	1,093.3	1,139.7	1,187.6	1,237.1	1,300.8	1,365.7	1,432.0	1,499.8	1,569.0	1,639.6	1,711.8
Other Property	190.7	197.8	200.9	200.9	4.1	4.4	4.4	4.4	3.7	2.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Current																				
Cash General Funds & Special Deposits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Cash Balance	96.5	148.3	146.0	184.6	125.0	100.9	104.6	122.7	62.8	43.5	45.1	235.6	29.2	23.3	43.8	31.1	26.7	31.7	34.9	33.6
Transition Reserve	-	-	-	35.0	35.0	36.4	37.9	39.4	40.9	42.6	44.3	46.1	47.9	49.8	51.8	53.9	56.0	58.3	60.6	63.0
Non-Smelter Member Economic Reserve	-	-	-	157.0	157.0	127.8	96.8	69.9	34.4	-	-	-	-	-	-	-	-	-	-	-
Smelter FAC Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accounts Receivable	17.5	26.3	19.9	19.9	19.87	44.71	46.1	49.7	52.4	55.2	50.5	50.9	51.2	55.1	53.9	55.9	56.5	58.4	58.7	60.3
Regulatory Asset		-	-	-	-	0.3	-	1.0	2.4	5.0	4.4	4.4	5.2	12.3	14.3	20.5	18.8	21.5	22.8	27.4
Fuel Stock & Related	-	-	-	31.4	31.4	31.3	35.2	37.3	42.4	46.3	29.2	29.3	29.5	30.3	30.4	31.2	31.5	31.9	32.7	33.0
Emissions Inventory				2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Materials and Supplies Other	0.8	0.8	0.8	20.4	20.4	21.0	21.6	22.3	22.9	23.6	24.3	25.1	25.8	26.6	27.4	28.2	29.1	29.9	30.8	31.8
Other Current Assets	4.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Credits																				
AMBAC/Credit Suisse July '98	4.7	4.3	3.8	3.8	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax	4.7	5.0	5.4	6.8	6.8	6.8	6.8	6.8	6.8	6.3	6.0	5.7	5.4	5.1	4.8	4.5	4.2	3.8	3.5	3.1
Deferred Debt Debits/PCB Refunding 10/(	0.6	0.8	0.7	1.1	1.1	7.1	6.7	7.3	6.9	6.5	6.0	12.6	11.9	11.2	10.5	9.8	9.0	8.3	7.5	6.8
Other Deferred Assets	-	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
LEM Settlement Note/Marketing Payment	17.1	16.1	15.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Assets	1,253.4	1,313.3	1,308.1	1,676.8	1,420.3	1,456.5	1,452.6	1,473.1	1,385.0	1,345.3	1,320.0	1,514.0	1,302.9	1,291.9	1,296.3	1,280.2	1,259.3	1,252.8	1,241.7	1,231.0
Liabilities & Equities																				
Margins & Equities	(218.2)	(175.0)	(138.5)	388.3	372.2	386.4	399.7	413.0	426.9	440.1	453.0	465.7	478.0	490.1	501.9	513.7	525.2	536.4	547.2	557.8
Long-Term Debt																				
Existing Debt	1,053.1	1,061.7	1,027.1	871.7	871.7	864.8	856.5	906.2	834.5	810.9	785.8	966.2	742.0	713.6	708.2	676.4	642.7	621.5	598.6	574.2
Sale-Leaseback Obligation	177.3	183.9	189.7	189.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Long-Term Debt	1,230.4	1,245.6	1,216.9	1,061.4	871.7	864.8	856.5	906.2	834.5	810.9	785.8	966.2	742.0	713.6	708.2	676.4	642.7	621.5	598.6	574.2
Current & Accrued Liabilities																				
Accounts Payable	12.6	18.0	12.7	12.7	12.7	69.5	72.5	76.8	81.9	86.7	73.3	74.0	74.6	79.5	77.4	81.0	82.1	85.4	86.1	88.9
Regulatory Liability					0.0	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
Taxes Accrued	0.2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Non-Smelter Member Economic Reserve I	-	-	-	157.0	157.0	127.8	96.8	69.9	34.4	-	-	-	-	-	-	-	-	-	-	-
Smelter FAC Reserve Deferred Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest Accrued	7.6	7.8	7.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other Accrued Liabilities	6.0	5.2	5.4	5.4	5.4	5.6	5.7	5.9	6.1	6.2	6.4	6.6	6.8	7.0	7.2	7.5	7.7	7.9	8.2	8.4
Deferred TIER Rebate Payable					0.0	1.0	18.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WKEC Lease (Resid. Value Obligation)	158.1	156.9	152.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sale-Leaseback Gain	56.4	53.5	50.6	50.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Deferred Credits & Century Reactiv	0.4	0.3	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities & Equity	1,253.4	1,313.3	1,308.1	1,676.8	1,420.3	1,456.5	1,452.6	1,473.1	1,385.0	1,345.3	1,320.0	1,514.0	1,302.9	1,291.9	1,296.3	1,280.2	1,259.3	1,252.8	1,241.7	1,231.0

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
267	Change in Working Capital																				
268	Other Property	6.7	7.1	3.1	-	(196.8)	0.3	-	-	(0.7)	(1.6)	(1.5)	-	-	-	-	-	-	-	-	-
269	Accounts Receivable	1.2	8.9	(6.4)	-	-	24.8	1.4	3.6	2.7	2.8	(4.7)	0.4	0.3	3.9	(1.2)	2.1	0.6	1.9	0.3	1.6
270	Materials, Supplies & Other	0.1	(0.0)	0.0	-	0.0	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9
271	Other Current Assets	3.8	(3.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
272	Accounts Payable	0.5	(5.4)	5.3	-	-	(56.8)	(3.0)	(4.3)	(5.1)	(4.8)	13.4	(0.7)	(0.5)	(5.0)	2.1	(3.6)	(1.1)	(3.3)	(0.7)	(2.8)
273	Taxes Accrued	0.2	(0.8)	(0.0)	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
274	Other Accruals	(0.1)	0.8	(0.2)	-	(0.0)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
275	Investment - Special Deposit (B/S)	(6.0)	(6.2)	(6.4)	-	196.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Net SLB	(0.3)	(0.3)	0.5																	
277	CoBank Patronage Capital	(0.4)	(0.4)	(0.4)	-	(0.0)	(0.3)	-	-	0.7	1.6	1.5	-	-	-	-	-	-	-	-	-
278	Adjustment	1.1	4.1	(0.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	Total	6.8	4.6	(4.9)	-	0.0	(31.5)	(1.1)	(0.2)	(2.0)	(1.5)	9.1	0.2	0.3	(0.5)	1.4	(0.9)	0.1	(0.8)	0.3	(0.6)
280																					
281	Cash Balance																				
282	Beginning	67.8	96.5	148.3	146.0	219.6	160.0	137.3	142.5	162.0	103.7	86.1	89.3	281.7	77.1	73.1	95.6	84.9	82.8	90.0	95.5
283	Ending	96.5	148.3	146.0	219.6	160.0	137.3	142.5	162.0	103.7	86.1	89.3	281.7	77.1	73.1	95.6	84.9	82.8	90.0	95.5	96.6
284																					
285	**VI. Credit Measures**																				
286																					
287	Contract TIER																				
288	Earnings						14.3	13.3	13.2	13.9	13.2	12.9	12.6	12.4	12.1	11.8	11.8	11.5	11.2	10.9	10.6
289	Plus: Interest Expense, Financing Fees, and Restucturing						53.6	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
290	Plus: Imputed Rate Increase in 2010						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
291	Less: Offset to Imputed Rate Increase in 2010						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
292	Less: Interest on Sequestered Funds						(1.40)	(1.46)	(1.51)	(1.57)	(1.64)	(1.70)	(1.77)	(1.84)	(1.92)	(1.99)	(2.07)	(2.16)	(2.24)	(2.33)	(2.42)
293	Total						66.4	61.1	60.6	63.7	59.9	58.1	56.1	54.4	52.6	50.6	50.3	48.1	46.3	44.1	42.2
294	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
295	Total						66.4	61.1	60.6	63.7	59.9	58.1	56.1	54.4	52.6	50.6	50.3	48.1	46.3	44.1	42.2
296	Divided by																				
297	Interest Expense, Financing Fees, and Restructuring						53.6	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
298	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
299	Total						53.6	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
300																					
301	*Contract TIER*						1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
302																					
303	Conventional TIER																				
304	Earnings						14.3	13.3	13.2	13.9	13.2	12.9	12.6	12.4	12.1	11.8	11.8	11.5	11.2	10.9	10.6
305	Plus: Interest Expense, Financing Fees, and Restucturing						53.6	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
306	Plus Income Tax						-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
307	Total						67.8	62.6	62.1	65.3	62.1	60.4	58.5	56.9	55.2	53.3	53.1	51.0	49.3	47.3	45.5
308	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Total						67.8	62.6	62.1	65.3	62.1	60.4	58.5	56.9	55.2	53.3	53.1	51.0	49.3	47.3	45.5
310	Divided by																				
311	Interest Expense, Financing Fees, and Restructuring						53.6	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
312	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Total						53.6	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
314																					
315	*Conventional TIER*						1.27	1.27	1.27	1.27	1.29	1.29	1.29	1.30	1.30	1.31	1.31	1.32	1.32	1.33	1.34
316																					

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
317	DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																				
318	Cash Available for Debt Service																				
319	Receipts less Disbursements						92.4	78.4	53.1	69.2	69.0	116.7	106.1	105.1	111.5	114.7	113.4	119.9	116.2	115.5	113.4
320	Economic Reserve						35.5	36.1	30.8	38.3	35.7	-	-	-	-	-	-	-	-	-	-
321	Taxes						(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)
322	Net						127.8	114.5	83.8	107.5	104.8	116.5	105.8	104.7	111.1	114.3	113.0	119.5	115.7	115.0	113.0
323	Plus Sale-Leaseback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
324	Total						127.8	114.5	83.8	107.5	104.8	116.5	105.8	104.7	111.1	114.3	113.0	119.5	115.7	115.0	113.0
325	Divided by																				
326	Interest Expenditures						43.7	43.0	42.1	44.2	40.7	38.8	36.7	34.7	32.8	30.6	29.7	27.2	24.6	22.7	20.4
327	Scheduled Principal						13.3	15.1	15.8	16.7	31.6	33.5	35.6	37.9	38.2	40.4	42.8	45.3	34.0	35.9	38.2
328	Plus Sale-Leasback Interest						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Total Debt Service						57.0	58.0	57.9	60.9	72.3	72.3	72.3	72.6	71.0	71.0	72.5	72.5	58.6	58.6	58.6
330																					
331	*DSCR*						2.24	1.97	1.45	1.77	1.45	1.61	1.46	1.44	1.57	1.61	1.56	1.65	1.98	1.96	1.93
332																					
333	Days Cash on Hand																				
334	Average Cash Balance	96.5	122.4	147.2	182.8	189.8	148.7	139.9	152.3	132.9	94.9	87.7	185.5	179.4	75.1	84.4	90.3	83.9	86.4	92.8	96.1
335	Line of Credit	100.0				100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
336	Total	196.5	122.4	147.2	182.8	289.8	248.7	239.9	252.3	232.9	194.9	187.7	285.5	279.4	175.1	184.4	190.3	183.9	186.4	192.8	196.1
337	Divided by																				
338	Total Operating Expense																				
339	PPA	98.0	96.3	95.4	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
340	Fuel Costs	-	-	-	-		270.8	301.0	305.8	339.5	366.4	276.1	259.3	261.7	260.2	267.6	268.0	275.4	277.0	285.9	285.5
341	SEPA & Other Purchases	11.4	68.0	11.6	-		22.8	19.3	25.9	24.3	27.1	26.5	28.1	29.4	41.7	31.9	38.8	39.1	46.6	44.0	51.3
342	Non-Fuel Variable Production O&M	0.4	0.5	0.6	-		30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
343	Fixed Production O&M	-	-	-	-		101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
344	Transmission O&M	6.6	7.1	7.4	-		8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
345	APM, L/C, Cogen, CW & TVA Trans	4.7	8.8	5.9	-		6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
346	A&G	13.8	15.6	17.2	-		29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
347	Property Taxes & Insurance	2.4	2.3	2.2	-		6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
348	Interest Expense (Incl. Financing Fe	60.7	60.9	59.9	-		53.1	48.9	48.4	51.0	47.9	46.4	44.8	43.5	42.0	40.4	40.1	38.4	36.9	35.2	33.7
349	Total	198.0	259.5	200.4	-		529.7	545.7	574.8	612.2	642.3	549.2	552.5	554.9	587.5	571.3	595.8	601.2	622.5	625.5	643.5
350																					
351	*Days Cash on Hand (including Line of C*	362.2	172.2	268.1			171.3	160.4	160.2	138.8	110.8	124.8	188.6	183.8	108.8	117.8	116.6	111.6	109.3	112.5	111.2
352	*Days Cash on Hand (excluding Line of C*	177.8	172.2	268.1			102.4	93.6	96.7	79.2	53.9	58.3	122.5	118.0	46.6	53.9	55.3	50.9	50.6	54.1	54.5
353																					

		2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
354	VII. Debt Service Detail, as of Transaction Date (M$)																				
355																					
356	Capital Markets Issue (Tranche 1)																				
357	Beginning Principal			-	-	-	-	-	-	58.3	58.3	49.1	39.2	28.6	28.6	28.6	53.2	53.2	53.2	52.7	24.9
358	Principal			-	-	-	-	-	(58.3)	-	9.3	9.9	10.6	-	-	(24.6)	-	-	0.5	27.9	15.7
359	Interest			-	-	-	-	-	-	4.1	4.1	3.4	2.7	2.0	2.0	2.0	3.5	3.5	3.5	3.4	1.6
360	Debt Service			-	-	-	-	-	(58.3)	4.1	13.3	13.3	13.3	2.0	2.0	(22.6)	3.5	3.5	3.9	31.3	17.3
361	Blended Interest Cost			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	6.50%	6.50%	6.50%	6.50%	6.50%
362																					
363	Capital Markets Issue (Tranche 2)																				
364	Beginning Principal			-	-	-	-	-	-	-	-	-	-	207.0	207.0	207.0	207.0	207.0	207.0	207.0	199.0
365	Principal			-	-	-	-	-	-	-	-	-	(207.0)	-	-	-	-	-	-	8.0	22.5
366	Interest			-	-	-	-	-	-	-	-	-	-	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.2
367	Debt Service			-	-	-	-	-	-	-	-	-	(207.0)	11.6	11.6	11.6	11.6	11.6	11.6	19.7	33.7
368	Blended Interest Cost			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.63%
369																					
370	Variable Rate Bonds																				
371	Beginning Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
372	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
373	Interest			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
374	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
375	Blended Interest Cost			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
376																					
377	Ongoing RUS Note (Stated)																				
378	Beginning Principal			-	768.4	628.2	628.2	614.9	599.8	584.0	504.7	482.3	458.7	433.7	200.2	162.0	121.6	78.8	33.5	0.0	0.0
379	Principal			-	140.2	-	13.3	15.1	15.8	79.4	22.3	23.6	25.0	233.5	38.2	40.4	42.8	45.3	33.5	-	-
380	Interest			-	-	0.0	36.1	35.4	34.5	32.5	29.0	27.7	26.4	13.4	11.5	9.3	7.0	4.5	1.9	0.0	0.0
381	Debt Service			-	140.2	0.0	49.4	50.4	50.3	111.9	51.4	51.4	51.4	246.9	49.7	49.7	49.8	49.8	35.4	0.0	0.0
382	Blended Interest Cost				0.00%	0.00%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%		
383																					
384	ARVP																				
385	Beginning Principal			-	104.1	104.1	104.1	110.2	116.8	123.7	131.0	138.7	146.9	155.6	164.8	174.6	184.9	195.8	207.4	219.7	232.7
386	Principal/ Reserve			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
387	Interest/ Reserve			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
388	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
389	Accretion Rate			0.00%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
390																					
391	PCB																				
392	Beginning Principal			-	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
393	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
394	Interest			-	-	0.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
395	Debt Service			-	-	0.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
396	Blended Interest Cost				0.00%	0.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
397																					
398	Total (Incorporates RUS on Stated Basis)																				
399	Beginning Principal			-	1,014.6	874.4	874.4	867.2	858.7	908.1	836.0	812.2	786.9	967.0	742.7	714.3	708.8	676.9	643.2	621.5	598.6
400	Principal			-	140.2	-	13.3	15.1	(42.5)	79.4	31.6	33.5	(171.5)	233.5	38.2	15.8	42.8	45.3	34.0	35.9	38.2
401	Interest			-	-	0.0	43.2	42.5	41.6	43.7	40.2	38.3	36.2	34.2	32.3	30.1	29.2	26.7	24.1	22.2	19.9
402	Line of Credit Fee			-	-	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
403	Debt Service			-	140.2	0.0	57.0	58.0	(0.4)	123.6	72.3	72.3	(134.7)	268.2	71.0	46.4	72.5	72.5	58.6	58.6	58.6

Smelter Rate Structure

October 2008

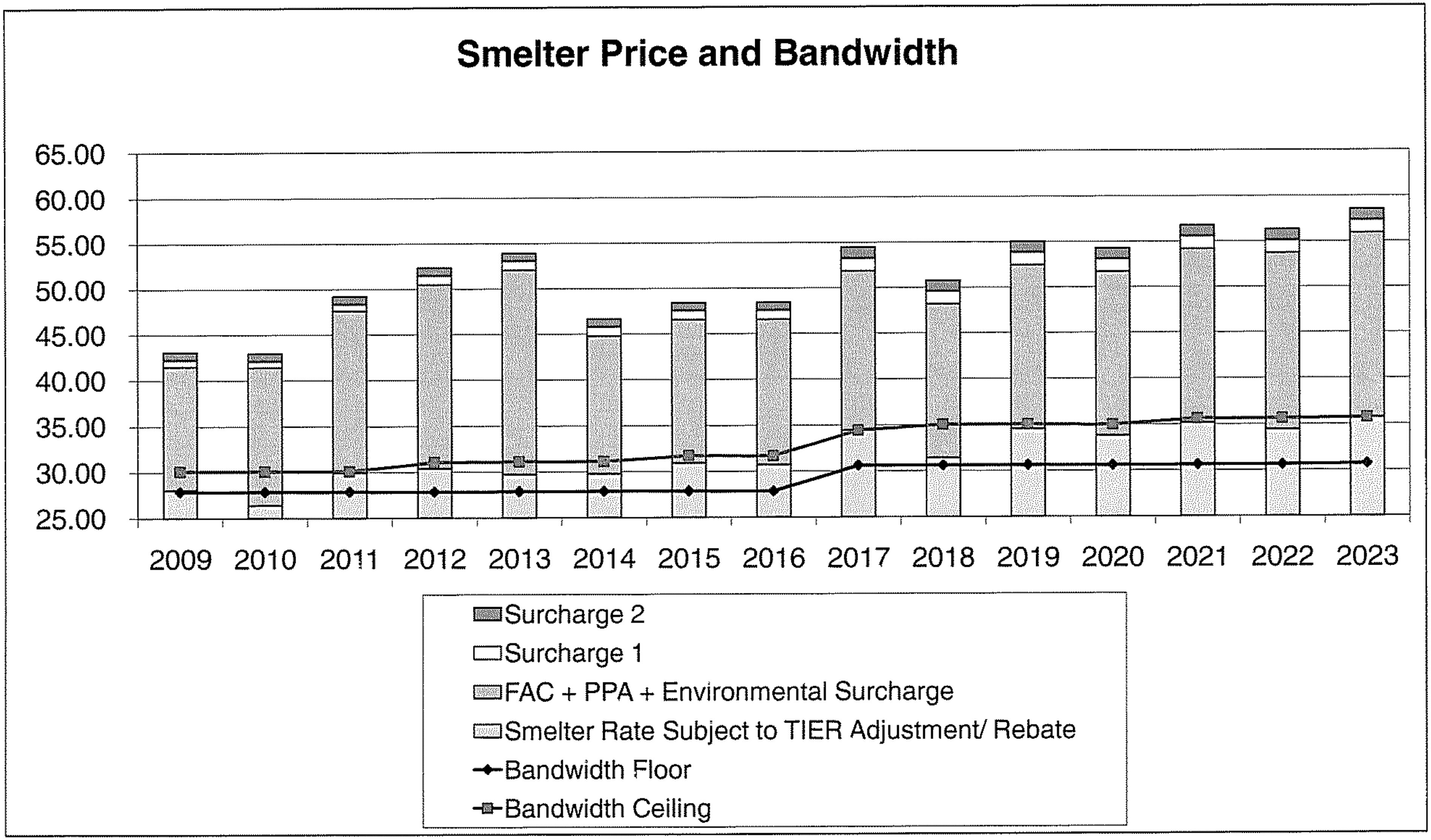
Smelter Rates

#		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Days in Year	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
	General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	9.74%	0.00%	0.00%	0.00%	0.00%	0.00%	0.31%
1	Smelter Sales															
2	Century	4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14
3	Alcan	3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16
4	Total Energy (TWh)	7.297	7.297	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297
5	Total Demand (GW)	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200
6	Smelter Load Factor (%)	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
7																
8	Smelter Rate ($/ MWh)															
9	Large Industrial Rate															
10	Sales (TWH)	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11	Load Factor (%)	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12	Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	11.14	11.14	11.14	11.14	11.14	11.14	11.17
13	Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	15.05	15.05	15.05	15.05	15.05	15.05	15.10
14	Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	MRDA ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Regulatory Account Charge	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
17	Less: Regulatory Account Charge	-	-	0.10	0.10	0.10	(0.42)	(0.41)	(0.40)	(0.41)	(0.40)	(0.39)	(1.52)	(1.48)	(1.45)	(1.59)
18	Net Rate ($/ MWH)	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	34.45	34.45	34.45	34.47	34.45	34.45	34.56
19																
20	Large Industrial Rate @ 98% LF	27.90	27.90	27.90	27.86	27.90	27.90	27.90	27.86	30.62	30.62	30.62	30.58	30.62	30.62	30.71
21	Plus Margin	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22	Smelter Base Rate	28.15	28.15	28.15	28.11	28.15	28.15	28.15	28.11	30.87	30.87	30.87	30.83	30.87	30.87	30.96
23	Plus TIER Adjustment	-	-	1.79	2.25	1.59	1.64	2.78	2.59	3.55	0.54	3.67	2.97	4.30	3.53	4.75
24	Less TIER Related Rebate	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Smelter Rate Subject to TIER Adjustment	28.06	26.42	29.95	30.36	29.75	29.79	30.93	30.70	34.42	31.41	34.54	33.80	35.17	34.40	35.71
26																
27	Plus FAC + PPA + Environmental Surcharge	13.48	14.99	17.67	20.10	22.30	15.01	15.62	15.87	17.45	16.77	17.91	17.91	19.00	19.33	20.22
28	Plus Surcharge 1	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
29	Plus Surcharge 2	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	1.20	1.20	1.20	1.20	1.20	1.20	1.20
30	Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	43.11	42.98	49.19	52.33	53.92	46.67	48.42	48.44	54.47	50.77	55.05	54.30	56.77	56.32	58.53
31																
32	TIER Adjustment Cap ($/ MWh)															
33	Bandwidth Floor	28.15	28.15	28.15	28.11	28.15	28.15	28.15	28.11	30.87	30.87	30.87	30.83	30.87	30.87	30.96
34	Bandwidth Range	1.95	1.95	1.95	2.95	2.95	2.95	3.55	3.55	3.55	4.15	4.15	4.15	4.75	4.75	4.75
35	Bandwidth Ceiling	30.10	30.10	30.10	31.06	31.10	31.10	31.70	31.66	34.42	35.02	35.02	34.98	35.62	35.62	35.71
36	Smelter Rate Subject to TIER Adjustment/ Rebate	28.06	26.42	29.95	30.36	29.75	29.79	30.93	30.70	34.42	31.41	34.54	33.80	35.17	34.40	35.71

Smelter Rate Structure October 2008

Smelter Rates

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	9.74%	0.00%	0.00%	0.00%	0.00%	0.00%	0.31%



Smelter Rate Structure

October 2008

Smelter Rates

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Days in Year	365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
	General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	9.74%	0.00%	0.00%	0.00%	0.00%	0.00%	0.31%
37	***TIER Adjustment Rebate/Charge***															
38	Pre-TIER Rebate Member Revenues	124.1	134.4	150.5	155.1	170.0	185.2	191.5	196.4	210.6	217.7	223.9	236.9	243.0	251.3	258.4
39	Pre-TIER Adj/Rebate Smelter Revenues	315.3	326.2	345.9	366.5	381.8	328.6	333.1	335.5	371.6	366.6	374.9	375.6	382.9	385.2	392.5
40	Other Revenues	*140.0*	*153.1*	*123.5*	*134.5*	*139.1*	*83.8*	*69.4*	*66.9*	*56.2*	*60.9*	*49.4*	*47.4*	*46.8*	*46.0*	42.0
41	Pre TIER Adj/Rebate Revenues	579.4	613.8	620.0	656.1	690.9	597.5	593.9	598.8	638.4	645.2	648.2	659.9	672.7	682.5	692.8
42	*Total Expenses*	564.1	581.7	619.8	658.7	689.3	596.6	601.5	605.4	652.2	637.4	663.2	670.1	692.9	697.4	716.8
43	Net Margin Before TIER Adjustment	15.3	32.1	0.1	(2.5)	1.6	1.0	(7.6)	(6.6)	(13.8)	7.9	(15.0)	(10.3)	(20.2)	(14.9)	(24.1)
44																
45	Interest + Margin	68.8	81.4	49.0	48.8	49.9	47.8	37.6	37.3	28.6	48.7	25.6	28.5	17.1	20.7	10.0
46	Interest Charges	53.6	49.3	48.8	51.4	48.3	46.8	45.3	43.9	42.4	40.8	40.6	38.8	37.3	35.6	34.1
47	*Pre-TIER Adjustment TIER*	1.29	1.65	1.00	0.95	1.03	1.02	0.83	0.85	0.67	1.19	0.63	0.73	0.46	0.58	0.29
48																
49	Increment needed for 1.24x TIER	(2.4)	(20.3)	11.6	14.9	10.0	10.3	18.5	17.1	24.0	1.9	24.7	19.6	29.2	23.4	32.2
50	Contract TIER Adjustments															
51	Plus: Imputed Rate Increase in 2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Less: *Offset to Imputed Rate Increase in 2010*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Less: Interest on Sequestered Funds	(1.4)	(1.5)	(1.5)	(1.6)	(1.6)	(1.7)	(1.8)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)
54	*Total Adjustments*	(1.4)	(1.5)	(1.5)	(1.6)	(1.6)	(1.7)	(1.8)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)
55	Increment needed for 1.24x TIER with Adj.	(1.0)	(18.8)	13.1	16.4	11.6	12.0	20.3	18.9	25.9	3.9	26.8	21.7	31.4	25.7	34.7
56																
57	Rebate Amount ($M)	(1.0)	(18.8)	-	-	-	-	-	-	-	-	-	-	-	-	-
58	TIER Adjustment Charge ($M)	-	-	13.1	16.4	11.6	12.0	20.3	18.9	25.9	3.9	26.8	21.7	31.4	25.7	34.7
59																
60	Rebate to Members/Smelters ($/MWh)															
61	Rurals	(0.10)	(1.79)	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Large Industrials	(0.09)	(1.59)	-	-	-	-	-	-	-	-	-	-	-	-	-
63	Smelters	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
64																
65	TIER Adjustment Charge to Smelters ($/MWh)	-	-	1.79	2.25	1.59	1.64	2.78	2.59	3.55	0.54	3.67	2.97	4.30	3.53	4.75

