COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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

O R D E R

By Order dated April 30, 1998 in Case No. 97-204,[1] the Commission approved new rates for Big Rivers Electric Corporation ("Big Rivers"), and approved in principle a 25 year lease of its generating units to a subsidiary of LG&E Energy Corp. The Commission's decision was based on the transaction as reflected in the documents filed as of February 27, 1998. However, since many of the documents were revised after that date, the Commission directed that the final drafts of all jurisdictional documents be submitted in this case for a determination of whether material changes have been made to the structure of the transaction.

This case was established on May 15, 1998 when Big Rivers filed the 1998 Amendments to Station Two Contracts which relate to its operation of the City of Henderson's Station Two Generating Plant. Over the next 45 days, Big Rivers filed the

[1] 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.

final drafts of all transaction documents. A procedural schedule was entered providing all parties an opportunity to engage in discovery and a public hearing was held on July 6, 1998.

The Commission notes at the outset that this is anything but a routine review of documents relating to a rate adjustment and asset lease. Big Rivers is a debtor in possession under Chapter 11 of the United States Bankruptcy Code. The documents under review are essential and critical components of Big Rivers' plan of reorganization as approved by the Bankruptcy Court on June 1, 1998. All of the parties to Case No. 97-204 were made parties to this case. Most of them participated to some extent in this case, but no party objected to any of the documents under review herein. The absence of any objection, however, does not diminish the Commission's obligation to ensure that there have been no material changes in the transaction. This obligation takes on greater importance here since the term of the lease is 25 years and the power contracts have terms that extend up to 25 years.

Based on a comprehensive analysis of the final drafts of the transaction documents, the Commission finds that there have been several material changes made to the structure of the lease transaction. The most current economic analysis of the lease transaction, filed by Big Rivers on July 7, 1998 and identified as PSC2-38R, has been compared to the one identified as SUP-11, which formed the basis for our conditional approval in Case No. 97-204. To the extent the transaction has undergone a material change, it is discussed herein.

Transmission Service for Smelter Loads

The documents on file with the Commission as of February 27, 1998 provided as follows with respect to the Smelters' transmission service:

1) Green River Electric Corporation ("Green River") and Henderson Union Electric Cooperative Corp. ("Henderson Union") would arrange for and reserve transmission on Big Rivers' transmission system for Tier 1 Energy, Tier 2 Energy, and Tier 3 Energy purchased from LG&E Energy Marketing Inc. ("LEM") for resale to Southwire Company ("Southwire") and Alcan Aluminum Corporation ("Alcan").[2]

2) Transmission services were to be provided at Big Rivers' Open Access Transmission Tariff ("OATT") rates.[3]

3) Green River and Henderson Union were responsible for all transmission costs and were entitled to a transmission credit against the total payments owed to LEM. The credit equaled the amount the cooperative paid to Big Rivers for the transmission of Tier 1 Energy, Tier 2 Energy, Tier 3 Interruptible Energy, and Tier 3 Backup Energy.[4]

4) LEM would pay to the RUS, on behalf of Big Rivers, a monthly smelter margin payment ("monthly margin payments"), which reflected the net

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[2] See Case No. 97-204, Document filing of February 23, 1998, Volume III, Tabs 15 and 16, at 8-12. The reference is to the Amendments to the Wholesale Power Agreements between Big Rivers and Green River and Big Rivers and Henderson Union, Paragraphs 3 and 4.

[3] Id. at 11.

[4] See Case No. 97-204, Documents filed February 27, 1998, the Agreements between Henderson Union and LEM and Green River and LEM, Schedule A, part g.

smelter margins originally included in Big Rivers' financial model. The monthly margin payments would remain fixed regardless of the amount of power actually supplied by LEM to the Smelters and the payments specifically excluded any transmission service revenues.[5]

Big Rivers, the LG&E Parties, and the Smelters had strongly stressed the significance of the guaranteed monthly margin payments and the significant benefit this arrangement represented to Big Rivers.[6] The Commission accepted this argument, noting in the April 30, 1998 Order that the guarantee of the smelter margins was an improvement to the overall transaction, which the Commission approved in principle.

The changes made to the transaction documents reviewed in Case No. 97-204 include the following relating to transmission service for the Smelters' load:

1) LEM will arrange for and reserve transmission on Big Rivers' transmission system for Tier 1 Energy, Tier 2 Energy, and Tier 3 Energy. LEM will continue to provide Green River and Henderson Union with the energy resold to the Smelters, with the types and amounts of transmission reserved by LEM for these sales being referred to as Member Transmission.[7]

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[5] See Case No. 97-204, Supplemental Testimony of A. J. Robison, Stephen Schaefer, and Mark A. Hite, at 4, 5, and 8.

[6] See Case No. 97-204, Transcript of Evidence, Volume VI, March 18, 1998, at 11-12, 15, and 48; Big Rivers Supplemental Initial Brief at 14-16; LG&E Parties Initial Brief Addressing Future Unforeseen Cost Issue at 3; Alcan and Southwire Supplemental Brief on Unforeseen Cost Resolution at 4-5.

[7] Document filing of May 29, 1998, Volume II, Tab 8, at 19-25. The reference is to the Transmission Service and Interconnection Agreement, Sections 6.5.1. and 6.5.2.

2) LEM will continue to pay the monthly margin payments to the RUS on behalf of Big Rivers. However, these payments have been revised to include the revenue for smelter transmission service, which was originally shown separately in the Big Rivers financial model.[8]

3) As long as the full monthly margin payments are made pursuant to the terms of the transaction agreements, Big Rivers will deem the full cost of the Member Transmission to have been paid at the then applicable OATT rate as part of the monthly margin payments. Consequently, LEM's cumulative cost for Member Transmission charged by Big Rivers will never exceed the cumulative amount of the monthly margin payments.[9]

The impact of these changes on Big Rivers is that if its OATT transmission rate increases, it will no longer recover the full smelter margin payments and its cost of transmission service. The margin payments are now to be reduced by any increase in transmission rates above the levels agreed to by the Smelters.

Big Rivers contends that it had always borne the economic risk of future changes in transmission costs as applied to the fixed wholesale power rates for service to the Smelters for which the monthly margin payments are to be received. Big Rivers argues that the designation of a portion of the monthly margin payments as a transmission payment at OATT rates in no way changes the economic positions of Big Rivers and the

[8] Response to the Commission's June 12, 1998 Order, Item 7, page 37 of 81.

[9] Document filing of May 29, 1998, Volume II, Tab 8, at 22-23.

LG&E Parties, but merely provides Big Rivers with the same economic risk regarding transmission which it has always had.[10]

The significant changes to the smelter transmission arrangements presented by Big Rivers and the LG&E Parties have affected the Commission's evaluation of the overall lease transaction. The documents upon which the Commission based its April 30, 1998 approval in principle stated that smelter transmission service would be obtained at OATT rates. At that time, the monthly margin payments excluded transmission service revenues, making it impossible to adjust the payments for transmission cost changes. The revisions proposed in this proceeding allow the smelter margins modeled by Big Rivers to be used to offset any shortfall in transmission revenues resulting from the actual OATT rates exceeding the transmission rates agreed to by the Smelters. In the event of such a shortfall in transmission revenue, the proposed revisions to the smelter transmission service will result in lower overall revenues to Big Rivers and expose its non-smelter customers to potential rate increases.

Big Rivers contends that it has always borne this economic risk, and that the proposed revisions do not change the arrangement that was part of the unforeseen cost resolution. The documents on file with the Commission as of February 27, 1998 do not support this position. Based on those documents, Green River and Henderson Union had the initial risk of fluctuations in OATT rates for the smelter load transmission service; however, the transmission credit appeared to shift this risk to LEM. The revisions proposed in this proceeding now shift that risk back to Big Rivers.

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[10] Response to the Commission's June 12, 1998 Order, Item 13(c), page 7 of 10.

Big Rivers has contended that it does not expect its transmission rates, as modeled in its financial model,[11] to change during the terms of the Smelters' contracts. Big Rivers claims that it is just as likely that its transmission rates will decrease as increase, but has offered no analysis or study to support its claim.

The Commission finds it likely, however, that for Big Rivers to improve its ability to make arbitrage sales, it may have to join an Independent System Operator ("ISO") to eliminate transmission rate pancaking. In the event the transmission rates established for the ISO are higher than Big Rivers' OATT, under the proposed revision, Big Rivers is faced with a no win situation. If it does not join an ISO, its ability to make critical arbitrage sales could be restricted. If it does join, it would incur additional costs for transmitting power to the Smelters, but would be unable to recover those costs from LEM or the Smelters. Big Rivers' inability to recover these costs would put pressure on its overall financial condition, and could eventually result in higher rates for its remaining customers.

Having considered all of the factors discussed herein, the Commission will accept the designation of LEM, rather than Green River and Henderson Union, as the party responsible for arranging and reserving transmission service with Big Rivers. The Commission also accepts the inclusion of the transmission revenues from the Smelters, as shown in Big Rivers' financial model, in the monthly margin payments. However, the

[11] The latest update of Big Rivers' financial model, identified as PSC2-38R, shows transmission rates through 2006 at $.98/KW/month. In 2007, the rate for network transmission appears to increase to $1.02/KW/month while non-firm point-to-point transmission is priced at $1.04/KW/month. In the year immediately after the Smelter contracts are scheduled to expire, all transmission is shown at the $1.04/KW/month rate.

Commission finds unreasonable the provision that allows increases in the OATT rates charged to LEM, except as modeled originally by Big Rivers, to be offset by the remaining portion of the monthly margin payment. That portion of the monthly margin payment reflecting the modeled net smelter margins exclusive of transmission revenues should remain as described in the documents on file with the Commission as of February 27, 1998.

In determining an equitable methodology for the recovery of unforeseen increases in transmission costs due to the Smelters' load, the Commission will be guided by the unforeseen cost resolution previously negotiated by the parties to the transaction. Under this approach, for any increase in Big Rivers' OATT rate in excess of that included in its financial model, 50 percent of the excess will be charged to LEM as part of its transmission costs. The bundled rates charged by LEM to Green River and Henderson Union will be equally adjusted. Consequently, the bundled rates charged by Green River and Henderson Union to Southwire and Alcan, respectively, will be adjusted to reflect the 50 percent of the increase in transmission costs. In the event that Big Rivers' OATT rate falls below the transmission rate included in its financial model, the rates charged to LEM, Green River, Henderson Union, Southwire, and Alcan will not be reduced. Any revenues in excess of the OATT rates should be retained by Big Rivers as an offset to the $1.85 million payment it makes each year as its 50 percent contribution to resolve the Smelters' indemnification for future unforeseen costs.

Agreement for Electric Service to Commonwealth Industries, Inc.

One of the documents filed in this proceeding was a draft of a new Agreement for Retail Electric Service ("Agreement") between Green River and Commonwealth

Industries, Inc. ("Commonwealth"). As a preliminary matter, the Commission notes that filing of this Agreement was not anticipated. There was no indication by any party in Case No. 97-204 that the agreement for service to Commonwealth would be subject to any additional negotiations or revisions. Apparently, one or both of the parties to the Agreement were dissatisfied with the Commission's April 30, 1998 Order in Case No. 97-204, and seized the opportunity presented by this instant case to submit a revised contract for electric service. Although the Agreement is not within the intended scope of this case, in the interest of administrative efficiency we will consider the merits of the Agreement.

This Agreement, when compared to one reviewed in Case No. 97-204, contains several changes which tend to favor the interests of Commonwealth over those of Green River and its wholesale power supplier, Big Rivers. The most significant of these changes is the establishment of two primary levels of power and billing for service to Commonwealth: (1) Peaking Power - defined as power and associated energy taken at 35,000 KW and above at a load factor of 10 percent or less, up to a maximum of 5,000 KW; and (2) all other power ("non-peaking power") and associated energy, taken at 35,000 KW and below.

Under its previous agreement, Commonwealth was required to take-or-pay for the full $10.15 demand charge applied to its contract demand of 40,000 KW, regardless of its actual demand level. Under the proposed Agreement, Commonwealth's non-peaking demand will be capped at a maximum of 35,000 KW to which the $10.15 demand charge will be applied. All energy taken up to the 35,000 KW level will be billed at Big Rivers' wholesale energy rate plus a retail energy adder of $.0003 per KWH. For the Peaking Pôwer, all demand in excess of 35,000 KW would incur no demand charge, but would be billed a "peaking energy charge of $0.075" per KWH plus the retail adder previously mentioned.

Commonwealth contends that, compared to its previous agreement, this Peaking Power provision provides it with the proper financial incentive to manage its operation processes to eliminate the short term surges in power consumption that occur on its system from time to time. These surges in consumption cause its billing demand to spike above its 35,000 KW contract demand.[12] Commonwealth also argues that the pricing terms included in the proposed Agreement will produce a revenue level closer to the level envisioned in the Commission's April 30, 1998 Order in Case No. 97-204. Commonwealth makes these assertions based on its historic demand and energy billing units for calendar years 1996-1997.

Based on a review of the merits of the proposed Agreement, the Commission finds that it should be rejected. None of the proponents of the Agreement have shown good cause to justify granting Commonwealth terms or prices for electric service that are more favorable than those available to others within the same customer class, i.e. non-smelter industrial customers served from dedicated delivery points. A demand charge of $10.15 for each KW in excess 35,000 KW will provide Commonwealth with a far greater financial incentive to avoid surges in consumption than will the proposed Peaking Power energy rate.

[12] In Case No. 97-204, Big Rivers modeled a continuous demand level of 35,000 KW for Commonwealth throughout the 25-year planning horizon without recognizing any "needle peaks" or "spike demands" in excess of 35,000 KW.

Particularly unpersuasive are Commonwealth's arguments regarding its annual electric bill as calculated under: 1) the rates proposed by Big Rivers in Case No. 97-204; 2) the rates approved by the Commission in Case No. 97-204; and 3) the rates under this proposed Agreement. Commonwealth's Exhibit 2, which is intended to be an analysis of its annual electric bill and the corresponding level of revenues flowing to Big Rivers, is misleading. The Commission did not design rates for only the 1996 normalized test year, as implied in this exhibit. The billing units in Commonwealth's Exhibit 2 do not correspond to those included in the Big Rivers' financial model which the Commission utilized to develop rates for Commonwealth and all other members of its class for the entire 25-year term of the lease transaction.

Commonwealth has calculated its annual electric bill to be higher than what it might have expected because it utilized a demand level consistently higher than the 35,000 KW included in Big Rivers' model. Had Commonwealth utilized its expected demand level of 35,000 KW, its calculation of revenues would have been less by $487,200 per year.[13]

Customers' electric bills and the corresponding level of utility revenues are affected by both the rates and the customers' usage. It would be pure coincidence if Commonwealth or any other customer consumed power at levels identical to those in the normalized historic test year or the 25-year forecast. Commonwealth cannot reasonably expect to receive special treatment merely because it now asserts that its consumption levels will differ from those incorporated into the Big Rivers' model.

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[13] (468,000 KW * $10.15) = $4,750,200
less: (420,000 KW * $10.15) = $4,263,000 equals $487,200.

Capital Budgets

On April 6, 1998, Big Rivers and the LG&E Parties executed a document entitled "New Participation Agreement," which replaced the original Participation Agreement and the Amended and Restated Participation Agreement contemplated by the lease transaction. This New Participation Agreement reflected changes in the transaction documents related to the resolution of the unforeseen cost issue, as well as clarifications of the parties' intent and the correction of errors.[14] On June 10, 1998, Big Rivers and the LG&E Parties filed a document entitled "Second Amendment to the New Participation Agreement" ("Second Amendment"). The Second Amendment reflected numerous clarifications and corrections to the majority of the lease transaction documents, reflected the decisions announced in the Commission's April 30, 1998 Order, and resolved uncertainties related to environmental issues. In addition, the Second Amendment addressed and resolved differences of opinion between Big Rivers and the LG&E Parties concerning the appropriate composition of the annual capital budget.[15]

Subsequent to filing the documents in February 1998 to resolve the unforeseen cost issue, Big Rivers and the LG&E Parties discovered there were significant differences between the amounts each party projected for the annual capital budgets for Big Rivers' generating plants. At that time, there was no upper limit on Big Rivers' exposure for non-incremental capital costs, which were reflected in the annual capital budget. Thus, the annual capital budget levels represented a major area of uncertainty

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[14] Response to the Commission's June 12, 1998 Order, Item 7, page 5 of 81.

[15] Id., pages 13 through 22 of 81.

in Big Rivers' financial modeling. As reflected in the Second Amendment, the LG&E Parties agreed to limit Big Rivers' exposure to unlimited increases in the annual capital budgets. Big Rivers had originally projected non-incremental capital costs to be $83.8 million over the life of the lease transaction. The Second Amendment capped this total exposure at $147.7 million, an increase of $63.9 million over the transaction term.[16]

While the Commission can appreciate Big Rivers' desire to limit its exposure to increases in the capital budgets, the impacts of incurring an additional $63.9 million in costs on Big Rivers' financial model should be considered. Big Rivers was requested to provide an update of the SUP-11 version of its financial model that reflected the lease transaction as described in the documents filed in this case. The ending cash balance at the end of the lease term was shown in SUP-11 as $171.8 million.[17] The updated financial model, PSC2-38R,[18] showed that the ending cash balance at the end of the lease term was $24.8 million.[19] The difference between the SUP-11 and PSC2-38R versions of the financial model reflected numerous revisions to the financial model,

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[16] Response to the Attorney General's First Information Request, Item 4, pages 2 and 3 of 5.

[17] See Case No. 97-204, Supplemental Testimony of A. J. Robison, Stephen Schaefer, and Mark A. Hite, Supplemental Exhibit 11, Printout of File SUP11.WK4, Year 2022, Line 404.

[18] Big Rivers had originally filed an updated financial model, PSC2-38, in its response to the Commission's June 23, 1998 Order, Item 38. However, at the public hearing on July 6, 1998, Big Rivers indicated that it had discovered some errors in that filing and submitted the revised financial model, PSC2-38R, as Big Rivers Cross-Examination Exhibit No. 2.

[19] Big Rivers Cross-Examination Exhibit No. 2, File PSC2-38R.WK4, Year 2022, Line 326.

including the additional $63.9 million in non-incremental capital costs provided by the terms of the Second Amendment.

The Commission finds that the modifications to the annual capital budgets required by the Second Amendment are reasonable and should be approved. However, this and other modifications contained in Big Rivers' financial model heighten concerns about Big Rivers' financial condition during the later years of the lease. In the April 30, 1998 Order, the Commission required Big Rivers to file a supplemental annual report comparing its actual cash flows for the calendar year with the amounts included in the SUP-11 financial model. The report was to be based on lines 363 through 411 of SUP-11, and include explanations for any deviations from the SUP-11 amounts in excess of 10 percent. The Commission will continue this requirement, but will substitute the updated financial model PSC2-38R for SUP-11, with the report now based on lines 285 through 333 of PSC2-38R. In addition, to better monitor Big Rivers' financial condition over the term of the lease transaction, Big Rivers will be required to submit with its annual report an updated version of its financial model.[20] The updated financial model will cover the period beginning with the current annual report year and ending with the last year of the lease transaction. All changes in assumptions and variables from one year to the next should be explained in detail.

Revolving Credit Agreement

On June 26, 1998, Big Rivers filed a copy of a revolving credit agreement ("Credit Agreement") it has entered into with the National Rural Utilities Cooperative

[20] One hard copy of the updated financial model and one computer disc version should be provided.

Finance Corporation ("CFC"). Under the terms of the Credit Agreement, CFC will provide Big Rivers a maximum aggregate principle amount outstanding of $15 million. For each 12-month period the Credit Agreement is in effect, Big Rivers will be required to reduce to zero all amounts outstanding for at least five consecutive business days, with the first reduction due within 360 days of the first advance. The term of the Credit Agreement is 5 years. Big Rivers believes that the CFC Credit Agreement does not require Commission approval.