Memb.. Rates Cash Method

Octo. 2008

Member Rates (Cash Method) Calculation

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Member Sales (TWh)**															
2	Rural	2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
3	Large Industrial	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
4	Total	3.50	3.58	3.67	3.76	3.85	3.94	4.03	4.12	4.22	4.31	4.40	4.50	4.60	4.69	4.79
5																
6	**Rates (Cash Method)**															
7	***Rural***															
8	Load Factor (%)	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
9	Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	8.09	8.09	8.09	8.09	8.09	8.09	8.11
10	Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	22.39	22.39	22.39	22.39	22.39	22.39	22.46
11	Base	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
12	MRDA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Regulatory Account Charge	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
14	GRA	-	-	-	-	-	-	-	-	3.60	3.60	3.60	3.60	3.60	3.59	3.72
15	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
16	Env. Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
17	Surcharge Rebate	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
18	TIER Related Rebate	-	(0.10)	(1.76)	-	-	-	-	-	-	-	-	-	-	-	-
19	Non-Smelter Member Economic Reserve	(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
20	Net	-	2.00	3.93	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
21	Effective Rate	37.22	39.19	41.00	43.04	45.92	48.80	49.28	49.42	51.90	52.50	52.80	54.61	54.84	55.52	55.93
22																
23	***Large Industrial***															
24	Load Factor (%)	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
25	Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	11.14	11.14	11.14	11.14	11.14	11.14	11.17
26	Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	15.05	15.05	15.05	15.05	15.05	15.05	15.10
27	Base	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
28	MRDA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Regulatory Account Charge	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
30	GRA	-	-	-	-	-	-	-	-	3.06	3.06	3.06	3.06	3.06	3.06	3.16
31	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
32	Env. Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
33	Surcharge Rebate	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
34	TIER Related Rebate	-	(0.08)	(1.54)	-	-	-	-	-	-	-	-	-	-	-	-
35	Non-Smelter Member Economic Reserve	(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
36	Net	-	2.01	4.15	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
37	Effective Rate	31.39	33.40	35.44	37.30	40.20	43.10	43.60	43.79	45.73	46.35	46.67	48.54	48.75	49.46	49.87
38																

Member Rates (Cash Method) Calculation

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
39	***Non-Smelter Member Blend***															
40	Base	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
41	MRDA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Regulatory Account Charge	-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
43	GRA	-	-	-	-	-	-	-	-	3.43	3.43	3.43	3.43	3.42	3.42	3.54
44	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
45	Env. Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
46	Surcharge Rebate	(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
47	TIER Related Rebate	-	(0.09)	(1.69)	-	-	-	-	-	-	-	-	-	-	-	-
48	Non-Smelter Member Economic Reserve	(10.13)	(10.08)	(8.38)	(10.19)	(9.28)	-	-	-	-	-	-	-	-	-	-
49	Net	-	2.00	4.00	6.00	8.91	11.28	11.80	11.97	10.87	11.50	11.83	12.54	12.82	13.55	13.72
50	Effective Rate	35.45	37.42	39.29	41.26	44.14	47.01	47.49	47.64	49.94	50.54	50.84	52.67	52.88	53.57	53.98
51																
52	***Revenues Delta($M)***															
53	Rural	0.24	4.22	(4.46)	-	-	-	-	-	-	-	-	-	-	-	-
54	LI	0.09	1.65	(1.74)	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	0.33	5.87	(6.20)	-	-	-	-	-	-	-	-	-	-	-	-
56																
57	***Smelter Rebate Lag***															
58	TWh	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
59	Accrued ($/ MWh)	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Realized ($/ MWh)	-	(0.10)	(1.73)	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust ($M)	0.70	11.94	(12.63)	-	-	-	-	-	-	-	-	-	-	-	-

Regulatory Accounts

October 2008

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Purchased Power Cost not Included in Member Rates ($M)	0.26	(1.39)	1.77	1.03	2.20	1.02	1.76	2.39	8.83	3.78	7.86	5.17	9.50	8.16	12.18
EXPENSE DEFERRAL METHOD															
Income Statement (Change in Regulatory Account)															
1. Deferral															
Power Purchase Expense															
Debit	-	1.39	-	-	-	-	-	-	-	-	-	-	-	-	-
Credit	(0.26)	-	(1.77)	(1.03)	(2.20)	(1.02)	(1.76)	(2.39)	(8.83)	(3.78)	(7.86)	(5.17)	(9.50)	(8.16)	(12.18)
Total	(0.26)	1.39	(1.77)	(1.03)	(2.20)	(1.02)	(1.76)	(2.39)	(8.83)	(3.78)	(7.86)	(5.17)	(9.50)	(8.16)	(12.18)
2. Recognition of Prior Year Balance (Set to Start in 2013)															
Credit Member Revenue (Charge to Members)			(0.37)	(0.37)	(0.37)	1.67	1.67	1.67	1.72	1.72	1.72	6.82	6.82	6.82	7.61
Debit Power Purchase Expense			(0.37)	(0.37)	(0.37)	1.67	1.67	1.67	1.72	1.72	1.72	6.82	6.82	6.82	7.61
Net Income	0.26	(1.39)	1.77	1.03	2.20	1.02	1.76	2.39	8.83	3.78	7.86	5.17	9.50	8.16	12.18
Balance Sheet															
Assets															
Cash			(0.4)	(0.7)	(1.1)	0.5	2.2	3.9	5.6	7.3	9.1	15.9	22.7	29.5	37.1
Regulatory Asset	0.3	-	1.0	2.4	5.0	4.4	4.4	5.2	12.3	14.3	20.5	18.8	21.5	22.8	27.4
Total	0.3	-	0.6	1.7	3.9	4.9	6.7	9.1	17.9	21.7	29.5	34.7	44.2	52.4	64.5
Liabilities & Equity															
Equity	0.3	(1.1)	0.6	1.7	3.9	4.9	6.7	9.1	17.9	21.7	29.5	34.7	44.2	52.4	64.5
Regulatory Liability	-	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	0.3	-	0.6	1.7	3.9	4.9	6.7	9.1	17.9	21.7	29.5	34.7	44.2	52.4	64.5

FAC PPA Env Sur

October 2008

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	11.9	12.4	11.8	12.0	12.1	12.1	12.2	12.2	11.8	12.2	11.9	12.1	12.1	12.2	12.1
2	**Sales (TWh)**	12.3	12.7	12.3	12.4	12.6	12.6	12.6	12.7	12.6	12.7	12.6	12.7	12.8	12.8	12.9
3																
4																
5	**A. FAC**															
6	Fuel Costs ($M)	270.8	301.0	305.8	339.5	366.4	276.1	259.3	261.7	260.2	267.6	268.0	275.4	277.0	285.9	285.5
7																
8	Total Costs for Passthrough ($/ MWh Sold)	21.94	23.67	24.76	27.30	29.18	21.99	20.54	20.64	20.72	21.04	21.32	21.68	21.70	22.28	22.19
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
11	**B. PPA**															
12	Purchased Power Costs ($M)	22.55	17.35	27.57	25.20	29.18	25.26	27.61	29.57	48.30	33.44	44.44	36.86	48.75	44.80	55.28
13																
14	Total Costs for Passthrough ($/ MWh Sold)	1.83	1.36	2.23	2.03	2.32	2.01	2.19	2.33	3.85	2.63	3.54	2.90	3.82	3.49	4.30
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
17																
18	**C. Environmental Surcharge**															
19	Eligible Cost ($M)	27.00	30.76	38.88	40.35	41.08	43.74	67.70	68.06	67.34	70.95	69.42	73.61	76.01	77.42	79.85
20																
21	Total Costs for Passthrough ($/ MWh Sold)	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/M	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
24																
25																
26	**1 - FAC + Environmental Surcharge to Members**															
27	Rurals															
28	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
29	Environmental Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
30	**Total**	13.41	15.37	17.19	19.83	21.73	14.75	15.18	15.29	15.36	15.90	16.13	16.76	16.94	17.59	17.68
31	Large Industrials															
32	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
33	Environmental Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
34	**Total**	13.41	15.37	17.19	19.83	21.73	14.75	15.18	15.29	15.36	15.90	16.13	16.76	16.94	17.59	17.68
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**															
36	FAC	11.22	12.95	14.04	16.58	18.46	11.27	9.82	9.93	10.00	10.32	10.60	10.96	10.98	11.56	11.47
37	PPA	0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
38	Environmental Surcharge	2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
39	**Total**	13.48	14.99	17.67	20.10	22.30	15.01	15.62	15.87	17.45	16.77	17.91	17.91	19.00	19.33	20.22

UW Transaction

#	($M)	2008	Transaction	Lease Termination
	Unwind Allocation	-	-	0.000
	Pre-Transaction Allocation	1.000	-	-
	Transaction Index	-	1.000	-
	A. Transaction Components			
1	**1. Cash Payment/ Credit Escrow Draws**	-	387.7	-
2	**2. WKE Residual Value Obligation**			
3	**WKE Gen. Capex - Cum.**			
4	Non-Incremental (RV Obligation Balance)			
5	Beginning Balance	50.2	55.0	-
6	WKE Share of Non-Incremental Capex	7.0	-	-
7	Amortization of WKE Share	2.1	-	-
8	Net	55.0	55.0	-
9	Incremental			
10	Beginning Balance	90.9	86.3	-
11	WKE Share of Non-Incremental Capex	-	-	-
12	Amortization of WKE Share	4.6	-	-
13	Net	86.3	86.3	-
14	Total	141.4	141.4	
15	**3. LG&E Rental Income Advance**			
16	Cash Flow	47.7	-	-
17	Income Statement	52.3	-	-
18	Balance	(11.2)	(11.2)	-
19	**4. Fuel & Other Inventories**	-	51.0	-
20	**5. Cancellation of Settlement Prom. Note**	-	15.7	-
21	**6. Coleman Scrubber Completion**	-	98.5	-
22	**7. LG&E Emissions Allowance**	-	2.0	-
23	**8. Expense Unamortized Mktg Payment/ Settlement Note**		(15.1)	
24	**9. Assurances Agreement**	-	1.5	-
25				
26	**Total Residual Value Obligation**	152.6	152.6	-
27	**Cancellation of RV Obligation**			
28	Reclassification as Equity	-	152.6	-
29				
30	**Net WKE Obligation**	152.6	-	-
31				

UW Transaction

	($M)		2008	Transaction	Lease Termination
	Unwind Allocation		-	-	0.000
	Pre-Transaction Allocation		1.000	-	-
	Transaction Index		-	1.000	-
32					
33	**B. Transaction Cash Flows**				
34	Cash Balances Pre-Transaction			146.0	
35	Transaction Proceeds			387.7	
36	Lease Buyout			-	
37	Smelter Payment (Assurances Agreement)			(1.5)	
38	Consent Fee to Lease-Equity Parties			-	
39	Lump-Sum Member Rebate			-	
40	Net DSL Termination			-	
41	Century/Century Reactive Power Transaction Refund			(0.2)	
42	Income Tax			(1.3)	
43	Net Transaction Cash			384.6	
44	Debt Restructuring:				
45	Debt Reduction (Net)			(147.0)	
46	Underwriting Costs	1.75%		-	
47	Bond Insurance	0.80%		-	
48	ARVP Defeasance Premium			-	
49	Total			(147.0)	
50	Restricted Cash Balances:				
51	Transition Reserve			(35.0)	
52	Non-Smelter Member Economic Reserve			(157.0)	
53	Smelter Economic Reserve			-	
54	Unrestricted Cash Balances Post-Transaction			191.6	
55					
56	**C. Debt Restructuring:**				
57	Beginning Balance - GAAP			1,027.1	
58	Cancellation of Settlement Prom. Note			(15.7)	
59	Capitalize Accrued Interest on RUS New Note			6.9	
60	Step-Up RUS New Note to Stated Basis:				
61	GAAP RUS New Note				
62	Ending Balance			765.3	
63	Accrued Interest			6.9	
64	Total			772.2	
65	Stated RUS New Note				
66	Ending Balance			768.4	
67	Accrued Interest			6.8	
68	Total			775.2	
69	Step-Up			3.0	
70	Beginning Balance - Stated			1,021.4	
71	Cash Flow:				
72	Prepay RUS New Note			(147.0)	
73	Defease ARVP			-	
74	Issue Capital Markets Debt			-	
75	Net			(147.0)	
76	Ending Balance - Stated			874.4	
77	Step-Down Remaining RUS New Note to GAAP Basis:			(2.7)	
78	Ending Balance - GAAP			871.7	
79					

UW Transaction

	($M)		2008	Transaction	Lease Termination
	Unwind Allocation		-	-	0.000
	Pre-Transaction Allocation		1.000	-	-
	Transaction Index		-	1.000	-
80	**D. Reflection on Income Statement**				
81	1. Cash		-	387.675	-
82	2. Residual Value Payment		-	141.356	-
83	3. LG&E Rental Income Advance		-	11.222	-
84	4. Fuel Inventory & Other		-	51.040	-
85	5. Settlement Promissory Note		-	15.659	-
86	6. Coleman Scrubber		-	98.520	-
87	7. SO2 Allowances			1.960	
88	8. Expense Unamortized Mktg Payment/ Settlement Note		-	(15.068)	-
89	9. Assurances Agreement Payment			(1.525)	
90	Total		-	690.839	-
91					
92	E. Non-Patronage Allocations and Taxable Income				
93					
94	**Cash Flows**	15%	-	58.15	-
95					
96	**Income Statement**				
97	Cash	15%	-	58.15	-
98	RVP	15%	-	22.89	-
99	Fuel Inventory & Other (plus emissions allowances)	15%	-	7.95	-
100	Settlement Promissory Note	15%	-	2.35	-
101	Coleman Scrubber	15%	-	14.78	-
102	Expense Unamortized Mktg Payment/ Settlement Note	15%	-	(5.83)	-
103		15%			
104	Total		-	100.29	-
105					
106	**Taxable Income**				
107	Gain on Transaction (above)		-	100.29	-
108	Less RVP		-	(22.89)	-
109	Less M1 - Coleman Scrubber		-	(14.78)	-
110	Plus Previously Expensed Mktg. Pmt.		-	4.20	-
111	Total		-	66.82	-
112					

Production-Fixed

Production - Fixed

	($M)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	A&G															
2	Labor	10.99	10.79	11.12	11.45	11.79	12.15	12.51	12.89	13.27	13.67	14.08	14.50	14.94	15.39	15.85
3	Non-Labor	12.12	12.48	12.85	13.24	13.63	14.04	14.46	14.90	15.34	15.80	16.28	16.77	17.27	17.79	18.32
4	Intellectual Property	6.42	4.51	5.26	4.82	4.91	5.51	5.09	5.18	5.69	5.66	5.65	6.19	5.98	6.33	6.74
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	29.54	27.78	29.22	29.51	30.33	31.70	32.06	32.96	34.31	35.14	36.01	37.46	38.19	39.51	40.91
7																
8	APM, L/C, Cogen, CW & TVA Trans	6.31	6.46	5.80	5.69	5.86	6.03	6.21	6.39	6.58	6.78	6.98	7.19	7.40	7.62	7.85
9																
10	Property Insurance	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11																
12	Property Tax															
13	Baseline	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	2.86	2.94	3.54	4.11	4.23	4.36	4.49	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17																
18	Transmission O&M															
19	Baseline Labor	6.07	6.25	6.43	6.63	6.83	7.03	7.24	7.46	7.68	7.91	8.15	8.40	8.65	8.91	9.17
20	Baseline Non-Labor	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I															
22	O&M	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	8.02	8.26	8.51	8.76	9.02	9.29	9.57	9.86	10.16	10.46	10.77	11.10	11.43	11.77	12.13
28																
29	Fixed O&M															
30																
31	Labor	48.36	45.62	46.99	48.40	49.85	51.35	52.89	54.47	56.11	57.79	59.53	61.31	63.15	65.05	67.00
32																
33	Non-Labor	40.30	45.41	45.93	42.50	54.48	42.33	53.38	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34																
35	Plant Maintenance															
36	Coleman	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
37	Green	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
38	HMP&L	0.24	0.17	-	-	-	-	2.94	-	-	-	-	-	-	-	-
39	Reid	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson	0.34	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Adjust for Station 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Total (Real)	1.84	0.65	0.24	-	-	-	2.94	-	3.44	-	-	-	-	-	-
43	Total (Nominal)	2.01	0.74	0.28	-	-	-	3.83	-	4.77	-	-	-	-	-	-
44																
45	T/G Overhauls (Cash Flows)	9.17	-	10.22	12.45	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)	9.17	-	10.22	12.45	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																
48	Environmental Monitoring and Other	1.46	1.50	1.54	1.59	1.64	1.69	1.74	1.79	1.84	1.90	1.95	2.01	2.07	2.14	2.20
49																
50	08/2007 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																
52	Total Fixed O&M (to Cash Flows)	101.30	93.26	104.96	104.93	105.97	102.31	111.83	108.49	129.65	113.55	129.28	123.79	133.46	128.67	136.97
53	Total Fixed O&M (to Income Statement)	101.30	93.26	104.96	104.93	105.97	102.31	111.83	108.49	129.65	113.55	129.28	123.79	133.46	128.67	136.97

#	($M)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	18.39	10.28	5.26	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
3	Transmission Upgrades																			
4	Phase I		-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	5.40	5.30	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	5.40	5.30	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	5.56	5.62	-	-	-	-	-	-	-	-	-	-	-	-	-
9	A&G		0.86	1.25	1.29	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
11	Shared HQ Building																			
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	1.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	1.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Intellectual Property																			
17	Total			-	-	9.74	1.02	0.92	0.79	0.80	0.98	0.83	0.85	1.00	0.92	0.94	1.06	0.89	0.91	1.23
19	WKE Share of Generation Capex																			
20	(%)		51%	51%	51%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	(M$)		6.69	6.84	6.99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Generation																			
24	Baseline		-	-	-	33.10	18.29	27.20	19.58	31.34	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92
25	Adjustment for Station 2		-	-	-	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
26	Total Real		-	-	-	33.10	18.29	27.20	19.58	31.34	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92
27	Total Nominal	3.00%	13.12	13.41	13.71	36.16	20.59	31.54	23.38	38.55	32.83	33.81	34.83	35.87	36.95	38.06	39.20	40.38	41.59	42.83
29	Plant Maintenance																			
30	Coleman		-	-	-	1.14	1.11	2.37	1.05	1.02	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	0.94	1.16	2.36	3.72	3.25	2.86	0.43	0.43	0.43	0.43	1.03	1.03	0.43	0.43	0.43
33	Reid		-	-	-	1.03	-	-	-	-	-	1.40	-	-	-	-	-	-	-	-
34	Wilson		-	-	-	14.63	6.47	11.19	1.91	1.57	1.24	1.57	1.24	1.57	1.24	3.74	1.24	1.57	1.24	1.57
35	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Total Real		-	-	-	26.29	15.49	20.16	8.97	7.15	4.10	3.40	1.68	2.00	1.68	4.77	2.28	2.00	1.68	2.00
37	Total Nominal	3.00%	-	-	-	28.73	17.44	23.37	10.71	8.80	5.19	4.44	2.25	2.77	2.39	7.01	3.44	3.12	2.69	3.31
39	Environmental																			
40	NOx Removal Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	-	-	1.73	-	-	-	-	-	-	-	-	-	-	-	-
42	Clmn FGD Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	FGD ongoing upkeep capital (0.10%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Additional FGD thickener & filter drum		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	R-CT reliability study & upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Wilson super heater tubes replacment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total Real		-	-	-	-	-	1.73	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	-	-	2.00	-	-	-	-	-	-	-	-	-	-	-	-
51	BigRivers Capex																			
52	Gross Generation		13.12	13.41	13.71	36.16	20.59	31.54	23.38	38.55	32.83	33.81	34.83	35.87	36.95	38.06	39.20	40.38	41.59	42.83
53	*Less* WKE Generation Share		6.69	6.84	6.99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	BigRivers Generation		6.43	6.57	6.72	36.16	20.59	31.54	23.38	38.55	32.83	33.81	34.83	35.87	36.95	38.06	39.20	40.38	41.59	42.83
55	Transmission		5.91	9.62	18.39	10.28	5.26	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
56	Transmission Upgrades		-	4.12	-	5.56	5.62	-	-	-	-	-	-	-	-	-	-	-	-	-
57	A&G		0.86	1.25	1.29	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
58	Shared HQ Building		-	-	-	1.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Intellectual Property		-	-	-	9.74	1.02	0.92	0.79	0.80	0.98	0.83	0.85	1.00	0.92	0.94	1.06	0.89	0.91	1.23
60	Plant Maintenance		-	-	-	28.73	17.44	23.37	10.71	8.80	5.19	4.44	2.25	2.77	2.39	7.01	3.44	3.12	2.69	3.31
61	Environmental		-	-	-	-	-	2.00	-	-	-	-	-	-	-	-	-	-	-	-
62	08/2007 Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	Total		13.19	21.56	26.40	93.47	51.30	63.67	42.23	50.11	40.90	41.16	41.14	44.13	45.35	51.24	49.11	49.94	50.92	53.27

	($M)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
65																				
66																				
67	**Depreciation**																			
68																				
69	*Additional Book Depreciation*																			
70	Prior year non-incremental + in service		12.83	13.12	13.41	112.234	66.56	38.03	56.91	34.08	47.35	38.02	38.25	37.08	38.64	39.34	45.06	42.64	43.49	44.28
71	Current year non-incremental + in service		13.12	13.41	112.23	66.559	38.030	56.909	34.083	47.346	38.022	38.253	37.080	38.644	39.338	45.063	42.641	43.494	44.276	46.143
72	Average of Production		12.97	13.26	62.82															
73	Prior year Transmission and A&G					17.333	17.17	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
74	Current year Transmission and A&G					17.174	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
75	Average of Transmission and A&G		6.38	10.88	17.33															
76	Total		19.35	24.14	80.16															
77	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%															
78	Capital Depreciation Rate (excl. Environmental)					1.53%	1.53%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
79	Additional Depreciation		0.30	0.37	1.23	1.63	1.02	1.49	1.37	1.19	1.17	1.06	1.06	1.10	1.15	1.25	1.29	1.28	1.30	1.34
80																				
81	HMP&L Station Two																			
82	Prior year non-incremental		12.83	13.12	13.41	13.71	36.16	20.59	31.54	23.38	38.55	32.83	33.81	34.83	35.87	36.95	38.06	39.20	40.38	41.59
83	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%
84	Additional Depreciation		0.01	0.01	0.01	0.01	0.04	0.02	0.03	0.02	0.04	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.05
85																				
86	Environmental																			
87	Prior year environmental					-	-	-	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
88	Current year environmental					-	-	2.00	-	-	-	-	-	-	-	-	-	-	-	-
89	*Environmental Depreciation Rate*					1.53%	1.53%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
90	Additional Depreciation					-	-	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
91																				
92	Other																			
93	Prior year		6.00	6.77	14.99	19.68	17.17	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
94	Current year		6.77	10.87	19.68	17.17	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
95	Average		6.38	8.82	17.33															
96	Rate to Apply to *2007 Capital* in 08		*0.00*	*0.00*	*0.00*															
97	Capital Depreciation Rate (excl. Environmental)					0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
98	Additional Depreciation		0.02	0.03	0.05	0.11	0.09	0.05	0.04	0.03	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
99																				
100	Book Depreciation & Amortization																			
101	Generation																			
102	Big Rivers' Plants		26.89	26.17	26.414	28.077	29.100	49.24	50.66	51.91	53.13	54.24	55.36	56.51	57.71	59.01	60.36	61.69	63.04	64.44
103																				
104	Intellectual Property					0.149	0.164	0.31	0.33	0.35	0.38	0.40	0.42	0.45	0.47	0.49	0.52	0.55	0.57	0.60
105	HMP&L Station Two		0.92	0.93	0.934	0.949	0.986	1.01	1.04	1.06	1.10	1.13	1.17	1.20	1.24	1.28	1.32	1.36	1.40	1.45
106	Total Generation Depr & Amort		27.81	27.10	27.349	29.175	30.251	50.55	52.03	53.32	54.61	55.77	56.94	58.15	59.42	60.78	62.20	63.59	65.02	66.49
107	Other		5.03	5.06	5.106	5.214	5.300	5.35	5.39	5.42	5.43	5.44	5.46	5.48	5.51	5.54	5.57	5.60	5.63	5.67
108	Blended Depreciation Adj.		-	-	-	-	-	(11.27)	(11.38)	(12.65)	(13.67)	(13.24)	(12.90)	-	-	-	-	-	-	-
109	*Total*		32.84	32.15	32.45	34.389	35.551	44.64	46.04	46.09	46.36	47.97	49.50	63.63	64.93	66.32	67.77	69.19	70.65	72.16
110																				
111	Years Depreciation					56	57	46	46	47	48	47	47	37	37	37	37	37	37	37

Unwind Debt

October 2008

#	($M)		Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	1.000	2.000	3.000	4.000	5.000	6.000	7.000	8.000	9.000	10.000	11.000	12.000	13.000	14.000	15.000
1	Capital Markets (Tranche 1)																		
2	Beginning Balance		-	-	-	-	-	58.3	58.3	49.1	39.2	28.6	28.6	28.6	53.2	53.2	53.2	52.7	24.9
3	Coupon		0.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	6.50%	6.50%	6.50%	6.50%	6.50%
4	Principal (%)		0.00%	0.00%	0.00%	0.00%	-100.00%	0.00%	15.88%	16.98%	18.11%	0.00%	0.00%	-42.21%	0.00%	0.00%	0.80%	47.82%	26.89%
5	Interest		-	-	-	-	-	4.1	4.1	3.4	2.7	2.0	2.0	2.0	3.5	3.5	3.5	3.4	1.6
6	Principal		-	-	-	-	(58.3)	-	9.3	9.9	10.6	-	-	(24.6)	-	-	0.5	27.9	15.7
7	Debt Service		-		-	-	(58.3)	4.1	13.3	13.3	13.3	2.0	2.0	(22.6)	3.5	3.5	3.9	31.3	17.3
8																			
9	Capital Markets (Tranche 2)																		
10	Beginning Balance		-	-	-	-	-		-	-	-	207.0	207.0	207.0	207.0	207.0	207.0	207.0	199.0
11	Coupon		0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
12	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.88%	10.86%
13	Interest		-	-	-	-	-	-	-	-	-	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.2
14	Principal		-	-	-	-	-	-	-	-	(207.0)	-	-	-	-	-	-	8.0	22.5
15	Debt Service		-	-	-	-	-	-	-	-	(207.0)	11.6	11.6	11.6	11.6	11.6	11.6	19.7	33.7
16																			
17	RUS -- GAAP																		
18	Beginning Balance		765.3	625.5	625.5	612.5	597.7	582.2	503.1	481.0	457.6	432.9	199.5	161.3	121.0	78.3	33.0	-	-
19	Coupon		0.00%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
20	Principal (%)		0.00%	0.00%	2.12%	2.40%	2.51%	12.63%	3.56%	3.76%	3.98%	37.17%	6.08%	6.44%	6.81%	7.21%	5.33%	0.00%	0.00%
21	Interest		-	0.0	36.4	35.6	34.8	33.9	29.3	28.0	26.6	25.2	11.6	9.4	7.0	4.6	1.9	-	-
22	Mid Year Prepay Adjustment to Interes			-	-	-	-	(1.1)	-	-	-	(11.6)	-	-	-	-	0.5	-	-
23	Principal + Accrued Interest		139.8	0.0	13.0	14.8	15.5	79.1	22.1	23.4	24.8	233.4	38.1	40.4	42.7	45.3	33.0	0.0	0.0
24	Debt Service		139.8	0.0	49.4	50.4	50.3	111.9	51.4	51.4	51.4	246.9	49.7	49.7	49.8	49.8	35.4	0.0	0.0
25																			
26	Variable																		
27	Beginning Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Coupon		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	Interest+Remarketing		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33																			
34	PCB																		
35	Beginning Balance		142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
36	Coupon		0.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
37	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
38	Interest		-	0.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
39	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Debt Service		-	0.0	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
41																			
42	ARVP																		
43	Beginning Balance		104.1	104.1	104.1	110.2	116.8	123.7	131.0	138.7	146.9	155.6	164.8	174.6	184.9	195.8	207.4	219.7	232.7
44	Accretion Rate	5.9%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
45	Interest Rate		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
46	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
47	Accretion		-	0.0	6.2	6.5	6.9	7.3	7.7	8.2	8.7	9.2	9.7	10.3	10.9	11.6	12.3	13.0	13.8
48	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																			
52	Total																		
53	Beginning Balance		1,011.5	871.7	871.7	864.8	856.5	906.2	834.5	810.9	785.8	966.2	742.0	713.6	708.2	676.4	642.7	621.5	598.6
54	Accretion		-	0.0	6.2	6.5	6.9	7.3	7.7	8.2	8.7	9.2	9.7	10.3	10.9	11.6	12.3	13.0	13.8
55	Principal		139.8	0.0	13.0	14.8	(42.8)	79.1	31.3	33.3	(171.7)	233.4	38.1	15.7	42.7	45.3	33.5	35.9	38.2
56	Interest		-	0.0	43.5	42.7	41.9	44.0	40.5	38.5	36.5	34.3	32.3	30.1	29.2	26.8	24.6	22.2	19.9
57	Debt Service		139.8	0.0	56.5	57.5	(0.9)	123.1	71.8	71.8	(135.2)	267.7	70.5	45.9	72.0	72.0	58.1	58.1	58.1
58	Ending Balance		871.7	871.7	864.8	856.5	906.2	834.5	810.9	785.8	966.2	742.0	713.6	708.2	676.4	642.7	621.5	598.6	574.2
59																			

Unwind Debt

October 2008

($M)		Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation		0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		0.000	0.000	1.000	2.000	3.000	4.000	5.000	6.000	7.000	8.000	9.000	10.000	11.000	12.000	13.000	14.000	15.000
Supporting Schedules																		
Amortization of Financing Costs																		
Capital Markets (Tranche 1)																		
Straightline																		
BB						-	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6
Accretion					-	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EB					-	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6
Capital Markets (Tranche 2)																		
Net Borrowing and YTM	5.94%	-	-	-	-	-	-	-	-	(200)	12	12	12	12	12	12	20	34
BB		-	-	-	-	-	-	-	-	-	200	200	201	201	201	201	202	194
YTM		-	-	-	-	-	-	-	-	-	12	12	12	12	12	12	12	12
Principal Amort.		-	-	-	-	-	-	-	-	(200)	-	-	-	-		-	8	22
Accretion		-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0
EB			-	-		-	-	-	-	200	200	201	201	201	201	202	194	172
Variable																		
Net Borrowing and YTM	0.00%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
YTM		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Principal Amort.		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accretion		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EB		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of Financing Costs																		
Deferred debit - BOY		-	-	-	-	-	1.0	1.0	1.0	0.9	7.9	7.6	7.3	7.0	6.7	6.3	6.0	5.6
Financing Costs						1.0				7.0								
Amortization				-	-	-	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
Deferred debit - EOY		-		-	-	1.0	1.0	1.0	0.9	7.9	7.6	7.3	7.0	6.7	6.3	6.0	5.6	5.2
Interest Expense																		
Total Interest		-	0.0	43.5	42.7	41.9	44.0	40.5	38.5	36.5	34.3	32.3	30.1	29.2	26.8	24.6	22.2	19.9
ARVP Accretion		-	0.0	6.2	6.5	6.9	7.3	7.7	8.2	8.7	9.2	9.7	10.3	10.9	11.6	12.3	13.0	13.8
Capitalized Interest		-	-	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
AMBAC Amortization (PCB) A/C 165		-	0.0	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Line of Credit Fee		-	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total		-	0.0	53.1	48.9	48.4	50.9	47.9	46.4	44.8	43.1	41.7	40.1	39.8	38.0	36.5	34.8	33.3

Sale Leaseback

	($M)	2005	2006	2007	2008	se Termina	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BOY Deferred Gain	62.1	59.3	56.4	53.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Amortization (I/S)	2.9	2.9	2.9	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	EOY Deferred Gain (B/S)	59.3	56.4	53.5	50.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4																					
5																					
6	Investment - Special Deposit (B/S)	180.6	186.7	192.9	199.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Adjustment	0.5	0.7	0.7	(2.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Balance Sheet	181.2	187.4	193.7	196.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9																					
10	Liability - Long-Term Debt (B/S)	171.0	177.3	183.9	189.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11																					
12	Cash Flow (Investment and Liability)	5.7	6.0	6.2	6.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13																					
14	True Unrecognized Gain	(49.6)	(47.0)	(44.4)	(41.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
15																					
16	Sale-Leaseback Interest Income	11.7	12.1	12.5	12.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17																					
18	Sale-Leaseback Interest Expense	12.0	12.4	12.8	12.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Sale-Leaseback Gain Amortization	2.9	2.9	2.9	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Net Sale-Leaseback Expense	9.1	9.5	9.9	9.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21																					
22	Net Sale-Leaseback Income	2.6	2.6	2.6	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23																					
24	Sale-Leaseback - LeaseCo.																				
25	Defeasance Income	63.5	64.1	64.5	64.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(48.9)	(48.9)	(48.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Net	14.7	15.2	15.6	15.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Gain on Lease Buyout																				
29	BOY Deferred Gain					(16.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Amortization (I/S)					(16.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	EOY Deferred Gain (B/S)					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																					
33	Supporting Schedules																				
34	Original Gain Amortization			2.9	2.9	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Adjusted for Lease Buyout			2.9	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Applied to Gain on Lease Buyout					(16.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Income Taxes

October 2008

	($M)	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	Summary																	
2	Income Tax Expense	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
3	Income Taxes Paid	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
4	Current Provision for Deferred Income Tax	(1.3)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
5																		
6	Calculation																	
7	Offsystem Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
9	Nonpatronage Revenues	-	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
10	Nonpatronage Expenses																	
11	Nonpatronage MWH	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	Nonpatronage Expenses (Ex. Int.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	-	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
15																		
16	Transaction Impact	66.8	-	-														
17																		
18																		
19	Temporary Differences (Timing)																	
20	Depreciation:																	
21	Prorated from Pre-Transaction Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																	
25	Defeasance Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																	
28	Net	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	66.8	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
31																		
32	Regular Tax																	
33	Regular NOLs Used	66.8	0.0	1.4	1.5	1.5	1.6	-	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
37	Tax	-	-	-	-	-	-	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
38																		
39	AMT																	
40	ACE Adjustment	-	(0.0)	(0.9)	(0.9)	(0.6)	(0.4)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
41	Taxable Income	66.8	0.0	0.5	0.6	0.9	1.1	1.3	1.4	1.7	1.8	1.9	2.0	2.1	2.1	2.2	2.3	2.4
42	AMT NOLs Used	60.1	0.0	0.5	0.5	0.8	1.0	1.1	-	-	-	-	-	-	-	-	-	-
43	Net Taxable Income	6.7	0.0	0.1	0.1	0.1	0.1	0.1	1.4	1.7	1.8	1.9	2.0	2.1	2.1	2.2	2.3	2.4
44	TMT	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
46	Net AMT	1.3	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																	
48	BB	5.3	6.7	6.7	6.7	6.7	6.7	6.7	6.2	5.9	5.6	5.3	5.0	4.7	4.4	4.1	3.7	3.4
49	Additions	1.3	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
51	EB	6.7	6.7	6.7	6.7	6.7	6.7	6.2	5.9	5.6	5.3	5.0	4.7	4.4	4.1	3.7	3.4	3.0
52																		
53	Total Tax	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
54																		
55	Est. Book Tax	-	-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8

	($M)	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
56																		
57	Capex Not Reflected in Pre-Transaction Tax Calculation																	
58																		
59	WKE Share																	
60	Non-Incremental			0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
61	Incremental			0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
62	Capex Amounts																	
63	Non-Incremental			18.4	10.5	18.8	15.5	25.5	21.7	22.4	23.0	23.7	24.4	25.2	25.9	26.7	27.5	28.3
64	Incremental Generation																	
65	WKE Total			18.4	10.5	18.8	15.5	25.5	21.7	22.4	23.0	23.7	24.4	25.2	25.9	26.7	27.5	28.3
66	Plant Maintenance			28.7	17.4	23.4	10.7	8.8	5.2	4.4	2.3	2.8	2.4	7.0	3.4	3.1	2.7	3.3
67	Environmental			-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-
68	Transmission Upgrades			5.6	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Shared HQ Building			1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Intellectual Property			9.7	1.0	0.9	0.8	0.8	1.0	0.8	0.8	1.0	0.9	0.9	1.1	0.9	0.9	1.2
71	8/07 Adjustment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Total			64.1	34.6	45.1	26.9	35.1	27.9	27.6	26.1	27.5	27.7	33.1	30.4	30.7	31.1	32.9
73																		
74	Cumulative Balance			64.1	98.7	143.9	170.8	205.9	233.8	261.4	287.5	315.0	342.7	375.8	406.2	436.9	468.0	500.9
75																		
76	Book Depreciation			1.1	1.7	3.1	3.7	4.4	4.9	5.5	6.2	8.5	9.3	10.2	11.0	11.9	12.8	13.7
77																		
78	Tax Depreciation @ 20 Years			3.2	4.9	7.2	8.5	10.3	11.7	13.1	14.4	15.7	17.1	18.8	20.3	21.8	23.4	25.0
79																		
80	Timing Difference (Tax Deduction)			(2.1)	(3.2)	(4.1)	(4.8)	(5.9)	(6.8)	(7.5)	(8.2)	(7.2)	(7.8)	(8.6)	(9.3)	(10.0)	(10.6)	(11.4)

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	(5,694,777)	(1,488,056)	0	0
1984	22,448,681	0	(11,951,703)	(10,496,978)	0	0
1985	67,286,392	0	(67,286,392)	0	0	0
1986	56,198,468	0	(56,198,468)	0	0	0
1987	75,567,924	0	(75,567,924)	0	0	0
1988	44,315,156	0	(44,315,156)	0	0	0
1989	22,819,745	0	(22,819,745)	0	0	0
1990	36,952,270	0	(34,627,493)	(2,324,777)	0	0
1991	29,446,433	0	(20,568,120)	(8,878,313)	0	0
1992	14,648,800	0	(14,648,800)	0	0	0
1993	30,220,578	0	(30,220,578)	0	0	0
1994	36,390,275	0	(36,390,275)	0	0	0
1995	43,631,999	0	(43,631,999)	0	0	0
1996	12,713,387	0	(6,225,540)	(6,487,847)	0	0
1997	29,946,372	0	(1,574,810)	(28,371,562)	0	0
1998	(5,694,777)	5,694,777	0	0	0	0
1999	(11,951,703)	11,951,703	0	0	0	0
2000	(211,273,153)	211,273,153	0	0	0	0
2001	(20,133,776)	20,133,776	0	0	0	0
2002	(18,036,546)	18,036,546	0	0	0	0
2003	(17,437,192)	17,437,192	0	0	0	0
2004	(14,433,689)	14,433,689	0	0	0	0
2005	(19,500,822)	19,500,822	0	0	0	0
2006	(20,568,120)	20,568,120	0	0	0	0
2007	(42,500,882)	42,500,882	0	0	0	0
2008	(17,426,731)	17,426,731	0	0	0	0
Transaction	(66,819,339)	66,819,339	0	0	0	0
	(0)	0	0	0	0	0
2009	(1,400,000)	1,400,000	0	0	0	0
2010	(1,456,000)	1,456,000	0	0	0	0
2011	(1,514,240)	1,514,240	0	0	0	0
2012	(1,574,810)	1,574,810	0	0	0	0
2013	(1,637,802)	0	0	0	0	0
2014	(1,703,314)	0	0	0	0	0
2015	(1,771,447)	0	0	0	0	0
2016	(1,842,304)	0	0	0	0	0
2017	(1,915,997)	0	0	0	0	0
2018	(1,992,637)	0	0	0	0	0
2019	(2,072,342)	0	0	0	0	0
2020	(2,155,236)	0	0	0	0	0
2021	(2,241,445)	0	0	0	0	0
2022	(2,331,103)	0	0	0	0	0
2023	(2,424,347)	0	0	0	0	0
Total Carryforward to 2024	35,959,561	471,721,779	(471,721,779)	(58,047,534)	0	0
				222,668,370		

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	280,715,904	249,053,409	(249,053,409)	(11,985,034)	268,730,870	268,730,870
Total Carryforward to 2003	262,679,358	267,089,955	(267,089,955)	(11,985,034)	250,694,324	250,694,324
Total Carryforward to 2004	245,242,166	284,527,147	(284,527,147)	(11,985,034)	233,257,132	233,257,132
Total Carryforward to 2005	230,808,477	298,960,836	(298,960,836)	(11,985,034)	218,823,443	218,823,443
Total Carryforward to 2006	211,307,655	318,461,658	(318,461,658)	(14,309,811)	196,997,844	196,997,844
Total Carryforward to 2007	190,739,535	339,029,778	(339,029,778)	(23,188,124)	167,551,411	167,551,411
Total Carryforward to H1 2008	148,238,653	381,530,660	(381,530,660)	(23,188,124)	125,050,529	125,050,529
Total Carryforward to Transactio	130,811,923	398,957,390	(398,957,390)	(23,188,124)	107,623,799	107,623,799
Total Carryforward to H2 2008	63,992,583	465,776,730	(465,776,730)	(23,188,124)	40,804,459	40,804,459
Total Carryforward to 2009	63,992,583	465,776,730	(465,776,730)	(23,188,124)	40,804,459	40,804,459
Total Carryforward to 2010	62,592,583	467,176,730	(467,176,730)	(23,188,124)	39,404,459	39,404,459
Total Carryforward to 2011	61,136,583	468,632,730	(468,632,730)	(23,188,124)	37,948,459	37,948,459
Total Carryforward to 2012	59,622,343	470,146,970	(470,146,970)	(29,675,971)	29,946,372	29,946,372
Total Carryforward to 2013	58,047,534	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2014	56,409,732	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2015	54,706,418	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2016	52,934,971	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2017	51,092,667	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2018	49,176,670	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2019	47,184,033	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2020	45,111,691	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2021	42,956,456	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2022	40,715,011	471,721,779	(471,721,779)	(58,047,534)	0	0
Total Carryforward to 2023	38,383,908	471,721,779	(471,721,779)	(58,047,534)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	0	0	(7,182,833)	0	0
1984	22,448,681	0	0	0	(22,448,681)	0	0
1985	67,286,392	0	0	(67,286,392)	0	0	0
1986	56,198,468	0	0	(56,198,468)	0	0	0
1987	74,385,162	0	0	(62,522,466)	(11,862,696)	0	0
1988	44,314,663	0	0	(14,775,845)	(29,538,819)	0	0
1989	20,107,778	0	0	(12,087,111)	(8,020,667)	0	0
1990	29,346,400	0	0	(16,651,074)	(12,695,326)	0	0
1991	22,667,781	0	0	(17,624,779)	(5,043,002)	0	0
1992	9,553,735	0	0	(9,553,735)	0	0	0
1993	21,693,629	0	0	(21,693,629)	0	0	0
1994	27,573,481	0	0	(27,573,481)	0	0	0
1995	34,018,244	0	0	(34,018,244)	0	0	0
1996	9,443,662	0	0	(9,443,662)	0	0	0
1997	32,657,152	0	0	(12,967,339)	(19,689,813)	0	0
1998	44,897	0	0	(44,897)	0	0	0
1999	8,082,161	0	0	(1,088,527)	(6,993,634)	0	0
2000	(165,931,656)	149,338,490	(16,593,166)	0	0	0	0
2001	(19,634,252)	19,634,252	0	0	0	0	0
2002	(17,034,584)	17,034,584	0	0	0	0	0
2003	(16,417,605)	14,775,845	(1,641,761)	0	0	0	0
2004	(13,430,123)	12,087,111	(1,343,012)	0	0	0	0
2005	(18,501,193)	16,651,074	(1,850,119)	0	0	0	0
2006	(19,583,088)	17,624,779	(1,958,309)	0	0	0	0
2007	(41,583,419)	37,425,077	(4,158,342)	0	0	0	0
2008	(16,509,268)	14,858,341	(1,650,927)	0	0	0	0
Transaction	(66,819,339)	60,137,405	(6,681,934)	0	0	0	0
	(0)	0	(0)	0	0	0	0
2009	(506,119)	455,507	(50,612)	0	0	0	0
2010	(579,898)	521,908	(57,990)	0	0	0	0
2011	(914,296)	822,866	(91,430)	0	0	0	0
2012	(1,143,318)	1,028,986	(114,332)	0	0	0	0
2013	(1,259,361)	1,133,424	(125,936)	0	0	0	0
2014	(1,441,534)	0	(1,441,534)	0	0	0	0
2015	(1,673,867)	0	(1,673,867)	0	0	0	0
2016	(1,818,705)	0	(1,818,705)	0	0	0	0
2017	(1,910,473)	0	(1,910,473)	0	0	0	0
2018	(1,987,258)	0	(1,987,258)	0	0	0	0
2019	(2,067,109)	0	(2,067,109)	0	0	0	0
2020	(2,149,688)	0	(2,149,688)	0	0	0	0
2021	(2,236,063)	0	(2,236,063)	0	0	0	0
2022	(2,325,886)	0	(2,325,886)	0	0	0	0
2023	(2,419,295)	0	(2,419,295)	0	0	0	0

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ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2024	67,127,724	363,529,649	(56,347,746)	(363,529,649)	(123,475,470)	0	0

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	301,439,211	168,972,742	(16,593,166)	(168,972,742)	(29,631,514)	288,400,863	288,400,863
Total Carryforward to 2003	284,404,627	186,007,326	(16,593,166)	(186,007,326)	(41,494,210)	259,503,583	259,503,583
Total Carryforward to 2004	267,987,022	200,783,171	(18,234,926)	(200,783,171)	(71,033,028)	215,188,920	215,188,920
Total Carryforward to 2005	254,556,899	212,870,282	(19,577,938)	(212,870,282)	(79,053,695)	195,081,142	195,081,142
Total Carryforward to 2006	236,055,706	229,521,355	(21,428,058)	(229,521,355)	(91,749,022)	165,734,742	165,734,742
Total Carryforward to 2007	216,472,618	247,146,135	(23,386,367)	(247,146,135)	(96,792,024)	143,066,961	143,066,961
Total Carryforward to 2008	174,889,199	284,571,211	(27,544,708)	(284,571,211)	(96,792,024)	105,641,884	105,641,884
Total Carryforward to Transacti	158,379,931	299,429,552	(29,195,635)	(299,429,552)	(96,792,024)	90,783,543	90,783,543
	158,379,931	359,566,958	(35,877,569)	(359,566,958)	(96,792,024)	97,465,477	97,465,477
Total Carryforward to 2009	91,560,592	359,566,958	(35,877,569)	(359,566,958)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	91,054,474	360,022,464	(35,928,181)	(360,022,464)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	90,474,576	360,544,373	(35,986,171)	(360,544,373)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2012	89,560,280	361,367,239	(36,077,600)	(361,367,239)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2013	88,416,962	362,396,225	(36,191,932)	(362,396,225)	(116,481,836)	FALSE	FALSE
Total Carryforward to 2014	87,157,602	363,529,649	(36,317,868)	(363,529,649)	(116,481,836)	FALSE	FALSE
Total Carryforward to 2015	85,716,067	363,529,649	(37,759,403)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2016	84,042,200	363,529,649	(39,433,270)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2017	82,223,496	363,529,649	(41,251,974)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2018	80,313,022	363,529,649	(43,162,448)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2019	78,325,764	363,529,649	(45,149,706)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2020	76,258,656	363,529,649	(47,216,814)	(363,529,649)	(123,475,470)	FALSE	FALSE
Total Carryforward to 2021	74,108,967	363,529,649	(49,366,503)	(363,529,649)	(123,475,470)	0	0
Total Carryforward to 2022	71,872,905	363,529,649	(51,602,565)	(363,529,649)	(123,475,470)	0	0
Total Carryforward to 2023	69,547,019	363,529,649	(53,928,451)	(363,529,649)	(123,475,470)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

** For years ended December 31, 2001 and December 31, 2002, the Job Creation and Worker Assistance Act of 2002 allowed 100% of the AMTI to be offset with NOL carryforwards.