The Commission's jurisdiction to approve evidences of indebtedness is set forth in KRS 278.300. Specifically excluded from that jurisdiction under KRS 278.300(8) is the approval of notes payable at periods of not more than 2 years from the date issued and renewable for not more than a total of 6 years. The Commission finds that the terms of the CFC Credit Agreement fall within this exemption and, therefore, we agree with Big Rivers that no Commission approval is needed.

Smelters' Tier 3 Service Contracts

The proposed power contracts between Green River, Henderson Union, and the Smelters contain specific provisions concerning contracts for Tier 3 service from third-party power suppliers. When seeking Commission approval to make a sale of Tier 3 power to the Smelters, Green River and Henderson Union are contractually obligated to request that such approval be effective 20 days from the date of notice.[21] However, KRS 278.180(1) requires a minimum of 30 days notice prior to changing a rate, unless good cause is shown to shorten the notice period to 20 days. Green River and

[21] See Agreement for Electric Service between Alcan and Henderson Union and Agreement for Electric Service between Southwire and Green River, Section 9.2.

Henderson Union have indicated that the parties would accept a revision to the power agreements that reflects the 30-day statutory requirement.[22]

The Commission finds that the power agreements between Green River, Henderson Union, and the Smelters should be revised to reflect the 30-day notice provision set forth in KRS 278.180(1). Including this notice in the power agreements will not prevent any of the parties to those agreements from requesting a shorter notice period on a case-by-case basis when a Tier 3 service contract is filed.

Promissory Note for LEM Advances

Big Rivers has requested that the Commission approve the promissory note associated with the LEM advances, noting that such approval was omitted from the April 30, 1998 Order in Case No. 97-204. While we believe that note to have been implicitly approved by that Order, the Commission now explicitly finds that the promissory note for the LEM advances is for a lawful object within Big Rivers' corporate purpose, is necessary and appropriate for the proper performance of its wholesale electric service to the public and will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purpose.

1998 Amendments to the Station Two Contracts

Big Rivers has requested that the Commission approve the 1998 Amendments to the Station Two Contracts, which were filed with the Commission on May 15, 1998. The Commission finds that these documents are reasonable and should be approved.

[22] Response to the Commission's June 23, 1998 Order, Item 20.

Green River Wholesale Contract Amendment, Schedule 1

On June 6, 1998, Big Rivers submitted a substitute Schedule 1 to its wholesale power agreement with Green River. The substitute Schedule 1 reflects the inclusion of the proposed new service agreement between Green River and Commonwealth. Based on the decision herein to reject the new Commonwealth agreement, the Commission rejects the substitute Schedule 1 to the wholesale power agreement.

Standby Bond Purchase Agreements

On June 24, 1998, Big Rivers filed Standby Bond Purchase Agreements ("Standby Agreements") related to its 1983 and 1985 Pollution Control Bonds ("1983 and 1985 Bonds") and Credit Suisse First Boston, the new provider of letters of credit for those bonds. The Standby Agreements were required as part of the rating agencies' evaluation of the 1983 and 1985 Bonds. Big Rivers requested that the Commission permit the late filing of the Standby Agreements in this case.

As the Standby Agreements are an integral part of the overall financial restructuring of Big Rivers' obligations, the Commission will permit the late filing and hereby approves the Standby Agreements as part of all other financial agreements presented in this proceeding.

Confidentiality Petition for Marketing Plan

As part of its April 30, 1998 Order in Case No. 97-204, the Commission required Big Rivers to file an interim sales plan which would address how Big Rivers planned to pursue arbitrage sales opportunities until the lease transaction closed. On May 29, 1998, Big Rivers filed its Interim Sales Plan and a petition for confidential treatment of that document. On June 18, 1998, Alcan and Southwire responded to the petition, requesting a modification to the petition that would permit all parties to Case No. 97-204 who have executed appropriate confidentiality agreements to obtain copies of the Interim Sales Plan. On June 23, 1998, Big Rivers filed its reply to the Smelters' response, expressing its opposition to the request. At the July 6, 1998 public hearing, Big Rivers requested that the Commission include a ruling on the petition for confidential treatment in its Order in this proceeding.

The Commission finds that it is not appropriate to rule on Big Rivers' petition for confidentiality or the Smelters' request for access in this proceeding. The Interim Sales Plan was filed in Case No. 97-204, and the petition and request will be adjudicated in that case. In addition, the Commission finds no reason to modify its normal procedures for the processing of requests for confidentiality.

Distribution Cooperative Tariff

Green River and Henderson Union have submitted proposed Smelter tariffs to the Commission for approval. The proposed tariffs incorporate both the agreements for electric service between the cooperatives and the respective Smelters and Schedule A of those agreements, which details the terms and rates for Smelter service. Alcan and Southwire have notified the Commission of their opposition to incorporating the agreements for electric service into the tariffs, contending that the proposed tariffs only need to incorporate Schedule A. At the July 6, 1998 hearing the Smelters identified this disagreement as an issue for the Commission to address in this Order.

The Commission finds that there has been no evidence offered by the Smelters to justify the exclusion of the agreements for electric service from the smelter tariffs as filed with the Commission. Consequently, the Commission will not require Green River or Henderson Union to remove the language incorporating the agreements for electric service from the proposed tariffs.

Jurisdiction over OATT

On July 1, 1998, Big Rivers, Alcan, Green River, Henderson Union, and Southwire filed a joint motion requesting that the Commission assert jurisdiction over Big Rivers' OATT to the extent that the Federal Energy Regulatory Commission ("FERC") does not assert jurisdiction over the OATT. The July 1, 1998 motion notes that Big Rivers' status as a generation and transmission cooperative, combined with the limited jurisdiction of FERC over such entities, creates a "regulatory gap" in jurisdiction over many provisions of the OATT. The parties to the July 1, 1998 motion request that the Commission fill this regulatory gap by asserting jurisdiction, subject to five specific limitations enumerated in the motion.

Big Rivers was formed pursuant to the requirements of KRS Chapter 279. KRS 279.210 provides that every corporation formed under that chapter shall be subject to the general supervision of the Commission and shall be subject to all the provisions of KRS 278.010 to 278.450 inclusive, and KRS 278.990. Therefore, to the extent that FERC has not asserted jurisdiction over Big Rivers' OATT, the Commission will do so, in accordance with KRS Chapters 278 and 279. However, the Commission will assert this jurisdiction without the specific limitations referenced in the July 1, 1998 motion, as the applicants have not demonstrated why the expression of such limitations are necessary or reasonable.

Fuel Adjustment Clause Cases

Big Rivers has requested that, concurrent with our decision in this case, all pending fuel adjustment clause ("FAC") cases be dismissed. Motions to dismiss are currently pending in each of those FAC cases. While the FAC cases have not been consolidated with the instant case, the Commission recognizes their importance to the closing of Big Rivers' lease transaction. Therefore, Orders will be issued in the near future holding in abeyance those FAC cases that have been remanded to the Commission and that are not directly affected by the Franklin Circuit Court Order of June 29, 1998 in Civil Action No. 94-CI-01184. Those cases will be closed once Franklin Circuit Court recalls and vacates its Judgment of October 20, 1995 in that action. As to those cases that are directly affected by the Franklin Circuit Court Order of June 29, 1998, we find that the motions to dismiss are moot and Orders to that effect will be issued by the Commission in the near future. As to all remaining FAC cases, the Commission intends to issue Orders in the near future closing those cases without the need for further action by Big Rivers.

SUMMARY AND CONCLUSION

As announced in the April 30, 1998 Order in Case No. 97-204, the purpose of this proceeding was to review the final drafts of all jurisdictional documents to determine whether any material changes had been made to the lease transaction. As discussed in this Order, material changes have been made in the areas of smelter transmission service and Big Rivers' funding obligations to the annual capital budgets.

While we have denied the proposed methodology for the recovery of unforeseen increases in transmission costs due to the Smelters' load, we believe that the approved methodology represents a fair and reasonable solution. While we have accepted the modifications to the annual capital budgets, these changes will be costly to Big Rivers over the next 25 years. Consequently, Big Rivers' long-term financial survival is not a certainty but, rather, is a goal that will have to be achieved by management. Critical to meeting this goal will be the successful marketing of power off-system. A greater degree of Commission monitoring will also be necessary and, thus, we have established additional financial reporting requirements for Big Rivers. The Commission remains optimistic that with continued hard work and dedication by Big Rivers, its financial viability will be assured and it will prosper hand-in-hand with the economy of Western Kentucky.

IT IS THEREFORE ORDERED that:

1. Based on the final drafts of all documents filed in this proceeding, Big Rivers' proposed lease transaction with the LG&E Parties is approved, subject to the modifications contained in this Order.

2. The proposed methodology for the recovery of unforeseen changes in transmission costs due to the Smelters' load is denied.

3. A 50/50 sharing methodology for the recovery of unforeseen changes in transmission costs due to the Smelters' load, as discussed in this Order, is approved.

4. The proposed revision to Schedule 1 of the Green River Wholesale Power Contract with Big Rivers and the proposed new agreement between Green River and Commonwealth are denied.

5. Ordering Paragraph No. 21 of the April 30, 1998 Order in Case No. 97-204 is modified to the extent that the PSC2-38R financial model, lines 285 through 333,

shall replace the reference to the SUP-11 financial model, lines 363 through 411. In addition, Big Rivers shall annually file an updated version of its financial model with its annual report to the Commission, covering the period beginning with the current annual report year and ending with the last year of the lease transaction. All changes in assumptions and variable from one year to the next shall be explained in detail.

6. All evidences of indebtedness required to be issued by Big Rivers in conjunction with the transaction documents are approved, including the LEM Promissory Note and the Standby Agreements. The CFC Credit Agreement is exempt from Commission approval.

7. The Smelter Tier 3 Service Contracts are modified to provide the Commission with 30 days notice of effectiveness, in accordance with KRS 278.180(1).

8. The 1998 Amendments to the Station Two Contracts are approved.

9. The Smelters' objection to the form of the Green River and Henderson Union Smelter Tariffs is overruled.

10. Big Rivers' OATT filed in this proceeding is hereby approved and the OATT shall be subject to the jurisdiction of this Commission to the extent that FERC has not asserted jurisdiction and preempted this Commission.

11. Within 30 days of the date of this Order, Big Rivers shall file its tariffs, reflecting all revisions and modifications as described in this Order.

12. Ordering Paragraph Nos. 13, 15, 16, 18, 20, and 22 of the April 30, 1998 Order in Case No. 97-204 shall remain in full force and effect as if separately ordered herein.

Nothing contained herein shall be construed as a finding of value for any purpose or as a warranty on the part of the Commonwealth of Kentucky, or any agency thereof, as to the securities authorized herein.

Done at Frankfort, Kentucky, this 14th day of July, 1998.

By the Commission

ATTEST:

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

EXHIBIT 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

December 2007

EXHIBIT 7

RESPONSE TO ITEM NO. 3 IN MAY 2, 2007 LETTER FROM BETH O'DONNELL, EXECUTIVE DIRECTOR FOR THE KENTUCKY PUBLIC SERVICE COMMISSION

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EXHIBIT 7

RESPONSE TO ITEM NO. 3 IN MAY 2, 2007 LETTER FROM BETH O'DONNELL, EXECUTIVE DIRECTOR FOR THE KENTUCKY PUBLIC SERVICE COMMISSION

3. An analysis comparing the termination clauses contained in each of the documents comprising the 1998 Lease Transaction with the provisions of the Termination Agreement. Include a discussion of how each termination clause is addressed by the applicable provision of the Termination Agreement. When possible, include a calculation of the potential cost exposure of Big Rivers or E.ON U.S. LLC under the termination clause and how that exposure is addressed in the Termination Agreement. Because this could be a voluminous response, an original and two copies of this information should be filed with the Commission, with copies to all parties.

Response:

I. EXISTING AGREEMENTS.

A. *Terms of Agreements.*

The Lease and Operating Agreement, Power Purchase Agreement and Transmission Services and Interconnection Agreement that were entered into by Big Rivers Electric Corp. ("Big Rivers"), Western Kentucky Energy Corp. ("WKEC"), its predecessor affiliates, and LG&E Energy Marketing Inc. ("LEM") in 1998 (as amended, collectively, the "Key Lease Transaction Documents"), as well as the Agreement and Amendments to Agreement (commonly referred to as the Station Two Agreement) that was entered into by Big Rivers, WKEC, its predecessor affiliates, LEM, the City of Henderson, Kentucky, and the City of Henderson Utility Commission in 1998 (as amended, the "Station Two Agreement"), each has a term that commenced on July 15, 1998, and will expire on December 31, 2023, unless terminated earlier in accordance with its respective terms or by the mutual agreement of the parties thereto. The wholesale power purchase and sale agreement that was entered into by LEM and Henderson Union Rural Electric Cooperative Corp. (now Kenergy Corp.) in 1998, to serve a portion of the retail load of the aluminum smelting facilities of Alcan Corporation (or its affiliate), has a term that commenced on July 15, 1998, and will expire on December 31, 2011, unless terminated earlier in accordance with its respective terms or by the mutual agreement of the parties thereto (as amended, the "LEM/Henderson Union Agreement"). The wholesale power purchase and sale agreement that was entered into by LEM and Green River Electric Corporation (now Kenergy Corp.) in 1998, to serve a portion of the retail load of the aluminum smelting facilities of Southwire Company (now Century Aluminum Company (or its affiliate)) and of the adjacent rod and cable mill of Southwire Company or its affiliate, has a term that commenced on July 15, 1998, and will expire on December 31, 2010, unless terminated earlier in accordance with its respective terms or by the mutual agreement of the parties thereto (as amended, the "LEM/Green River Agreement"). Notwithstanding the expiration of the term of a Key Lease Transaction Document, the Station Two Agreement, the LEM/Henderson Union Agreement or the LEM/Green River Agreement, one or more of those agreements contain certain indemnification covenants or other risk allocation covenants (among other covenants) that would ordinarily survive[1] that expiration to the extent required to address (as between the parties thereto) certain risks or loss contingencies that existed as of the date of their expiration.

Generally speaking (and with certain limited exceptions), the various other agreements and instruments that were entered into by one or more of the above-described parties in 1998 (or subsequently), and that relate to, support or complement the Key Lease Transaction Documents, the

[1] As noted in Section II of this response below, these indemnification covenants and other risk allocation covenants will be terminated pursuant to the Transaction Termination Agreement and the agreements to be entered into in connection therewith.

Station Two Agreement, the LEM/Henderson Union Agreement (such as the related retail power purchase and sale agreement between Kenergy Corp. and Alcan Corporation or its affiliate), or the LEM/Green River Agreement (such as the related retail power purchase and sale agreement between Kenergy Corp. and Century Aluminum Company or its affiliate) (as amended, collectively, the "Related Documents"), have terms or durations that are expressly co-terminus with the term of the Key Lease Transaction Document(s), the Station Two Agreement, the LEM/Henderson Union Agreement or the LEM/Green River Agreement to which they relate, or will have no practical purpose, force or effect following the expiration or termination of that Key Lease Transaction Document, the Station Two Agreement, the LEM/Henderson Union Agreement or the LEM/Green River Agreement (as applicable). An exception to this, however, is the New Participation Agreement that was entered into by Big Rivers, WKEC, certain predecessor affiliates of WKEC and LEM on April 6, 1998 (i.e., the "omnibus transaction agreement" for the 1998 transactions) (as amended, "New Participation Agreement"). That document does not contain an express term or duration applicable to it, or a date by which it will expire (but does contain provisions for its termination as described below). In addition, it contains certain indemnification and risk allocation provisions as between Big Rivers, on the one hand, and WKEC and LEM, on the other hand (either directly related to the parties' respective covenants or representations under the Key Lease Transaction Documents or the Station Two Agreement, or independent of those covenants or representations) that, under certain circumstances, would ordinarily survive[2] the expiration or termination of the New Participation Agreement, the Key Lease Transaction Documents and/or the Station Two Agreement.

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[2] As noted in Section II of this response below, these indemnification covenants and other risk allocation covenants will be terminated pursuant to the Transaction Termination Agreement and the agreements to be entered into in connection therewith.

On April 16, 1998, LG&E Energy Corp. (now E.ON U.S. LLC) executed and delivered a parent guarantee in favor of Big Rivers (the "Guarantee for Big Rivers"), and on July 15, 1998, at the closing of the 1998 transactions, LG&E Energy Corp. executed and delivered certain additional parent guarantees in favor of the City of Henderson, Kentucky, the City of Henderson Utility Commission, Henderson Union Rural Electric Cooperative (now Kenergy Corp.), Green River Electric Corporation (now Kenergy Corp.), Alcan Corporation (or its predecessor) and/or certain of its affiliates, and Southwire Company (now including Century Aluminum Company and/or certain of its affiliates). Pursuant to those parent guarantees, among other transactions, E.ON U.S. LLC guaranteed the obligations of its relevant direct and indirect subsidiaries (WKEC, its predecessor affiliates and LEM) under the New Participation Agreement, the Key Lease Transaction Documents, the Station Two Agreement, the LEM/Henderson Union Agreement and the LEM/Green River Agreement, among other obligations of those subsidiaries. Generally speaking, absent their prior termination by the mutual agreement of E.ON U.S. LLC and the beneficiaries thereof, those parent guarantees will continue in force and effect throughout the term(s) of the agreement(s) that they guarantee, and will continue thereafter to the extent any obligations of those subsidiaries under those agreements survive their expiration or termination. The Guarantee for Big Rivers and the other parent guarantees of E.ON U.S. LLC described in this paragraph are hereinafter collectively referred to as the "Parent Guarantees."

B. *Existing Early Termination Rights.*

The Guarantee for Big Rivers contains certain provisions that permit the termination by Big Rivers of the Key Lease Transaction Documents, the New Participation Agreement and the Station Two Agreement upon the occurrence of certain defaults on the part of E.ON U.S. LLC under the Guarantee for Big Rivers, none of which has become relevant to date.

The New Participation Agreement, the Key Lease Transaction Documents, the Station Two Agreement, the LEM/Henderson Union Agreement, the LEM/Green River Agreement and certain of the Related Documents contain provisions (some uniquely tailored to those transactions and others which are customary for agreements of that type) that expressly set forth various circumstances under which those agreements may be terminated by one or more of the parties prior to the expiration of the original term of those agreements.

For example, Section 17.1.2 of the New Participation Agreement defines a "default" of a party under that agreement as including (among other events) certain misrepresentations by that party made in the New Participation Agreement, a breach or default by that Party of any material obligations set forth in the New Participation Agreement, certain "bankruptcy" or "insolvency" events involving that party, a wrongful assignment by that party of the New Participation Agreement, or the failure of that party to cure its "default" under one of the Key Lease Transaction Documents resulting in a termination of that Key Lease Transaction Document by another party thereto. Section 17.3.4 of the New Participation Agreement sets forth the remedies that can be pursued by the other parties in the event of such a default by a party (which is not cured as permitted elsewhere in the New Participation Agreement). Among other remedies (all of which are cumulative), a non-defaulting party has the right to terminate the New Participation Agreement upon a designated prior notice to the defaulting party.

In addition, there are certain other expressed rights of one or more of the parties to terminate the New Participation Agreement. However, those expressed rights are generally tied to the occurrence of events that could jeopardize Big Rivers' rights under its Parent Guarantee from E.ON U.S. LLC, or to certain risks that the leased generators could be taken by condemnation proceedings, none of which have become relevant to date.

Sections 11.1 and 11.5 of the 1998 Lease and Operating Agreement contain default and remedy provisions that are comparable to those of Sections 17.1.2 and 17.3.4 of the New Participation Agreement, including a provision allowing a party to terminate the Lease and Operating Agreement in the event of a default by another party (which is not cured as permitted by the relevant agreement) under one of the other Key Lease Transaction Documents or under the New Participation Agreement, in either case which gives rise to a termination of that other agreement. The Lease and Operating Agreement contains certain additional provisions contemplating an early termination of that document upon the occurrence of certain condemnation proceedings involving the leased generators, none of which have become relevant to date.

Section 2.2 of the 1998 Power Purchase Agreement also contains default and remedy provisions that are comparable to those of Sections 17.1.2 and 17.3.4 of the New Participation Agreement, including a provision allowing a party to terminate the Power Purchase Agreement in the event of a default by another party (which is not cured as permitted by the relevant agreement) under one of the other Key Lease Transaction Documents or under the New Participation Agreement, in either case which gives rise to a termination of that other agreement.

Section 3.2 of the 1998 Transmission Service and Interconnection Agreement also contains default and remedy provisions that are comparable to those of Sections 17.1.2 and 17.3.4 of the New Participation Agreement, including a provision allowing a party to terminate the Transmission Service and Interconnection Agreement in the event of a default by another party (which is not cured as permitted by the relevant agreement) under one of the other Key Lease Transaction Documents or under the New Participation Agreement, in either case which gives rise to a termination of that other agreement.

Sections 13.4 and 13.7 of the 1998 Station Two Agreement also contain default and remedy provisions that are comparable to those of Sections 17.1.2 and 17.3.4 of the New Participation Agreement, including a provision generally allowing WKEC and LEM, on the one hand, or Big Rivers, on the other, to terminate the Station Two Agreement in the event of a default by the other of those parties (which is not cured as permitted by the relevant agreement) under one of the Key Lease Transaction Documents or under the New Participation Agreement, in either case which gives rise to a termination of that other agreement. However, given the unique nature of the Station Two Agreement as involving the City of Henderson and the City of Henderson Utility Commission, and given the particular motivations of the parties at the time of the negotiation of that agreement in 1998, Section 13 of the Station Two Agreement also contains a number of elaborate (a) limitations on one or more of the parties' respective rights to terminate that agreement, (b) conditions precedent to the exercise of such termination rights by one or more of the parties, and (c) provisions dictating certain consequences of such a termination and certain of the parties' respective rights and obligations that will survive such a termination. Those elaborate provisions are generally unique to the Station Two Agreement, and are not found in the New Participation Agreement, the Key Lease Transaction Documents, the LEM/Henderson Union Agreement, the LEM/Green River Agreement, the Related Documents or the Parent Guarantees. The Station Two Agreement also contains certain additional provisions contemplating an early termination of that agreement upon the occurrence of condemnation proceedings involving Station Two, none of which have become relevant to date.

Articles XVII and XVIII of the LEM/Henderson Union Agreement also contain default and remedy provisions (but only as between LEM and Henderson Union (now Kenergy Corp.)) that are comparable to those of Sections 17.1.2 and 17.3.4 of the New Participation Agreement, including a provision allowing LEM to terminate that agreement upon a failure, inability or refusal of Kenergy

Corp. to cure a breach or default by it under the corresponding retail power purchase and sale agreement between Kenergy Corp. and Alcan Corporation (or its affiliate), which gives rise to a termination of that retail agreement.

And Articles XVII and XVIII of the LEM/Green River Agreement contain provisions that are substantially identical to the default and remedy provisions of the LEM/Henderson Union Agreement described in the preceding paragraph.

II. TRANSACTION TERMINATION AGREEMENT AND RELATED DOCUMENTS.

Notwithstanding that the Key Lease Transaction Documents, the New Participation Agreement, the Station Two Agreement, the LEM/Henderson Union Agreement, the LEM/Green River Agreement, certain of the Related Documents, and/or certain of the "Parent Guarantees" contain provisions which expressly contemplate their early termination under certain circumstances (and in some cases expressly contemplate the survival of certain remedies and covenants set forth in those documents following their termination), for various reasons deemed important to them, Big Rivers, E.ON U.S. LLC, WKEC, LEM, Kenergy Corp., Alcan Corporation (and its relevant affiliates), Century Aluminum Company (and its relevant affiliates), and Southwire Company have expressed to one another their willingness to dispense with each of those express termination rights (and survival provisions), and to instead effect a termination and release in their entirety of each of the Key Lease Transaction Documents, the New Participation Agreement, the Station Two Agreement, the LEM/Henderson Union Agreement, the LEM/Green River Guarantees, the Related Documents and the Parent Guarantees, subject to the satisfaction of various conditions precedent:

(a) set forth in the Transaction Termination Agreement among Big Rivers, WKEC and LEM dated March 26, 2007, as amended by a First Amendment to Transaction Termination Agreement dated November 1, 2007 (the "Transaction Termination Agreement") (including, but not limited to, the condition precedent that the City of Henderson and the City of Henderson Utility Commission similarly agree to dispense with the termination and remedy provisions of the Station Two Agreement, the Parent Guarantee in favor of the City of Henderson and the City of Henderson Utility Commission, and the Related Documents to which they are a party or a beneficiary, and to instead agree to terminate and release those agreements and instruments in their entirety on the same basis as the terminations and releases to be effected with respect to the New Participation Agreement and the Key Lease Transaction Documents as between Big Rivers, on the one hand, and E.ON U.S. LLC, WKEC and LEM, on the other; and

(b) set forth in various other agreements required to effect certain aspects of the unwind transactions that are to be entered into between or among Big Rivers, Kenergy Corp., Alcan Corporation (and/or its affiliates) and Century Aluminum Company (and/or its affiliates).

As currently contemplated by the parties, at the "Closing" of the unwind transactions pursuant to the Transaction Termination Agreement:

(a) E.ON U.S. LLC, WKEC, LEM and Big Rivers would enter into a Termination and Release Agreement in the form attached to the Transaction Termination Agreement as Exhibit B, thereby terminating the New Participation Agreement, the Key Lease Transaction Documents, the Guarantee for Big Rivers and the Related Documents associated with each of the foregoing, and releasing each of those parties from any further obligations or liabilities to the others under those agreements (including any obligations which, by the terms of those agreements, would ordinarily survive their expiration or termination). Thus, any termination and remedy provisions set forth in the New Participation Agreement, the Key Lease Transaction Documents, those Related Documents and the Guarantee for Big Rivers would have no relevance in the proposed unwind transactions, and would be dispensed with in those transactions;

(b) E.ON U.S. LLC, WKEC, LEM, Big Rivers, the City of Henderson and the City of Henderson Utility Commission would enter into a Termination and Release Agreement in a form satisfactory to those parties, thereby terminating the Station Two Agreement, the Parent Guarantee for the City of Henderson and the City of Henderson Utility Commission, and the Related Documents associated with each of the foregoing, and releasing each of those parties from any further obligations or liabilities to the others under those agreements (including any obligations which, by the terms of those agreements, would ordinarily survive their expiration or termination). Thus, the termination and remedy provisions set forth in the Station Two Agreement, those Related Documents and the Parent Guarantee for the City of Henderson and the City of Henderson Utility Commission would have no relevance in the proposed unwind transactions, and would be dispensed with in those transactions;

(c) E.ON U.S. LLC, LEM, Kenergy Corp., Alcan Corporation and its relevant affiliates would enter into a Termination and Release Agreement in a form satisfactory to those parties, thereby terminating the LEM/Henderson Union Agreement, the Parent Guarantees for each of Kenergy Corp. and Alcan Corporation (and its relevant affiliates), respectively, and the Related Documents associated with each of the foregoing, and releasing each of those parties from any further obligations or liabilities to the others under those agreements (including any obligations which, by the terms of those agreements, would ordinarily survive their expiration or termination). Thus, the termination and remedy provisions set forth in the LEM/Henderson Union Agreement, those Parent Guarantees and those Related Documents would have no relevance in the proposed unwind transactions, and would be dispensed with in those transactions; and

(d) E.ON U.S. LLC, LEM, Kenergy Corp., Century Aluminum Company and its relevant affiliates would enter into a Termination and Release Agreement in a form satisfactory to those parties, thereby terminating the LEM/Green River Agreement, the Parent Guarantees for each of Kenergy Corp. and Century Aluminum Company (and its relevant affiliates), respectively, and the Related Documents associated with each of the foregoing, and releasing each of those parties from any further obligations or liabilities to the others under those agreements (including any obligations which, by the terms of those agreements, would ordinarily survive their expiration or termination). Thus, the termination and remedy provisions set forth in the LEM/Green River Agreement, those Parent Guarantees and those Related Documents would have no relevance in the proposed unwind transactions, and would be dispensed with in those transactions.

To facilitate the Commission's review of the proposed Unwind Transaction, the joint applicants have prepared the following summary description of the disposition of the 1998 Transaction documents that is being accomplished by the Transaction Termination Agreement and related documents:

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<u>**DOCUMENT TITLE**</u>	<u>**DESCRIPTION OF DOCUMENT**</u>	<u>**DISPOSITION AFTER UNWIND TRANSACTION**</u>
A. <u>Agreements among E.ON or its Affiliates and Big Rivers</u>		
1. New Participation Agreement, dated April 6, 1998, by and among LEM, Western Kentucky Leasing Corp., Station Two Subsidiary, WKEC and Big Rivers (including Exhibits and Schedules thereto), as amended by the following documents:	The "omnibus" transaction agreement whereby E.ON, the WKE Parties and Big Rivers agreed to complete the 1998 lease, power purchase and sale, and related transactions upon the satisfaction of certain conditions precedent to closing, all of which conditions were satisfied or waived by the parties prior to the closing of those transactions on July 15, 1998.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
i. Letter Amendments dated April 6, 1998;	Addressed certain issues between the parties with respect to their responsibility for the funding of certain portions of the debt service owing on certain municipal bonds associated with the Station Two generating units.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the transaction Termination Agreement.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
ii. Second Amendment to New Participation Agreement dated June 15, 1998;	Implemented certain amendments to the original New Participation Agreement deemed necessary by the parties for the completion of the 1998 transactions.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
iii. Third Amendment to New Participation Agreement dated July 15, 1998;	Implemented certain amendments to the original New Participation Agreement deemed necessary by the parties for the completion of the 1998 transactions.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
iv. Letter Amendment dated July 17, 1998 (the ***"July 17 Amendment"***);	Implemented certain amendments to the original New Participation Agreement and certain other 1998 transaction documents deemed necessary by the parties for the completion of the 1998 transactions, including the allocation among the parties of certain operating costs and power purchase costs incurred by the parties from July 15, 1998, through July 17, 1998 (the date of this Letter Amendment).	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
v. Letter Amendments dated April 18, 2000 (the ***"April 18 Amendments"***);	Implemented certain amendments to the New Participation Agreement, the Lease and Operating Agreement identified in Item 2 below, and the Power Purchase Agreement identified in Item 3 below, in each case as deemed appropriate by the parties on the basis of their business dealings following the July 15, 1998 closing (including, among other changes, in the case of the Lease and Operating Agreement, certain changes dealing with the parties' funding of capital assets for the leased generators and Station Two, and in the case of the New Participation Agreement, certain changes to the provisions dealing with the calculation and payment of the LG&E Parties' Residual Value Payment (Section 24.1)).	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
vi. Letter Amendment dated March 20, 2001 (the ***"March 20 Amendments"***);	Implemented certain amendments to the New Participation Agreement and certain other 1998 transaction documents deemed necessary in light of a contemporaneous sale and assignment by Southwire Company to Century Aluminum Company of its aluminum smelter and associated contracts with the WKE Parties and Big Rivers (among other assets).	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
vii. Letter Agreement dated February 19, 2002 (with attached Letter Agreement dated November 29, 2001);	Memorialized certain agreements between the parties regarding the NOx compliance plan to thereafter be implemented by the parties with respect to the leased generators and Station Two, and regarding certain funding matters associated with that plan.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
viii. Fifth Amendment to New Participation Agreement and Second Amendment to Lease and Operating Agreement, dated August 22, 2002 (the ***"Fifth Amendment"***);	Implemented certain amendments to the New Participation Agreement, and to the Lease and Operating Agreement identified in Item 2 below, deemed necessary by the parties in connection with the installation of a new wet flue gas de-sulfurization system at Plant Coleman.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
ix. Letter Amendment dated July 18, 2003 (the ***"July 18 Amendments"***); and	Implemented certain amendments to the New Participation Agreement and certain other 1998 transaction documents deemed necessary in light of a contemporaneous internal corporate restructuring being undertaken by Alcan Aluminum Corporation and certain of its affiliates.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
x. Letter Agreement dated October 20, 2003.	Addressing certain agreements regarding the funding of certain "Incremental Capital Costs" and "Incremental Environmental O&M Costs" at Reid Station in response to the NOx SIP Call	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

DOCUMENT TITLE	DESCRIPTION OF DOCUMENT	DISPOSITION AFTER UNWIND TRANSACTION
2. Lease and Operating Agreement, dated July 15, 1998, by and between Big Rivers and WKEC, as amended by the July 17 Amendment, the April 18 Amendments, the July 18 Amendments, the March 20 Amendments and the Fifth Amendment.	Implemented WKEC's lease of the Big Rivers generating plants for an approximately 25 year term, and allocated between WKEC and Big Rivers responsibility for the operation and maintenance of those leased generators, and for the funding of capital costs and operations and maintenance costs associated with those leased generators, among other commitments.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
3. Power Purchase Agreement, dated July 15, 1998, by and between Big Rivers and LEM, as amended by the July 17 Amendment, the April 18 Amendments, the July 18 Amendments and the March 20 Amendments.	Implemented a 25-year power purchase and sale transaction between LEM (now WKEC, as assignee of LEM) and Big Rivers, whereby LEM agreed to provide Big Rivers certain quantities of power to meet the loads of Big Rivers' member distribution cooperatives (<u>other than their Smelter loads</u>).	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
4. Transmission Services and Interconnection Agreement, dated July 15, 1998, by and between Big Rivers, Station Two Subsidiary, LEM and WKEC, as amended by the July 17 Amendment, the April 18 Amendments, the March 20 Amendments and the July 18 Amendments, and as supplemented by Big Rivers' Open Access Transmission Tariff.	Provision by Big Rivers to the WKE Parties of transmission services over the Big Rivers system to support power deliveries to Big Rivers, to Kenergy (for the Smelters), and to others.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
5. Assignment and Assumption Agreement, dated July 15, 1998, by and between Big Rivers and WKEC.	Effected the 1998 assignment by Big Rivers to WKEC of various contracts, leases and other intangible assets necessary for WKEC's operation of the leased generators.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
6. Transformer Operation and Maintenance Agreement, dated July 15, 1998, by and among WKEC, WKE and Big Rivers.	Retention by WKEC and WKE of Big Rivers to provide certain transformer equipment operation and maintenance services.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
7. Meter and Telemetry Equipment Operation and Maintenance Agreement, dated July 15, 1998, by and among WKEC, Station Two Subsidiary, WKE and Big Rivers.	Retention by WKEC, Station Two Subsidiary and WKE of Big Rivers to provide certain meter and telemetry equipment operation and maintenance services.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
8. Telecommunications Agreement, dated July 15, 1998, by and between Big Rivers and WKEC.	Retention by WKEC of Big Rivers to provide certain telecommunications equipment operation and maintenance services.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
9. Agreement, dated July 29, 2002, by and among Big Rivers, WKEC, Gregory Black and Ralph Bowling.	Retention of Mr. Black as the "Designated Representative" of the leased generators for NOx and SO2 compliance purposes, and retention of Mr. Bowling as the "Alternative Designated Representative".	WKEC will be released from further obligation under this document either pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement or pursuant to a separate document (to be developed by the parties) relating specifically to this document. This document may or may not be terminated and replaced by a new, similar retention agreement, in Big Rivers' discretion.
10. Agreement, dated July 15, 1998, by and among Big Rivers, WKEC, Deborah A. Dewey and Gregory Black.	Previous retention of Ms. Dewey as the "Designated Representative" of the leased generators for NOx and SO2 compliance purposes, and retention of Mr. Black as the "Alternate Designated Representative".	This document was previously terminated and replaced with the document identified in Item 9 above.
11. Short Form Lease, dated July 15, 1998, by and among Big Rivers, WKEC, Station Two Subsidiary, LEM and WKE.	Abbreviated form of the Lease and Operating Agreement described in Item 2 above, which was recorded in 1998 in various Kentucky counties.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
12. Settlement Promissory Note, dated July 15, 1998, by Big Rivers in favor of LEM, in the original principal amount of $19,675,603.00.	Reflects certain indebtedness of Big Rivers undertaken in connection with the 1998 transactions.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
13. Promissory Note, dated July 15, 1998, by Big Rivers to LEM in the original principal amount of $50,000,000.00.	Reflects certain indebtedness of Big Rivers undertaken in connection with the 1998 transactions.	This Promissory Note was previously satisfied and discharged by Big Rivers, and is no longer owing.
14. Mortgage and Security Agreement, dated July 15, 1998, by Big Rivers in favor of WKEC, LEM, Station Two Subsidiary and WKE.	Granted the WKE Parties a mortgage and security interest in certain of Big Rivers' assets to secure the obligations of Big Rivers under the 1998 transaction documents.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
15. Mortgage and Security Agreement (LEM Mortgage), dated July 15, 1998, by Big Rivers in favor of LEM, WKEC, Station Two Subsidiary and WKE, as amended by the First Amendment to Mortgage and Security Agreement (LEM Mortgage) dated as of August 22, 2002.	Granted the WKE Parties a mortgage and security interest in certain of Big Rivers' assets to secure the obligations of Big Rivers to: (a) pay the Settlement Promissory Note identified in item 12 above, and (b) pay the LG&E Parties Residual Value Payment under Section 24.1 of the 1998 New Participation Agreement.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	Description of Document	Disposition After Unwind Transaction
16. New Guarantee Agreement between LEC (now E.ON) and Big Rivers dated April 6, 1998.	Guaranteed the obligations of the WKE Parties to Big Rivers under the 1998 transaction documents.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
17. Participation Agreement, dated June 9, 1997, by and among LEM, Western Kentucky Leasing Corp., Station Two Subsidiary, WKEC and Big Rivers, as amended.	This agreement preceded the New Participation Agreement referred to in Item 1 above. It was replaced by that New Participation Agreement and was terminated effective as of the 1998 closing.	Each party will be fully released from further obligation (if any) under this document at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
18. Amended and Restated Guarantee Agreement, dated March 18, 1998, by and between LEC (now E.ON) and Big Rivers.	This Agreement preceded the New Guarantee Agreement referred to in Item 16 above. It was replaced by that New Guarantee Agreement and was terminated effective as of the 1998 closing.	Each party will be fully released from further obligation (if any) under this document at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	Description of Document	Disposition After Unwind Transaction
19. Agreement, dated May 25, 2004, by and among Big Rivers, WKEC, LEM, Station Two Subsidiary, WKE and E.ON, relating to the Wilson run-off pond settlement.	Resolved certain disputes and differences among the parties regarding the condition of a certain Wilson Station storm water run-off pond and expenses incurred to address that condition.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
20. Baseline Study Agreement, dated October 15, 1997, by and between Big Rivers, the WKE Parties and LEC.	Sets forth the parameters for the parties to undertake environmental audits of the leased generator sites and the Station Two site prior to the 1998 closing.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
21. Agreement for Professional and Environmental Services, dated October 15, 1997, by and among Woodward-Clyde International Americas, WKEC and Big Rivers.	Agreement to engage Woodward-Clyde consultants to conduct the environmental audits described in Item 20, above.	This document, as between WKEC and Big Rivers, will be terminated and released at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement. It will remain in effect, however, to the extent WKEC or Big Rivers have any recourse as against Woodward-Clyde for damages, etc. (if any) arising out of its consulting services or other covenants under this agreement, as contemplated in Section 14.3 of the Transaction Termination Agreement.