	Electricity Sales, Purchases, and Production	Source:	005/ Othe	2006	2007	2008	Transactions Termin ########	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Sales																					
2	Rural																					
3	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls and file: Annu		2.232	2.406	2.396	0.000	2.438	2.487	2.543	2.595	2.651	2.704	2.763	2.819	2.879	2.935	2.997	3.059	3.120	3.180	3.242
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	63.26%	62.51%	60.17%	60.02%	60.12%	60.21%	60.15%	60.40%	60.49%	60.57%	60.51%	60.74%	60.82%	60.89%	60.83%	61.04%	61.11%	61.17%
5	MW			413	434	437	0	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
6	Large Industrial																					
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5MW/year i		0.957	0.921	0.953	0.000	1.063	1.097	1.131	1.165	1.200	1.235	1.269	1.303	1.338	1.373	1.407	1.440	1.476	1.510	1.545
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	76.45%	77.71%	78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
9	MW			140	138	140	0	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																					
11	TWH	Smelter Retail Agreement, Section 1.1.17			0	0	0.000	3.159	3.159	3.159	3.168	3.159	3.159	3.159	3.168	3.159	3.159	3.159	3.168	3.159	3.159	3.159
12	LF	Smelter Retail Agreement, Section 1.1.17			98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15					368	368	368	368	368	368	368	368	368	368	368	368	368	368	368	368
14	Century																					
15	TWH	Smelter Retail Agreement, Section 1.1.16					0.000	4.138	4.138	4.138	4.149	4.138	4.138	4.138	4.149	4.138	4.138	4.138	4.149	4.138	4.138	4.138
16	LF	Smelter Retail Agreement, Section 1.1.16			98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
17	MW	Smelter Retail Agreement, Section 1.1.14					482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482
18																						
19	Offsystem (TWh)	file: Annual Output - 9-8-08 - BREC Update.xls		2.06	2.64	1.66		1.55	1.83	1.38	1.36	1.41	1.32	1.29	1.24	1.05	1.12	0.87	0.89	0.87	0.85	0.78
20																						
21	Purchases & Production																					
22	Purchases (TWh)																					
23	Market	file: Annual Output - 9-8-08 - BREC Update.xls		0.07	0.02	0.01	0.00	0.24	0.16	0.31	0.22	0.30	0.26	0.30	0.32	0.62	0.40	0.54	0.42	0.53	0.49	0.61
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10	0.00	0.30	0.31	0.30	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
25	Production (TWh)	file: Annual Output - 9-8-08 - BREC Update.xls					(0.00)	11.90	12.35	11.84	12.02	12.10	12.14	12.17	12.20	11.79	12.17	11.88	12.13	12.09	12.20	12.11
26	Loss Rate (%)	file: Annual Output - 9-8-08 - BREC Update.xls			0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
27																						
28	Fuel Consumption (Millions of MMBtu)	file: Annual Output - 9-8-08 - BREC Update.xls					0.0	132.9	137.2	131.9	133.5	133.6	134.1	134.4	134.7	130.3	134.4	131.2	134.1	133.5	134.7	133.8
29																						
30	Startup Costs (M$)	file: Annual Output - 9-8-08 - BREC Update.xls						11.46	11.89	11.74	10.64	10.39	11.00	10.23	10.81	13.05	11.43	13.62	12.55	12.50	14.15	13.39
31	Kentucky Coal Tax Credit ($M)							0	1.4	0.7	0	0	0	0	0	0	0	0	0	0	0	0
32	Emissions																					
33	SO2																					
34	Emitted (Tons)	file: Annual Output - 9-8-08 - BREC Update.xls						19,145	20,453	19,301	19,812	19,341	19,855	20,836	21,282	19,910	21,199	20,456	19,823	20,812	21,263	20,716
35	Allocation (Tons)	file: Annual Output - 9-8-08 - BREC Update.xls						48,979	48,979	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	18,352	17,125	18,352	18,352	18,352
36	NOX																					
37	Emitted (Tons)	file: Annual Output - 9-8-08 - BREC Update.xls						5,141	5,105	13,489	13,371	13,531	13,340	13,579	13,378	13,303	13,413	13,214	13,553	13,445	13,365	13,558
38	Allocation (Tons)	file: Annual Output - 9-8-08 - BREC Update.xls						4,652	4,652	11,068	11,057	11,057	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)																					
40																						
41	Rates																					
42	Fuel ($/ MMBtu)	file: Annual Output - 9-8-08 - BREC Update.xls					1.96	1.95	2.15	2.25	2.50	2.69	1.85	1.85	1.87	1.90	1.91	1.94	1.96	1.98	2.02	2.04
43	Power Purchases ($/ MWh)																					
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44	22.44	22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
45	Market	file: Annual Output - 9-8-08 - BREC Update.xls		67.8347	77.90	200.00	65.53	65.53	66.17	67.28	74.14	71.54	65.38	65.42	66.75	64.85	63.37	67.39	67.48	76.46	74.47	76.94
46	Variable Production ($/ MWh sales)	file: Annual Output - 9-8-08 - BREC Update.xls				2.59	2.59	2.59	2.73	3.23	3.32	3.38	3.44	4.22	4.34	4.48	4.54	4.65	4.79	4.99	5.03	5.23
47	SO2 Allowances ($/ Ton)	file: Annual Output - 9-8-08 - BREC Update.xls				140	140	140	115	868	878	875	850	842	825	757	706	561	413	350	302	279
48	NOX Allowances ($/ Ton)	file: Annual Output - 9-8-08 - BREC Update.xls				700	700	700	650	2,120	1,951	1,909	2,570	3,071	2,863	2,764	2,665	2,564	2,574	2,578	2,581	2,584
49																						
50	Coal used (ktons)	file: Annual Output - 9-8-08 - BREC Update.xls	100%				0	6,041	6,219	5,967	6,046	6,058	6,063	6,097	6,100	5,910	6,095	5,938	6,078	6,058	6,083	6,065
51																						
52	**Sales Rates & Related**																					
53																						
54	General Rate Adjustments (%)	Stipulated Inputs (subject to Commission Approval at time)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	9.74%	0.00%	0.00%	0.00%	0.00%	0.00%	0.31%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	0	0																		
56	Market ($/ MWh)	file: Annual Output - 9-8-08 - BREC Update.xls		40.45	52.68	48.74	60.94	60.94	59.20	63.59	66.81	70.55	62.13	63.43	63.52	64.53	66.02	68.95	67.21	67.69	69.01	69.79
57																						
58	Rural																					
59	Demand ($/ KW-mo.)	Current Member Tariff		7.37 Escalated by GRAs																		
60	Energy ($/ MWh)	Current Member Tariff		20.4 Escalated by GRAs			0															
61																						
62	Large Industrial																					
63	Demand ($/ KW-mo.)	Current Member Tariff		10.15 Escalated by GRAs																		
64	Energy ($/ MWh)	Current Member Tariff		13.715 Escalated by GRAs			0															
65																						
66	Smelters																					
67	Margin ($/ MWh)	Smelter Retail Agreements, Section 1.1.20 (Alcan) and 1.1.19 (Century)					0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	Annual Revenue Guarantee ($/ MWh)	Smelter Retail Agreements, Section 4.7 (see formula in Smelter Rate Structure, lines 99 - 127)					(0.25)			1.79	2.25	1.59	1.64	2.78	2.59	3.55	0.54	3.67	2.97	4.30	3.53	4.75
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)					5.11	5.11	5.11	5.11	7.30	7.30	7.30	7.30	7.30	10.18	10.18	10.18	10.18	10.18	10.18	10.18
70	Surcharge 2 ($/MWh)	Smelter Retail Agreements, Sections 4.11 (b) and (c)	0				0.60	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15					0.00	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
72	Surcharge 2 (M$)	line 70 * line 71					0.00	6.36	6.36	6.36	6.38	6.36	6.36	6.36	6.38	8.76	8.76	8.76	8.78	8.76	8.76	8.76
73																						
74	Member Revenue Discount Adjustment (M$)	Amortization of Gain on Year 2000 Sale-Leaseback ransa	E	3.68	3.68000	3.68000																
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.75	0.75	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	Big Rivers Assumption		0.19	0.07																	
77																						
78	TIER Rebate Related to Rurals ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below						0.24	4.46													
79	TIER Rebate Related to Large Industrials ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on $						0.09	1.74													
80	TIER Rebate Related to Smelters ($M)	Smelter Retail Agreements, Section 4.9 (energy basis allocation)						0.70	12.63													
81	FAC Base, 12/2004 ($/ MWh Sold)																					
82	W/o Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY_ADJ_6mo-12-(	10.72																			
83	W/ Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY_ADJ_6mo-12-(	12.47																			
84	Allocation of Revenues on '																					
85	Total																					
86	NOx + SO3	file: Annual Output - 9-8-08 - BREC Update.xls																				
87	VOM	file: Annual Output - 9-8-08 - BREC Update.xls					0.00	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
88	Allowances	file: Annual Output - 9-8-08 - BREC Update.xls						0.34	0.29	5.13	4.51	4.72	5.87	14.23	12.70	13.30	13.63	12.98	14.43	14.78	15.16	15.86
89	SO2	file: Annual Output - 9-8-08 - BREC Update.xls																				

		Source:	2005/ Other	2006	2007	2008	Transactions	Termin	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	file: Annual Output - 9-8-08 - BREC Update.xls						(0.00)	27.54	30.00	34.69	36.14	37.24	37.71	47.28	48.57	48.85	50.68	50.77	53.35	55.51	56.21	58.27
91	Net Allowances	file: Annual Output - 9-8-08 - BREC Update.xls							(4.18)	(3.28)	(4.50)	(4.11)	(4.50)	(3.94)	2.09	2.42	1.18	2.01	1.18	1.11	0.86	0.88	0.66
92	Total	file: Annual Output - 9-8-08 - BREC Update.xls						0.00	27.00	30.76	38.88	40.35	41.08	43.74	67.70	68.06	67.34	70.95	69.42	73.61	76.01	77.42	79.85
93	**Allowed in ES**																						
94	NOx + SO3	file: Annual Output - 9-8-08 - BREC Update.xls																					
95	VOM	file: Annual Output - 9-8-08 - BREC Update.xls						0.00	3.30	3.74	3.56	3.60	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
96	Allowances	file: Annual Output - 9-8-08 - BREC Update.xls							0.34	0.29	5.13	4.51	4.72	5.87	14.23	12.70	13.30	13.63	12.98	14.43	14.78	15.16	15.86
97	SO2	file: Annual Output - 9-8-08 - BREC Update.xls																					
98	VOM in Excess of 2009	file: Annual Output - 9-8-08 - BREC Update.xls						(0.00)	27.54	30.00	34.69	36.14	37.24	37.71	47.28	48.57	48.85	50.68	50.77	53.35	55.51	56.21	58.27
99	Net Allowance Costs in Excess of 2009	file: Annual Output - 9-8-08 - BREC Update.xls							(4.18)	(3.28)	(4.50)	(4.11)	(4.50)	(3.94)	2.09	2.42	1.18	2.01	1.18	1.11	0.86	0.88	0.66
100	Total	file: Annual Output - 9-8-08 - BREC Update.xls						0.00	27.00	30.76	38.88	40.35	41.08	43.74	67.70	68.06	67.34	70.95	69.42	73.61	76.01	77.42	79.85
101																							
102	Smelter Rate Structure																						
103	Bandwidth	Smelter Retail Agreements, Section 4.7.1						2.20	2.20	2.20	2.20	3.20	3.20	3.20	3.80	3.80	3.80	4.40	4.40	4.40	5.00	5.00	5.00
104																							
105																							
106	**Financing**																						
107																							
108	Principal Schedules																						
109	Capital Markets Tranche 1	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	-100.00%	0.00%	15.88%	16.98%	18.11%	0.00%	0.00%	-42.21%	0.00%	0.00%	0.80%	47.82%	26.89%
110	Capital Markets Tranche 2	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.88%	10.86%
111	RUS	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	2.12%	2.40%	2.51%	12.63%	3.56%	3.76%	3.98%	37.17%	6.08%	6.44%	6.81%	7.21%	5.33%	0.00%	0.00%
112	Variable	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
113	PCB (Swapped to Fixed)	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
114	ARVP	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
115																							
116	Rates																						
117	Capital Markets Tranche 1	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	6.50%	6.50%	6.50%	6.50%	6.50%
118	Capital Markets Tranche 2	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
119	RUS -- Stated	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
120	Variable	NA						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
121	PCB (Swapped to Fixed/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
122	ARVP (Accretion/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls	0.05914					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
123	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
124																							
125	Beginning Balances (M$)																						
126	Capital Markets Tranche 1	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances									58.3												
127	Capital Markets Tranche 2	Modeled to accommodate PMCC buyout, RUS max outstandings and cash balances													207.0								
128	Variable	NA																					
129	PCB	Long Term Debt Schedule - Historical from July 1998 - Actual 2007 - Budget 2008.xls + Modeling for					142																
130	ARVP	Long Term Debt Schedule - Historical from July 1998 - Actual 2007 - Budget 2008.xls + N				249.89	104																
131	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls					626																
132	Remarketing on Variable	NA	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman Sachs verbal guidance.	1.75%																				
136	Bond Insurance	Goldman Sachs verbal guidance.	0.80%																				
137																							
138	Capitalized Interest	Big Rivers' estimate		(0.24)	(0.39)	(0.51)			(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)
139	Deferred Debit - PCB Refunding A/C 181																						
140	Beginning Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.90	0.84	0.79	0.74	0.74	0.74														
141	Amortization	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.05	0.05	0.05		0.00	0.74														
142	Ending Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.84	0.790	0.737	0.737	0.74															
143	AMBAC Amortization (PCB) A/C 165																						
144	Amortization	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.42	0.42	0.42		0.00	3.85														
145	Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		4.69	4.27	3.85	3.85	3.85															
146	Settlement Note/Marketing Payment																						
147	Amortization	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		1.00	1.00	1.00		0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
148	Ending Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		17.08	16.07	15.07	15.07	15.07	14.06	13.06	12.06	11.05	10.05	9.04	8.04	7.04	6.03	5.03	4.02	3.02	2.02	1.01	
149	Green River Coal Settlement Ending Balance			0.09	0.05	0.00	0.00	0.00															
150	Other			(0.21)																			
151	Line of Credit	Big Rivers' estimate	0.50%	100.00																			
152	Prepayment on Transaction Date	Modeled to achieve target cash balances					147.00																
153	Pre-Transaction Debt Service																						
154	Principal	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		26.43	13.30	41.79																	
155	Interest (Cash Flow)	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		36.93	36.866	51.493																	
156	Interest (Income Statement)	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		60.72	60.90	59.91																	
157	Amortization of RUS/PCB Account	Straightline amortization of RUS and PCB restructuring costs					0.34	0.34	7.13	6.73	6.32	5.92	5.51	5.11	4.70	4.30	3.89	3.49	3.08	2.68	2.27	1.89	1.51
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		812.23	803.60	807.56	768.39	628.18	628.18	614.89	599.80	584.02	504.66	482.33	458.70	433.69	200.18	161.98	121.56	78.78	33.50	0.00	0.00
161	Base Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		54.48	42.69	84.83																	
162	Interest Expense	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		45.88	46.80	45.14		0.00	36.12	35.36	34.49	32.50	29.02	27.73	26.38	13.44	11.51	9.31	6.99	4.53	1.93	0.00	0.00
163	Interest Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		31.57	31.14	45.67		0.00	36.12	35.36	34.49	32.50	29.02	27.73	26.38	13.44	11.51	9.31	6.99	4.53	1.93	0.00	0.00
164	Accrued Interest	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		7.16	7.32	6.79	6.79																
165	Principal Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		22.91	11.54	39.17			13.29	15.09	15.78	79.36	22.33	23.62	25.01	233.51	38.20	40.43	42.78	45.29	33.50		
166	Ending Principal	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		803.60	807.56	768.39	768.39	628.18	614.89	599.80	584.02	504.66	482.33	458.70	433.69	200.18	161.98	121.56	78.78	33.50	0.00	0.00	0.00
167	Orig Scheduled Principal Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		938.60	912.60	878.61	878.61																
169																							
170	New RUS Promissory Note (GAAP)																						
171	Beginning Principal - RUS New Note	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		815.30	807.04	811.51	772.18	772.18															
172	Interest Expense	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		46.21	47.16	45.50		0.00															
173	Interest Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		32.29	31.24	46.03		0.00															
174	Accrued Interest	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		7.25	7.41	6.88	6.88	6.89															
175	Principal Payment	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		22.19	11.45	38.80		0.00															
176	Principal Balance	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		799.79	804.10	765.30	765.30	765.29															
177	Imputed Interest	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.00	0.00			0.00															
178																							
179	**Receipts (M$)**																						
180																							

#	Item	Source:	2005/ Othe	2006	2007	2008	Transactions	Termin	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.89	50.82	47.75																	
182	Transmission	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.95	6.29	5.12																	
183	Smelter - Tier 3 Transmission (Cash Flow)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.70	1.72	1.72		1.20	1.74	1.74	4.42	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
184	Smelter - Tier 3 Transmission (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.78	1.80	1.80		1.22	1.82	1.82	4.45	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
185	Proceeds of Unwind Transaction (LG&E Payment)	Termination Agreement					387.68																
186	Cobank Patronage Capital & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.57	0.58	0.58	(0.20)					0.70	1.56	1.46									
187	Interest Earnings	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		3.73	6.83	5.03																	
188	Net Conforming Receipts	Big Rivers' estimate																					
189	Cobank Patronage Capital - Balance Sheet	Historic results and adapted from 2007 Budget-REVISED	2.19	2.59	2.98	3.38	3.38	3.38	3.72	3.72	3.72	3.02	1.46										
190	Lease Related & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.04	5.34	5.58																	
191	Cobank Patronage Capital (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.96	0.98	0.96		0.00	0.34														
192																							
193																							
194	**Fixed Production (M$)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls	2008 Fact	0.0%				0.00	36.88	40.34	39.62	35.59	44.30	33.41	40.91	33.85	34.05	37.77	37.00	36.07	38.78	33.06	41.00
198	Labor (Nominal)	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls							48.36	45.62	46.99	48.40	49.85	51.35	52.89	54.47	56.11	57.79	59.53	61.31	63.15	65.05	67.00
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.58	0.24	0.24												
201	Green	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.34	0.24							2.58						
202	HMP&L	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.24	0.17					2.94								
203	Reid	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.34								0.87						
204	Wilson	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0					0.34														
205	Adjust for Station 2	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0																			
206	Fixed Environmental O&M, Clear Skies (Real Basis)																						
207	NOx ongoing	file: Fin Model inputs BREC Aug-08 net City rev 2.xls		0																			
208				0																			
209	Non-Production			0																			
210	Production			0																			
211	Transition			0																			
212	O&M (includes Consultants)			0																			
213	Outsource to LG&E for 2006			0																			
214	Adjustment (8/2007)			0.3																			
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls						0.00	9.17		10.22	12.45		6.95		6.74	19.80		13.46	5.91	7.82	8.44	
217	T/G Overhauls (Income Statement)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls						0.00	9.17		10.22	12.45		6.95		6.74	19.80		13.46	5.91	7.82	8.44	
218																							
219	Environmental Monitoring and Other		0																				
220	WKE "incremental" items moved to O&M								1.46	1.50	1.54	1.59	1.64	1.69	1.74	1.79	1.84	1.90	1.95	2.01	2.07	2.14	2.20
221	W-1 stack repair	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
223	SCR catalyst replacement	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combined	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls		6.59	7.07	7.43		0.00	6.07	6.25	6.43	6.63	6.83	7.03	7.24	7.46	7.68	7.91	8.15	8.40	8.65	8.91	9.17
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K							1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
227	Upgrades, Phase I (Real Basis)																						
228	O&M	Historic results and adapted from 2007 Budget-REVISED-MARCH 2						0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
229	Property Tax	Historic results and adapted from 2007 Budget-REVISED-MARCH 2						0.00	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
230	Property Ins.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2						0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
231																							
232	A&G																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls							10.99	10.79	11.12	11.45	11.79	12.15	12.51	12.89	13.27	13.67	14.08	14.50	14.94	15.39	15.85
234	Non-Labor	2004 actual escalated @ 3%						0.00	12.12	12.48	12.85	13.24	13.63	14.04	14.46	14.90	15.34	15.80	16.28	16.77	17.27	17.79	18.32
235	Intellectual Property (Nominal Basis)	Unwind spreadsheet -- 6-29-07_Rev1.xls							6.42	4.51	5.26	4.82	4.91	5.51	5.09	5.18	5.69	5.66	5.65	6.19	5.98	6.33	6.74
236	Intellectual Property Contingency																						
237	Total			13.81	15.62	17.16		0.00	29.54	27.78	29.22	29.51	30.33	31.70	32.06	32.96	34.31	35.14	36.01	37.46	38.19	39.51	40.91
238																							
239	APM, L/C, Cogen, CW & TVA Trans	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		4.66	8.78	5.94		0.00	6.31	6.46	5.80	5.69	5.86	6.03	6.21	6.39	6.58	6.78	6.98	7.19	7.40	7.62	7.85
240																							
241	Property Insurance	2004 actual escalated @ 3%		0.40	0.36	0.35		0.00	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.96	6.13
242			2244.57																				
243	Property Tax			3.94	3.94	3.86																	
244	Baseline	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.10	1.08	1.11		0.00	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
245	Transmission -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.74	0.77	0.75		0.00	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
246	General Plant -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.11	0.04		0.00	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
247																							
248																							
249	**Capital Expenditures**																						
250																							
251	Generation			13.12	13.41	13.71																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls	08 Factor:	0.00					33.10	18.29	27.20	19.58	31.34	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92	25.92
253	Adjustment for Station 2 (Real Basis 2006)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls						0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
254																							
255	Gross Incremental																						
256																							
257	Transmission (Nominal)	Per Crockett Memo dated 11/12/07		5.91	9.62	18.39			10.28	5.26	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
258																							
259	A&G (Nominal)	$1.25M 2007 escalated @ 3%		0.86	1.25	1.29		0.00	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
260																							
261	WKE Share of Generation Capex	Participation Agreement - Cost Sharing		51%	51%	51%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
262																							
263	Plant Maintenance (Real Basis 2007)																						
264	Coleman	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							1.14	1.11	2.37	1.05	1.02										
265	Green	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							8.55	6.75	4.23	2.29	1.32										
266	HMP&L	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							0.94	1.16	2.36	3.72	3.25	2.86	0.43	0.43	0.43	0.43	1.03	1.03	0.43	0.43	0.43
267	Reid	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							1.03						1.40								
268	Wilson	file: Fin Model inputs BREC Aug-08 net City rev 2.xls							14.63	6.47	11.19	1.91	1.57	1.24	1.57	1.24	1.57	1.24	3.74	1.24	1.57	1.24	1.57
269	Adjustment for Station 2	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
270																							
271	Plant Maintenance Claim Amount																						

		Source:	2005/ Othe	2006	2007	2008	Transactions	Termin	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
272																							
273	Environmental (Real Basis 2006)																						
274	NOx Removal Equipment Capital	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
275	Mercury Monitoring	file: Fin Model inputs BREC Aug-08 net City rev 2.xls									1.73												
276	Cmn FGD Equipment Capital	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
277	FGD ongoing upkeep capital (0.10%)	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
278	Additional FGD thickener & filter drum	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
279	R-CT reliability study & upgrades	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
280	Wilson super heater tubes replacment	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
281	Adjustment for Station 2	file: Fin Model inputs BREC Aug-08 net City rev 2.xls																					
282																							
283	Transmission Upgrades																						
284	Phase I	Per Crockett Memo dated 11/12/07			4.00																		
285	Phase II	Per Crockett Memo dated 11/12/07							5.40	5.30													
286																							
287	Shared HQ Building																						
288	Phase I																						
289	Phase II								1.66														
290																							
291	Intellectual Property																						
292	Capex Purposes	Unwind spreadsheet -- 8-29-07_Rev1.xls						0.00	9.74	1.02	0.92	0.79	0.80	0.98	0.83	0.85	1.00	0.92	0.94	1.06	0.89	0.91	1.23
293	Depreciation Purposes	Depreciated at Average Capital Depreciation Rate						0.00	0.15	0.16	0.31	0.33	0.35	0.38	0.40	0.42	0.45	0.47	0.49	0.52	0.55	0.57	0.60
294	Trial Balance Adjust		101.0%																				
295																							
296	Cash Adder																						
297																							
298	**Other Disbursements (M$)**																						
299																							
300	PPA	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		98.00	96.29	95.44																	
301	Environmental	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.41	0.48	0.65																	
302	PCB Restructuring	Proforma transaction and bond insurance costs							7.20														
303	LEM Settlement Note	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		1.82	1.82	1.82		0.00	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.06
304	'Other Deductions'	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.13	0.15		(0.00)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.06)
305	Transition Costs																						
306	Deferred Debit - PCB Refunding A/C 181	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		(0.05)	(0.05)	(0.05)		(0.00)	(0.74)														
307	Green River Coal Settlement	Long Term Debt Schedule - Historical from July 1998 - Actual 2007		0.35	0.05	0.04		0.00															
308	MISO Credit Fee																						
309	Deferred Tax Asset Write-Down																						
310	Payment to City of Henderson	file: Annual Output - 9-8-08 - BREC Update.xls							0.52	0.52	0.52	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
311	Smelter Payment (Assurances Agreement)	Coordination Agreement					1.53																
312	Lease-Equity Consent Fees/ Smelter Exit																						
313	Non-Smelter Member Excess Cash Rebate																						
314	Economic Reserve						157.00		(35.46)	(36.13)	(30.80)	(38.31)	(35.74)										
315	Working Capital Adj.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.09	4.06	(0.45)																	
316	*CoBank Patronage Capital*	*Historic results and adapted from 2007 Budget-REVISED*	*2.25*	*2.64*	*3.04*	*3.43*		*3.43*	*3.77*	*3.77*	*3.77*	*3.07*	*1.51*	*0.05*	*0.05*	*0.05*	*0.05*	*0.05*	*0.05*	*0.05*	*0.05*	*0.05*	*0.05*
317	Amortization of RUS/PCB Charges	Straightline amortization of RUS and PCB restructuring costs						0.00	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.38	0.38
318	**Other Assumptions**																						
319																							
320	Interest Earnings Rate on Cash Balances	Big Rivers estimate	4.00%																				
321																							
322	Inflation	Big Rivers estimate	3.00%																				
323																							
324	Receivables (days)	Big Rivers estimate	30.00																				
325																							
326	Payables (days)	Big Rivers estimate	52.50																				
327																							
328	Non-Patronage Taxable Allocation (Transaction)	Orrick Herrington/ Deloitte	15%																				
329																							
330	Sequestered Cash Ending Balance	Smelter Retail Agreements, Section 1.1.119	35.00		0																		
331																							
332																							
333	**Balance Sheet (2005)**																						
334																							
335	Assets																						
336	Property																						
337	Total Utility Plant in Service	Historic Balance Sheet	1,714.8	1,731.2	1,749.9	1,783.8																	
338	Construction in Progress	Historic and Projected Balance Sheet	12.7	13.1	15.1	15.1	15.1	15.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
339	Depreciation & Amortization	Historic Balance Sheet	798.7	827.5																			
340	Other Property	Historic Balance Sheet	184.0	190.7																			
341	Current																						
342	Cash General Funds & Special Deposits	Historic Balance Sheet	0.0	0.0	0.0	0.0	0.0																
343	Ending Cash Balance	Historic Balance Sheet	67.8	96.5																			
344	Accounts Receivable	Historic Balance Sheet	16.3	17.5	26.3	19.9																	
345	Fuel Stock & Related	Historic Balance Sheet																					
346	Credit Escrow	Economic Reserve					157.0	157.0	127.8	96.8	69.9	34.4											
347	Materials and Supplies Other	Historic Balance Sheet	0.7	0.8	0.8	0.8																	
348	Other Current Assets	Historic Balance Sheet	0.3	4.1	1.1	1.1	1.1																
349	Credits																						
350	AMBAC/Credit Suisse July '98	Historic and Projected Balance Sheet	5.1	4.7	4.3	3.8	3.8	3.8															
351	Deferred Tax	Historic Balance Sheet	4.3																				
352	Other Deferred Debits/PCB Refunding 10/01	Historic Balance Sheet																					
353	*LEM Settlement Note/Marketing Payment*	Historic Balance Sheet	18.1	17.1	16.1	15.1																	
354	Total Assets																						
355																							
356	Liabilities																						
357	Margins & Equities	Historic Balance Sheet	(251.9)	(218.2)	(175.0)	(138.5)																	
358	Long-Term Debt																						
359	Existing Debt	Historic Balance Sheet	1,058.2	1,053.1	1,061.7	1,027.1																	
360	Sale-Leaseback Obligation	Historic Balance Sheet	171.0	177.3	183.9	189.7																	
361	Total Long-Term Debt																						
362	Current & Accrued Liabilities																						