DOCUMENT TITLE	**DESCRIPTION OF DOCUMENT**	**DISPOSITION AFTER UNWIND TRANSACTION**
22. Software License Agreement, dated July 15, 1998, by and between WKEC and Big Rivers.	Granted WKEC a license to use certain software and other information of Big Rivers.	This agreement was terminated by mutual agreement of the parties prior to the date hereof. The parties will fully release each other from further obligation (if any) under this document at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
23. Lease and Option Agreement, dated July 15, 1998, by and between Big Rivers and WKEC.	Granted WKEC a lease to use and occupy Big Rivers' "Central Lab" building, and an option to lease two floors in Big Rivers' headquarters building.	This Agreement was terminated when WKEC purchased the Central Lab building from Big Rivers and declined to timely exercise its option to lease those two floors of the Big Rivers headquarters building.
24. Generation Dispatching Services Agreement, dated July 15, 1998, by and among Big Rivers, WKEC, Station Two Subsidiary and LEM.	Retention of Big Rivers to provide certain generation dispatching support services to the WKE Parties.	This agreement was previously terminated by the parties in accordance with its terms, as the WKE Parties no longer required these services.
25. Economic Development Agreement, dated June 18, 1997, by and among LEM, Big Rivers and the member distribution cooperatives of Big Rivers.	Provision by LEM of certain economic development support services and assistance to Big Rivers and its member distribution cooperatives.	This document was previously terminated by Big Rivers in accordance with its terms.

Document Title	Description of Document	Disposition After Unwind Transaction
26. Interim Wholesale Marketing Assistance Agreement, dated June 18, 1997, by and between Big Rivers and LEM, as amended.	Temporary provision by LEM to Big Rivers of certain wholesale power marketing services and assistance prior to the closing of the 1998 transactions.	This document was terminated by mutual agreement of the parties prior to the closing of the 1998 transactions.
27. Third Amended and Restated Subordination, Non-Disturbance, Attornment and Inter-Creditor Agreement, dated as of August 1, 2001, among Big Rivers, the WKE Parties and certain other secured creditors of Big Rivers (including without limitation, RUS and the Economically Defeased Lease Parties), as amended by the First Amendment thereof dated August 22, 2002, and by the Second Amendment thereof dated July 15, 2003	Provides for certain non-disturbance and attornment commitments among the secured creditors of Big Rivers upon a foreclosure of Big Rivers' assets, and for the priority of those creditors as to those assets in the event of such a foreclosure, among other commitments between those creditors and Big Rivers.	The WKE Parties and E.ON will be released from their respective obligations under this agreement pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement, and pursuant to the "Creditor Termination and Release" contemplated in Section 3.2(l) of the Transaction Termination Agreement. Big Rivers anticipates that the document identified in this Item 27 will be replaced at the unwind closing with a new inter-creditor agreement among Big Rivers and its secured creditors.
28. Letter Agreement, dated July 7, 2000, by and between Big Rivers and WKEC, relating to certain survey work associated with the Plant Reid gas line.	Granted access rights to conduct certain survey work required for the installation of a new natural gas line at Reid Station.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	Description of Document	Disposition After Unwind Transaction
29. Transmission Service Use Agreement, dated August 1, 2002, by and between Big Rivers and LEM, as amended.	Granted LEM certain rights to utilize transmission services over the TVA transmission system that are held by Big Rivers pursuant to a Service Agreement for Long-Term Firm Point-to-Point Transmission Service between Big Rivers and TVA, dated August 1, 2002.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
30. Coleman Switchyard Support Services Agreement, dated September 29, 2004, by and between Big Rivers and WKEC.	Retention by Big Rivers of WKEC to provide certain emergency response and restoration services within the Coleman switchyard, among other related commitments.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
31. Tower Lease and Agreement, dated November 1, 2000, by and between Big Rivers and WKEC.	Lease by Big Rivers to WKEC of certain space on and about various tower sites owned by Big Rivers, for the installation and use by WKEC of certain meteorological equipment.	Will be terminated and released in its entirety at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.

Document Title	Description of Document	Disposition After Unwind Transaction
B. Agreements Between E.ON and its Affiliates, and the Century Parties		
1. Agreement for Electric Service, dated July 15, 1998, by and between LEM and Kenergy (as successor to GREC).	Provision by WKEC (formerly LEM) of certain quantities of power to Kenergy for resale to meet certain needs of the aluminum smelter of Century (formerly owned by Southwire Company), and the nearby rod and cable mill of Southwire Company (or its affiliate), located in Western Kentucky.	Will be terminated and released in its entirety at the unwind closing pursuant to a Termination and Release Agreement in form satisfactory to LEM, E.ON, Kenergy and Century (as contemplated in Section 3.2(k) of the Transaction Termination Agreement). A form of this Termination and Release Agreement satisfactory to Big Rivers and the WKE Parties is attached as Exhibit L to the Transaction Termination Agreement, and is under discussion with Kenergy and Century.
2. Agreement for Tier 3 Electric Service (2001-2002), dated July 15, 1998, by and between LEM and Kenergy (as successor to GREC).	Provision by LEM of certain quantities of power to Kenergy for resale to meet certain needs of the aluminum smelter and/or the rod and cable mill described in Item 1 above.	This document previously expired and is no longer in force or effect.
3. Agreement for Tier 3 Electric Service (2001-2005), dated July 15, 1998, by and between LEM and Kenergy (as successor to GREC).	Provision by LEM of certain quantities of power to Kenergy for resale to meet certain needs of the aluminum smelter and/or the rod and cable mill described in Item 1 above.	This document previously expired and is no longer in force or effect.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
4. Security and Lockbox Agreement, dated as of July 15, 1998, by and among PNC Bank, N.A., LEM, Kenergy (as successor to GREC), Southwire Company, Century (as successor to Southwire Company), Century Kentucky (as successor of Southwire Company and Century), Hancock (as successor to Century Kentucky), and Century Kentucky GP (as successor to Hancock and NSA, Ltd.).	Agreement for the parties' respective payment of power sales purchase price amounts and transmission rates through a secure lock box account maintained with PNC Bank, N.A.	Same as in Item B.1 above.
5. Assurances Agreement, dated July 15, 1998, by and among LEM, Southwire Company, Century (as successor to Southwire Company), Century Kentucky (as successor to Century), Hancock (as successor to Century Kentucky), and Century Kentucky GP (as successor to Hancock and NSA, Ltd.), as amended.	Mutual agreements of WKEC (formerly LEM) and the Century entities to honor and enforce their respective power purchase and sale agreements with Kenergy, among other commitments.	Same as in Item B.1 above.
6. Special Assignment Agreement, dated March 26, 2001, by and among LEM, Southwire Company, Century Kentucky and Century.	Document required to implement the sale and assignment by Southwire Company to Century of its smelter facilities and associated contracts as described in Item A.1.vi, above.	Same as in Item B.1 above.
7. Consent and Agreement, dated December 23, 2005, by and among Century Kentucky, Century, Hancock, NSA, Ltd., Century Kentucky GP, Metalsco, Ltd., Skyliner, Inc., Century Kentucky, Inc. and LEM.	Document required to accommodate an internal corporate restructuring undertaken by Century and its affiliates.	Same as in Item B.1 above.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
8. Systems Disturbance Agreement, dated as of July 15, 1998, by and among Big Rivers, WKEC (for itself and as successor to Station Two Subsidiary), Kenergy (as successor to Henderson Union and GREC), Alcan (as successor to Alcan Aluminum Corporation), Alcan PPC (as successor to Alcan), Southwire Company, Century (as successor to Southwire Company), Century Kentucky (as successor to Century), Hancock (as successor to Century Kentucky), and Century Kentucky GP (as successor to Hancock and NSA, Ltd.).	Agreement to jointly cooperate to minimize disturbances on the Big Rivers transmission and the Kenergy distribution system, and to mitigate the effects of such disturbances.	WKEC will be released from this document pursuant to the Termination and Release Agreements contemplated in Items A.1 and B.1 above. It may continue in force and effect following the unwind closing as among the other parties thereto, however, unless those other parties elect to replace it as of that closing. This is still under discussion among Big Rivers, Kenergy, Alcan and Century.
9. Load Management Agreement for Electric Power Supply, dated as of July 15, 1998, by and among LEM, Southwire Company, Century (as successor to Southwire Company), Century Kentucky (as successor to Century), Hancock (as successor to Century Kentucky), and Century Kentucky GP (as successor to Hancock and NSA, Ltd.).	Agreement of LEM and the Century entities regarding certain opportunities, from time-to-time, to curtail power deliveries to Kenergy, for the benefit of the Century entities, under certain limited circumstances where it may be economically advantageous for the parties to do so.	The WKE Parties will be released from this document pursuant to the Termination and Release Agreement contemplated in Item B.1 above.
10. Guaranty, dated July 15, 1998, by E.ON (as successor to LEC) to and in favor of Kenergy (as successor to GREC).	Guaranteed the obligations of WKEC (formerly LEM) under the agreement identified in Item B.1 above (among other obligations).	Same as in Item B.1 above.

Document Title	Description of Document	Disposition After Unwind Transaction
11. Guaranty, dated as of July 15, 1998, of E.ON (as successor to LEC) to and in favor of Southwire Company, Century (as successor to Southwire Company), Century Kentucky (as successor to Southwire Company or Century), Hancock (as successor to Century Kentucky), and Century Kentucky GP (as successor to Hancock and NSA, Ltd.) (which Guaranty is appended to the Assurances Agreement described in Item 5 above).	Guaranteed the obligations of WKEC (formerly LEM) under the agreement identified in Item B.5 above (among other obligations).	Same as in Item B.1 above.

Document Title	Description of Document	Disposition After Unwind Transaction
C. Agreements Between E.ON and its Affiliates, and the Alcan Parties		
1. Agreement for Electric Service, dated July 15, 1998, by and between LEM and Kenergy (as successor to Henderson Union).	Provision by WKEC (formerly LEM) of certain quantities of power to Kenergy for resale to meet certain needs of the aluminum smelter of Alcan located in Western Kentucky.	Will be terminated and released in its entirety at the unwind closing pursuant to a Termination and Release Agreement in form satisfactory to LEM, E.ON, Kenergy and Alcan (as contemplated in Section 3.2(j) of the Transaction Termination Agreement). A form of this Termination and Release Agreement satisfactory to Big Rivers and the WKE Parties is attached as Exhibit K to the Transaction Termination Agreement, and is under discussion with Kenergy and Alcan.
2. Security and Lock Box Agreement, dated as of July 15, 1998, by and among PNC Bank, N.A., LEM, Kenergy (as successor to Henderson Union), Alcan (as successor to Alcan Aluminum Corporation), and Alcan PPC (as successor to Alcan).	Agreement for the parties' respective payment of power sales purchase price amounts and transmission rates through a secure lock box account maintained with PNC Bank, N.A.	Same as in Item C.1 above.

DOCUMENT TITLE	DESCRIPTION OF DOCUMENT	DISPOSITION AFTER UNWIND TRANSACTION
3. Assurances Agreement, dated as of July 15, 1998, by and among LEM, Alcan (as successor to Alcan Aluminum Corporation) and Alcan PPC (as successor to Alcan), as amended.	Mutual agreements of WKEC (formerly LEM) and the Alcan entities to honor and enforce their respective power purchase and sale agreements with Kenergy, among other commitments.	Same as in Item C.1 above.
4. Assumption and Consent Agreement, dated as of August 1, 2003, by and among Alcan PPC, Station Two Subsidiary, LEM, WKEC and Kenergy.	Document required to accommodate an internal corporate restructuring undertaken by Alcan and its affiliates.	Same as in Item C.1 above.
5. Guaranty, dated August 1, 2003, from Alcan to and in favor of the E.ON Parties.	Document required to accommodate an internal corporate restructuring undertaken by Alcan and its affiliates.	Same as in Item C.1 above.
6. Undertaking of Alcan, dated August 1, 2003, from Alcan to and in favor of LEM ("Current Undertaking"), and the Undertaking of Alcan Aluminum Corporation, dated July 15, 1998, from Alcan Aluminum Corporation to and in favor of LEM (which was previously terminated, replaced and superseded by the Current Undertaking).	Document required to accommodate an internal corporate restructuring undertaken by Alcan and its affiliates.	Same as in Item C.1 above.

DOCUMENT TITLE	DESCRIPTION OF DOCUMENT	DISPOSITION AFTER UNWIND TRANSACTION
7. Systems Disturbance Agreement, dated as of July 15, 1998, by and among Big Rivers, WKEC (for itself and as successor to Station Two Subsidiary), Kenergy (as successor to Henderson Union and GREC), Alcan (as successor to Alcan Aluminum Corporation), Alcan PPC (as successor to Alcan), Southwire Company, Century (as successor to Southwire Company), Century Kentucky (as successor to Century), Hancock (as successor to Century Kentucky), and Century Kentucky GP (as successor to Hancock and NSA, Ltd.).	Agreement to jointly cooperate to minimize disturbances on the Big Rivers transmission and the Kenergy distribution system, and to mitigate the effects of such disturbances.	WKEC will be released from this document pursuant to the Termination and Release Agreements contemplated in Items A.1 and B.1 above. It may continue in force and effect following the unwind closing as among the other parties thereto, however, unless those other parties elect to replace it as of that closing. This is still under discussion among Big Rivers, Kenergy, Alcan and Century.
8. Load Management Agreement for Electric Power Supply, dated as of July 15, 1998, by and among LEM, Alcan (as successor to Alcan Aluminum Corporation) and Alcan PPC (as successor to Alcan).	Agreement of LEM and the Alcan entities regarding certain opportunities, from time-to-time, to curtail power deliveries to Kenergy, for the benefit of the Alcan entities, under certain limited circumstances where it may be economically advantageous for the parties to do so.	The WKE Parties will be released from this document pursuant to the Termination and Release Agreement contemplated in Item C.1 above.
9. Guaranty, dated July 15, 1998, of E.ON (as successor to LEC) to and in favor of Kenergy (as successor to Henderson Union).	Guaranteed the obligations of WKEC (formerly LEM) under the agreement identified in Item C.1 above (among other obligations).	Same as in Item C.1 above.

Document Title	Description of Document	Disposition After Unwind Transaction
10. Guaranty, dated July 15, 1998, by E.ON (as successor to LEC) to and in favor of Alcan (as successor to Alcan Aluminum Corporation) and Alcan PPC (as successor to Alcan) (which Guaranty is appended to the Assurances Agreement described in Item 3 above).	Guaranteed the obligations of WKEC (formerly LEM) under the agreement identified in Item C.3 above (among other obligations).	Same as in Item C.1 above.

DOCUMENT TITLE	DESCRIPTION OF DOCUMENT	DISPOSITION AFTER UNWIND TRANSACTION
D. Agreements Between E.ON, its Affiliates and the City of Henderson		
1. ***Station Two Terminated Agreements***		
i. Agreement and Amendments to Agreement, dated July 15, 1998, as amended, by and among the City, the City Utility Commission, Big Rivers, LEM, WKEC, WKE and Station Two Subsidiary, including without limitation, as amended by the Amendatory Agreement, dated April 1, 2005, by and among the City, the City Utility Commission, Big Rivers, Station Two Subsidiary, WKEC, LEM and WKE (collectively, the ***"Station Two Agreement"***).	The "omnibus" transaction agreement whereby Station Two Subsidiary (now WKEC) assumed Big Rivers' rights and obligations to operate and maintain Station Two, and to purchase the capacity and energy of Station Two in excess of the City's reserved capacity and energy therefrom, among other related transactions.	Will be terminated and released in its entirety at the unwind closing pursuant to a Station Two Termination and Release Agreement in form satisfactory to the WKE Parties, E.ON, Big Rivers, the City and the City Utility Commission (as contemplated in Section 3.2(m) of the Transaction Termination Agreement). A draft of this Station Two Termination and Release Agreement satisfactory to Big Rivers and the WKE Parties has been presented to the City and the City Utility Commission for their consideration, and is still under discussion with them.
ii. Station Two G&A Allocation Agreement, dated July 15, 1998, by and among the City Utility Commission, Big Rivers and Station Two Subsidiary.	Allocation among the parties, on an agreed basis, of certain general and administrative "overhead" costs associated with Station Two and the adjacent Green Station.	Same as in Item D.1.i above.

DOCUMENT TITLE	DESCRIPTION OF DOCUMENT	DISPOSITION AFTER UNWIND TRANSACTION
iii. Agreement with Respect to Operating Reserves and Amendment No. 1 to Systems Reserve Agreement, dated July 15, 1998, by and among the City Utility Commission, Big Rivers and LEM.	Agreement to maintain and provide certain back-up power to meet the City's needs, among other commitments.	Same as in Item D.1.i above.
iv. Assignment and Assumption Agreement (Station Two), dated July 15, 1998, by and between Big Rivers and Station Two Subsidiary.	Effected the 1998 assignment by Big Rivers to Station Two Subsidiary (now WKEC) of various contracts, leases and other intangible assets necessary for the operation of Station Two.	Same as in Item D.1.i above. This document will also be terminated and released at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
v. Deed of Easement and Right-of-Way, dated July 15, 1998, by and between Big Rivers, as grantor, and Station Two Subsidiary, LEM and WKEC, as grantees.	Granted certain access rights for ingress and egress on, over and across the leased generator sites, to facilitate the use and operation of Station Two.	Same as in Item D.1.i above. This document will also be terminated and released at the unwind closing pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement.
vi. Deed and Easement and Right-of-Way, dated July 15, 1998, by and between the City and the City Utility Commission, as grantors, and Station Two Subsidiary, LEM and WKEC, as grantees.	Granted certain access rights for ingress and egress on, over and across the Station Two site.	Same as in Item D.1.i above.