		Source:	005/ Othe	2006	2007	2008	Transactions	Termin	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable	Historic Balance Sheet	13.1	12.6	18.0	12.7																	
364	Taxes Accrued	Historic Balance Sheet	0.4	0.2	1.0	1.0																	
365	Deferred Revenue (Credit Escrow)																						
366	Interest Accrued	Historic Balance Sheet	7.5	7.6	7.8	7.3	0.4	0.4															
367	Other Accrued Liabilities	Historic Balance Sheet	5.9	6.0	5.2	5.4	5.4	5.4															
368	WKEC Lease (Resid. Value Obligation)*	Historic Balance Sheet		150.1	156.9	152.6																	
369	Sale-Leaseback Gain	Historic Balance Sheet																					
370	Other Deferred Credits & Century Reactive Power	Historic Balance Sheet	1.0	0.4	0.3	0.2																	
371	Total Liabilities & Equity	Historic Balance Sheet																					
372																							
373	Misc included in Other Property		i																				
374																							
375																							
376	**Sale-Leaseback**																						
377																							
378	BOY Deferred Gain	Sale-Leaseback	62.12																				
379	Amortization (I/S)	Sale-Leaseback	2.86	2.88	2.90	2.92		0.00	2.76	2.79	2.83	2.84	2.85	2.87	2.88	2.89	2.91	2.92	2.94	2.95	2.97	2.99	3.01
380																							
381	Investment - Special Deposit (B/S)	Sale-Leaseback	180.65																				
382	Adder	Sale-Leaseback	0.50	0.73	0.74	-																	
383																							
384	Liability - Long-Term Debt (B/S)	Sale-Leaseback	170.95																				
385																							
386	Interest Income (I/S)	Sale-Leaseback	11.67	12.07	12.48	12.61																	
387	Interest Expense (I/S)	Sale-Leaseback	11.97	12.39	12.82	12.16																	
388																							
389	Cash Flow (Investment and Liability)	Sale-Leaseback	5.72	6.03	6.24	6.24																	
390																							
391	Sale-Leaseback - LeaseCo.																						
392	Defeasance Income	Sale-Leaseback	63.53	64.06	64.47	64.47																	
393	Rent Expense	Sale-Leaseback	(48.87)	(48.87)	(48.87)	(48.87)																	
394																							
395																							
396	**Unwind Transaction**																						
397																							
398	WKE Residual Value Obligation																						
399	WKE Gen. Capex - Cum.																						
400	Non-Incremental (RV Obligation Balance)																						
401	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		40.2	45.3	50.3	55.2																
402	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		6.7	6.8	7.0																	
403	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.6	1.8	2.1																	
404	Unattributed Plugs	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(145.1)																			
405	Incremental																						
406	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		100.2	95.6	90.9	86.3																
407	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.8																			
408	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.4	4.6	4.6																	
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.9	50.8	47.7																	
412	Income Statement	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		52.3	52.3	52.3																	
413	Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(17.3)	(15.8)	(11.2)	(11.2)																
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories	Termination Agreement					51.0																
418																							
419	Coleman Scrubber Completion	Termination Agreement/ file: Coleman Scrubber.xls					98.5																
420																							
421	Cancellation of Settlement Prom. Note	Termination Agreement					15.7																
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment	Smelter Coordination Agreement					1.5																
425	Consent Fees																						
426																							
427	7. Non-Smelter Member Excess Cash Rebate																						
428																							
429	8. Non-Smelter Member Excess Cash Rate Mitigation Account																						
430	BB						-	157.0	157.0	127.8	96.8	69.9	34.4										
431	IE	Assumed 4.28% interest earnings rate					-	0.0	6.3	5.1	3.9	2.8	1.4	-									
432	Contribution	LG&E Unwind Deal Stipulated					157.0		-	-		-											
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	-	(35.5)	(36.1)	(30.8)	(38.3)	(35.7)										
434	EB						157.0	157.0	127.8	96.8	69.9	34.4	-										
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance																						
439	Volume (tons)	Termination Agreement					14,000																
440	Price ($/ton)	file: Annual Output - 9-8-08 - BREC Update.xls					140																
441																							
442	Lease Termination Payment																						
443	Assumed Make Whole to CoBank																						
444	Total Expense																						
445																							
446	Lease Termination Payment from Unwind Counterparties																						
447	Recognition of Deferred Gain on Original Lease																						
448	Lease Termination Payment from Unwind Counterparties																						
449																							
450	DSL Termination		0																				
451	PMCC Share		0																				
452	Net SLB		i																				
453	**Depreciation**																						

		Source:	005/ Othe	2006	2007	2008	Transactions	Termin	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
454																							
455	Additional Book Depreciation																						
456	Prior year non-incremental + in service	Historic		12.83	13.12	13.41																	
457	Average of Transmission and A&G	Historic		6.38	10.86	17.33																	
458	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)		1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)	Based on 1993 Depreciation Study	38																				
461	Capital Depreciation Rate (Environmental)	Based on 1993 Depreciation Study	38																				
462																							
463																							
464	HMP&L Station Two																						
465	*Prior year non-incremental*	Historic		12.83	13.12	13.41																	
466	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
467																							
468	Other																						
469	Prior year	Historic		6.00	6.77	14.99																	
470	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
471																							
472	Book Depreciation & Amortization																						
473	Generation																						
474	Big Rivers' Plants	Historic		26.89	26.17	26.41		26.58	28.08														
475	HMP&L Station Two	Historic		0.92	0.93	0.93		0.93	0.93														
476	Other	Historic		5.03	5.06	5.11		5.06	5.11														
477																							
478	Adjustment to Depreciation		0																				
479	9/24/07 Blended Depreciation Amount	Coordination Agreement, Section 3.10						0.01976	0.0204	0.02103	0.02155	0.02167	0.02122	0.0209	0.02123	0.0215							
480	**Income Tax Related**																						
481																							
482	Previously Expensed Marketing Payment	Historic		0	0	0	4.196																
483																							
484	Status Quo Depreciation	Proforma	23.69																				
485																							
486	WKE Share of Capex																						
487	Non-incremental	Participation Agreement - Cost Sharing		51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental	Participation Agreement - Cost Sharing		0%	80%	80%		80%	80%	80%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
489	Incremental Dep			0.80	0.00	0.00																	
490	Temporary Differences																						
491	2005 Cumulative Balance of Capex not reflected in SQ	Historic	149.87																				
492	Other Temporary Differences	Historic	19.65																				
493																							
494	NOL Related																						
495	Year			1983	1984	1984	1984	1984	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
496																							
497	Tax Rates																						
498	Regular	Big Rivers' estimate	35%																				
499	AMT	Big Rivers' estimate	20%																				
500																							
501	ACE																						
502	ACE Deduction			(1.23)	(1.22)	(1.22)	.	(0.00)	(1.19)	(1.17)	(0.80)	(0.58)	(0.50)	(0.35)	(0.13)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
503	ACE %		75%																				
504																							
505	SQ Addition	Historic		0.41	0.25	0.38	#REF!	0.26	0.44	0.43	0.71	1.61	0.47	0.90	1.35	1.77	2.26	4.72	5.56	6.36	6.71	6.76	7.87
506	2006 AMT BB			4.28	4.69	4.93	5.32																
507																							
508	Nonpatronage MWH	Historic	1	38%	0.46009	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales	Orrick Herrington/ Deloitte	PE																				
510	Interest Income on Unrestricted Cash	Orrick Herrington/ Deloitte	PE																				
511	Interest on Transition Reserve	Orrick Herrington/ Deloitte	NP																				
512	Interest on Economic Reserve	Orrick Herrington/ Deloitte	PE																				
513																							
514	Carbon Tax Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year																					
515	Carbon Allowance Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year																					
516	Carbon BY Allowance Cost ($/MWh)	5,073,775 tons in base year, $7/ton charge starting in 2012, escalating at $1/year																					
517																							
518	Smelter Excess Cash Rate Mitigation Account																						
519	BB																						
520	IE	Assumed 4.28% interest earnings rate																					
521	Contribution	Smelter Retail Agreement, Section ???																					
522	Release/ Amortization	Releases to offset FAC increase from Feb. Filed Model																					
523	EB																						
524	RUS Prepay Adjustments																						
525	Stated											(1,078.1)				######							
526	GAAP											(1,090.7)				######					500.4		
527	Interest earnings											(750.0)				(8,000.0)							
528	Smelter Payment						-7																
529	Other Deferred Assets				2.1373	2.1373	2.137299	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373	2.1373
530	Historic Purchases Through Close				68	12																	
					7	4																	
					61	8																	

Fuel Inventory

	($M)	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Inventory Maintenance	100%																
2																		
3	Fuel Purchases ($/mmbtu)	1.56	1.96	1.95	2.15	2.25	2.50	2.69	1.85	1.85	1.87	1.90	1.91	1.94	1.96	1.98	2.02	2.04
4																		
5	Heat Value btu/ lb		500	10,999	11,028	11,050	11,037	11,024	11,061	11,019	11,038	11,020	11,025	11,045	11,029	11,023	11,074	11,030
6	Heat Value mmbtu/ ton		1.00	22.00	22.06	22.10	22.07	22.05	22.12	22.04	22.08	22.04	22.05	22.09	22.06	22.05	22.15	22.06
7	Coal Consumed [from PCM (000s tons)]		0	6,041	6,219	5,967	6,046	6,058	6,063	6,097	6,100	5,910	6,095	5,938	6,078	6,058	6,083	6,065
8	Coal Consumed (Gbtus)		0	132,904	137,165	131,878	133,453	133,576	134,113	134,367	134,658	130,264	134,396	131,171	134,064	133,548	134,716	133,785
9																		
10	***Volumes Fuel Inventory (Gbtus)***																	
11	BB	-	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210
12	Fuel Purchased		0	132,904	137,165	131,878	133,453	133,576	134,113	134,367	134,658	130,264	134,396	131,171	134,064	133,548	134,716	133,785
13	LG&E Additions to Fuel Inventory	20,210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Fuel Consumed	-	(0)	(132,904)	(137,165)	(131,878)	(133,453)	(133,576)	(134,113)	(134,367)	(134,658)	(130,264)	(134,396)	(131,171)	(134,064)	(133,548)	(134,716)	(133,785)
15	EB	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210	20,210
16																		
17	***$Millions***																	
18	BB	-	31.4	31.4	31.3	35.2	37.3	42.4	46.3	29.2	29.3	29.5	30.3	30.4	31.2	31.5	31.9	32.7
19	Fuel Purchased	-	0.0	259.2	294.4	296.9	334.0	359.9	248.1	249.1	251.2	248.0	256.2	255.1	263.2	265.0	272.5	272.4
20	LG&E Additions to Fuel Inventory	31.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fuel Expensed	-	0.0	(259.4)	(290.5)	(294.8)	(328.9)	(356.0)	(265.1)	(249.0)	(250.9)	(247.2)	(256.2)	(254.3)	(262.8)	(264.5)	(271.7)	(272.1)
22	EB	31.4	31.4	31.3	35.2	37.3	42.4	46.3	29.2	29.3	29.5	30.3	30.4	31.2	31.5	31.9	32.7	33.0

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		Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**SO2 Emissions Inventory**																	
2																		
3	*Price ($/ ton)**	$ 140	$ 140	$ 140	$ 115	$ 868	$ 878	$ 875	$ 850	$ 842	$ 825	$ 757	$ 706	$ 561	$ 413	$ 350	$ 302	$ 279
4	*LG&E Contribution*	14,000																
5	*Excess Sold Annually (2008-2010)*	100%																
6	*Excess Sold Annually (post 2010)*	100%																
7	*CAIR Factor*	1.00	1.00	1.00	1.00	2.00	2.00	2.00	2.00	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86
8																		
9	**Allowances (in tons)**																	
10	BB	-	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
11	Allocated	14,000	-	48,979	48,979	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	18,352	17,125	18,352	18,352	18,352
12	Consumed		-	(19,145)	(20,453)	(19,301)	(19,812)	(19,341)	(19,855)	(20,836)	(21,282)	(19,910)	(21,199)	(20,456)	(19,823)	(20,812)	(21,263)	(20,716)
13	Sold	-	-	(29,834)	(28,526)	(5,188)	(4,677)	(5,148)	(4,635)	2,484	2,929	1,558	2,847	2,104	2,697	2,460	2,911	2,364
14	Net Contributed	14,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Withdrawn/ Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	EB	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
17	**Dollars (Balance Sheet)**																	
18	BB	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Net Contributed	1,960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Withdrawn/ Sold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	EB	1,960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Average Inventory Value ($/ Allowance)	140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23																		
24																		
25	Income Statement																	
26	Revenue																	
27	Sales	-	-	4,177	3,280	4,503	4,106	4,505	3,939	(2,091)	(2,417)	(1,180)	(2,010)	(1,180)	(1,114)	(861)	(879)	(659)
28	Allocation to Inventory	1,960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Expense																	
30	Purchases		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Net	1,960	-	4,177	3,280	4,503	4,106	4,505	3,939	(2,091)	(2,417)	(1,180)	(2,010)	(1,180)	(1,114)	(861)	(879)	(659)
32																		
33	Cash Flow																	
34	Sales	-	-	4,177	3,280	4,503	4,106	4,505	3,939	(2,091)	(2,417)	(1,180)	(2,010)	(1,180)	(1,114)	(861)	(879)	(659)
35	Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Net	-	-	4,177	3,280	4,503	4,106	4,505	3,939	(2,091)	(2,417)	(1,180)	(2,010)	(1,180)	(1,114)	(861)	(879)	(659)
37																		
38	Balance Sheet (Incremental)																	
39	Cash	-	-	4,177	7,457	11,961	16,067	20,572	24,511	22,419	20,003	18,823	16,813	15,633	14,519	13,658	12,779	12,119
40	Emissions Inventory	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960
41	Total	1,960	1,960	6,137	9,417	13,921	18,027	22,532	26,471	24,379	21,963	20,783	18,773	17,593	16,479	15,618	14,739	14,079
42																		

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		Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
43	**NOX Emissions Inventory**																	
44																		
45	**Price ($/ ton)***	$ 700	$ 700	$ 700	$ 650	$ 2,120	$ 1,951	$ 1,909	$ 2,570	$ 3,071	$ 2,863	$ 2,764	$ 2,665	$ 2,564	$ 2,574	$ 2,578	$ 2,581	$ 2,584
46	**LG&E Contribution**	-																
47	**Excess Sold Annually**	100%																
48																		
49	**Allowances**																	
50	BB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Allocated		-	4,652	4,652	11,068	11,057	11,057	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
52	Consumed		-	(5,141)	(5,105)	(13,489)	(13,371)	(13,531)	(13,340)	(13,579)	(13,378)	(13,303)	(13,413)	(13,214)	(13,553)	(13,445)	(13,365)	(13,558)
53	Sold		-	489	453	2,421	2,314	2,474	2,284	4,635	4,435	4,811	5,116	5,061	5,605	5,732	5,874	6,139
54	Net Contributed	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Withdrawn/ Sold		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	EB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	**Dollars (Balance Sheet)**																	
58	BB	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Net Contributed	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Withdrawn/ Sold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	EB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Average Inventory Value ($/ Allowance)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63																		
64																		
65	Income Statement																	
66	Revenue																	
67	Sales		-	(342)	(295)	(5,132)	(4,514)	(4,723)	(5,870)	(14,233)	(12,697)	(13,299)	(13,634)	(12,976)	(14,428)	(14,776)	(15,160)	(15,862)
68	Allocation to Inventory	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Expense																	
70	Purchases		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	Net	-	-	(342)	(295)	(5,132)	(4,514)	(4,723)	(5,870)	(14,233)	(12,697)	(13,299)	(13,634)	(12,976)	(14,428)	(14,776)	(15,160)	(15,862)
72																		
73	Cash Flow																	
74	Sales	-	-	(342)	(295)	(5,132)	(4,514)	(4,723)	(5,870)	(14,233)	(12,697)	(13,299)	(13,634)	(12,976)	(14,428)	(14,776)	(15,160)	(15,862)
75	Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Net	-	-	(342)	(295)	(5,132)	(4,514)	(4,723)	(5,870)	(14,233)	(12,697)	(13,299)	(13,634)	(12,976)	(14,428)	(14,776)	(15,160)	(15,862)
77																		
78	Balance Sheet (Incremental)																	
79	Cash	-	-	(342)	(637)	(5,769)	(10,283)	(15,005)	(20,875)	(35,109)	(47,805)	(61,104)	(74,738)	(87,713)	(102,141)	(116,917)	(132,078)	(147,940)
80	Emissions Inventory	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	Total	-	-	(342)	(637)	(5,769)	(10,283)	(15,005)	(20,875)	(35,109)	(47,805)	(61,104)	(74,738)	(87,713)	(102,141)	(116,917)	(132,078)	(147,940)

Lease Buyout Summary

Lease Buyout Impact

	Total	Journal Entries	
		Debit	Credit
Assets			
Sale-Leaseback Investments	(196.8)	-	196.8
Cash & Investments	(59.6)	-	59.6
	-		
Assets	(256.4)		
	-		
Liabilities & Equities	-		
Equities	(16.1)	16.1	-
Sale-Leaseback Obligation & Unamortiz	-	-	-
Obligation	(189.7)	189.7	-
Unamortized Gain	(50.6)	50.6	-
Total	-	-	-
Liabilities & Equities	(256.4)		
Check	-	256.4	256.4

EXHIBIT 80

THIRD AMENDMENT TO TRANSACTION TERMINATION AGREEMENT

THIRD AMENDMENT TO
TRANSACTION TERMINATION AGREEMENT

THIS THIRD AMENDMENT TO TRANSACTION TERMINATION AGREEMENT (***"Third Amendment"***) is made and entered into as of this _____ day of October 2008 , by and among **BIG RIVERS ELECTRIC CORPORATION** (***"Big Rivers"***), **LG&E ENERGY MARKETING INC.** (***"LEM"***), and **WESTERN KENTUCKY ENERGY CORP.** (***"WKEC"***) (collectively, the ***"Parties"***).

RECITALS:

A. Reference is made to the Transaction Termination Agreement by and among the Parties dated as of March 26, 2007, as amended by a First Amendment to Transaction Termination Agreement dated as of November 1, 2007, as clarified in part by a letter agreement among the Parties dated December 4, 2007, and as amended by a Second Amendment to Transaction Termination Agreement dated as of June 19, 2008 (collectively, the ***"Termination Agreement"***). Pursuant to the Termination Agreement, among other transactions, the Parties agreed to terminate certain property interests and contractual relationships between LEM and WKEC, on the one hand, and Big Rivers, on the other hand, at the Closing, upon the terms and subject to the conditions set forth therein. Capitalized terms used but not defined in this Third Amendment shall have their same respective meanings as in the Termination Agreement.

B. The Parties now desire to further amend the Termination Agreement in the manner set forth in this Third Amendment, including without limitation, in order to increase the Termination Payment contemplated as to be paid by WKEC to Big Rivers at the Closing, and in order to evidence certain additional agreements and understandings among them with respect to certain actual or potential environmental conditions or circumstances that have been identified by Big Rivers through its due diligence investigation of the Generating Plants.

C. Attached hereto as Appendix D is a draft order that is being jointly sought by the Parties and that may be issued by the Kentucky Energy and Environment Cabinet (the "***Draft Agreed Order***").

AGREEMENT:

NOW, THEREFORE, in consideration of the premises and for other valuable consideration, the receipt of which is hereby acknowledged, the Parties agree as follows, effective immediately:

1. **AMENDMENT TO SUBSECTION 3.3(a)**. The first (1^{st}) sentence of Subsection 3.3(a) of the Termination Agreement (as previously amended pursuant to the Second Amendment to Transaction Termination Agreement dated as of June 19, 2008) is hereby further amended to be and read in its entirety as follows:

"At the Closing, WKEC shall pay to Big Rivers (in immediately available funds) the sum of ______________________________ Dollars and no cents ($____________.00) **[NOTE: this amount will be the sum of $383,500,000.00, plus one-half of the net PMCC buyout price (TBD), plus $172,500.00, representing WKEC's proposed reimbursement to Big Rivers relating to its previous 20% funding of the Reid 1 gas burners]**, subject to the adjustment provided for in the following two sentences (as adjusted, collectively, the ***"Termination Payment"***)."

2. **SUBSECTION 15.3(d)**. The Parties hereby amend the Termination Agreement to include a new Schedule 15.3(d) thereto, which new Schedule 15.3(d) shall be in the form (and shall contain only the items or matters set forth in the form) attached to this Third Amendment as Appendix A (***"Schedule 15.3(d)"***). The Parties agree that each and every matter, description, event, condition or circumstance set forth or identified in Schedule 15.3(d) (as the same may be supplemented as hereinafter provided) shall be deemed for all purposes to be included in, made a part of and incorporated by reference in Subsection 15.3(d) of the Termination Agreement (together with the matters, descriptions, events, conditions and circumstances included as a part of Subsection 15.3(d) prior to the date of this Third Amendment), rendering each of the same the subject of WKEC's indemnification and hold harmless covenants set forth in that Subsection 15.3(d) (but subject to the limitations and exclusions provided for therein). The Parties may by mutual written agreement (specifically referring to Schedule 15.3(d)), from time-to-time following the date of this Third Amendment, substitute a new Schedule 15.3(d) for the version of that Schedule attached to this Third Amendment, without the need for the Parties to amend Subsection 15.3(d) of the Termination Agreement or this Third Amendment.

3. COLEMAN TITLE V AIR PERMIT. Following the Closing, and expiring at such time as the Kentucky Energy and Environment Cabinet shall have issued or entered into an agreed order in the form (in all material respects) of the Draft Agreed Order (but with paragraph 14 thereof in the form set forth in the Draft Agreed Order), WKEC shall indemnify and hold harmless Big Rivers from and against any claims, demands, losses, damages, liabilities, costs, expenses, obligations and deficiencies (including without limitation, any costs of corrective or remedial actions, fines, civil or criminal penalties, settlements or attorney's fees) that have been or may be suffered or incurred by Big Rivers to the extent (but only to the extent) resulting from or arising out of any failure of WKEC to apply for the renewal of the Air Quality Title V permit number V-02-003 issued on October 24, 2003, Source ID# 21-091-00003, for Coleman Station (the ***"Coleman Title V Permit"***), on or before the date such application was required in order to authorize continued operation of Plant Coleman under the Coleman Title V Permit after it would otherwise expire on October 24, 2008, including any operation of Plant Coleman prior to the renewal of the Coleman Title V Permit that was not authorized by the provisions of Section 8 of 410 KAR 52:020. The covenants and agreements set forth in this Section 3 are covenants and agreements of the type contemplated in Subsection 15.3(e) of the Termination Agreement. The provisions of this Section 3 shall be deemed for all purposes of the Termination Agreement to be included in and a part of Section 15.3 of the Termination Agreement, as contemplated in Subsection 15.3(e) of the Termination Agreement, and all provisions of this Section 3 shall be and remain subject to the last sentence of that Subsection 15.3(e).

4. WILSON KPDES PERMIT. Following the Closing, and expiring at such time as the Kentucky Energy and Environment Cabinet shall have issued or entered into an agreed order in the form (in all material respects) of the Draft Agreed Order (but with paragraph 15 thereof in the form set forth in the Draft Agreed Order), WKEC shall indemnify and hold harmless Big Rivers from and against any claims, demands, losses, damages, liabilities, costs, expenses, obligations and deficiencies (including without limitation, any costs of corrective or remedial actions, fines, civil or criminal penalties, settlements or attorney's fees) that have been or may be suffered or incurred by Big Rivers to the extent (but only to the extent) resulting from or arising out of any failure of WKEC to apply for the renewal of Kentucky Pollutant Discharge Elimination System (***"KPDES"***) permit number KY0054836 for Wilson Station (the ***"Wilson***

KPDES Permit") on or before the date such application was required in order to authorize continued operation of Plant Wilson under the Wilson KPDES Permit after its original expiration date of October 31, 2004, including any discharges from Plant Wilson that are subject to the Wilson KPDES Permit and are not authorized by 401 KAR 5:060, Section 1(5)(c). The covenants and agreements set forth in this Section 4 are covenants and agreements of the type contemplated in Subsection 15.3(e) of the Termination Agreement. The provisions of this Section 4 shall be deemed for all purposes of the Termination Agreement to be included in and a part of Section 15.3 of the Termination Agreement, as contemplated in Subsection 15.3(e) of the Termination Agreement, and all provisions of this Section 4 shall be and remain subject to the last sentence of that Subsection 15.3(e).

5. WILSON CONVEYOR BELT RUN-OFF BASINS. Following the Closing, and expiring at such time as the Kentucky Energy and Environment Cabinet shall have issued or entered into an agreed order in the form (in all material respects) of the Draft Agreed Order (but with paragraph 16 thereof in the form set forth in the Draft Agreed Order), WKEC shall indemnify and hold harmless Big Rivers from and against any claims, demands, losses, damages, liabilities, costs, expenses, obligations and deficiencies (including without limitation, any costs of corrective or remedial actions, fines, civil or criminal penalties, settlements or attorney's fees) that have been or may be suffered or incurred by Big Rivers to the extent (but only to the extent) resulting from or arising out of any failure of WKEC to apply for or obtain an amendment to the Wilson KPDES Permit on a timely basis in order to construct, maintain and operate the Wilson conveyor belt runoff ponds. The covenants and agreements set forth in this Section 5 are covenants and agreements of the type contemplated in Subsection 15.3(e) of the Termination Agreement. The provisions of this Section 5 shall be deemed for all purposes of the Termination Agreement to be included in and a part of Section 15.3 of the Termination Agreement, as contemplated in Subsection 15.3(e) of the Termination Agreement, and all provisions of this Section 5 shall be and remain subject to the last sentence of that Subsection 15.3(e).

6. COLEMAN POND.

(a) Following the Closing, WKEC shall indemnify and hold harmless Big Rivers from and against any fines and civil or criminal penalties that may be suffered or incurred by Big Rivers to the extent (but only to the extent) resulting from or arising out of any failure of WKEC to obtain a KPDES permit required for the discharge of wastewater from the new wastewater treatment facility at Plant Coleman (the ***"Coleman WWTF"***); provided, that the foregoing obligation of WKEC to indemnify and hold harmless Big Rivers shall be limited to the percentage of all such fines and civil and criminal penalties, collectively, equal to the ratio (the "***WKE Contribution Ratio***") by which all waste materials that were deposited by WKEC into the Coleman WWTF prior to the Closing bears to the total amount of all waste materials that were deposited into the Coleman WWTF (whether by WKEC, by Big Rivers or by any other Person (exclusive of the Affiliates of WKEC)) at any time prior to the last date in the period for which such fines and/or penalties are imposed by the relevant Governmental Entity, regardless of whether any of those waste materials were removed from the Coleman WWTF prior to that date of imposition. Notwithstanding the foregoing, WKEC shall have no obligation to indemnify or hold harmless Big Rivers under or pursuant to this Subsection (a) in the event a KPDES permit for the discharge of wastewater from the Coleman WWTF is issued at any time prior to the Closing, it being understood and agreed that this Subsection (a) shall become null, void and of no further force or effect in the event such a permit is issued prior to the Closing.