DOCUMENT TITLE	**DESCRIPTION OF DOCUMENT**	**DISPOSITION AFTER UNWIND TRANSACTION**
vii. Acknowledgement and Consent, dated July 15, 1998, by and among the City, the City Utility Commission and LEM.	Consent of the City to Station Two Subsidiary's assignment to LEM of the document identified in Item 2.i below; agreement of the City and LEM regarding certain charges for systems reserves services.	Same as in Item D.1.i above.
viii. Agreement, entered into August 27, 2002, by and among the City, the City Utility Commission, Big Rivers, Station Two Subsidiary (now WKEC), Gregory Black and Ralph Bowling.	Retention of Mr. Black as the "Designated Representative" of Station Two for NOx and SO2 compliance purposes, and retention of Mr. Bowling as the "Alternative Designated Representative".	WKEC will be released from further obligation under this document either pursuant to the Station Two Termination and Release Agreement identified in Item D.1.i above, or pursuant to a separate document (to be developed by the parties) relating specifically to this document. This document may or may not be terminated and replaced by a new, similar retention agreement, in Big Rivers' and the City's discretion.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
ix. Deed of Easement, dated August 12, 2003, but with retroactive effect to June 1, 1999, by and among the City, the City Utility Commission, Big Rivers, WKEC, LEM, Station Two Subsidiary and WKE, relating to the Reid Station gas line.	Granted an easement and right-of-way required to accommodate the installation of a new natural gas line to Reid Station.	WKEC will be released from further obligation under this document either pursuant to the Station Two Termination and Release Agreement identified in Item D.1.i above, or pursuant to a separate document (to be developed by the parties) relating specifically to this document. This document may or may not be terminated and replaced by a new, similar easement agreement, in Big Rivers' and the City's discretion.
x. Guarantee Agreement [Station Two Obligations], dated July 15, 1998, from E.ON (as successor to LEC) in favor of the City and the City Utility Commission.	Guaranteed the obligations of the WKE Parties under the agreement identified in Item D.1.i above (among other obligations).	Same as in Item D.1.i above.
xi. Agreement for Interim Funding Station Two SCR System, dated May 7, 2002, by and among the City, the City Utility Commission, WKEC (including as successor to Station Two Subsidiary and WKE) and LEM, as amended by the First Amendment to Agreement for Interim Funding Station Two SCR System dated April 1, 2005.	Initial funding of the Station Two SCR installation costs in advance of the effectiveness of the amendments contemplated in the document identified in Item D.2.i.e below.	Same as in Item D.1.i above.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
xii. Supplementary Agreement on SO_2 Emission Allowances, dated January 18, 2002, by and between the City Utility Commission and WKEC (including as successor by merger of Station Two Subsidiary).	Modified the protocol for distributing or disposing of SO2 allowances to WKEC and the City which are surplus to the compliance needs of Station Two in a given year.	WKEC will be released from further obligation under this document pursuant to the Station Two Termination and Release Agreement identified in Item D.1.i above. Big Rivers may or may not assume this agreement from WKEC, and this document may or may not be terminated and replaced by a different agreement. These issues are still to be discussed by Big Rivers and the City's.
xiii. Excess Power Agreement (letter agreement), dated July 23, 1999, by and between LEM and the City Utility Commission.	Provides for LEM's purchase from the City, under certain circumstances, of energy of the City in excess of its needs.	This agreement will be terminated by LEM and the City Utility Commission pursuant to the Station Two Termination and Release Agreement identified in Item D.1.i, above.
2. ***Released Station Two Contracts***		

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
i. Power Sales Contract, dated August 1, 1970, by and among the City, Big Rivers, Station Two Subsidiary (as assignee of Big Rivers), LEM (as assignee of Station Two Subsidiary), and WKEC (as successor of LEM), as amended by the documents identified below:	Agreement whereby WKEC, as successor by assignment from Big Rivers in 1998, purchases from the City capacity and energy from Station Two in excess of the City's reserved capacity and energy from Station Two (among other commitments).	The relevant WKE Party will be released from further obligation under this document as of the unwind closing pursuant to the Station Two Termination and Release Agreement referred to in Item D.1.i above. However, it is anticipated that this document will thereafter continue in force and effect as among Big Rivers, the City and/or the City Utility Commission (subject to such changes to this document as those parties may choose to implement).
a. Amendment No. 1, dated March 2, 1971, to Power Sales Contract dated August 1, 1970.	Implemented certain amendments to the Power Sales Contract identified above in this Item i.	Same as in Item D.2.i above.
b. Amendment No. 2, dated march, 1973, to power Sales Contract dated August 1, 1970.	Implemented certain amendments to the Power Sales Contract identified above in this Item i.	Same as in Item D.2.i above.
c. Amendments, dated May 1, 1993, to Contracts among the City, the City Utility Commission, Big Rivers, Station Two Subsidiary (as assignee of Big Rivers) and LEM (as assignee of Station Two Subsidiary) (the ***"1993 Amendments"***).	Implemented certain amendments to the Power Sales Contract identified above in this Item i.	Same as in Item D.2.i above.
d. Amendments to Contracts among the City, the City Utility Commission and Big Rivers, dated July 15, 1998 (the	Implemented certain amendments to the Power Sales Contract identified above	Same as in Item D.2.i above.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
"1998 Amendments").	in this Item i.	
e. 2005 Amendments to Contracts, dated April 1, 2005, by and among the City, the City Utility Commission, Big Rivers, Station Two Subsidiary and LEM (the ***"2005 Amendments"***).	Implemented certain amendments to the Power Sales Contract identified above in this Item i.	Same as in Item D.2.i above.
ii. Power Plant Construction and Operation Agreement, dated August 1, 1970, by and among the City, the City Utility Commission, Big Rivers and Station Two Subsidiary (as assignee of Big Rivers), as amended by the 1993 Amendments, the 1998 Amendments, and the 2005 Amendments.	Agreement whereby WKEC, as successor by assignment from Big Rivers in 1998, operates and maintains Station Two, and jointly funds, together with the City, the costs to operate and maintain Station Two (among other commitments).	Same as in Item D.2.i above.
iii. Joint Facilities Agreement, dated August 1, 1970, by and among the City, the City Utility Commission, Big Rivers and Station Two Subsidiary (as assignee to Big Rivers), as amended by the 1993 Amendments, the 1998 Amendments, and the 2005 Amendments.	Agreement whereby WKEC, as successor by assignment from Big Rivers in 1998, and as the lessee of Green Station, together with the City as owner of Station Two, each agreed to dedicate certain equipment and other assets at Green Station and Station Two, respectively, for common use by, and the support of, the other of those generating stations (among other commitments).	Same as in Item D.2.i above.
iv. Grant of Rights and Easements, dated as of April 1, 2005, by and among the City, the	Grant of easement to the City to utilize a portion of the Green Station site for the installation and use of the Station	WKEC will be released from further obligation under this document as of the unwind

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
City Utility Commission, Big Rivers and WKEC.	Two SCRs.	closing pursuant to the Station Two Termination and Release Agreement referred to in Item D.1.i above. However, it is anticipated that this document will thereafter continue in force and effect as among Big Rivers, the City and/or the City Utility Commission (subject to such changes to this document as those parties may choose to implement).

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
v. Agreement (commonly referred to as the "Subordination Agreement"), dated as of April 1, 2005, by and among the City; the City Utility Commission; Big Rivers; Station Two Subsidiary; LEM; WKEC; The United States of America; Ambac Assurance Corporation; National Rural Utilities Cooperative Finance Corporation; Credit Suisse; U.S. Bank National Association; PBR-1 Statutory Trust, a Connecticut statutory trust; PBR-2 Statutory Trust, a Connecticut statutory trust; PBR-3 Statutory Trust, a Connecticut statutory trust; FBR-1 Statutory Trust, a Connecticut statutory trust; FBR-2 Statutory Trust, a Connecticut statutory trust; PBR-1 OP Statutory Trust, a Connecticut statutory trust; PBR-2 OP Statutory Trust, a Connecticut statutory trust; PBR-3 OP Statutory Trust, a Connecticut statutory trust; FBR-1 OP Statutory Trust, a Connecticut statutory trust; FBR-2 OP Statutory Trust, a Connecticut statutory trust; Bluegrass Leasing, a New York general partnership; Trisail Capital Corporation; AME Investments; CoBank, ACB, a government sponsored enterprise of the United States; AME Asset Funding and Ambac Credit Products.	Subordination by the Big Rivers secured creditors of their mortgage rights in the Green Station site to the rights and interests of the City under the Grant of Rights and Easements identified in Item 2.iv above.	The WKE Parties will be released and discharged from further obligation under this document pursuant to the Station Two Termination and Release Agreement referred to in Item D.1.i above, and pursuant to the "Creditor Termination and Release" contemplated in Section 3.2(l) of the Transaction Termination Agreement. This document will continue in effect following the unwind closing, however, as between the other parties thereto.

Document Title	**Description of Document**	**Disposition After Unwind Transaction**
vi. Settlement Agreement for Diverter Dampers and NEMS Systems, dated April 28, 2005, by and among WKEC (including as successor by merger with Station Two Subsidiary), the City Utility Commission, Alstom Power Inc., Zachry Construction Corporation, and the consortium comprised of Alstom Power Inc. and Zachry Construction Corporation pursuant to that certain Consortium Agreement dated effective April 2, 2002 (the "Consortium").	Document required to implement a settlement of certain disputes and differences with the vendor of the new SCRs at Station Two.	WKEC will be released from further obligation under this document by the release agreement contemplated in Section 10.2(jj) of the Transaction Termination Agreement. Big Rivers will receive an assignment of WKEC's rights under this document at the unwind closing, and this document will continue in effect thereafter as among the parties thereto other than WKEC.
vii. Agreement Regarding Costs in Connection with Correction or Repair of Diverter Dampers and NEMS Systems, dated May 5, 2005, by and among the City Utility Commission, WKEC (including as successor by merger with Station Two Subsidiary), Alstom Power Inc., Zachry Construction Corporation, the Consortium and Big Rivers, including the Amendment thereto executed on December 18, 2006, but dated effective December 13, 2006.	Document required to implement a settlement of certain disputes and differences with the vendor of the new SCRs at Station Two.	WKEC will be released from further obligation under this document by the release agreement contemplated in Section 10.2(jj) of the Transaction Termination Agreement. Big Rivers will receive an assignment of WKEC's rights under this document at the unwind closing, and this document will continue in effect thereafter as among the parties thereto other than WKEC.

Document Title	Description of Document	Disposition After Unwind Transaction
viii. Agreement and Supplemental Settlement Agreement, dated December 13, 2006, by and among the City Utility Commission, WKEC, Alstom Power Inc., Zachry Construction Corporation, the Consortium and Big Rivers.	Document required to implement a settlement of certain disputes and differences with the vendor of the new SCRs at Station Two.	WKEC will be released from further obligation under this document by the release agreement contemplated in Section 10.2(jj) of the Transaction Termination Agreement. Big Rivers will receive an assignment of WKEC's rights under this document at the unwind closing, and this document will continue in effect thereafter as among the parties thereto other than WKEC.

Document Title	Description of Document	Disposition After Unwind Transaction
E. Other Agreements Associated with 1998 Transactions		
1. Demand Promissory Note, dated July 15, 1998, from LEM in favor of the RUS, in the original principal amount of $933,333.33;	Reflects certain indebtedness of LEM undertaken as a condition to the approval of the 1998 transactions by the RUS.	To be released and discharged by the RUS at the unwind closing pursuant to the written instrument contemplated in Section 3.2(p) of the Transaction Termination Agreement, which must still be negotiated with the RUS.
2. Systems Disturbance Agreement, dated as of April 2001, among Big Rivers, Kenergy, Williamette Industries, Inc., Station Two Subsidiary and WKEC.	Agreement to jointly cooperate to minimize disturbances on the Big Rivers transmission and the Kenergy distribution system, and to mitigate the effects of such disturbances.	The WKE Parties will be released at the unwind closing from further obligation under this document (a) by Kenergy pursuant to the Termination and Release Agreements attached as Exhibits K and L to the Transaction Termination Agreement, (b) by Big Rivers pursuant to the Termination and Release Agreement attached as Exhibit B to the Transaction Termination Agreement, and (c) by Williamette Industries pursuant to a separate release agreement to be developed by the parties.

DOCUMENT TITLE	DESCRIPTION OF DOCUMENT	DISPOSITION AFTER UNWIND TRANSACTION
E. Other Agreements Associated with 1998 Transactions		
3. Letter Agreement dated December 20, 2000, among Big Rivers, WKEC, E.ON and Texas Gas Transmission Corporation, and the related Facilities Agreement dated May 17, 2000, among Texas Gas Transmission Corporation, WKEC and E.ON.	The Letter Agreement requires WKEC to incur certain potential future costs to move and re-install a natural gas pipeline located at Reid Station, and the Facilities Agreement contemplates the provision, operation and maintenance by Texas Gas Transmission Corp. of certain natural gas pipeline facilities at Reid Station.	WKEC and E.ON will be released from further obligation under these documents pursuant to the release agreement contemplated in Section 10.2(r) of the Transaction Termination Agreement, which release agreement is being developed for consideration by Texas Gas Transmission Corporation.

F. DEFINED TERMS:

As used in this summary, terms defined parenthetically immediately after their use shall have the respective meanings provided by such definitions, and the terms set forth below shall have the following meanings:

1. ***"Alcan"*** shall mean Alcan Corporation, a Texas corporation.

2. ***"Alcan PPC"*** shall mean Alcan Primary Products Corporation, a Texas corporation.

3. ***"Ambac Assurance Corporation"*** shall mean Ambac Assurance Corporation, a Wisconsin-domiciled stock insurance corporation.

4. ***"Ambac Credit Products"*** shall mean Ambac Credit Products, LLC, a Delaware limited liability company.

5. ***"AME Asset Funding"*** shall mean AME Asset Funding, LLC, a Delaware limited liability company.

6. ***"AME Investments"*** shall mean AME Investments, LLC, a Delaware limited liability company.

7. ***"Big Rivers"*** shall mean Big Rivers Electric Corporation, a Kentucky rural electric generation and transmission cooperative.

8. ***"Century"*** shall mean Century Aluminum Company, a Delaware corporation.

9. ***"Century Kentucky"*** shall mean Century Aluminum of Kentucky LLC, a Delaware limited liability company.

10. ***"Century Kentucky GP"*** shall mean Century Aluminum of Kentucky General Partnership, a Kentucky general partnership.

11. ***"City"*** shall mean the City of Henderson, in the Commonwealth of Kentucky.

12. ***"City Utility Commission"*** shall mean the City of Henderson Utility Commission doing business as Henderson Municipal Power & Light.

13. ***"Closing"*** shall have the meaning set forth in the Transaction Termination Agreement.

14. ***"Economically Defeased Lease Parties"*** shall mean Bluegrass Leasing, a New York general partnership; Fleet Real Estate, Inc., a Rhode Island corporation; PBR-1 Statutory Trust, a Connecticut statutory trust; PBR-2 Statutory Trust, a Connecticut statutory trust; PBR-3 Statutory Trust, a Connecticut statutory trust; FBR-1 Statutory Trust, a Connecticut statutory trust; FBR-2 Statutory

Trust, a Connecticut statutory trust; PBR-1 OP Statutory Trust, a Connecticut statutory trust; PBR-2 OP Statutory Trust, a Connecticut statutory trust; PBR-3 OP Statutory Trust, a Connecticut statutory trust; FBR-1 OP Statutory Trust, a Connecticut statutory trust; FBR-2 OP Statutory Trust, a Connecticut statutory trust; U.S. Bank National Association, a National Banking Association; CoBank, ACB, a government sponsored enterprise of the United States; Ambac Assurance Corporation; AME Investments; Ambac Credit Products; and AME Asset Funding.

15. ***"E.ON"*** shall mean E.ON U.S. LLC, a Kentucky limited liability company and the successor in interest of LEC.

16. ***"E.ON Parties"*** shall mean WKEC, E.ON and LEM.

17. ***"GREC"*** shall mean Green River Electric Corporation.

18. ***"Hancock"*** shall mean Hancock Aluminum LLC, a Delaware limited liability company.

19. ***"Henderson Union"*** shall mean Henderson Union Rural Electric Cooperative Corp.

20. ***"Kenergy"*** shall mean Kenergy Corp., a Kentucky cooperative corporation.

21. ***"LEC"*** shall mean LG&E Energy Corp., a Kentucky corporation and a predecessor to E.ON.

22. ***"LEM"*** shall mean LG&E Energy Marketing Inc., an Oklahoma corporation.

23. ***"RUS"*** shall mean the United States of America, acting through the Administrator of the Rural Utilities Service -- United States Department of Agriculture or any successor agency or administration.

24. ***"Southwire Company"*** shall mean Southwire Company, a Delaware corporation.

25. ***"Station Two Subsidiary"*** shall mean WKE Station Two Inc., formerly a Kentucky corporation that was merged into WKEC.

26. ***"Transaction Termination Agreement"*** shall mean that certain Transaction Termination Agreement, dated March 26, 2007, by and among Big Rivers, LEM and WKE.

27. ***"Western Kentucky Leasing Corp."*** shall mean Western Kentucky Leasing Corp., formerly a Kentucky corporation that was merged into WKEC.

28. ***"WKE"*** shall mean WKE Corp., formerly a Kentucky corporation that was merged into WKEC.

29. ***"WKE Parties"*** shall mean LEM and WKEC.

30. ***"WKEC"*** shall mean Western Kentucky Energy Corp., a Kentucky corporation.

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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
E.ON U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING, INC. FOR APPROVAL OF TRANSACTIONS	)	

EXHIBIT 8

Unwind Financial Model

December 2007

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I. Pro Forma
II. Smelter Rate Structure
III. Member Rates Cash Method
IV. Regulatory Accounts
V. FAC, PPA, and Environmental Surcharge
VI. Unwind Transaction
VII. Production - Fixed
VIII. Capital Expenditures and Depreciation
IX. Debt
X. Sale Leaseback
XI. Income Taxes
XII. Regular Net Operating Losses (NOLs)
XIII. Alternative Minimum Tax (AMT) NOLs
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Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:			4/30/2008	
I. Sales (TWH)																			
Rural	2.40	0.76	-	1.63	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	0.97	0.32	-	0.69	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	-	-	-	2.79	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16
Alcan	-	-	-	2.11	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14
Market	1.16	0.71	-	1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
Total Sales	4.53	1.80	-	8.28	12.29	12.49	12.29	12.29	12.35	12.41	12.45	12.52	12.43	12.59	12.40	12.53	12.64	12.67	12.78

Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:			4/30/2008
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)																			
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	1.02%	0.00%	9.98%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FAC ($/ MWH)				5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
PPA ($/ MWH)				(0.54)	0.05	(0.37)	0.73	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
Environmental Surcharge Adjustment ($/ MWH)																			
Rural				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Large Industrial				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Smelters				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Rural																			
Load Factor (%)	64.3%	60.2%		60.2%	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 ($/ KW-mo.)	7.37	7.37		7.37	7.37	7.37	7.52	7.52	7.52	7.52	7.59	7.59	8.35	8.35	8.35	8.35	8.35	8.35	8.35
Energy ($/ MWH)	20.40	20.40		20.40	20.40	20.40	20.81	20.81	20.81	20.81	21.02	21.02	23.12	23.12	23.12	23.12	23.12	23.12	23.12
Base	36.10	37.18		37.18	37.22	37.19	37.17	37.18	37.12	37.09	37.07	37.08	37.02	37.00	36.98	37.00	36.94	36.92	36.90
MRDA	(1.13)	(0.39)		(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
Regulatory Account Charge				-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
GRA	-	-		-	-	-	0.74	0.70	0.74	0.74	1.13	1.08	4.93	4.93	4.93	4.88	4.92	4.92	4.92
FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Economic Reserve	-	-		(2.39)	(3.58)	(5.34)	(5.56)	(6.42)	(1.14)	-	-	-	-	-	-	-	-	-	-
Net	-	-		-	0.16	0.52	0.88	0.00	5.89	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
Pre TIER Rebate Total	34.96	36.79		36.07	36.28	36.64	37.73	36.85	42.92	44.96	46.57	47.43	50.63	51.18	51.53	52.26	52.71	53.34	53.61
TIER Related Rebate	-	-		(0.25)	(0.56)	(0.94)	-	-	(0.00)	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	34.96	36.79		35.82	35.72	35.70	37.73	36.85	42.92	44.96	46.57	47.43	50.63	51.18	51.53	52.26	52.71	53.34	53.61
Large Industrial																			
Load Factor (%)	80.2%	78.1%		78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
Demand ($/ KW-mo.)	10.15	10.15		10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.46	10.46	11.50	11.50	11.50	11.50	11.50	11.50	11.50
Energy ($/ MWH)	13.72	13.72		13.72	13.72	13.72	13.99	13.99	13.99	13.99	14.13	14.13	15.54	15.54	15.54	15.54	15.54	15.54	15.54
Base	31.06	31.52		31.52	31.39	31.39	31.39	31.45	31.39	31.39	31.39	31.46	31.39	31.39	31.39	31.46	31.39	31.39	31.39
Power Factor Penalty/ Demand Cr. (L	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MRDA	(0.99)	(2.85)		(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
Regulatory Account Charge				-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
GRA	-	-		-	-	-	0.63	0.58	0.63	0.63	0.96	0.91	4.18	4.18	4.18	4.14	4.18	4.18	4.18
FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Economic Reserve	-	-		(2.39)	(3.58)	(5.34)	(5.56)	(6.42)	(1.14)	-	-	-	-	-	-	-	-	-	-
Net	-	-		-	0.16	0.52	0.88	0.00	5.89	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
Pre TIER Rebate Total	30.07	28.67		30.58	30.62	31.01	32.01	31.16	37.24	39.30	40.87	41.77	44.39	44.96	45.33	46.11	46.55	47.20	47.49
TIER Related Rebate	-	-		(0.22)	(0.48)	(0.81)	-	0.00	0.00	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	30.07	28.67		30.36	30.14	30.19	32.01	31.16	37.24	39.30	40.87	41.77	44.39	44.96	45.33	46.11	46.55	47.20	47.49