(b) To the extent not issued or obtained prior to the Closing, Big Rivers agrees to use its reasonable best efforts to obtain a KPDES permit for the discharge of wastewater from the Coleman WWTF at the earliest practicable time following the Closing. In the event, however, despite such reasonable best efforts of Big Rivers, the Kentucky Energy and Environment Cabinet (the ***"Cabinet"***) shall, in writing, refuse to issue, or shall otherwise make a determination that it will not issue, a KPDES permit required for the discharge of wastewater from the Coleman WWTF (the "***Cabinet Determination***"), then Big Rivers shall evaluate and develop various alternatives of how to address the collective waste material which has been deposited by Big Rivers and by WKEC in the Coleman WWTF, including, without limitation, evaluate and develop alternatives, if any, that would result in the Coleman WWTF continuing to be utilized for the disposal of these waste materials. If within 180 days following the date of the Cabinet Determination, Big Rivers provides written notice to WKEC of Big Rivers' intent to carry out a particular alternative in order to address the collective waste material which has been deposited by Big Rivers and by WKEC in the Coleman WWTF, WKEC shall, upon completion of the work with respect to such selected alternative, reimburse Big Rivers for WKEC's share (determined as provided below) of the total, direct, out-of-pocket costs actually incurred by Big Rivers for the carrying out of the selected alternative; provided however, that in no event shall WKEC's obligation to reimburse Big Rivers for costs under this Subsection (b) ever exceed total, direct, out-of-pocket costs that WKEC would incur for hauling and disposing of the waste materials deposited by WKEC in the Coleman WWTF prior to Closing in the Plant Wilson landfill at the time such alternative disposal is required. The aforementioned notice from Big Rivers shall set forth a description of the alternatives evaluated by Big Rivers, the alternative Big Rivers has selected to pursue, the estimated total, direct, out-of-pocket costs for carrying out the selected alternative by Big Rivers, and WKEC's share of the costs. WKEC's "share" of the costs to be reimbursed hereunder shall be the portion of the total, direct, out-of-pocket costs for carrying out the selected alternative which Big Rivers believes, in good faith, is properly allocable to WKEC given the nature of such alternative; provided however, in no event shall WKEC's "share" exceed the WKE Contribution Ratio. Upon reimbursement by WKEC to Big Rivers as provided herein, or in the event Big Rivers does not provide the written notice contemplated herein to WKEC within the above described 180 day period, (i) WKEC shall have no further responsibility or liability with respect to any material that may be remaining in the Coleman WWTF (whether or not originally deposited in the Coleman WWTF by WKEC), or that may have been or may be deposited in the Coleman WWTF after Closing, and (ii) Big Rivers shall indemnify and hold harmless WKEC from and against any claims, demands, losses, damages, liabilities, costs, expenses, obligations and deficiencies (including without limitation, any costs of corrective or remedial actions, fines, civil or criminal penalties, settlements or attorney's fees) that have been or may be suffered or incurred by WKEC with respect to any material that may be remaining in the Coleman WWTF (whether or not originally deposited in the Coleman WWTF by WKEC), or that may have been or may be deposited in the Coleman WWTF after Closing. The covenants and agreements set forth in this

Section 6 are covenants and agreements of the type contemplated in Subsection 15.3(e) of the Termination Agreement.

7. **SUBSECTION 15.3(e)**. The Parties hereby amend the Termination Agreement to include a new Schedule 15.3(e) thereto, which new Schedule 15.3(e) shall be in the form attached to this Third Amendment as Appendix B (***"Schedule 15.3(e)"***). From and after the date hereof (and with the exception of the indemnification and hold harmless covenants and agreements set forth on that new Schedule 15.3(e) or in Sections 3, 4 and 5 of this Third Amendment), in the event the Parties desire to agree in writing on one or more additional mutually-satisfactory indemnification and hold harmless covenants, risk allocation covenants or other covenants, agreements, representations or warranties of the type(s) contemplated in Subsection 15.3(e) of the Termination Agreement, such additional covenants, agreements, representations and/or warranties need not be set forth in one or more amendments or addenda to the Termination Agreement as contemplated in that Subsection 15.3(e), but rather may be implemented by the mutual written agreement of the Parties (specifically referring to Schedule 15.3(e)) to substitute a new Schedule 15.3(e) for the Schedule 15.3(e) attached to this Third Amendment, so that it includes such additional covenants, agreements, representations and/or warranties. The covenants and agreements set forth in Schedule 15.3(e) (including any future substitutions therefor) shall be deemed for all purposes to be covenants and agreements of the type contemplated in Subsection 15.3(e) of the Termination Agreement. The provisions of this Section 7 and of Schedule 15.3(e) (including any future substitutions therefor) shall be deemed for all purposes of the Termination Agreement to be included in and a part of Section 15.3 of the Termination Agreement, as contemplated in Subsection 15.3(e) of the Termination Agreement, and all provisions of this Section 7 and of Schedule 15.3(e) shall be and remain subject to the last sentence of that Subsection 15.3(e).

8. **SECTION 15.4**. Notwithstanding anything to the contrary set forth in Section 15.4 of the Termination Agreement or elsewhere in that agreement, the Parties agree that following the date of this Third Amendment they need not amend that Section 15.4 or any other provision of the Termination Agreement in order to add one or more Secondary Conditions to Schedule 15.4 of the Termination Agreement (thereby rendering such Secondary Condition(s) the subject of the covenants and agreements set forth in that Section 15.4). Rather, the Parties

may by mutual written agreement (specifically referring to Schedule 15.4) substitute a new Schedule 15.4 for the Schedule 15.4 attached to the Termination Agreement (which continues to be intentionally left blank by the Parties as of the date of this Third Amendment) at any time following the date hereof.

9. GREEN RIVER DREDGING PROCESS AT WILSON STATION. From and after the date of this Third Amendment through the Closing (or the earlier termination of the Termination Agreement), WKEC agrees to continue to maintenance dredge the Green River adjacent to Wilson Station (at such times as WKEC shall deem appropriate, consistent with Prudent Utility Practice) in a manner and using methods consistent with the past practices of WKEC. As of the Closing, WKEC shall ensure that no material amount of Green River sediment that was dredged by WKEC since the Effective Date is still located at any sediment stockpile on the east bank of the Green River adjacent to Wilson Station.

10. CLEAN-OUT OF PONDS. The Parties agree that, as additional conditions precedent to Big Rivers' obligation to consummate the transactions contemplated in the Termination Agreement at the Closing (but not as a covenant or agreement on the part of WKEC), WKEC must clean out each of the ponds identified below in a manner consistent with WKEC's previous practices and to the reasonable satisfaction of Big Rivers:

10.1 The metal cleaning waste pond at Sebree Complex that was sampled by the Environmental Consultant at point SD-1;

10.2 The settling pond associated with controlling runoff from the stack-out pad and areas around the FGD waste handling system, commonly known as the CSI Building, at the Sebree Complex, which was sampled by the Environmental Consultant at point SD-2 (the outfall from which is identified as KPDES Discharge Point 011);

10.3 The coal pile runoff pond at Coleman Station that was sampled by the Environmental Consultant at point SD-2;

10.4 The wastewater ponds at Wilson Station, which were sampled by the Environmental Consultant at points SD-1, SD- 2 and SD-3; and

10.5 The Reid Station ash pond, but limited, in the case of that pond and WKEC's obligation to clean out the same under this Section 10, to the removal of materials sufficient to provide Big Rivers thirty (30) days of capacity in that pond following the Closing, assuming normal operations of Station Two and Plant Reid following the Closing consistent with the past practices of WKEC.

11. CLEANUP OF SURFACE SPILLS. As an additional condition to the Closing (but not as a covenant or agreement on the part of WKEC), WKEC shall clean up and remove all visible surface staining resulting from the spills identified on Appendix E attached hereto. As a condition to the Closing only, such areas shall be excavated to remove all visually detectable evidence of contamination and, upon Big Rivers' request, the adequacy of the removal shall be demonstrated by post-excavation sampling (for target contaminants involved in the release) indicating that residual levels of contamination, if any, meet the USEPA Region IX Preliminary Remediation Goals for industrial property or such other standards for industrial property as may be satisfactory to the Kentucky Energy and Environment Cabinet. Excavations shall be backfilled with clean fill, and removed soil shall be disposed of lawfully off-site, or at an on-site location approved by Big Rivers (which approval shall not be unreasonably withheld, conditioned or delayed). Any other surface staining identified by Big Rivers to WKEC in writing prior to Closing shall, upon Big Rivers' request and as an additional condition to the Closing (but not as a covenant or agreement on the part of WKEC), be excavated and removed in accordance with the procedures and requirements of this Section 11.

12. AMENDMENT TO SUBSECTION 15.3(d)(x). Subsection 15.3(d)(x) of the Termination Agreement is hereby amended to be and read in its entirety as follows:

> "(x) (1) the request from the Division of Waste Management dated December 12, 2006, to conduct a groundwater assessment of statistically significant increases in constituents in the groundwater adjacent to the special waste landfill at the Green Plant, but only to the extent those increases occurred from the Effective Date through the Closing Date; or (2) actions required to comply with the groundwater assessment requirements of 401 KAR 45:160 or 401 KAR 48:300, as applicable, as a result of groundwater monitoring reports indicating above background concentrations of constituents in the groundwater which are attributable to migration, occurring from the Effective Date through the Closing Date, from ash ponds at the Coleman and Wilson Plants and Sebree Complex;"

13. EXHIBIT S. Exhibit S to the Termination Agreement is hereby amended to add the following additional agreements, instruments and documents at the end thereof, and new Exhibit S to the Termination Agreement in its entirety (as so amended) is attached to this Third Amendment as Appendix C:

35. All documents of conveyance, assignment and transfer as shall be required to transfer to Big Rivers at the Closing all of WKEC's rights, title and interests in and to all tow boats and other motorized vessels owned by WKEC (but excluding the "Barges" (as defined in Section 15 below)), including without limitation, any such documents as are required to be filed with the United States Coast Guard to effect that conveyance, assignment and transfer;

36. The Closing Memorandum among Big Rivers, WKEC, LEM and E.ON to be entered into as of the Closing and to be dated as of the Unwind Closing Date, evidencing certain agreements of the Parties with respect to the Closing or certain transactions relating to the Closing;

37. The letter agreement dated April 14, 2008, among the Parties, and relating to the capacity testing of the Generating Plants contemplated in Subsection 10.2(ee) of the Termination Agreement;

38. The First Amendment to Transaction Termination Agreement dated November 1, 2007, among the Parties, together with the related letter agreement among the Parties dated December 4, 2008;

39. The Second Amendment to Transaction Termination Agreement among the Parties dated June 19, 2008;

40. The Third Amendment to Transaction Termination Agreement among the Parties dated October ______, 2008;

41. The letter agreement dated April 17, 2008, among the Parties, setting the Scheduled Unwind Closing Date;

42. The letter agreement among Big Rivers, Alcan Primary Products Corporation, Century Aluminum of Kentucky General Partnership and E.ON, dated June 24, 2008, relating to the buy-out of Bank of America's defeased lease position by Big Rivers;

43. The letter agreement between Big Rivers and E.ON, dated June 24, 2008, relating to the buy-out of Bank of America's defeased lease position by Big Rivers;

44. The sublease to Big Rivers of the space leased by WKEC in the Soaper Building located in downtown Henderson, Kentucky;

45. The letter agreement between Big Rivers and E.ON dated September 26, 2008, relating to the treatment of certain costs associated with the buy-out of Philip Morris Capital Corporation's defeased lease position by Big Rivers; and

46. Any and all amendments to any of the other agreements or instruments identified in this Exhibit S that have been or may hereafter be implemented by the written agreement of the parties to such agreements or instruments.

Notwithstanding anything to the contrary set forth in the Termination Agreement or this Third Amendment, the Parties agree that following the date of this Third Amendment they need not amend the Termination Agreement in order to add one or more agreements, instruments or documents to Exhibit S of the Termination Agreement. Rather, the Parties may by mutual written agreement (specifically referring to Exhibit S of the Termination Agreement) substitute a new Exhibit S for the Exhibit S attached to this Third Amendment at any time following the date hereof.

14. Amendment to Subsection 3.2(d). Subsection 3.2(d) of the Termination Agreement is hereby amended to delete from that Subsection the reference to "the two Farm Lease and Security Agreements, each dated March 1st, 2006, between LCC, LLC and (i) Steve and Rona Ogle and (ii) Sean Taylor, respectively", and to replace the same with the following: "the two Farm Lease and Security Agreements, each dated March 1, 2008, between LCC, LLC and (i) Aaron Payne and (ii) Steve Ogle, respectively".

15. Barge Purchase. WKEC hereby agrees to sell and convey to Big Rivers at the Closing (but not before), and Big Rivers hereby agrees to purchase and accept from WKEC at the Closing, all (but not less than all) of the barges identified on Appendix F attached hereto (the ***"Barges"***), for an aggregate purchase price payable by Big Rivers to WKEC at the Closing (in immediately available funds) equal to the net book value of the Barges for the month in which the Closing occurs, as reflected in the regular books of account of WKEC. Upon tender of the purchase price described above, WKEC shall execute and deliver to Big Rivers at the Closing such instruments of conveyance, assignment and transfer as shall be reasonably required in order for WKEC to transfer to and vest in Big Rivers of all of WKEC's rights, title and interests in and to the Barges; provided, that the Barges shall be so conveyed and transferred to Big Rivers in "AS IS", "WHERE IS" condition as of October 6, 2008, subject to reasonable wear and tear after such date and prior to Closing, and with no representation or warranty of any nature whatsoever, including without limitation, with no representation or warranty with respect to the condition or state of repair of the Barges AND NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

16. WILSON STACK BUILD-UP RISKS.

(a) Following the Closing, and provided that Big Rivers complies with the provisions of Section 16(b) hereof, then WKEC shall comply with Sections 16(c) and 16(d) hereof, subject to the further requirements of Sections 16(e) and (f) hereof.

(b) Big Rivers shall cause Plant Wilson to be taken out of service for a period of seven (7) consecutive weeks (24 hours a day, seven days a week) ending prior to December 31, 2009 (the ***"Minimum Outage"***) it being understood by the Parties that such period of outage may be extended beyond the scheduled Minimum Outage for an additional period (the "***Outage Extension***," and collectively with the Minimum Outage, the "***Actual Outage Period***"). Big Rivers shall notify WKEC of the start date of the Minimum Outage at least sixty (60) days prior to the approximate date of commencement of the Minimum Outage. Big Rivers shall afford WKEC and its designated employees and contractors reasonable access, 24 hours a day, to Plant Wilson, to the operating and maintenance logs, data and information relating to Plant Wilson, and to the employees of Big Rivers relating to Plant Wilson, in each case throughout the period from and after the Unwind Closing Date through the expiration of the Actual Outage Period, for the purposes of allowing WKEC: (i) to continuously monitor and inspect the condition, operation and usage of the Plant Wilson stack wall, stack brick lining, stack foundation, stack support, stack breeching duct and other stack ductwork (collectively, the ***"Wilson Stack"***) and the Plant Wilson FGD facilities (but in each case with no obligation of Big Rivers to shut down Plant Wilson to accommodate those monitoring or inspection efforts); (ii) to reasonably prepare for and stage for the removal and cleaning work to be undertaken by WKEC as described below; (iii) solely during the entire period of the Minimum Outage (and, as necessary, any Outage Extensions made by Big Rivers in its sole discretion or requested by WKEC as contemplated below), to undertake and complete that removal and cleaning work; and (iv) to undertake any repair work of the types described below that may be required as contemplated below. Big Rivers shall make its Plant Wilson management personnel available to reasonably assist WKEC in WKEC's coordination and control of the contractors of WKEC to undertake the removal, cleaning and, as applicable, repair work contemplated below.

(c) (1) WKEC agrees to undertake and complete, during the Minimum Outage (and, if requested by WKEC, any Outage Extension), the removal and cleaning from the interior of the brick lining of the Wilson Stack (the "***Interior Lining***") of the build-up of FGD reagent, ash, moisture and other commingled materials that have accumulated on that lining and in the bottom of the stack through the start date of the Minimum Outage (the ***"Build-Up Materials"***), at WKEC's sole cost and expense; provided, that the standards and procedures required to be followed or undertaken by WKEC (or its contractor) in performing that removal and cleaning work, and the extent or level to which the Build-Up Materials must be removed down to the Interior Lining, shall each be such as would be consistent with Prudent Utility Practice and with the standards and procedures of the generating plant stack cleaning industry generally in connection with similar facilities and consistent with Appendix G. The work under the preceding sentence shall be undertaken by WKEC on a 24 hours per day, 7 days per week, basis in order to expeditiously complete the work. WKEC shall begin such removal and cleaning work as soon after the Minimum Outage begins as is practicable, provided WKEC is given the notice of the start date of the Minimum Outage provided for in Subsection 16(b). WKEC shall oversee the removal and cleaning work while permitting Big Rivers' representative(s) to observe the condition of the cleaned stack lining on a regular basis so that any repair work required to be undertaken by WKEC under Subsection 16(c)(3) below can be promptly scheduled, initiated, completed and inspected in accordance with that Subsection; provided, that such observation by Big Rivers' representative(s) shall not unreasonably interfere with the removal, cleaning and repair work of WKEC. In the event the removal and cleaning work contemplated in this Subsection 16(c)(1) cannot be completed by WKEC during the Minimum Outage, then upon the written request of WKEC, Big Rivers agrees to extend that outage in order to accommodate the completion of that cleaning and removal work, which extension shall be an Outage Extension. If at least 48 hours prior to the expiration of the Minimum Outage or any Outage Extension requested by WKEC, WKEC shall not have notified Big Rivers in writing that it is requesting an Outage Extension or another Outage Extension during which to complete the removal, cleaning and, as applicable, repair work contemplated in this Subsection 16(c)(1) or in Subsection 16(c)(3) below, then WKEC shall be deemed to have declined that Outage Extension and to have instead (y) elected to request that Big Rivers return Plant Wilson to generating operation, and (z) elected to complete that work at a subsequent outage of Plant Wilson, in each case as contemplated in Subsection 16(d)(4) below. If, during the Minimum Outage or any Outage Extension requested by WKEC, (i) Big Rivers notifies WKEC in writing (specifying the effective date of termination) that Big Rivers is terminating the Minimum Outage or any Outage Extension requested by WKEC, or (ii) Big Rivers shall materially breach Subsection 16(b) above, then the Parties agree that whatever work that was completed by WKEC at the completion of the shortened Minimum Outage or Outage Extension or as of the date of such material breach shall be deemed as the fulfillment of all of WKEC's obligations under this Subsection 16(c)(1), and Big Rivers shall be deemed as having accepted this work as complete and acceptable, and neither party shall have any further responsibility or liability to the other under Subsections 16(a), (b), (c), (d) and (e).

(2) If, following the Closing and prior to restart of Plant Wilson following the completion of the removal and cleaning of the Build-Up Materials contemplated in Subsection 16(c)(1) above and, as applicable, in Subsection 16(d)(4), any physical damage to the Wilson Stack shall occur as a direct consequence of one or more separations (each a ***"Separation"***) from the Interior Lining of the Wilson Stack of any portion(s) of the Build-Up Materials, howsoever caused, or as a consequence of the work conducted by WKEC to remove the Build-Up Materials, including the deposition of Build-Up Materials at the bottom of the stack (any such physical damage, a ***"Damage Event"***), then WKEC shall promptly thereafter, at its sole cost and expense, undertake and complete a repair of that physical damage at the earliest practicable time consistent with Prudent Utility Practice. In the event such physical damage is discovered and such damage cannot be safely and/or economically repaired absent a shutdown of the generating operations of Plant Wilson, and in the event Big Rivers shall refuse in writing to so shut down those operations for a consecutive period of time reasonably sufficient for WKEC to undertake and complete that repair work, then WKEC shall not be obligated to undertake or complete that

repair work until such time as the generating operations of Plant Wilson are so shut down for that reasonably sufficient period. Big Rivers agrees to notify WKEC immediately (to be confirmed in writing within 48 hours) following the occurrence of a Separation or Damage Event of which Big Rivers becomes aware, describing that Separation and any Damage Event to the extent known to Big Rivers in reasonable detail. Following the occurrence of any Damage Event, Big Rivers shall afford WKEC and its consultants and advisors (at WKEC's risk and expense) a reasonable opportunity to inspect and photograph any resulting physical damage to the Wilson Stack, the associated Build-Up Materials causing that damage, and the Interior Lining of the Wilson Stack, in each case prior to any attempt by Big Rivers or its contractors to remedy that damage (which Big Rivers shall in any event not undertake without first giving WKEC notice thereof and a reasonable period of time and opportunity to repair the same as contemplated in this Subsection 16(c)(2)) or to remove the "Separated" Build-Up Materials; provided, that in the event WKEC so elects to inspect and/or photograph that damage, the associated Build-Up Materials and/or the Interior Lining of the Wilson Stack during a forced outage, or an unplanned outage requested by WKEC to inspect and photograph any resulting physical damage to the Wilson Stack, of Plant Wilson as contemplated above, the period of outage resulting from such activities by WKEC or its consultants or advisors at Plant Wilson (rounded up to the nearest whole hour) shall be added to the duration of the period for which WKEC is required to deliver replacement energy to Big Rivers as contemplated in Subsection 16(d)(2) below.

(3) During any cleaning and removal efforts by WKEC contemplated in Subsection 16(c)(1) and, as applicable, Subsection 16(d)(4), or during any inspection or repair efforts contemplated in Subsection 16(c)(2), Big Rivers shall observe and inspect the interior of the brick lining of the Wilson Stack for the purpose of assessing the condition of the brick lining. Big Rivers shall immediately notify WKEC of the nature, location and extent of any material deterioration in the physical condition of the Interior Lining of the Wilson Stack that was not reasonably observable or detectable prior to the cleaning and removal of the Build-Up Materials. WKEC shall schedule, undertake and complete a repair of that material deterioration consistent with Prudent Utility Practice, taking into consideration the age and historical usage of that brick lining generally (it being expressly agreed that WKEC shall not be obligated to repair that brick lining to "like new" condition, but only to repair that lining to the extent reasonably required to

return it to a safe and functional condition with a remaining useful life approximately equal to that of a brick lining of similar age and historical usage).

(d) (1) During an Outage Extension requested by WKEC as contemplated in Subsection 16(c)(1) above, and so long as the failure of WKEC to complete the relevant removal and cleaning work during the Minimum Outage is not the result of a breach by Big Rivers of Section 16(b) above or of the gross negligence or willful misconduct of Big Rivers or its employees, agents or contractors, WKEC shall, or shall cause an Affiliate to, sell and deliver to Big Rivers (at any point of interconnection to the Big Rivers' transmission system, where available to deliver energy to Big Rivers' member load, satisfactory to WKEC) an amount of replacement energy equal to 418 MW per hour for the number of hours during which Plant Wilson is not capable of any generating operations solely by reason of that requested Outage Extension. Subject to Subsection 16(d)(4) below, Big Rivers shall pay a purchase price equal to the lower of (y) WKEC's actual cost for such replacement energy or (z) the product of $18.50 per MWh multiplied by the volume (in MWh) of such replacement energy, which shall be immediately due and payable within 30 days after the invoice is delivered to Big Rivers following the delivery of such energy. If for any reason replacement energy scheduled by WKEC to a particular interconnection point is cut, WKEC shall reschedule the cut energy at an alternative interconnection point. WKEC may not declare a Force Majeure for failure to deliver replacement energy. WKEC shall reimburse Big Rivers for any costs above $18.50 per MWh (or, for replacement energy to be delivered during the "Cumulative Interruption Period" (as defined in Subsection 16(d)(4) below) under the circumstances described in the first sentence of that Subsection 16(d)(4), above an average cost of $58.50 per MWh) that Big Rivers incurs to procure replacement energy required to be delivered by WKEC hereunder and that WKEC fails to deliver.

(2) Except during the Minimum Outage, during any Outage Extension requested by WKEC, and during any subsequent outage of the type contemplated in Subsection 16(d)(4), if a Damage Event contemplated in Subsection 16(c)(2) above shall occur that prevents all generating operations of Plant Wilson from occurring without risk of injury to personnel or further damage to Plant Wilson (i.e., that causes a forced outage or an unplanned outage that is

requested by WKEC of Plant Wilson, as opposed to an elective outage by Big Rivers of Plant Wilson), then WKEC shall, or shall cause its Affiliate to, sell and deliver to Big Rivers (at any point of interconnection to the Big Rivers' transmission system, where available to deliver energy to Big Rivers' member load, satisfactory to WKEC) an amount of replacement energy equal to 418 MW per hour for the number of hours during which Plant Wilson is not capable of any generating operations solely by reason of the Damage Event or the repair work by WKEC required hereunder to address the Damage Event. Big Rivers shall pay a purchase price equal to the lower of (y) WKEC's actual cost for such replacement energy or (z) the product of $18.50 per MWh multiplied by the volume (in MWh) of such replacement energy, which shall be immediately due and payable within 30 days after the invoice is delivered to Big Rivers following the delivery of such energy. Notwithstanding the foregoing, WKEC shall have no obligation to, nor any obligation to cause its Affiliate to, deliver replacement energy to Big Rivers pursuant to this Subsection 16(d)(2) for any periods during which WKEC's efforts to repair any physical damage to the Wilson Stack as contemplated in Subsection 16(c)(2) above shall be prevented or delayed as a result of a breach by Big Rivers of Section 16(b) above or of the gross negligence or willful misconduct of Big Rivers or its employees, agents or contractors. If for any reason replacement energy scheduled by WKEC to a particular interconnection point is cut, WKEC shall reschedule the cut energy at an alternative interconnection point. WKEC may not declare a Force Majeure for failure to deliver replacement energy. WKEC shall reimburse Big Rivers for any costs above $18.50 per MWh that Big Rivers incurs to procure replacement energy required to be delivered by WKEC hereunder and that WKEC fails to deliver.

(3) During any portion of an outage required solely for the purpose of repairing any material deterioration contemplated in Subsection 16(c)(3) above, WKEC shall sell and deliver to Big Rivers (at any point of interconnection to the Big Rivers' transmission system, where available to deliver energy to Big Rivers' member load, satisfactory to WKEC) an amount of replacement energy equal to 418 MW per hour for the number of hours during which Plant Wilson is not capable of any generating operations by reason of that required outage. Subject to Subsection 16(d)(4) below, Big Rivers shall pay a purchase price equal to the lower of (y) WKEC's actual cost for such replacement energy or (z) the product of $18.50 per MWh multiplied by the volume (in MWh) of such replacement energy, which shall be immediately due

and payable within 30 days after the invoice is delivered to Big Rivers following the delivery of such energy. Notwithstanding the foregoing, WKEC shall have no obligation to, nor any obligation to cause its Affiliate to, deliver replacement energy to Big Rivers pursuant to this Subsection 16(d)(3) for any periods during which WKEC's efforts to repair any material deterioration of the Interior Lining as contemplated in Subsection 16(c)(3) above shall be prevented or delayed as a result of a breach by Big Rivers of Section 16(b) above or of the gross negligence or willful misconduct of Big Rivers or its employees, agents or contractors. If for any reason replacement energy scheduled by WKEC to a particular interconnection point is cut, WKEC shall reschedule the cut energy at an alternative interconnection point. WKEC may not declare a Force Majeure for failure to deliver replacement energy. WKEC shall reimburse Big Rivers for any costs above $18.50 per MWh (or, for replacement energy to be delivered during the "Cumulative Interruption Period" (as defined in Subsection 16(d)(4) below) under the circumstances described in the first sentence of Subsection 16(d)(4), above an average cost of $58.50 per MWh) that Big Rivers incurs to procure replacement energy required to be delivered by WKEC hereunder and that WKEC fails to deliver.

(4) Notwithstanding anything contained in Subsection 16(d)(1) or 16(d)(3) to the contrary, in the event, during the Minimum Outage or any Outage Extension requested by WKEC, WKEC is rendered incapable for one or more periods of time, each of at least four consecutive hours in duration (each an "Interruption Period"), of performing the removal, cleaning or, as applicable, repair work contemplated in Subsection 16(c)(1) or 16(c)(3) above by reason of the actions or omissions of Big Rivers or its employee(s), agent(s) or contractor(s) which constitute negligence, but such actions or omissions did not constitute gross negligence or willful misconduct on the part of Big Rivers or such employee(s), agent(s) or contractor(s), and in the event as a result of the cumulative total of such Interruption Period(s), WKEC is not able to complete all such removal, cleaning and, as applicable, repair work during the Minimum Outage or that Outage Extension, then Big Rivers' cost for replacement energy delivered by WKEC, or its Affiliate, to Big Rivers during the first 168 hours of that Outage Extension necessary to make up the cumulative total of such Interruption Periods (such cumulative periods, up to a maximum of 168 hours, being referred to herein as the ***"Cumulative Interruption Period"***) shall be the lower of (y) WKEC's actual cost for such replacement energy or (z) the

product of $58.50 per MWh multiplied by the volume (in MWh) of such replacement energy. WKEC agrees to consult with Big Rivers with a view toward locating least cost sources for replacement energy to be delivered under the circumstances contemplated in this Subsection 16(d)(4). Big Rivers agrees to use its reasonable best efforts to return Plant Wilson to generating operation promptly following the request of WKEC made at the end of the Minimum Outage or at any time during the Outage Extension contemplated above; provided, that in the event, as of such request by WKEC, all removal, cleaning and/or repair work required to be undertaken and completed by WKEC has not been so completed by WKEC in accordance with Subsection 16(c)(1) or 16(c)(3) above, then WKEC agrees to complete the removal, cleaning and, as applicable, repair work of areas of the Interior Lining not cleaned or repaired by it during the Minimum Outage or that Outage Extension at a subsequent outage of Plant Wilson of sufficient duration to permit WKEC to complete the remaining removal, cleaning and, as applicable, repair work, but with no obligation on the part of WKEC to provide Big Rivers any replacement energy during that subsequent outage absent the agreement of WKEC to the contrary; and provided further, that such removal, cleaning and, as applicable, repair work during that subsequent outage shall be conditioned (i) on the fulfillment by Big Rivers of its covenants and agreements in Subsection 16(b) (exclusive of the first sentence of that Subsection) during the period following the Minimum Outage or the Outage Extension described above through that subsequent outage as though the provisions of Subsection 16(b) were originally applicable to that period and to that subsequent outage, and (ii) on that subsequent outage being of a duration reasonably sufficient for WKEC to complete that removal and cleaning work. In the event WKEC shall believe that an action or omission on the part of Big Rivers or its employee, agent or contractor constituting negligence shall have caused a failure of WKEC to complete the removal, cleaning or, as applicable, repair work contemplated in Subsection 16(c)(1) or 16(c)(3) during the Minimum Outage or the Outage Extension contemplated above, WKEC shall promptly notify Big Rivers of the circumstances leading to that belief, and the Parties shall immediately thereafter consult and attempt to mutually agree on the best course of action for promptly eliminating the impediment such that WKEC's work can be completed during the remainder of the Minimum Outage or the Outage Extension contemplated above.

(e) (1) In the absence of a breach by WKEC of its removal and cleaning commitment set forth in Subsection 16(c)(1), Big Rivers shall not attempt to remove or clean any Build-Up Materials from the Interior Lining of the Wilson Stack at any time following the Closing through the completion of the Minimum Outage or any Outage Extension requested by WKEC, without the prior written consent of WKEC; provided, that the foregoing shall not prevent Big Rivers from removing any Build-Up Materials that may completely "Separate" from the Interior Lining of the Wilson Stack.

(2) Notwithstanding anything to the contrary set forth in Section 16.4(b) of the Termination Agreement, the repair obligations, removal and cleaning obligations and energy sales obligations of WKEC provided for in this Section 16, and any costs and expenses associated with the same, shall be excluded for all purposes from (and from any limitation or calculation contemplated in) the first sentence of Section 16.4(b) of the Termination Agreement. The covenants and agreements of WKEC set forth in this Section 16 are in lieu of any other indemnification, defense, hold harmless, assumption, payment or reimbursement commitments or undertakings on the part of WKEC or LEM set forth elsewhere in the Termination Agreement or in any other Definitive Document with respect to Damage Events contemplated in this Section 16.

(f) WKEC shall indemnify and hold Big Rivers harmless from any loss, damage, cost, expense, claim and liability suffered or incurred in connection with the physical injury to any person due to a Damage Event, or resulting from or occurring in connection with the cleaning and removal work conducted by WKEC, its employees, agents and contractors pursuant to Section 16(c)(1) hereof, in each case occurring prior to an early termination of the Minimum Outage or the Outage Extension (as applicable) by Big Rivers as contemplated in Subsection 16(c)(1) above and not caused by the negligence or willful misconduct of Big Rivers or its employees, agents or contractors.

17. PAYMENT FOR CERTAIN COSTS. Upon the termination of the Termination Agreement in accordance with its terms at any time prior to a Closing (but not in the event a Closing occurs), WKEC shall remit and pay to Big Rivers in immediately available funds the amount of One Hundred Thousand Dollars ($100,000.00), in consideration of certain administrative and personnel costs theretofore or thereafter to be undertaken or incurred by Big Rivers. The provisions of this Section 17 shall survive the termination of the Termination Agreement for any reason and shall continue to be binding upon WKEC and to inure to the benefit of Big Rivers.

18. AMENDMENT TO SECTION 8.2. Consistent with the second sentence of Subsection 8.2(a)(ii) of the Termination Agreement, Section 8.2 of the Termination Agreement is hereby further amended to substitute Schedule 8.2 attached to this Third Amendment for and in place of the Schedule 8.2 referred to in Section 8.2 of the Termination Agreement and established pursuant to the First Amendment to Transaction Termination Agreement dated as of November 1, 2007, among the Parties (the *"First Amendment"*).

19. AMENDMENTS TO SECTION 12.2. The first sentence of Subsection 12.2(a)(vi) of the Termination Agreement is hereby further amended to be and read in its entirety as follows:

> "During 2007, 2008 and 2009, and provided Big Rivers funds the Big Rivers Contributions for 2007, 2008 and 2009 in accordance with the relevant Operative Document(s), WKEC shall spend not less than ninety percent (90%) of the cumulative total of the amounts (collectively, the "***Scheduled Amounts***") set forth on Schedule 12.2(a)(vi) through and including the Closing Month (pro-rated as contemplated below) for Non-Incremental Capital Costs and Henderson Non-Incremental Capital Costs."

In addition, Schedule 12.2(a)(vi) attached to this Third Amendment is hereby substituted for and in place of Schedule 12.2(a)(vi) referred to in Subsection 12.2(a)(vi) of the Termination Agreement and established pursuant to the First Amendment.

20. CERTAIN POTENTIAL RECEIPTS BY BIG RIVERS. In recognition that the Termination Payment to be made by WKEC to Big Rivers at the Closing will include an amount the purpose of which is to reimburse Big Rivers for certain costs incurred by it in connection with the September 30, 2008, termination of each of the three leveraged lease transactions between Big Rivers and Bluegrass Leasing, among other parties (the ***"PMCC Termination Transaction"***), Big Rivers hereby represents and warrants to E.ON, WKEC and LEM that no agreements, documents, instruments or other arrangements exist with any Person for the reimbursement of or contribution to Big Rivers with respect to the amounts paid or payable by Big Rivers or on its behalf in connection with the PMCC Termination Transaction (including, without limitation, amounts paid by Big Rivers or on its behalf in respect of "Lessor Consideration", as defined in the Omnibus Termination Agreement dated September 30, 2008, among Big Rivers, Bluegrass Leasing and other parties). In the event Big Rivers or any of its affiliates receives any reimbursement or other payment in connection with the PMCC Termination Transaction (including, without limitation, any contribution to the Lessor Consideration (other than the contribution by WKEC described above and other than proceeds received by Big Rivers from its three member distribution cooperatives, including in connection with the rates to be charged by Big Rivers to its three member distribution cooperatives, including the rates chargeable by Big Rivers to Kenergy Corp. for resale to the Smelters), and in the event such amounts received by Big Rivers or its affiliate(s) have not been contributed toward the Lessor Consideration, then Big Rivers hereby agrees to promptly pay fifty percent (50%) of such amount to WKEC.

21. SOLID FUEL STOCK INVENTORY LEVELS. (a) Section 10.3 of the Termination Agreement is hereby amended by adding the following condition precedent as a new Subsection 10.3(rr) thereto:

(rr) Solid Fuel Stock Inventory Levels. The quantities of Solid Fuel Stock constituting Inventory (as determined in accordance with Section 4.1) for each Generating Plant as of the date of Closing shall be at least an amount (on a Btu basis) equal to the following:

Generating Plant	Solid Fuel Stock Inventory Amount as of Closing (in GBtus)
Plant Wilson	2,791*
Plant Green	3,389**
Station Two/Plant Reid	2,142

Plant Coleman	3,156

*The amount of Petcoke included for purposes of determining the Solid Fuel Stock Inventory Amount above for Plant Wilson pursuant to this subsection 10.3(rr) will not exceed 50% on a Btu basis.

**The amount of Petcoke included for the purposes of determining the Solid Fuel Stock Inventory Amount above for Plant Green pursuant to this Subsection 10.3(rr) will not exceed 40% on a Btu basis.

For purposes of determining the Solid Fuel Stock Inventory Amount as of the date of Closing for each Generating Plant under this Subsection 10.3(rr), the following categories of Solid Fuel Stock shall be included:

1. all Solid Fuel Stock constituting Inventory located at such Generating Plant on September 30, 2008 which is still located at such Generating Plant on the date of Closing (the quantities of which shall be determined in accordance with Subsection 4.1(a));

2. all Solid Fuel Stock constituting Inventory at such Generating Plant which is delivered to such Generating Plant between September 30, 2008 and the date of Closing, and is still located at such Generating Plant (or is inventory in transit pursuant to Section 4.1 (a)) on the date of Closing (the quantities of which shall be determined in accordance with Section 4.1(a)), but only to the extent such deliveries (or inventory in transit) are attributable to a written contract to which WKEC is a party and either (i) was in existence as of September 30, 2008, or (ii) that is

related to or results from WKEC's solicitation for bids which were received by WKEC in September 2008 (a copy of which having been provided to Big Rivers);

3. all Solid Fuel Stock constituting Inventory at such Generating Plant which is delivered to such Generating Plant between September 30, 2008 and the date of Closing, and is still located at such Generating Plant (or is inventory in transit pursuant to Section 4.1 (a)) on the date of Closing (the quantities of which shall be determined in accordance with Section 4.1(a)), but only to the extent such Solid Fuel Stock (i) is attributable to a written contract (other than a contract described in clause 2) above), and (ii) such Solid Fuel Stock delivered in connection with the contract meets or exceeds the following specifications for the relevant Generating Plant:

	Coleman	Wilson	Green	Station Two/Reid
Moisture (max.) (lbs./MMBtu)	14.50	14.50	14.50	14.00
Ash (max.) (lbs./MMBtu)	12.00	15.00	17.00	11.00
Sulfur (max.) (lbs./MMBtu)	3.25	3.75	4.00	2.60
BTU/lb. (min.)	11,000	10,200	10,200	11,200

(b) Section 4.2 of the Termination Agreement is hereby amended by adding the following paragraph as a new paragraph:

Notwithstanding anything in this Section 4.2 to the contrary, if WKEC enters into a New Non-Solicitation Fuel Contract (as such term is defined below), and the delivered cost of Solid Fuel Stock under such New Non-Solicitation Fuel Contract is in excess of $3.44 per MMBtu, then WKEC shall make an adjustment at Closing with respect to the value of the Solid Fuel Stock to be included in the Inventory Value (as contemplated in the first sentence of this Section 4.2) to reflect that the delivered cost of Solid Fuel Stock delivered pursuant to such New Non-Solicitation Fuel Contract (and included in such value) is deemed to be $3.44 per MMBtu. For purposes of this paragraph, the term "New Non-Solicitation Fuel Contract" shall mean a written contract for the procurement of Solid Fuel Stock, entered into by WKEC between

September 30, 2008 and the date of the Closing, that is not related to nor resulting from WKEC's solicitation for bids which were received by WKEC in September 2008 (a copy of which having been provided to Big Rivers).

22. REAFFIRMATION. Except as amended or modified by this Third Amendment, the Termination Agreement shall continue in full force and effect from and after the date hereof in accordance with its terms.

[Signatures appear on the following page]

WITNESS the signatures of the undersigned as of the date first written above.

BIG RIVERS ELECTRIC CORPORATION

By:______________________________
Name:____________________________
Title:_____________________________

LG&E ENERGY MARKETING INC.

By:______________________________
Name:____________________________
Title:_____________________________

WESTERN KENTUCKY ENERGY CORP.

By:______________________________
Name:____________________________
Title:_____________________________

GUARANTOR'S CONSENT

FOR VALUE RECEIVED, the undersigned, **E.ON U.S. LLC**, a Kentucky limited liability company (***"E.ON"***), hereby consents to the Third Amendment to Transaction Termination Agreement to which this consent is appended (the ***"Third Amendment"***), which Third Amendment amends the Transaction Termination Agreement dated as of March 26, 2007, as amended (the ***"Termination Agreement"***), among Western Kentucky Energy Corp. (***"WKEC"***), LG&E Energy Marketing Inc. (***"LEM"***) and Big Rivers Electric Corporation (***"Big Rivers"***). The undersigned further agrees that the Termination Agreement as so amended (and the obligations of WKEC and LEM thereunder) shall continue to be the subject of that certain Guarantee dated as of March 26, 2007, from E.ON in favor of Big Rivers in accordance with its terms.

WITNESS the signature of the undersigned as of this _____ day of __________, 2008.

E.ON U.S. LLC

By: ______________________________
Name: ____________________________
Title: _____________________________

LOU: 3036012 4

APPENDIX A

SCHEDULE 15.3(d) TO THE TERMINATION AGREEMENT

Schedule 15.3(d)

1. May 31, 2007 spill of Turbine Lube Oil in the area by the auxiliary boiler feed pumps at Wilson Plant to the extent not remediated prior to the Closing.

2. June 16, 2007 spill of diesel fuel oil from underground piping into the sewage piping system at Wilson Plant to the extent not remediated prior to the Closing.

3. March 12, 2008 spill of power line chemical biocide materials at the cooling towers at Wilson Plant to the extent not remediated prior to the Closing.

4. May 19, 2008 spill of lube oil from #1 ID fan at Wilson Plant to the extent not remediated prior to the Closing.

5. April 21, 2007 spill of EHC fluid at the Green 1 EHC Unit at the Sebree Complex to the extent not remediated prior to the Closing.

6. September 22, 2007 spill of oil from the Green 2 step-up transformer at the Sebree Complex to the extent not remediated prior to the Closing.

7. September 30, 2007 spill of FGD thickener material from the Green 2 scrubber system at the Sebree Complex to the extent not remediated prior to the Closing.

8. October 23, 2007 spill of turbine lube oil from the Henderson 2 lube oil coolers at the Sebree Complex to the extent not remediated prior to the Closing.

9. April 14, 2008 spill of turbine lube oil from the Green 2 turbine lube oil reservoir at the Sebree Complex to the extent not remediated prior to the Closing.

10. August 15, 2007 spill of oil from the Coleman 2 main step-up transformer at the Coleman Plant to the extent not remediated prior to the Closing.

11. May 12, 2008 spill of turbine lube oil from the Coleman 1 turbine at the Coleman Plant to the extent not remediated prior to the Closing.

12. Notice of Violation received from the Division of Water on May 31, 2007, for excursions of TSS at the Sebree Complex;

13. Notice of Violation received from the Division for Air Quality on August 2, 2007, for exceedance of the Opacity Standard at the Reid 1 facility;

14. Notice of Violation received from the Division for Air Quality on August 3, 2007, for exceedances of the Opacity Standard at each unit at the Coleman facility;

15. Notice of Violation received from the Division of Water on March 4, 2008, for excursions of TSS at the Sebree Complex;

16. Notice of Deficiency received from the Division of Water on April 16, 2008, for errors in the Monthly Operating Report of the public water system at Wilson Plant;

17. Radiation exposure of personnel entering precipitator hoppers at the Wilson Station due to the failure of protective shutters on nuclear gauges to close (including five contractor personnel who may have experienced radiation exposure during the March 12, 2008 through March 13, 2008 period), and the related Notice of Violation received from the Radiation Health Branch on July 10, 2008;

18. Releases of petroleum or hazardous materials resulting from the sinking of the motor vessel Miss Debbie (Official Number 569023) on December 30, 2007, to the extent not remediated prior to the Closing;

19. Any complaints received during the period from the Execution Date through the Closing from any persons or entities (other than Big Rivers or any Member Cooperative) regarding particulate matter and plume impacts from the Wilson Plant that occurred at any time from the Execution Date through the Closing;

20. Any Notices of Violation received from the Division of Water following October _______, 2008 **[the date of this Third Amendment]** to the extent relating to excursions of pH or TSS at Sebree Complex occurring prior to the Closing;

21. Any noncompliances with existing reporting and recordkeeping protocols at the Sebree, Wilson, and Coleman Facilities under the Toxic Chemical Release Inventory (TRI) program from the Effective Date through the Closing relating to omission of metal releases from use of steel balls in stoker ball mills in the TRI reports; potential lack of certain release reporting back-up documentation; and potential inaccurate descriptions of materials as being "otherwise used" on Form R Reports; and

22. Any noncompliances with existing reporting and recordkeeping protocols under the Risk Management Planning (RMP) program at the Sebree and Wilson Facilities for ammonia and chlorine management from the Effective Date through the Closing relating to missing annual certifications that operating procedures are current and accurate; potential lack of documentation of management of change process information and mechanical integrity requirements; potential lack of triennial audit documentation; potential lack of coordination with local community emergency response plan; and potential deviations from operating procedure letters.

APPENDIX B

SCHEDULE 15.3(e) TO THE TERMINATION AGREEMENT

Schedule 15.3(e)

1. Wilson and Green Coal Conveyor Dust Collection Systems. Following the Closing, but subject to the limitations provided for below, WKEC shall indemnify and hold harmless Big Rivers from and against any and all fines and/or civil or criminal penalties that may be imposed or assessed against Big Rivers following the Closing under any applicable Environmental Law to the extent, but only to the extent, such fines and/or civil or criminal penalties resulted from or arose out of any failure of the coal conveyor dust collection system of Plant Green or Plant Wilson to comply with any Title V Permit condition during the period from the Effective Date through and including the date which is two hundred seventy (270) days following the Unwind Closing Date, solely by reason of the inoperability of any portion or component of that coal conveyor dust collection system during that same period, but then only to the extent Big Rivers has, throughout the 270-day period described above, maintained that coal conveyor dust collection system in the same general condition and state or repair as existed on the Unwind Closing Date, other than for such modifications, repairs and/or replacements of that system (or any components thereof) during that period by Big Rivers as are intended or designed to improve the operability, reliability or functionality of that system.

2. Indemnities for Groundwater Assessment Requirements.

(a) Notwithstanding anything to the contrary set forth elsewhere in this Third Amendment, in the Termination Agreement or in any other Definitive Document, and in lieu of any other indemnification, hold harmless or cost sharing covenants or other relief therefor set forth or contemplated elsewhere in this Third Amendment, in the Termination Agreement or in any other Definitive Document (but subject to the limitations contemplated in this Section 2), following the Closing WKEC and Big Rivers shall share responsibility (in the percentages set forth in Subsection (b) below) for any and all claims, demands, losses, damages, liabilities, costs, expenses, obligations and deficiencies (including without limitation, costs of corrective or remedial actions, fines, civil or criminal penalties, settlements and attorneys fees) that may following the Closing be suffered or incurred by WKEC, Big Rivers and their respective Affiliates, and their respective directors, officers, employees, agents, representatives, successors and assigns, or any of them (collectively, the ***"Applicable Costs"***), resulting from or arising out of any written requirement under Environmental Law (other than the letter identified in Subsection 15.3(d)(x) of the Termination Agreement) by the Kentucky Division of Waste Management (***"KDWM"***) for WKEC or Big Rivers to conduct a groundwater assessment of statistically significant increases in constituents in the groundwater adjacent to the special waste landfills at Plant Wilson or Plant Green, but only to the extent:

(i) the constituent at issue was detected in the groundwater by the Environmental Consultant in the Supplemental UEA Additional Groundwater Evaluation dated July 7, 2008 (being part of the Unwind Environmental Audit Report) for the Plant at issue, the concentration of that contaminant increased significantly since the audit that resulted in the Baseline Environmental Audit Report, and the concentration of that constituent was detected in the groundwater above Maximum Contaminant Levels or Region 9 Preliminary Remediation Goals for industrial sites as those levels/goals existed at that time; or

(ii) the constituents at issue are sulfates or chlorides; and

(iii) the constituent(s) so identified in subparagraph (i) or (ii) that is the subject of the requirement has statistically increased further in the groundwater adjacent to the special waste landfills at Plant Wilson or Plant Green between the Unwind Closing Date and the fifth (5^{th}) anniversary of that date, to a level which *either* then violates one or more Environmental Laws as in force and effect as of the Closing *or* is then required to be remedied or otherwise addressed by one or more Environmental Laws as in force and effect as of the Closing (but then only to the extent the same are so required to be remedied or addressed under Environmental Laws as in force and effect as of the Closing).

(b) Following the Closing, WKEC shall be responsible under this Section 2 for funding twenty percent (20%) of all Applicable Costs, and Big Rivers shall be responsible under this Section 2 for funding eighty percent (80%) of all Applicable Costs. In the event a Governmental Entity or other Person provides notice to Big Rivers alleging a claim, demand, violation or other deficiency which could give rise to an Applicable Cost, Big Rivers shall provide written notice thereof (together with a copy of any related written correspondence received from that Governmental Entity or Person) to WKEC within ten (10) business days thereafter in accordance with Section 18.4 of the Termination Agreement. Within twenty (20) business days of receipt of such notice, WKEC may notify Big Rivers that WKEC will participate in the Defense of or concerning any such claim, demand, violation or other deficiency in the manner contemplated in Section 16.6. Regardless of whether WKEC exercises its right hereunder to participate in the Defense of or concerning any such claim, demand, violation or other deficiency, Big Rivers and WKEC shall reasonably cooperate in good faith in opposing and defending against any such claim, demand, violation or other deficiency. Big Rivers and WKEC shall use their respective commercially reasonable efforts to minimize the Applicable Costs that are incurred.

(c) The provisions of this Section 2 shall be deemed for all purposes of the Termination Agreement to be included in and a part of Section 15.3 of the Termination Agreement, but shall not be subject to the last sentence of Section 15.3(e) of the Termination Agreement. Notwithstanding the foregoing provisions of this Section 2, the obligation of a Party to pay or fund its percentage share of Applicable Costs pursuant to this Section 2 shall only apply to the extent the relevant written requirement by the KDWM described above (or the statistically significant increase(s) in constituent(s) identified in that written requirement) is (or are) made the subject of a written claim for such payment or funding under this Section 2 from the other Party delivered prior to the sixtieth (60th) day following the fifth (5th) anniversary of the Unwind Closing Date, but then only to the extent that claiming Party believes in good faith that the criteria for such payment or funding obligation set forth above have been satisfied (the ***"Claim Deadline"***). Notwithstanding anything contained in this Section 2 to the contrary, in the event a Party (the "***First Party***") shall assert a claim against the other Party (the "***Second Party***") for payment or funding under this Section 2 at any time within thirty (30) days of the Claim Deadline, the period of time contemplated in the preceding sentence by which the Second Party must assert a claim against the First Party on the basis of any fact, event, circumstance which is the subject of that claim by the First Party shall be extended to the thirtieth (30th) day following the Claim Deadline. The covenants contemplated or contained in this Section 2 shall not apply to, and no Party shall be obligated hereunder for, any costs or expenses which constitute Incremental Environmental O&M, Henderson Incremental Environmental O&M, or costs or expenses for Capital Assets or Station Two Improvements that were or are necessary to comply with any requirement of any Environmental Law or any environmental regulatory authority.

3. <u>Indemnity Regarding SERC Audit</u>. Following the Closing, WKEC shall indemnify and hold harmless Big Rivers from and against any and all fines and/or civil penalties that may be imposed or assessed against Big Rivers by the SERC Reliability Corporation ("SERC") in connection with an audit by SERC of WKEC (to be conducted on or about November 2008) to the extent, but only to the extent, such fines and/or civil penalties resulted from or arose out of any failure of WKEC to comply with North American Electric Reliability Corporation ("NERC") reliability standards applicable to the Leased Generators (but not Station Two) and required to be met by WKEC as a registered Generation Operator. In no event shall WKEC have any obligation to indemnify and hold harmless Big Rivers or have any other responsibility or liability whatsoever under or pursuant to this Section 3 in connection with or related to any NERC reliability standards which are required to be met by a registered entity other than a registered Generation Operator, including without limitation, WKEC shall have no

obligation or responsibility for any NERC reliability standards which are required to be met by a Balancing Authority, Load-Serving Entity, Planning Authority, Resource Planner, Transmission Owner, Transmission Operator, Interchange Authority, Transmission Planner or Transmission Service Provider.