#	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:			4/30/2008	
69	Non-Smelter Member Blend																			
72	Base	34.64	35.50		35.50	35.45	35.42	35.39	35.41	35.33	35.31	35.28	35.31	35.24	35.21	35.20	35.23	35.16	35.14	35.13
73	MRDA	(1.09)	(1.12)		(1.06)	(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)
74	Regulatory Account Charge				-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
75	GRA	-	-		-	-	-	0.71	0.66	0.71	0.71	1.07	1.03	4.69	4.69	4.69	4.64	4.68	4.68	4.68
76																				
77	FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
78	Environmental Surcharge				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
79	Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
80	Economic Reserve	-	-		(2.39)	(3.58)	(5.34)	(5.56)	(6.42)	(1.14)	-	-	-	-	-	-	-	-	-	-
81	Net				-	0.16	0.52	0.88	0.00	5.89	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
82																				
83	Pre TIER Rebate Total	33.55	34.37		34.44	34.56	34.92	35.97	35.09	41.15	43.18	44.77	45.64	48.65	49.20	49.55	50.29	50.73	51.36	51.64
84	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.90)	-	0.00	(0.00)	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	33.55	34.37		34.19	34.02	34.02	35.97	35.09	41.15	43.18	44.77	45.64	48.65	49.20	49.55	50.29	50.73	51.36	51.64
86																				
87	Smelters																			
88	Base Rate	-	-		27.32	27.33	27.34	27.92	27.90	27.96	27.97	28.28	28.26	31.18	31.19	31.21	31.18	31.24	31.25	31.26
89	TIER Adjustment	-	-		-	-	0.00	1.81	2.64	2.40	2.26	3.16	2.88	3.14	0.15	3.17	2.16	3.46	2.50	3.69
90	Smelter Rate *Subject to Price Cap*	-	-		27.32	27.33	27.34	29.73	30.54	30.36	30.23	31.44	31.13	34.32	31.35	34.37	33.34	34.69	33.75	34.95
91	FAC				5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
92	PPA	-	-		(0.54)	0.05	(0.37)	0.73	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
93	Environmental Surcharge				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
94	Surcharge 1	-	-		0.70	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				1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
96	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.90)	-	-	-	-	-	-	-	-	-	-	-	-	-
97	Effective Rate	-	-		34.82	34.94	37.70	42.58	43.90	44.56	44.75	47.34	47.42	52.22	48.61	52.37	51.61	53.73	53.05	55.05
98																				
99	Market	55.81	37.82		48.40	51.34	49.47	50.22	48.34	51.48	51.92	53.69	52.59	53.75	54.70	57.55	57.70	56.11	59.94	59.12
100																				
101	Overall Blend	39.26	35.74		36.39	36.67	38.17	41.42	41.64	44.17	44.93	47.08	47.28	51.12	49.29	51.66	51.48	52.78	52.80	54.00
102																				

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:			4/30/2008	
103	**III. Cash Flows (M$)**																			
104																				
105	Operating Receipts																			
106	Rural	83.8	28.0	-	58.9	88.0	89.8	93.6	95.6	113.8	121.5	128.7	133.7	145.7	150.2	154.5	159.8	164.5	169.6	173.8
107	Large Industrial	29.3	9.3	-	21.1	32.4	33.5	35.3	36.3	44.7	48.5	51.9	54.4	59.4	61.7	63.8	66.4	68.7	71.3	73.4
108	Smelters	-	-	-	170.6	255.0	275.1	310.7	321.2	325.2	326.5	345.5	346.9	381.1	354.7	382.2	377.6	392.1	387.1	401.7
109	Offsystem	64.9	26.9	-	51.4	76.7	79.8	66.3	58.5	61.7	60.8	60.0	56.9	49.2	54.0	40.0	41.4	42.0	41.0	41.4
110	WKEC Lease	48.0	15.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Smelter - Tier 3 Transmission	1.7	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	0.7	0.4	0.8	0.4	(9.6)	(8.9)	(8.0)	(8.4)	(7.3)	(8.2)	(8.6)	(8.6)	(9.2)
114	Cobank Patronage Capital & Other	0.5	0.2	-	0.4	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
115	Interest Earnings	6.6	2.0	-	4.6	7.4	5.8	4.8	4.0	3.6	3.6	3.9	4.1	4.4	5.0	5.5	5.9	6.5	6.9	7.2
116	Total Receipts	239.9	84.398	-	321.2	478.5	482.5	511.9	516.7	550.4	562.0	580.7	587.7	632.4	617.8	639.2	643.5	665.6	668.0	688.8
117																				
118	Operating Disbursements																			
119	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
120	Fuel Costs	-	-	-	137.6	204.3	227.2	227.1	228.3	238.5	245.1	246.0	253.5	252.0	257.3	252.9	262.2	266.4	268.0	271.2
121	SEPA & Other Purchases	6.9	3.8	-	10.2	22.4	17.6	30.8	27.5	31.9	25.8	29.0	28.6	43.7	30.3	40.9	36.2	41.5	43.7	51.3
122	Environmental	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
123	Fixed O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
124	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
125	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
126	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
127	Property Taxes & Insurance	2.4	0.8	-	4.5	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
128	Working Capital	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	(1.2)	(0.6)	0.6	(0.4)	(1.3)	(0.6)	(1.1)	0.7	(1.6)	(0.5)	(1.6)	(0.4)	(1.6)
129	PCB Restructuring	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	3.3	-
130	Other	1.9	0.7	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	-
131	Total Disbursements	126.3	50.0	-	237.7	393.3	407.7	436.1	438.7	460.5	459.9	478.1	484.5	520.5	500.9	523.0	527.0	549.3	554.5	574.1
132																				
133	Operating Receipts less Disbursements	113.6	34.4	-	83.5	85.2	74.8	75.8	77.9	89.9	102.1	102.7	103.3	111.9	116.9	116.2	116.5	116.4	113.5	114.8
134																				

Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:			4/30/2008	
Operating Receipts less Disbursements	113.6	34.4	-	83.5	85.2	74.8	75.8	77.9	89.9	102.1	102.7	103.3	111.9	116.9	116.2	116.5	116.4	113.5	114.8
Capital Expenditures																			
Generation	6.6	2.2	-	14.6	32.5	23.7	28.8	30.1	30.4	31.3	32.2	33.2	34.2	35.2	36.2	37.3	38.5	39.6	40.8
Transmission	9.6	5.2	-	6.2	9.6	9.2	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
Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
A&G	1.3	0.4	-	0.9	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
Extraordinary Generation	-	-	-	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
Other (HQ Building, IP)	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
Total Capital Expenditures	21.6	7.8	-	37.5	76.0	58.6	56.3	53.9	35.5	37.5	37.3	37.8	40.0	45.7	47.1	45.1	47.4	46.9	48.8
Income Taxes from Operations	0.9	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
Net Pre-Finance Cash Flow	91.2	26.5	-	46.0	9.1	16.2	19.5	24.1	54.3	64.3	65.0	65.1	71.4	70.8	68.6	70.9	68.5	66.1	65.5
Financing																			
Principal	12.5	13.0	-	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
Interest	36.7	16.9	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
Line of Credit	-	-	-	0.3	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
Aggregate Debt Service (incl. Line	49.2	30.0	-	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4
Post-Finance Cash Flow	42.0	(3.5)	-	6.9	(49.3)	(42.2)	(38.9)	(34.3)	(4.1)	5.9	6.6	6.7	13.0	12.4	10.2	12.5	10.1	7.7	7.1
Unwind Transaction																			
Cash Proceeds			301.5																
Debt Reduction			(195.8)																
Misc. Transaction			(5.6)																
Net Before Member Reserves			100.1																
Economic Reserve			(75.0)	5.5	12.5	19.1	20.4	24.2	4.4	-	-	-	-	-	-	-	-	-	-
Net Before Transition Reserve			25.1	5.5	12.5	19.1	20.4	24.2	4.4	-	-	-	-	-	-	-	-	-	-
Ending Cash Balances (Incl. Transition Reserve)	138.4	134.9	160.0	172.4	135.7	112.6	94.2	84.0	84.3	90.1	96.7	103.4	116.4	128.8	139.0	151.4	161.5	169.2	176.2

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:			4/30/2008	
169	**IV. Income Statement (M$)**																			
170																				
171	Revenues																			
172	Rural	83.8	28.0	-	58.5	87.1	88.8	95.9	95.6	113.8	121.5	128.7	133.7	145.7	150.2	154.5	159.8	164.5	169.6	173.8
173	Large Industrial	29.3	9.3	-	21.0	32.0	33.1	36.2	36.3	44.7	48.5	51.9	54.4	59.4	61.7	63.8	66.4	68.7	71.3	73.4
174	Smelters	-	-	-	170.6	255.0	275.1	310.7	321.2	325.2	326.5	345.5	346.9	381.1	354.7	382.2	377.6	392.1	387.1	401.7
175	Off-System	64.9	26.9	-	51.4	76.7	79.8	66.3	58.5	61.7	60.8	60.0	56.9	49.2	54.0	40.0	41.4	42.0	41.0	41.4
176	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
177	Smelter - Tier 3 Transmission	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
178	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	0.7	0.4	0.8	0.4	(9.6)	(8.9)	(8.0)	(8.4)	(7.3)	(8.2)	(8.6)	(8.6)	(9.2)
179	WKEC Lease (Net)	52.3	17.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
180	Interest Earnings	6.6	2.0	-	4.6	7.4	5.8	4.8	4.0	3.6	3.6	3.9	4.1	4.4	5.0	5.5	5.9	6.5	6.9	7.2
181	*Total Revenues*	243.9	85.8	-	320.2	476.6	480.6	514.6	516.1	549.8	561.4	580.2	587.2	631.8	617.2	638.7	642.9	665.1	667.4	688.3
182																				
183	Expenses																			
184	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
185	Fuel Costs	-	-	-	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
186	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	28.1	25.8	29.5	25.3	27.4	28.7	38.5	29.7	38.2	35.3	38.6	42.1	46.8
187	Non-Fuel Variable Production O&M	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
188	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
189	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
190	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
191	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
192	Property Taxes & Insurance	2.4	0.8	-	4.5	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
193	Depreciation & Amortization	32.3	10.9	-	23.8	37.6	38.8	45.0	46.5	46.5	46.6	48.1	49.5	63.8	65.0	66.3	67.7	69.0	70.4	71.8
194	Income Tax	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
195	Interest Expense (Incl. Financing Fee	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
196	RUS Note & PCB Restructuring Char	-	-	-	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5
197	Net Sale-Leaseback	(2.6)	(0.8)	-	(1.7)	(2.4)	(2.5)	(2.5)	(2.5)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
198	Other - Net	(6.3)	(2.3)	-	(0.6)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
199	Total Expenses	206.3	76.9	-	315.2	473.3	486.4	519.1	524.4	538.2	545.5	564.2	571.2	615.8	601.1	622.5	626.7	648.8	651.1	671.9
200																				
201	Unwind Transaction	-	-	622.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
202																				
203	Economic Reserve	-	-	(75.0)	5.5	12.5	19.1	20.4	24.2	4.4	-	-	-	-	-	-	-	-	-	-
204																				
205	Net Margin	37.6	8.9	547.7	10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4

Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:		4/30/2008	
V. Balance Sheet (M$)																			
Assets																			
Property																			
Total Utility Plant in Service	1,760.4	1,780.2	1,877.7	1,923.7	2,000.5	2,060.0	2,117.1	2,171.8	2,208.2	2,246.5	2,284.6	2,323.2	2,364.1	2,410.6	2,458.6	2,504.5	2,552.8	2,600.5	2,650.1
Construction in Progress	13.1	13.1	13.1	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	5.0
Depreciation & Amortization	858.9	869.8	869.8	893.6	931.2	969.9	1,015.0	1,061.4	1,107.9	1,154.5	1,202.5	1,252.1	1,315.8	1,380.9	1,447.2	1,514.9	1,583.9	1,654.3	1,726.1
Other Property	197.3	199.2	199.2	204.4	205.9	214.6	223.6	232.3	241.6	251.5	262.1	273.4	285.4	298.4	312.2	326.9	342.7	359.6	377.7
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
General Cash Balance	138.4	134.9	125.0	135.9	97.6	72.9	52.8	40.8	39.2	43.2	47.8	52.3	63.2	73.3	81.1	91.1	98.6	103.5	107.8
Transition Reserve	-	-	35.0	36.5	38.1	39.7	41.4	43.2	45.0	46.9	48.9	51.0	53.2	55.5	57.9	60.4	62.9	65.6	68.4
Economic Reserve	-	-	75.0	71.6	62.1	45.7	27.2	4.2	-	-	-	-	-	-	-	-	-	-	-
Accounts Receivable	17.7	17.7	17.7	39.3	39.1	39.6	42.5	42.7	45.5	46.5	48.0	48.6	52.3	51.0	52.8	53.1	54.9	55.0	56.8
Regulatory Asset	-	-	-	-	-	-	0.3	2.0	4.4	5.0	6.5	6.4	11.6	12.1	14.8	15.7	18.6	20.2	24.8
Fuel Stock & Related	-	-	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6	74.4
Materials and Supplies Other	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
Other Current Assets	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Credits																			
AMBAC/Credit Suisse July '98	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
Deferred Tax	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
Deferred Debt Debits/PCB Refunding 1C	0.5	0.3	11.7	11.5	11.1	10.7	10.3	9.8	12.0	11.4	10.7	10.1	9.4	8.7	8.0	7.3	6.5	8.9	8.1
Other Deferred Assets	-	-	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
LEM Settlement Note/Marketing Paymei	16.1	15.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Assets	1,300.0	1,306.8	1,567.0	1,616.5	1,610.9	1,605.5	1,594.1	1,579.5	1,584.8	1,593.3	1,603.1	1,610.9	1,622.2	1,626.6	1,636.0	1,642.7	1,651.8	1,657.9	1,666.6
Liabilities & Equities																			
Margins & Equities	(179.8)	(170.9)	376.9	387.5	403.3	416.6	432.5	448.5	464.4	480.4	496.4	512.5	528.6	544.7	560.8	577.1	593.3	609.7	626.1
Long-Term Debt																			
Existing Debt	1,062.1	1,051.1	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
Sale-Leaseback Obligation	183.9	186.2	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
Total Long-Term Debt	1,246.0	1,237.3	1,044.1	1,040.8	1,030.1	1,026.0	1,021.5	1,015.9	1,010.1	1,004.0	997.8	991.3	984.6	977.7	970.5	963.1	955.4	947.6	939.6
Current & Accrued Liabilities																			
Accounts Payable	11.7	11.7	11.7	57.2	57.3	59.1	63.1	63.8	65.8	67.0	69.6	70.5	75.1	72.9	76.0	76.6	79.8	80.1	83.2
Regulatory Liability				1.3	1.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
Taxes Accrued	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	0.2	0.2	0.3
Economic Reserve Deferred Income	-	-	75.0	71.6	62.1	45.7	27.2	4.2	-	-	-	-	-	-	-	-	-	-	-
Interest Accrued	7.8	7.6	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	6.2	6.3	6.3	6.4	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1	8.4	8.6	8.9	9.1	9.4	9.7	10.0
Deferred TIER Rebate Payable				0.6	1.9	3.2	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)	154.1	161.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sale-Leaseback Gain	53.5	52.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
Other Deferred Credits & Century React	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Liabilities & Equity	1,300.0	1,306.8	1,567.0	1,616.5	1,610.9	1,605.5	1,594.1	1,579.5	1,584.8	1,593.3	1,603.1	1,610.9	1,622.2	1,626.6	1,636.0	1,642.7	1,651.8	1,657.9	1,666.6

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:			4/30/2008	
252	Change in Working Capital																			
253	Other Property	6.6	1.8	-	5.2	1.5	8.6	9.0	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.8	15.8	16.9	18.1
254	Accounts Receivable	0.3	-	-	21.6	(0.2)	0.5	2.9	0.2	2.8	1.0	1.5	0.6	3.7	(1.3)	1.7	0.3	1.8	0.2	1.7
255	Materials, Supplies & Other	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
256	Other Current Assets	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
257	Accounts Payable	0.9	-	-	(45.5)	(0.1)	(1.8)	(4.0)	(0.7)	(2.0)	(1.2)	(2.6)	(0.9)	(4.6)	2.2	(3.1)	(0.6)	(3.2)	(0.3)	(3.1)
258	Taxes Accrued	(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)
259	Other Accruals	(0.2)	(0.1)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
260	Investment - Special Deposit (B/S)	(6.2)	(2.2)	-	(4.5)	(1.1)	(8.3)	(8.7)	(8.3)	(8.9)	(9.5)	(10.2)	(11.0)	(11.7)	(12.6)	(13.5)	(14.4)	(15.5)	(16.6)	(17.7)
261	Net SLB	(0.3)	(0.1)																	
262	CoBank Patronage Capital	(0.4)	(0.1)	-	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
263	Adjustment	0.2	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
264	Total	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	(1.2)	(0.6)	0.6	(0.4)	(1.3)	(0.6)	(1.1)	0.7	(1.6)	(0.5)	(1.6)	(0.4)	(1.6)
265																				
266	Cash Balance																			
267	Beginning	96.5	138.4	134.9	160.0	172.4	135.7	112.6	94.2	84.0	84.2	90.1	96.7	103.4	116.4	128.8	139.0	151.4	161.5	169.2
268	Ending	138.4	134.9	160.0	172.4	135.7	112.6	94.2	84.0	84.2	90.1	96.7	103.4	116.4	128.8	139.0	151.4	161.5	169.2	176.2
269																				
270	**VI. Credit Measures**																			
271																				
272	Contract TIER																			
273	Earnings				10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
274	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
275	Plus: Imputed Rate Increase in 2010				-	-	2.5	2.6	2.7	2.8	2.8	2.9	3.0	3.1	3.4	3.5	3.6	3.7	3.7	3.8
276	Less: Offset to Imputed Rate Increase in 2010				-	-	-	(2.6)	(2.7)	(2.8)	(2.8)	(2.9)	(3.0)	(3.1)	(3.4)	(3.5)	(3.6)	(3.7)	(3.7)	(3.8)
277	Less: Interest on Sequestered Funds				(1.0)	(1.5)	(1.6)	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
278	Total				40.7	60.5	59.8	59.0	58.3	57.4	56.4	55.4	54.5	53.4	52.2	51.1	49.9	48.5	47.3	45.6
279	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
280	Total				49.6	73.8	73.7	73.5	73.4	73.1	72.7	72.5	72.3	71.9	71.7	71.4	71.2	70.9	70.8	70.3
281	Divided by																			
282	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
283	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
284	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
285																				
286	*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	1.24
287																				
288	Conventional TIER																			
289	Earnings				10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
290	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
291	Plus Income Tax				-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
292	Total				41.7	62.1	58.9	60.7	60.0	59.9	59.0	58.1	57.3	56.3	55.3	54.2	53.1	51.9	50.9	49.3
293	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
294	Total				50.6	75.4	72.8	75.2	75.1	75.5	75.3	75.1	75.0	74.8	74.7	74.6	74.5	74.3	74.4	74.0
295	Divided by																			
296	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
297	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
298	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
299																				
300	*Conventional TIER*				1.27	1.27	1.22	1.27	1.27	1.28	1.28	1.29	1.29	1.29	1.29	1.29	1.30	1.30	1.30	1.31
301																				

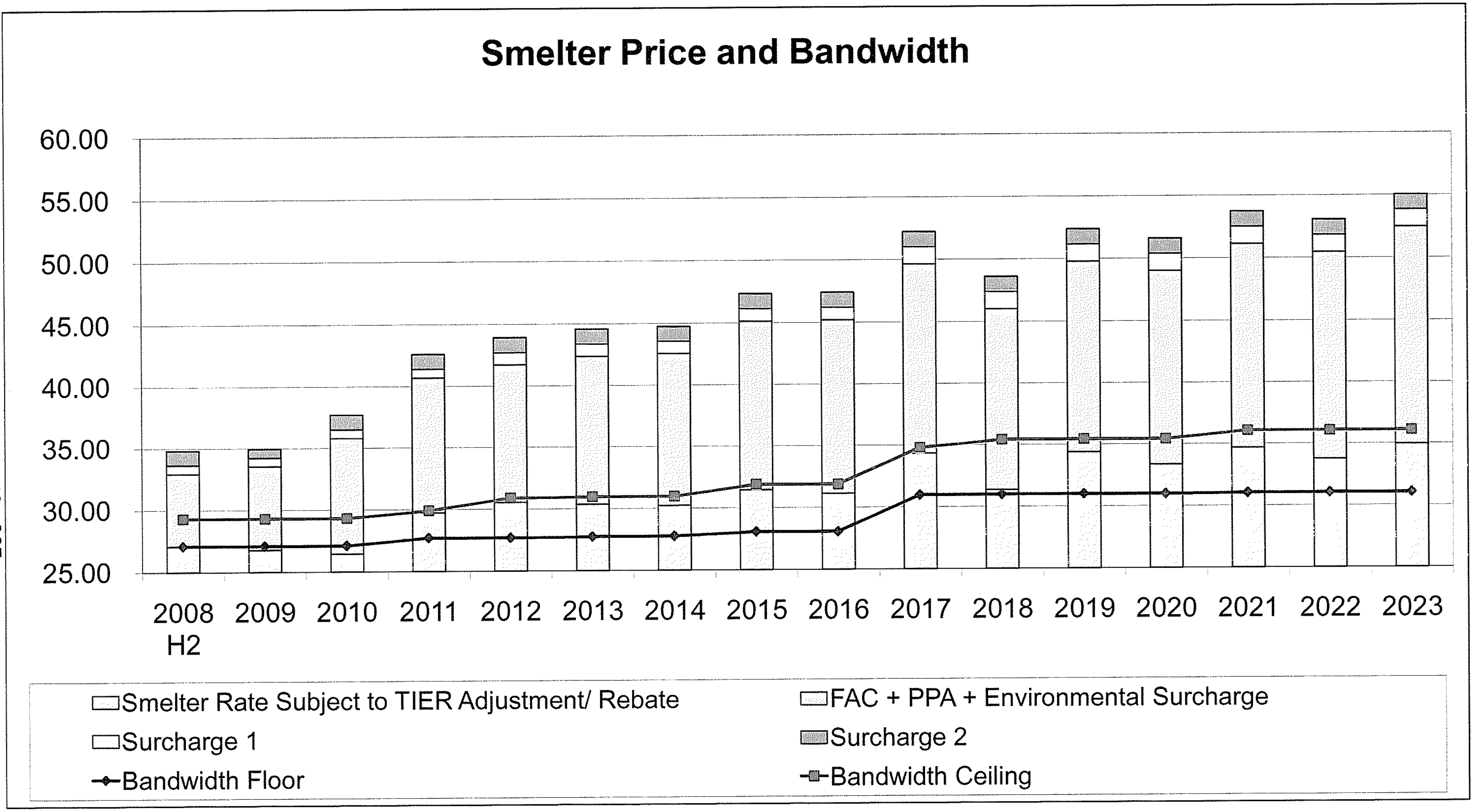
	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	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	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:			4/30/2008
302	DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																			
303	Cash Available for Debt Service																			
304	Receipts less Disbursements				83.5	85.2	74.8	75.8	77.9	89.9	102.1	102.7	103.3	111.9	116.9	116.2	116.5	116.4	113.5	114.8
305	Economic Reserve				5.5	12.5	19.1	20.4	24.2	4.4	-	-	-	-	-	-	-	-	-	-
306	Taxes				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
307	Net				89.0	97.7	93.9	96.2	102.1	94.2	101.7	102.3	102.9	111.5	116.4	115.7	116.0	115.8	113.0	114.2
308	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
309	Total				97.9	111.0	107.8	110.7	117.1	109.9	118.1	119.3	120.6	130.0	135.9	136.0	137.3	138.2	136.5	138.9
310	Divided by																			
311	Interest Expenditures				27.2	39.9	38.8	37.7	36.5	35.3	34.0	32.5	31.1	29.5	27.8	26.1	24.2	22.2	20.2	18.1
312	Scheduled Principal				11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
313	Plus Sale-Leasback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
314	Total Debt Service				48.0	71.7	72.3	72.9	73.5	74.1	74.7	75.4	76.2	77.0	77.8	78.7	79.7	80.8	81.9	83.1
315																				
316	*DSCR*				2.04	1.55	1.49	1.52	1.59	1.48	1.58	1.58	1.58	1.69	1.75	1.73	1.72	1.71	1.67	1.67
317																				
318	Days Cash on Hand																			
319	Average Cash Balance	117.5	136.7	147.5	166.2	154.1	124.1	103.4	89.1	84.1	87.2	93.4	100.0	109.9	122.6	133.9	145.2	156.5	165.3	172.7
320	Line of Credit				66.9	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
321	Total	117.5	136.7	147.5	233.2	254.1	224.1	203.4	189.1	184.1	187.2	193.4	200.0	209.9	222.6	233.9	245.2	256.5	265.3	272.7
322	Divided by																			
323	Total Operating Expense																			
324	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
325	Fuel Costs	-	-	-	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
326	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	28.1	25.8	29.5	25.3	27.4	28.7	38.5	29.7	38.2	35.3	38.6	42.1	46.8
327	Non-Fuel Variable Production O	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
328	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
329	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
330	APM, L/C, Cogen, CW & TVA Tı	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
331	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
332	Property Taxes & Insurance	2.4	0.8	-	4.5	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
333	Interest Expense (Incl. Financin	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
334	Total	182.8	69.2	-	293.6	439.0	450.9	477.3	481.1	494.2	501.3	518.5	523.9	554.3	538.3	558.4	561.2	581.9	582.5	601.9
335																				
336	*Days Cash on Hand (including Line o*	234.5	721.0		289.9	211.2	181.5	155.5	143.4	136.0	136.3	136.2	139.4	138.2	150.9	152.9	159.5	160.9	166.2	165.4
337	*Days Cash on Hand (excluding Line c*	234.5	721.0		206.7	128.1	100.5	79.0	67.6	62.1	63.5	65.8	69.7	72.4	83.1	87.5	94.4	98.1	103.6	104.7
338																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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:			4/30/2008	
339	**VII. Debt Service Detail, as of Transaction Date (M$)**																			
341	Fixed/ Insured Serial Bonds (Tranche 1)																			
342	Beginning Principal		-	-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
343	Principal		-	(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
344	Interest		-	-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
345	Debt Service		-	(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
346	Blended Interest Cost		0.00%	0.00%	3.78%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
348	Fixed/ Insured Serial Bonds (Tranche 2)																			
349	Beginning Principal		-	-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
350	Principal		-	(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
351	Interest		-	-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
352	Debt Service		-	(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
353	Blended Interest Cost		0.00%	0.00%	3.68%	5.49%	5.49%	5.49%	5.49%	5.49%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.52%
355	Variable Rate Bonds																			
356	Beginning Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
357	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
358	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
359	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
360	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%
362	Ongoing RUS Note (Stated)																			
363	Beginning Principal		-	794.7	352.0	340.1	321.7	302.4	281.9	260.2	237.3	213.0	187.4	160.3	131.6	101.3	69.3	35.4	-	-
364	Principal		-	442.7	11.9	18.3	19.4	20.5	21.7	22.9	24.2	25.6	27.1	28.7	30.3	32.1	33.9	35.4	-	-
365	Interest		-	-	13.5	19.6	18.5	17.4	16.2	15.0	13.6	12.2	10.8	9.2	7.6	5.8	4.0	2.0	-	-
366	Debt Service		-	442.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
367	Blended Interest Cost			0.00%	3.85%	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%		
369	ARVP																			
370	Beginning Principal		-	101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
371	Principal/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
372	Interest/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
373	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
374	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%
376	PCB																			
377	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
378	Principal		-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
379	Interest		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
380	Debt Service		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
381	Blended Interest Cost			0.00%	2.41%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
383	Total (Incorporates RUS on Stated Basis)																			
384	Beginning Principal		-	1,038.3	859.1	851.2	839.0	826.0	812.3	797.9	782.6	766.5	749.5	731.5	712.4	692.3	671.1	648.6	624.9	599.9
385	Principal		-	179.2	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
386	Interest		-	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
387	Line of Credit Fee		-	-	0.3	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
388	Debt Service		-	179.2	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4

December 2007

Smelter Rate Structure

	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.669	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
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%	2.00%	0.00%	0.00%	0.00%	1.02%	0.00%	9.98%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1 Smelter Sales																
2 Century	2.79	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16
3 Alcan	2.11	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14
4 Total Energy (TWh)	4.898	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)	6.847	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%	98.00%
7																
8 Smelter Rate ($/ MWh)																
9 Large Industrial Rate																
10 Sales (TWH)	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11 Load Factor (%)	78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12 Demand ($/ KW-mo.)	10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.46	10.46	11.50	11.50	11.50	11.50	11.50	11.50	11.50
13 Energy ($/ MWH)	13.72	13.72	13.72	13.99	13.99	13.99	13.99	14.13	14.13	15.54	15.54	15.54	15.54	15.54	15.54	15.54
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
16 Regulatory Account Charge	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
17 Less: Regulatory Account Charge	-	-	-	-	-	(0.17)	(0.17)	(0.16)	(0.53)	(0.52)	(0.51)	(0.92)	(0.90)	(0.88)	(1.32)	(1.30)
18 Net Rate ($/ MWH)	30.58	30.46	30.48	31.13	31.16	31.17	31.19	31.54	31.57	34.80	34.82	34.83	34.87	34.86	34.88	34.89
19																
20 Large Industrial Rate @ 98% LF	27.07	27.08	27.09	27.67	27.65	27.71	27.72	28.03	28.01	30.93	30.94	30.96	30.93	30.99	31.00	31.01
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	0.25
22 Smelter Base Rate	27.32	27.33	27.34	27.92	27.90	27.96	27.97	28.28	28.26	31.18	31.19	31.21	31.18	31.24	31.25	31.26
23 Plus TIER Adjustment	-	-	0.00	1.81	2.64	2.40	2.26	3.16	2.88	3.14	0.15	3.17	2.16	3.46	2.50	3.69
24 Less TIER Related Rebate	(0.24)	(0.54)	(0.90)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	27.08	26.79	26.45	29.73	30.54	30.36	30.23	31.44	31.13	34.32	31.35	34.37	33.34	34.69	33.75	34.95
26																
27 Plus FAC + PPA + Environmental Surcharge	5.85	6.74	9.36	10.95	11.16	12.00	12.32	13.70	14.08	15.30	14.66	15.40	15.67	16.44	16.70	17.50
28 Plus Surcharge 1	0.70	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	1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
30 Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	34.82	34.94	37.70	42.58	43.90	44.56	44.75	47.34	47.42	52.22	48.61	52.37	51.61	53.73	53.05	55.05
31																
32 TIER Adjustment Cap ($/ MWh)																
33 Bandwidth Floor	27.32	27.33	27.34	27.92	27.90	27.96	27.97	28.28	28.26	31.18	31.19	31.21	31.18	31.24	31.25	31.26
34 Bandwidth Range	1.95	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	29.27	29.28	29.29	29.87	30.85	30.91	30.92	31.83	31.81	34.73	35.34	35.36	35.33	35.99	36.00	36.01
36 Smelter Rate Subject to TIER Adjustment/ Rebate	27.08	26.79	26.45	29.73	30.54	30.36	30.23	31.44	31.13	34.32	31.35	34.37	33.34	34.69	33.75	34.95


Smelter Price and Bandwidth
60.00
55.00
50.00
45.00
40.00
35.00
30.00
25.00
2008 H2
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Smelter Rate Subject to TIER Adjustment/ Rebate
FAC + PPA + Environmental Surcharge
Surcharge 1
Surcharge 2
Bandwidth Floor
Bandwidth Ceiling

Member Rates Cash Method

		2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.669	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
1	**Member Sales (TWh)**																
2	Rural	1.6	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.2
3	Large Industrial	0.7	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5
4	Total	2.3	3.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
5																	
6	**Rates (Cash Method)**																
7	***Rural***																
8	*Load Factor (%)*	60.2%	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 ($/ KW-mo.)	7.37	7.37	7.37	7.52	7.52	7.52	7.52	7.59	7.59	8.35	8.35	8.35	8.35	8.35	8.35	8.35
10	Energy ($/ MWH)	20.40	20.40	20.40	20.81	20.81	20.81	20.81	21.02	21.02	23.12	23.12	23.12	23.12	23.12	23.12	23.12
11	Base	37.18	37.22	37.19	37.17	37.18	37.12	37.09	37.07	37.08	37.02	37.00	36.98	37.00	36.94	36.92	36.90
12	MRDA	(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
13	Regulatory Account Charge	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
14	GRA	-	-	-	0.74	0.70	0.74	0.74	1.13	1.08	4.93	4.93	4.93	4.88	4.92	4.92	4.92
15	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
16	Env. Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
17	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
18	TIER Related Rebate	-	(0.17)	(0.55)	(0.92)	-	-	(0.00)	-	-	-	-	-	-	-	-	-
19	Economic Reserve	(2.39)	(3.58)	(5.34)	(5.56)	(6.42)	(1.14)	-	-	-	-	-	-	-	-	-	-
20	Net	-	(0.01)	(0.02)	(0.04)	0.00	5.89	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
21	Effective Rate	36.07	36.11	36.09	36.82	36.85	42.92	44.96	46.57	47.43	50.63	51.18	51.53	52.26	52.71	53.34	53.61
22																	
23	***Large Industrial***																
24	Load Factor (%)	78.1%	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 ($/ KW-mo.)	10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.46	10.46	11.50	11.50	11.50	11.50	11.50	11.50	11.50
26	Energy ($/ MWH)	13.72	13.72	13.72	13.99	13.99	13.99	13.99	14.13	14.13	15.54	15.54	15.54	15.54	15.54	15.54	15.54
27	Base	31.52	31.39	31.39	31.39	31.45	31.39	31.39	31.39	31.46	31.39	31.39	31.39	31.46	31.39	31.39	31.39
28	MRDA	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
29	Regulatory Account Charge	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
30	GRA	-	-	-	0.63	0.58	0.63	0.63	0.96	0.91	4.18	4.18	4.18	4.14	4.18	4.18	4.18
31	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
32	Env. Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
33	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
34	TIER Related Rebate	-	(0.14)	(0.47)	(0.79)	-	0.00	0.00	-	-	-	-	-	-	-	-	-
35	Economic Reserve	(2.39)	(3.58)	(5.34)	(5.56)	(6.42)	(1.14)	-	-	-	-	-	-	-	-	-	-
36	Net	-	0.02	0.06	0.09	0.00	5.89	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
37	Effective Rate	30.58	30.48	30.54	31.22	31.16	37.24	39.30	40.87	41.77	44.39	44.96	45.33	46.11	46.55	47.20	47.49
38																	
39	***Non-Smelter Member Blend***																
40	Base	35.50	35.45	35.42	35.39	35.41	35.33	35.31	35.28	35.31	35.24	35.21	35.20	35.23	35.16	35.14	35.13
41	MRDA	(1.06)	(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)
42	Regulatory Account Charge	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
43	GRA	-	-	-	0.71	0.66	0.71	0.71	1.07	1.03	4.69	4.69	4.69	4.64	4.68	4.68	4.68
44	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
45	Env. Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
46	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
47	TIER Related Rebate	-	(0.16)	(0.52)	(0.88)	-	0.00	(0.00)	-	-	-	-	-	-	-	-	-
48	Economic Reserve	(2.39)	(3.58)	(5.34)	(5.56)	(6.42)	(1.14)	-	-	-	-	-	-	-	-	-	-
49	Net	-	0.00	-	-	0.00	5.89	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
50	Effective Rate	34.44	34.40	34.39	35.10	35.09	41.15	43.18	44.77	45.64	48.65	49.20	49.55	50.29	50.73	51.36	51.64
51																	
52	***Revenues Delta($M)***																
53	Rural	0.41	0.95	0.96	(2.33)	-	-	-	-	-	-	-	-	-	-	-	-
54	Li	0.15	0.36	0.38	(0.89)	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	0.56	1.32	1.34	(3.22)	-	-	-	-	-	-	-	-	-	-	-	-

Regulatory Accounts

December 2007

	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)	(1.26)	0.17	(1.33)	2.69	1.72	3.11	1.20	2.23	2.09	7.32	2.69	6.70	5.01	6.93	7.83	10.72
EXPENSE DEFERRAL METHOD																
Income Statement (Change in Regulatory Account)																
1. Deferral																
Power Purchase Expense																
Debit	1.26	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
Credit	-	(0.17)	-	(2.69)	(1.72)	(3.11)	(1.20)	(2.23)	(2.09)	(7.32)	(2.69)	(6.70)	(5.01)	(6.93)	(7.83)	(10.72)
Total	1.26	(0.17)	1.33	(2.69)	(1.72)	(3.11)	(1.20)	(2.23)	(2.09)	(7.32)	(2.69)	(6.70)	(5.01)	(6.93)	(7.83)	(10.72)
2. Recognition of Prior Year Balance (Set to Start in 2013)																
Credit Member Revenue (Charge to Members)						0.66	0.66	0.66	2.18	2.18	2.18	4.03	4.03	4.03	6.21	6.21
Debit Power Purchase Expense						0.66	0.66	0.66	2.18	2.18	2.18	4.03	4.03	4.03	6.21	6.21
Net Income	(1.26)	0.17	(1.33)	2.69	1.72	3.11	1.20	2.23	2.09	7.32	2.69	6.70	5.01	6.93	7.83	10.72
Balance Sheet																
Assets																
Cash						0.66	1.33	1.99	4.17	6.35	8.52	12.56	16.59	20.62	26.83	33.04
Regulatory Asset	-	-	-	0.27	1.99	4.43	4.97	6.53	6.44	11.58	12.10	14.76	15.74	18.63	20.25	24.76
Total	-	-	-	0.27	1.99	5.10	6.30	8.52	10.61	17.93	20.62	27.32	32.33	39.26	47.08	57.80
Liabilities & Equity																
Equity	(1.26)	(1.10)	(2.42)	0.27	1.99	5.10	6.30	8.52	10.61	17.93	20.62	27.32	32.33	39.26	47.08	57.80
Regulatory Liability	1.26	1.10	2.42	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	0.27	1.99	5.10	6.30	8.52	10.61	17.93	20.62	27.32	32.33	39.26	47.08	57.80

FAC PPA Env Sur

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	8.1	11.8	12.1	11.6	11.7	11.6	11.9	11.9	12.0	11.6	12.0	11.6	11.9	11.9	11.9	11.9
2	**Sales (TWh)**	8.3	12.3	12.5	12.3	12.3	12.3	12.4	12.4	12.5	12.4	12.6	12.4	12.5	12.6	12.7	12.8
3																	
4																	
5	**A. FAC**																
6	Fuel Costs ($M)	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
7																	
8	Total Costs for Passthrough ($/ MWh Sold)	16.62	16.56	17.77	18.31	18.53	19.03	19.71	19.72	20.13	20.17	20.47	20.35	20.83	21.02	21.10	21.16
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
11	**B. PPA**																
12	Purchased Power Costs ($M)	10.01	22.11	17.26	30.53	27.15	31.59	25.51	28.67	28.27	43.33	29.93	40.57	35.90	41.20	43.34	51.02
13																	
14	Total Costs for Passthrough ($/ MWh Sold)	1.21	1.80	1.38	2.48	2.21	2.56	2.06	2.30	2.26	3.49	2.38	3.27	2.86	3.26	3.42	3.99
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	(0.54)	0.05	(0.37)	0.73	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
17																	
18	**C. Environmental Surcharge**																
19	Eligible Cost ($M)	4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
20																	
21	Total Costs for Passthrough ($/ MWh Sold)	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/M	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
24																	
25																	
26	**1 - FAC + Environmental Surcharge to Members**																
27	Rurals																
28	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
29	Environmental Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
30	**Total**	6.39	6.69	9.73	10.22	10.70	11.20	12.01	13.15	13.58	13.57	14.04	13.88	14.56	14.93	15.04	15.26
31	Large Industrials																
32	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
33	Environmental Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
34	**Total**	6.39	6.69	9.73	10.22	10.70	11.20	12.01	13.15	13.58	13.57	14.04	13.88	14.56	14.93	15.04	15.26
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**																
36	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
37	PPA	(0.54)	0.05	(0.37)	0.73	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
38	Environmental Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
39	**Total**	5.85	6.74	9.36	10.95	11.16	12.00	12.32	13.70	14.08	15.30	14.66	15.40	15.67	16.44	16.70	17.50