APPENDIX C

EXHIBIT S TO TERMINATION AGREEMENT

<u>EXHIBIT S</u>

DEFINITIVE DOCUMENTS

1. Termination Agreement
2. Termination and Release
3. E.ON Guaranty
4. Inventory Bill of Sale
5. Personal Property Bill of Sale
6. Assignment and Assumption of Contracts
7. Intercreditor Agreement
8. Deed of Real Property (Central Lab parcel)
9. Deed of Real Property (Hancock County parcel)
10. Assignment of Owned Intellectual Property
11. License of Owned Intellectual Property
12. Information Technology Support Services Agreement
13. Assignment and Assumption of Permits
14. Conveyance of Allowances
15. Alcan Termination and Release
16. Century Termination and Release
17. Creditor Termination and Release
18. Station Two Termination and Release
19. Texas Gas Termination and Release
20. Transmission Agreement

21. Generation Dispatch Support Services Agreement

22. Assignment of Unemployment Reserve

23. Any Contract Counterparty Consents or other agreed forms of Assigned Contract Counterparty acknowledgments, releases and discharges that may be entered into as contemplated in Section 5.2.

24. The Assigned Contract Indemnity if any.

25. The letter agreement dated November 1, 2004, as amended, between Big Rivers and WKEC (as successor to WKE), and the related guaranty of even date therewith, as amended, from E.ON to and in favor of Big Rivers.

26. The letter agreement dated February 9, 2007, among Big Rivers, E.ON, Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, regarding the funding of certain consent fees.

27. The letter agreement dated February 9, 2007, among Big Rivers, E.ON, Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, regarding the funding of certain transaction costs.

28. The certificate of the Responsible Officer of Big Rivers contemplated in Section 10.2(a), and the certificate of the Responsible Officer of Big Rivers contemplated in Section 10.2(c).

29. The written acknowledgment regarding the Termination Payment contemplated in Section 10.2(z), and the written acknowledgment regarding the True-Up Payments contemplated in Section 10.2(aa).

30. The acknowledgment of Big Rivers contemplated in Section 10.2(hh).

31. The release and discharge contemplated in Section 10.2(ii) unless such release and discharge is accomplished pursuant to the agreements referred to in items 17 and 18 above.

32. The certificate of the Responsible Officer of each of the WKE Parties contemplated in Section 10.3(a), and the certificate of the Responsible Officer of the WKE Parties and E.ON contemplated in Section 10.3(c).

33. The Confidentiality Agreement dated April 26, 2004, as amended, between or among certain of the Parties and/or E.ON.

34. The written waiver of certain Member Cooperatives contemplated in Section 3.2(o).

35. All documents of conveyance, assignment and transfer as shall be required to transfer to Big Rivers at the Closing all of WKEC's rights, title and interests in

and to all tow boats and other motorized vessels owned by WKEC (but excluding the "Barges" (as defined in Section 15 of the Third Amendment to Transaction Termination Agreement)), including without limitation, any such documents as are required to be filed with the United States Coast Guard to effect that conveyance, assignment and transfer;

36. The Closing Memorandum among Big Rivers, WKEC, LEM and E.ON to be entered into as of the Closing and to be dated as of the Unwind Closing Date, evidencing certain agreements of the Parties with respect to the Closing or certain transactions relating to the Closing;

37. The letter agreement dated April 14, 2008, among the Parties, and relating to the capacity testing of the Generating Plants contemplated in Subsection 10.2(ee) of the Termination Agreement;

38. The First Amendment to Transaction Termination Agreement dated November 1, 2007, among the Parties, together with the related letter agreement among the Parties dated December 4, 2008;

39. The Second Amendment to Transaction Termination Agreement among the Parties dated June 19, 2008;

40. The Third Amendment to Transaction Termination Agreement among the Parties dated October _______, 2008;

41. The letter agreement dated April 17, 2008, among the Parties, setting the Scheduled Unwind Closing Date;

42. The letter agreement among Big Rivers, Alcan Primary Products Corporation, Century Aluminum of Kentucky General Partnership and E.ON, dated June 24, 2008, relating to the buy-out of Bank of America's defeased lease position by Big Rivers;

43. The letter agreement between Big Rivers and E.ON, dated June 24, 2008, relating to the buy-out of Bank of America's defeased lease position by Big Rivers;

44. The sublease to Big Rivers of the space leased by WKEC in the Soaper Building located in downtown Henderson, Kentucky;

45. The letter agreement between Big Rivers and E.ON, dated September 26, 2008, relating to the treatment of certain costs associated with the buy-out of Philip Morris Capital Corporation's defeased lease position by Big Rivers; and

46. Any and all amendments to any of the other agreements or instruments identified in this <u>Exhibit S</u> that have been or may hereafter be implemented by the written agreement of the parties to such agreements or instruments.

* * * * *

APPENDIX D

FORM OF AGREED ORDER

COMMONWEALTH OF KENTUCKY
ENERGY AND ENVIRONMENT CABINET
DIVISION FOR AIR QUALITY
DIVISION OF WATER
FILE NO. DOW-33299

IN RE: Western Kentucky Energy Corp.
P.O. Box 1518
Henderson, KY 42419
KYEIS I.D. #: 2109100003; AI #: 1640
Activity #: APE 20080001; and
KPDES No.: KY0054836; AI #: 3319
Activity #: 20040004

AGREED ORDER

WHEREAS, the parties to this Agreed Order, the Energy and Environment Cabinet (hereinafter "Cabinet") and Western Kentucky Energy Corp. (hereinafter "WKEC"), state:

STATEMENTS OF FACT

1. The Cabinet is charged with the statutory duty of enforcing KRS Chapter 224 and the regulations promulgated pursuant thereto.

2. WKEC is a Kentucky corporation with a principal office located in Henderson, Kentucky. WKEC leases and operates the following facilities that are the subject of this Agreed Order: (a) the Kenneth C. Coleman Station, which is an electric power plant located in Hawesville, Kentucky (hereinafter "Coleman Station"); and (b) the D.B. Wilson Station, which is an electric power plant located in Island, Kentucky (hereinafter "Wilson Station").

Coleman Station

3. WKEC, is the holder of Division for Air Quality Title V permit number V-02-003 issued on October 24, 2003, Source ID# 21-091-00003, for Coleman Station.

4. The Title V Permit for Coleman Station is set to expire on October 24, 2008. Kentucky regulations, specifically 401 KAR 52:020 Section 12(4), required WKEC to submit an application to the Kentucky Division for Air Quality (hereinafter "KDAQ") for renewal of this permit within six months of its expiration date. The KDAQ received WKEC's application to renew the Coleman Station permit on May 14, 2008, and it is presently undertaking a review of WKEC's permit renewal application. It is possible that a renewed Title V permit will not be issued before the current permit expires.

5. Pursuant to 401 KAR 52:020 Section 12, the expiration of a source's Title V permit will terminate its authority to operate unless the source submits a "timely and complete renewal application."

Wilson Station

6. WKEC is the holder of Kentucky Pollutant Discharge Elimination System ("KPDES") permit number KY0054836 for Wilson Station, which the Kentucky Division of Water ("KDOW") originally issued on February 26, 2001 with an effective date of April 1, 2001. This permit was set to expire on October 31, 2004. The KDOW notified WKEC of this fact in a letter dated June 23, 2004 and explained that WKEC was to complete and return a renewal application to the KDOW's KPDES permit branch by July 15, 2004.

7. Pursuant to the KDOW's June 23, 2004, letter, WKEC submitted a new KPDES permit application on July 14, 2004, although the KDOW did not receive WKEC's application

until July 16, 2004. The KDOW notified WKEC that its KPDES application was complete in a letter dated September 14, 2004. As of the date of this Agreed Order, the KDOW has not issued a renewed KPDES permit for Wilson Station.

8. If a permittee submits a timely application for a renewed KPDES permit, it may discharge pursuant to the terms of the expired permit until the effective date of the renewed permit issued by the KDOW. *401 KAR 5:060 Section 1(5)(c).*

Modification of the Wilson Station KPDES Permit

9. In a July 8, 2003 letter to the KDOW, WKEC requested a modification of its KPDES permit for the Wilson Station to allow for the addition of four process water treatment basins to run along a fuel conveyor, which extends from the Green River to a fuel pile at the facility. These basins collect storm water from the base of the conveyor and treat it by primary settling.

10. The KDOW advised WKEC that it could operate the above-referenced water treatment basins provided that WKEC monitor the discharge for Total Suspended Solids ("TSS"), pH, oil and grease. Based on this representation, WKEC has operated the aforementioned storm water basins according to the limitations imposed by the KDOW.

Operating Status and Permit Transfer

11. The Coleman Station and Wilson Station facilities discussed herein are of vital importance to serving the electrical power needs of residents and industry in Western Kentucky.

12. A transfer of the various operating permits issued by the Cabinet for Coleman Station and Wilson Station to a new operator is currently under consideration by WKEC. It is

important to provide for certainty with respect to permit and regulatory operating authorizations for the Coleman Station and the Wilson Station to support the potential transfer of the above-referenced permits to new operators.

13. This Agreed Order is intended to provide authorization for continued operation of the aforementioned facilities consistent with existing permit authorizations pending issuance of renewed permits based upon pending permit applications, and to resolve any potential claims that such operating authorizations would not exist without renewed or reissued permits.

NOW THEREFORE, in the interest of settling all claims and controversies involving the matters described above, the parties hereby consent to the entry of this Agreed Order and agree as follows:

14. In the event that the Title V permit for Coleman Station is not renewed in final form before the expiration of the facility's current permit on October 24, 2008, WKEC, or any successor operator of Coleman Station, is authorized to operate in accordance with its present Title V permit for Coleman Station, KRS Chapter 224 and the regulations promulgated thereto, including, but not limited to 401 KAR 52:020, "Title V permits," pending final action on the pending Title V permit application. The Cabinet agrees that for purposes of this matter, the Title V renewal application was complete and timely submitted.

15. With respect to the Wilson Station KPDES permit, as indicated in the KDOW's September 14, 2004 letter, the KDOW considers WKEC's application for a renewal of the KPDES permit for Wilson Station to be complete. In addition, the KDOW considers WKEC's renewal application to be timely made pursuant to 401 KAR 5:060, which allows the KDOW discretion to accept KPDES permit renewal applications within 180 days of the permit's

expiration date. Thus, WKEC, or any successor operator of Wilson Station, may continue to operate Wilson Station according to its present KPDES permit pursuant to 401 KAR 5:060 Section 1(5)(c) until a renewed KPDES permit is issued and becomes effective.

16. With respect to the conveyor belt storm water basins at Wilson Station, WKEC, or any successor operator at Wilson Station, may continue to operate these basins pending the issuance of a modified KPDES permit for the facility, as requested in WKEC's July 8, 2003 letter to the KDOW, provided that it continues to monitor the discharge from the ponds for TSS, pH, oil and grease, and otherwise employs best management practices to reduce pollutants in the storm water discharge from said facilities.

MISCELLANEOUS PROVISIONS

17. This Agreed Order addresses only the matters specifically described above. Other than those matters resolved by entry of this Agreed Order, nothing contained herein shall be construed to waive or to limit any remedy or cause of action by the Cabinet based on statutes or regulations under its jurisdiction and WKEC reserves its defenses thereto. The Cabinet expressly reserves its right at any time to issue administrative orders and to take any other action it deems necessary that is not inconsistent with this Agreed Order, including the right to order all necessary remedial measures, assess penalties for violations, or recover all response costs incurred, and WKEC reserves its defenses thereto.

18. This Agreed Order shall not prevent the Cabinet from issuing, reissuing, renewing, modifying, revoking, suspending, denying, terminating, or reopening any permit to WKEC or its successor. WKEC reserves his/its defenses thereto, except that WKEC shall not use this Agreed Order as a defense.

19. WKEC waives its right to any hearing on the matters described herein. However, failure by WKEC to comply strictly with any or all of the terms of this Agreed Order shall be grounds for the Cabinet to seek enforcement of this Agreed Order in Franklin Circuit Court and to pursue any other appropriate administrative or judicial action under KRS Chapters 224 and the regulations promulgated pursuant thereto.

20. The Agreed Order may not be amended except by a written order of the Cabinet's Secretary or his designee. WKEC may request an amendment by writing the Director of Division of Water or the Director of the Division for Air Quality at 200 Fair Oaks Lane, Frankfort, Kentucky 40601 and stating the reasons for the request. If granted, the amended Agreed Order shall not affect any provision of this Agreed Order unless expressly provided in the amended Agreed Order.

21. The Cabinet does not, by its consent to the entry of this Agreed Order, warrant or aver in any manner that WKEC's complete compliance with this Agreed Order will result in compliance with the provisions of KRS Chapter 224 and the regulations promulgated pursuant thereto. Notwithstanding the Cabinet's review and approval of any plans formulated pursuant to this Agreed Order, WKEC shall remain solely responsible for compliance with the terms of KRS Chapter 224 and the regulations promulgated pursuant thereto, this Agreed Order and any permit and compliance schedule requirements.

22. WKEC shall give notice of this Agreed Order to any purchaser, lessee or successor in interest prior to the transfer of operation of any part of the subject facilities occurring prior to termination of this Agreed Order, shall notify the Cabinet that such notice has been given, and shall follow all statutory and regulatory requirements for a transfer.

23. This Agreed Order applies specifically and exclusively to the unique facilities referenced herein and is inapplicable to any other site or facility.

24. This Agreed Order shall be of no force and effect unless and until it is entered by the Secretary or his designee as evidenced by his signature thereon.

25. This Agreed Order shall terminate upon the issuance of the final renewed Title V permit for Coleman Station and the issuance of a renewed KPDES permit for Wilson Station, except that the claims and controversies related to the matters described above shall remain resolved for enforcement purposes.

AGREED TO BY:

____ ________________________

President Date
Western Kentucky Energy Corp.

APPROVAL RECOMMENDED BY:

John S. Lyons, Director Division for Air Quality	Date
Sandy Gruzesky, Director Kentucky Division of Water	Date
John G. Horne, II, General Counsel Environmental Protection Legal Division	Date
C. Michael Haines, General Counsel Office of General Counsel	Date

ORDER

Wherefore, the foregoing Agreed Order is entered as the final Order of the Energy and Environment Cabinet this the _______ day of _______________, 200____.

ENERGY AND ENVIRONMENT CABINET

____

LEONARD K. PETERS, SECRETARY

FILE NO. DOW-33299

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing **AGREED ORDER** was mailed, postage prepaid, to the following
this the _____ day of ________________, _____:

Jack Bender
Greenebaum Doll & McDonald PLLC
300 West Vine Street, Suite 1100
Lexington, Kentucky 40507

And mailed via messenger mail to:

John S. Lyons, Director
Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601

Sandy Gruzesky, Director
Kentucky Division of Water
14 Reilly Road
Frankfort, KY 40601

John G. Horne, II, General Counsel
Environmental Protection Legal Division
300 Fair Oaks Lane
Frankfort, Kentucky 40601

____

DOCKET COORDINATOR

APPENDIX E

LIST OF KNOWN SURFACE SPILLS

ID #	PLANT	ID from INTERIM UEA REPORT	ID from SUPPLEMENTAL UEA REPORT	AREA DESCRIPTION	Post-Excavation Sampling	NOTES
1	Sebree	N/A	AOS-1 (Figure 2-1); Section 3.2.1.6	Stressed vegetation was observed south of the boneyard and west of Green Ash Pond.	Estimate 4 Samples (TPH & PAH)	
2	Sebree	3.2.1.9	AOS-2 (Figure 2-1)	Surface staining was observed in the area between Reid Oil Storage Building and Fueling Station adjacent to Green Cooling Towers and Front Gate. Staining of soils was observed around the new drummed lubricant storage area, used for storage of motor oil, anti-freeze, hydraulic fluid, gear oil, mineral spirits, turbine oil, and grease.	Estimate 2 Samples (TPH & PAH)	
3	Sebree	N/A	AOS-3 (Figure 2-1)	Surface staining was observed near Reid Central Machine Shop and the Oil Storage Building.	No Excavation and no Sampling Required	Oil drums no longer stored at this location. Minimal staining was observed on the asphalt.*

ID #	PLANT	ID from INTERIM UEA REPORT	ID from SUPPLEMENTAL UEA REPORT	AREA DESCRIPTION	Post-Excavation Sampling	NOTES
4	Sebree	Section 3.2.1.9	AOS-4 (Figure 2-1)	Staining of soils was observed around the transfer piping and truck unloading manifolds by the 750,000 gallon fuel oil AST near the Reid Bulk Fuel Oil Storage and HMP&L SCR Ammonia Storage.	Soil will be removed down to concrete. No sampling required.	The majority of the staining was observed on the concrete containment unit.*
5	Sebree	Section 3.2.1.9	AOS-5 (Figure 2-1)	Staining of soils was observed around the 550 gallon waste oil tank and area adjacent to the coal handling heavy equipment maintenance building. Area is outside HMP&L Warehouse and Reid Heavy Machine Shop.	Estimate 1 Sample (TPH, RCRA Metals and PAH)	
6	Sebree	Section 3.2.1.9	AOS-6 (Figure 2-1)	Staining of soils was observed around the piping manifold system connected to a 26,500 gallon fuel oil storage tank, south of the Green Fuel Tank.	Clean concrete. No sampling.	Staining was observed on the concrete pad.*
7	Sebree	N/A	AOS-7 (Figure 2-1)	Stained gravel surrounding Reid/HMP&L Transformer (aux & step-up) pads.	Estimate 4 Samples (PAH, TPH and PCBs)	
8	Wilson	Sections 3.4.1.9, 3.4.1.20	AOS-1 (Figure 2-5B)	Minor miscellaneous staining of the gravel surrounding the Coal Handling Heavy Equipment Maintenance Area building was observed. This includes the area adjacent to the former Fuel Dispensing Area (10,000 gal diesel; 1,800 gal gasoline; and 2,450 gal kerosene ASTs).	Estimate 5 Samples (TPH, PAH and RCRA Metals)	

ID #	PLANT	ID from INTERIM UEA REPORT	ID from SUPPLEMENTAL UEA REPORT	AREA DESCRIPTION	Post-Excavation Sampling	NOTES
9	Wilson	N/A	AOS-2 (Figure 2-5B)	Surface staining observed adjacent to #1 and #2 ID Fans.	Clean Concrete. No sampling.	Staining observed on concrete.*
10	Wilson	N/A	AOS-3 (Figure 2-5B)	Surface staining observed adjacent to #1 and #2 ID Fans.	Clean Concrete. No Sampling.	Staining observed on concrete.*
11	Wilson	N/A	AOS-4 (Figure 2-5B)	Surface staining observed adjacent to #1 and #2 ID Fans.	No action required.	No staining observed.*
12	Wilson	Section 3.4.1.8	AOS-5 (Figure 2-5B)	Surface staining observed adjacent to Drum Waste Storage Area.	No Action Required.	Minimal staining observed on asphalt.*
13	Wilson	Section 3.4.1.9	AOS-6 (Figure 2-5B)	Surface staining observed adjacent to GE Warehouse Building.	Estimate 2 Samples (TPH and PAH)	
14	Wilson	Section 3.4.1.9	AOS-7 (Figure 2-5B)	Surface staining observed in the area previously utilized for storing the Portable Diesel Tank.	Estimate 1 Sample (TPH & PAH)	A general area is indicated on the figure - the diesel tank is portable so the staining is not limited to one area, but is dependent on the location of coal piles.

ID #	PLANT	ID from INTERIM UEA REPORT	ID from SUPPLEMENTAL UEA REPORT	AREA DESCRIPTION	Post-Excavation Sampling	NOTES
WNS #1*	Wilson	N/A	N/A	Stained gravel was observed just off the concrete pad (east and west) that houses the Bulk Fuel Tanks used for boiler start-up fuel.	Estimate 2 Samples (TPH & PAH)	
WNS #2* (see also AOS 14)	Wilson	N/A	N/A	Stained gravel was observed in the storage shelter south of the coal storage area. The shelter is currently utilized for storing the Portable Diesel Tank.	See #14	
WNS #3*	Wilson	N/A	N/A	Stained gravel was observed within the containment unit that houses the GE step-up transformer.	Concrete containment unit. No sampling Required.	
15	Coleman	N/A	AOS-1 (Figure 2-3)	Surface staining observed in area north of Coal Handling Machine Shop.	Estimate 1 Sample (TPH & PAH	
16	Coleman	N/A	AOS-2 (Figure 2-3)	Surface staining was observed in the area north of Coal Handling Office.	Estimate 1 Sample (TPH & PAH)	
17	Coleman	Section 3.3.1.1	AOS-3 (Figure 2-3)	Stained gravel and/or soil was observed near transformers (aux., spare, and step-up) on the south face of the power units.	Estimate 1 Sample (TPH, PAH & PCB	
18	Coleman	Section 3.3.1.1	AOS-4 (Figure 2-3)	Stained gravel and/or soil was observed near transformers (aux., spare, and step-up) on the south face of the power units.	Estimate 2 Samples (TPH, PAH & PCB	

ID #	PLANT	ID from INTERIM UEA REPORT	ID from SUPPLEMENTAL UEA REPORT	AREA DESCRIPTION	Post-Excavation Sampling	NOTES
19	Coleman	Section 3.3.1.1	AOS-5 (Figure 2-3)	Stained gravel and/or soil was observed near transformers (aux., spare, and step-up) on the south face of the power units.	Estimate 2 Samples (TPH, PAH & PCB	
20	Coleman	Section 3.3.1.1	AOS-8 (Figure 2-3)	Stained soil and stressed vegetation was observed at the Power Unit between Units 1 and 2, likely due to the Soil Vapor Extraction system.	Estimate 1 Sample (TPH, PAH & PCB	
21	Coleman	Section 3.3.1.1	AOS-6 (figure 2-3)	The collection drum in front of C-1 sits directly on soil, which was heavily stained.	Estimate 1 Sample (TPH & PAH)	
22	Coleman	Section 3.3.1.18	AOS-7 (Figure 2-4)	Stressed vegetation and staining was observed in the vicinity of the former location of the 54,000 gallon fuel tank.	No excavation but 4 confirmation samples will be collected around perimeter of concrete pad	No definitive staining observed.
CNS #1*	Coleman	N/A	N/A	Stained gravel was observed adjacent to the concrete pad located on the south face of Coleman Unit #2. CNS #1 is located within 10 ft. to the south of AOS-20.	Estimate 1 Sample (TPH, PAH & PCB	
CNS #2*	Coleman	N/A	N/A	Stained soil was observed next to the building between Coleman Units #2 and #3. CNS #2 is located between AOS-17 and AOS-18.	Estimate 1 Sample (TPH & PAH)	

* Observations made during the site walks on 9/10-11/08.

APPENDIX F

BARGES

SEE ATTACHED

WKE - Owned Barge Information Summary

Barge New ID	Old ID	Hull ID	Type	Purchase Date	Construction Date	Model	Age (Years)	Dimensions (l'xw'xh')	Draft Weights (Tons) 9' 0"	9' 6"
WKE 001	PN 128	613537	Rake	3/23/05	1979	Jeffboat Inc	29	195'x35'x12'		
WKE 002B	RR 201	598521	Box	3/31/05	1978	Jeffboat Inc	30	200'x35'x12'	1,639	1,749
WKE 003B	RR 202	598257	Box	4/29/05	1978	Jeffboat Inc	30	200'x35'x12'	1,639	1,749
WKE 004	PC 104	604685	Rake	4/8/05	1979	Jeffboat Inc	29	195'x35'x12'	1,531	1,637
WKE 005	HLEM 504	629521	Rake	3/23/05	1980	Ingalls Ship	28	195'x35'x12'	1,512	1,616
WKE 006B	RR 204	598258	Box	4/21/05	1978	Jeffboat Inc	30	200'x35'x12'	1,639	1,749
WKE 007B	PJ 114	605143	Box	3/23/05	1979	Jeffboat Inc	29	200'x35'x12'	1,665	1,775
WKE 008	PN 132	613850	Rake	3/23/05	1979	Jeffboat Inc	29	195'x35'x12'	1,520	1,625
WKE 009	PN 124	613532	Rake	4/8/05	1979	Jeffboat Inc	29	195'x35'x12'	1,520	1,625
WKE 010B	PL 146	614804	Box	3/23/05	1979	St. Louis Ship	29	200'x35'x12'	1,647	1,757
WKE 011	PC 103	604684	Rake	3/31/05	1979	Jeffboat Inc	29	195'x35'x12'	1,531	1,637
WKE 012	SJT 152	621697	Rake	6/7/05	1980	Jeffboat Inc	28	195'x35'x12'		
WKE 013	SJT 155	621700	Rake	6/7/05	1980	Rake	28	195'x35'x12'		
WKE 014B	PJ 115	605144	Box	5/12/05	1978	Jeffboat Inc	30	200'x35'x12'	1,665	1,775
WKE 015	PJ 123	613531	Rake	5/12/05	1979	Jeffboat Inc	29	195'x35'x12'	1,521	1,626
WKE 016	SJT 153	621698	Rake	6/7/05	1980	Rake	28	195'x35'x12'		

APPENDIX G

Interior Stack Cleanup Specifications

- The interior wall of the brick liner shall be cleaned to expose the brick surface and mortar joints to allow visual inspection.

- The brick-work shall be cleaned adequately to allow for visual detection of mortar joint degradation, cracks or spalling

- The brick-work shall be cleaned adequately to allow for visual detection and continuation of tracking of cracks in brick to compare with previous baseline data attached to the Molter Corporation report performed in year 2000, as well as prior data collected.

- The area of the breech duct penetration to the stack shall be cleaned to expose all brick, hardware and expansion joint fabric to allow for visual detection of defects such as missing hardware, cracks, or tears without destructive testing techniques.

Schedule 8.2

LEASED GENERATOR SO_2 ALLOWANCES

Closing Year Month	SO_2 Allowances
January, 2008	5,069
February	4,632
March	1,349
April	2,741
May	2,747
June	2,811
July	4,839
August	4,940
September	2,594
October	3,047
November	2,957
December	3,067
January, 2009	4,198
February	3,649
March	2,658
April	2,326

The allowance amounts set forth above do not include SO_2 Allowances allotted to Station Two.

Schedule 12.2(a)(vi)

NON-INCREMENTAL CAPITAL EXPENDITURES

Closing Year Month	Non-Incremental Capital Expenditures ($)
January, 2007	49,000
February	972,500
March	4,015,100
April	2,335,000
May	6,038,000
June	2,606,300
July	1,560,300
August	2,414,500
September	1,047,500
October	2,865,500
November	1,152,500
December	121,500
January, 2008	156,000
February	475,667
March	6,334,500
April	3,519,167
May	5,240,500
June	2,045,667
July	3,593,000
August	1,943,117
September	1,942,300
October	2,024,267
November	281,500
December	67,665
January, 2009	923,500
February	4,123,030
March	5,411,435
April	4,443,035