UW Transaction

	($M)	2007	2008H1	Transaction	2008 H2
			0		0
	Unwind Allocation	-	-	-	0.669
	Pre-Transaction Allocation	1.000	0.331	-	-
	Transaction Index	-	-	1.000	-
	A. Transaction Components				
1	**1. Cash Payment/ Credit Escrow Draws**	-	-	301.5	-
2	**2. WKE Residual Value Obligation**				
3	**WKE Gen. Capex - Cum.**				
4	Non-Incremental (RV Obligation Balance)				
5	Beginning Balance	45.2	50.2	61.0	-
6	WKE Share of Non-Incremental Capex	6.8	11.7	-	-
7	Amortization of WKE Share	1.8	0.9	-	-
8	Net	50.2	61.0	61.0	-
9	Incremental				
10	Beginning Balance	95.6	90.9	89.4	-
11	WKE Share of Non-Incremental Capex	-	-	-	-
12	Amortization of WKE Share	4.6	1.6	-	-
13	Net	90.9	89.4	89.4	-
14	Total	141.1	150.4	150.4	
15	**3. LG&E Rental Income Advance**				
16	Cash Flow	48.0	15.8	-	-
17	Income Statement	52.3	17.3	-	-
18	Balance	(13.0)	(11.4)	(11.4)	-
19	**4. Fuel & Other Inventories**	-	-	55.0	-
20	**5. Cancellation of Settlement Prom. Note**	-	-	16.0	-
21	**6. Coleman Scrubber Completion**	-	-	97.5	-
22	**7. LG&E Emissions Allowance**	-	-	10.9	-
23	**8. Expense Unamortized Mktg Payment/ Settlement Note**			(15.7)	
24	**9. Assurances Agreement**	-	-	4.3	-
25					
26	**Total Residual Value Obligation**	154.1	161.8	161.8	-
27	**Cancellation of RV Obligation**				
28	Reclassification as Equity	-	-	161.8	-
29					
30	**Net WKE Obligation**	154.1	161.8	-	-
31					

	($M)		2007	2008H1	Transaction	2008 H2
				0		0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
32						
33	**B. Transaction Cash Flows**					
34	Cash Balances Pre-Transaction				134.9	
35	Transaction Proceeds				301.5	
36	Smelter Payment (Assurances Agreement)				(4.3)	
37	Consent Fee to Lease-Equity Parties				-	
38	Lump-Sum Member Rebate				-	
39	Net DSL Termination				-	
40	Century/Century Reactive Power Transaction Refund				(0.3)	
41	Income Tax				(1.1)	
42	Net Transaction Cash				295.9	
43	Debt Restructuring:					
44	Debt Reduction (Net)				(186.2)	
45	Underwriting Costs	1.75%			(4.6)	
46	Bond Insurance	0.80%			(5.0)	
47	ARVP Defeasance Premium				-	
48	Total				(195.8)	
49	Restricted Cash Balances:					
50	Transition Reserve				(35.0)	
51	Economic Reserve				(75.0)	
52	Unrestricted Cash Balances Post-Transaction				125.0	
53						
54	**C. Debt Restructuring:**					
55	Beginning Balance - GAAP				1,051.1	
56	Cancellation of Settlement Prom. Note				(16.0)	
57	Capitalize Accrued Interest on RUS New Note				7.2	
58	Step-Up RUS New Note to Stated Basis:					
59	GAAP RUS New Note					
60	Ending Balance				791.4	
61	Accrued Interest				7.2	
62	Total				798.6	
63	Stated RUS New Note					
64	Ending Balance				794.7	
65	Accrued Interest				7.0	
66	Total				801.7	
67	Step-Up				3.1	
68	Beginning Balance - Stated				1,045.3	
69	Cash Flow:					
70	Prepay RUS New Note				(449.7)	
71	Defease ARVP				-	
72	Issue Capital Markets Debt				263.5	
73	Net				(186.2)	
74	Ending Balance - Stated				859.2	
75	Step-Down Remaining RUS New Note to GAAP Basis:				(1.3)	
76	Ending Balance - Stated				857.8	
77						

UW Transaction

December 2007

	($M)		2007	2008H1	Transaction	2008 H2
				0		0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
78	**D. Reflection on Income Statement**					
79	1. Cash		-	-	301.500	-
80	2. Residual Value Payment		-	-	150.394	-
81	3. LG&E Rental Income Advance		-	-	11.445	-
82	4. Fuel Inventory & Other		-	-	55.000	-
83	5. Settlement Promissory Note		-	-	16.025	-
84	6. Coleman Scrubber		-	-	97.495	-
85	7. SO2 Allowances				10.892	
86	8. Expense Unamortized Mktg Payment/ Settlement Note		-	-	(15.740)	-
87	9. Assurances Agreement Payment				(4.263)	
88	Total		-	-	622.748	-
89						
90	**E. Non-Patronage Allocations and Taxable Income**					
91						
92	**Cash Flows**	15%	-	-	45.23	-
93						
94	**Income Statement**					
95	Cash	15%	-	-	45.23	-
96	RVP	15%	-	-	24.28	-
97	Fuel Inventory & Other (plus emissions allowances)	15%	-	-	9.88	-
98	Settlement Promissory Note	15%	-	-	2.40	-
99	Coleman Scrubber	15%	-	-	14.62	-
100	Expense Unamortized Mktg Payment/ Settlement Note	15%	-	-	(5.93)	-
101	Total		-	-	90.49	-
102						
103	**Taxable Income**					
104	Gain on Transaction (above)		-	-	90.49	-
105	Less RVP		-	-	(24.28)	-
106	Less M1 - Coleman Scrubber		-	-	(14.62)	-
107	Plus Previously Expensed Mktg. Pmt.		-	-	4.20	-
108	Total		-	-	55.78	-
109						
110	**Assumptions**					
111	(a) Non-Patronage Allocation:					
112	Transaction Settlement Attribution					
113	Patronage Eligible	89%				
114	Patronage	11%				
115	Non-Patronage	0%				
116	Patronage Eligible Allocation (based on retrospective sales)					
117	Patronage	85%				
118	Non-Patronage	15%				
119	Non-Patronage Allocation:	13%				
120						
121	(b) Base case posits no tax basis to Big Rivers. Will be treated as a non-shareholder					
122						
123	(c) Base case posits no tax basis to Big Rivers. Improvements made by LG&E, therefore no additional income.					
124						
125	(d) 100% non-patron for book and tax. As a result, the reversal will be treated in the same manner for consistency purposes.					

Production - Fixed

#	($M)	2007	2008 H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	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	0.331	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	A&G																		
2	Labor	-	-	7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
3	Non-Labor	-	-	6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
4	Intellectual Property	-	-	3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	13.80	4.86	17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
7																			
8	APM, L/C, Cogen, CW & TVA Trans	3.83	3.63	3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
9																			
10	Property Insurance	0.4013	0.14	2.63	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	1.08	0.37	1.18	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	0.77	0.26	0.57	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	0.11	0.04	0.11	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	1.9589	0.667	1.86	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	7.38	1.89	3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
20	Baseline Non-Labor	-	0.52	1.06	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	-	0.08	0.16	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	-	0.01	0.02	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.	-	0.00	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	0.01
25	Total (Real)	-	0.10	0.20	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)		0.10	0.21	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	7.38	2.52	5.10	7.84	8.08	8.32	8.57	8.83	9.09	9.36	9.65	9.93	10.23	10.54	10.86	11.18	11.52	11.86
28																			
29	Fixed O&M																		
30																			
31	Labor			29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
32																			
33	Non-Labor			29.21	36.97	41.06	41.89	39.65	50.31	41.88	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			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
39	Reid			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
41	Adjust for Station 2			-	(0.10)	(0.07)	(0.19)	(0.20)	(0.20)	(0.20)	(1.56)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)
42	Total (Real)			3.10	3.39	1.90	2.25	1.68	1.19	0.89	4.10	0.93	4.72	0.97	1.66	1.35	1.68	1.36	1.70
43	Total (Nominal)			2.19	3.71	2.14	2.61	2.00	1.46	1.12	5.35	1.25	6.54	1.39	2.44	2.03	2.62	2.19	2.81
44																			
45	T/G Overhauls (Cash Flows)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																			
48	Environmental Monitoring and Other			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49																			
50	08/2007 Adjustment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																			
52	Total Fixed O&M (to Cash Flows)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13
53	Total Fixed O&M (to Income Statement)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13

Capex & Depreciation

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
2																					
3	Transmission Upgrades																				
4	Phase I		-	4.00	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
8																					
9	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
10																					
11	Shared HQ Building																				
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																					
16	Intellectual Property																				
17	Total			-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
18																					
19	WKE Share of Generation Capex																				
20	(%)		51%	51%	84%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	(M$)		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																					
23	Generation																				
24	Baseline		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
25	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Real		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
27	Total Nominal	3.00%	13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
28																					
29	Plant Maintenance																				
30	Coleman		-	-	-	3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
33	Reid		-	-	-	-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
34	Wilson		-	-	-	4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
35	Adjustment for Station 2		-	-	-	(0.44)	(0.41)	(0.26)	(1.89)	(1.26)	-	(1.12)	-	-	-	-	(0.28)	(0.28)	-	-	-
36	Total Real		-	-	-	8.67	19.47	18.54	17.62	11.37	1.32	2.37	-	-	-	1.28	2.77	0.60	-	-	-
37	Total Nominal	3.00%	-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
38																					
39	Environmental																				
40	NOx Removal Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																					
51																					
52																					
53	BigRivers Capex																				
54	Gross Generation		13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
55	*Less* WKE Generation Share		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	BigRivers Generation		6.43	6.57	2.22	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
57	Transmission		5.91	9.62	5.19	6.21	9.56	9.19	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
58	Transmission Upgrades		-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
59	A&G		0.86	1.25	0.43	0.86	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
60	Shared HQ Building		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Intellectual Property		-	-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
62	Plant Maintenance		-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
63	Environmental		-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	08/2007 Adjustment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Total		13.19	21.56	7.84	37.45	76.01	58.58	56.26	53.85	35.54	37.47	37.30	37.79	40.02	45.68	47.10	45.13	47.37	46.91	48.76

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
67																					
68																					
69	**Depreciation**																				
70																					
71	Additional Book Depreciation																				
72	Prior year non-incremental + in service		12.83	13.12	4.43	9.34	133.67	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60
73	Current year non-incremental + in service		13.12	13.41	13.95	119.72	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60	40.79
74	Average of Production		12.97	13.26	9.19																
75	*Prior year Transmission and A&G*					10.03	16.06	16.86	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
76	Current year Transmission and A&G					10.77	16.86	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
77	Average of Transmission and A&G		6.38	10.88	5.29																
78	Total		19.35	24.14	14.48																
79	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%	1.54%															
80	Capital Depreciation Rate (excl. Environmental)					1.54%	1.63%	1.62%	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%
81	Additional Depreciation		0.30	0.37	0.22	1.15	1.79	1.03	1.47	1.40	1.12	0.92	0.93	0.93	0.99	1.06	1.15	1.17	1.15	1.18	1.21
82																					
83	HMP&L Station Two																				
84	Prior year non-incremental		12.83	13.12	4.43	8.98	28.56	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60
85	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
86	Additional Depreciation		0.01	0.01	0.00	0.01	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
87																					
88	Environmental																				
89	Prior year environmental						1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
90	Current year environmental					1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Environmental Depreciation Rate					1.54%	1.63%	1.62%	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%
92	Additional Depreciation					0.03	0.03	0.03	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
93																					
94	Other																				
95	Prior year		6.00	6.77	4.96	10.03	16.39	16.86	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
96	Current year		6.77	10.87	5.62	10.77	16.86	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
97	Average		6.38	8.82	5.29																
98	Rate to Apply to 2007 Capital in 08		0.00	0.00	0.00	0.00															
99	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%	0.58%
100	Additional Depreciation		0.02	0.03	0.02	0.05	0.10	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
101																					
102	Book Depreciation & Amortization																				
103	Generation																				
104	Big Rivers' Plants		25.36	25.39	8.582	19.62	31.13	32.20	49.75	51.19	52.36	53.34	54.32	55.30	56.34	57.45	58.66	59.88	61.09	62.31	63.58
105																					
106	Intellectual Property					0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
107	HMP&L Station Two		1.58	1.64	0.543	0.64	0.98	1.02	1.04	1.07	1.10	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47
108	Total Generation Depr & Amort		26.94	27.03	9.125	20.33	32.28	33.40	51.12	52.67	53.92	54.95	56.05	57.10	58.21	59.45	60.73	62.04	63.37	64.68	66.04
109	Other		5.05	5.25	1.750	3.50	5.28	5.37	5.42	5.46	5.48	5.50	5.51	5.52	5.54	5.57	5.60	5.63	5.67	5.70	5.73
110	*Blended Depreciation Adj.*		-	-	-	-	-	-	(11.53)	(11.66)	(12.93)	(13.90)	(13.46)	(13.08)	-	-	-	-	-	-	-
111	Total		31.99	32.27	10.88	23.83	37.56	38.77	45.01	46.47	46.47	46.55	48.09	49.54	63.75	65.02	66.34	67.67	69.04	70.38	71.78
112																					
113	Years Depreciation						52	52	46	46	47	48	47	47	37	37	37	37	37	37	37

	($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	0.669	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		0.331	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	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
1	Fixed/ Insured (Tranche 1)																			
2	Beginning Balance			-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
3	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%
4	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%
5	Interest			-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
6	Principal			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Debt Service			(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
8																				
9	Fixed/ Insured (Tranche 2)																			
10	Beginning Balance			-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
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%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
13	Interest			-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
14	Principal			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
15	Debt Service			(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
16																				
17	RUS -- GAAP																			
18	Beginning Balance			791.4	350.7	338.7	320.6	301.3	281.0	259.4	236.6	212.5	187.0	160.0	131.4	101.2	69.2	35.3	-	-
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%	3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
21	Interest			-	13.5	19.7	18.6	17.5	16.3	15.1	13.8	12.4	10.9	9.3	7.6	5.9	4.0	2.1	-	-
22	Principal + Accrued Interest			440.7	12.0	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.9	35.3	-	-
23	Debt Service			440.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
24																				
25	Variable																			
26	Beginning Balance			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Coupon			0.00%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
28	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%
29	Interest+Remarketing			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																				
33	PCB																			
34	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
35	Coupon			0.00%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
36	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%
37	Interest			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
38	Principal			-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Debt Service			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
40																				
41	ARVP																			
42	Beginning Balance			101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
43	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%
44	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%
45	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%
46	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
47	Interest			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																				
51	Total																			
52	Beginning Balance			1,035.0	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9
53	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
54	Principal			177.2	12.0	18.3	19.4	20.5	21.7	23.0	24.3	25.7	27.2	28.8	30.5	32.3	34.1	36.1	38.2	40.3
55	Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
56	Debt Service			177.2	38.8	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9
57	Ending Balance			857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
58																				

Unwina Debt

			2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	($M)		0.000	0.000	0.669	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
	Unwind Allocation		0.331	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
	Pre-Transaction Allocation		0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
59	Supporting Schedules																			
60	Amortization of Financing Costs																			
61	Fixed/ Insured (Tranche 1)																			
62	Net Borrowing and YTM	5.92%		(174.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
63	BB			-	174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6
64	YTM			-	6.9	10.3	10.3	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
65	Principal Amort.			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Accretion			-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2
67	EB			174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6	176.8
68																				
69	Fixed/ Insured (Tranche 2)																			
70	Net Borrowing and YTM	5.82%		(79.4)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
71	BB			-	79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2
72	YTM			-	3.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	2.3
73	Principal Amort.			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
74	Accretion			-	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
75	EB			79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2	0.0
76																				
77	Variable																			
78	Net Borrowing and YTM	0.00%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	BB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80	YTM			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	Principal Amort.			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82	Accretion			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
83	EB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84																				
85																				
86	Amortization of Financing Costs																			
87	Deferred debit - BOY			9.6	9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0
88	Amortization			-	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.3
89	Deferred debit - EOY			9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0	4.7
90																				
91	Interest Expense																			
92	Total Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
93	ARVP Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
94	Capitalized Interest			-	(0.5)	(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)
95	AMBAC Amortization (PCB) A/C 165			-	0.3	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-
96	Line of Credit Fee			-	0.3	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
97	Total			-	31.0	45.9	45.2	44.4	43.7	42.7	41.8	40.8	39.9	38.8	37.7	36.6	35.4	34.1	32.7	31.2

Sale Leaseback

December 2007

	($M)	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	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	0.331	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	56.4	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2
2	Amortization (I/S)	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
3	EOY Deferred Gain (B/S)	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
4																			
5																			
6	Investment - Special Deposit (B/S)	192.9	195.1	199.6	200.7	209.0	217.7	226.0	234.9	244.5	254.7	265.6	277.4	290.0	303.4	317.8	333.3	349.8	367.6
7	Adder	0.7	0.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
8	Balance Sheet	193.7	195.4	200.4	201.5	209.8	218.4	226.7	235.7	245.2	255.4	266.4	278.1	290.7	304.2	318.6	334.0	350.6	368.3
9																			
10	Liability - Long-Term Debt (B/S)	183.9	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
11																			
12	Cash Flow (Investment and Liability)	6.2	2.1	4.2	11.9	5.3	5.5	6.4	6.4	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3	6.3	6.3
13																			
14	True Unrecognized Gain	(44.4)	(43.6)	(41.9)	(39.4)	(37.0)	(34.5)	(32.1)	(29.6)	(27.2)	(24.8)	(22.3)	(19.9)	(17.5)	(15.1)	(12.8)	(10.4)	(8.0)	(5.7)
15																			
16	*Sale-Leaseback Interest Income*	12.5	4.3	8.7	13.0	13.6	14.1	14.7	15.3	15.9	16.6	17.3	18.1	18.9	19.8	20.8	21.8	22.9	24.1
17																			
18	Sale-Leaseback Interest Expense	12.8	4.4	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
19	Sale-Leaseback Gain Amortization	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
20	Net Sale-Leaseback Expense	9.9	3.4	6.9	10.6	11.1	11.7	12.2	12.8	13.5	14.2	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.7
21																			
22	Net Sale-Leaseback Income	2.6	0.8	1.7	2.4	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
23																			
24	Sale-Leaseback - LeaseCo.																		
25	Defeasance Income	64.5	21.3	64.9	61.3	62.1	62.9	63.1	63.4	63.6	63.9	64.1	64.4	64.7	65.1	65.4	65.8	66.2	66.6
26	Rent Expense	(48.9)	(16.2)	(48.9)	(48.9)	(48.9)	(48.9)	(50.6)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)
27	Net	15.6	5.2	16.0	12.4	13.2	14.1	12.5	3.6	3.9	4.1	4.4	4.7	5.0	5.3	5.7	6.1	6.5	6.9

Income Taxes

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
3	Income Taxes Paid	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
4	Current Provision for Deferred Income Tax	(0.9)	(0.1)	(1.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
5																				
6	Calculation																			
7	Offsystem Sales	64.9	26.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	-	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
9	Nonpatronage Revenues	64.9	26.9	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
10	Nonpatronage Expenses																			
11	Nonpatronage MWH	25.7%	39.6%	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%
12	Nonpatronage Expenses (Ex. Int.)	38.2	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	15.4	7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	11.3	(3.9)	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
15																				
16	Transaction Impact	-	-	55.8	-	-														
17																				
18																				
19	Temporary Differences (Timing)																			
20	Depreciation:																			
21	Prorated from Pre-Transaction Model	6.1	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	(1.4)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																			
25	Defeasance Income	64.5	8.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																			
28	Net	15.6	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	20.5	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
31																				
32	Regular Tax																			
33	Regular NOLs Used	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	0.0	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	-	-	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
37	Tax	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
38																				
39	AMT																			
40	ACE Adjustment	(0.9)	(0.3)	-	(0.6)	(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	30.9	0.3	55.8	0.4	0.6	0.7	1.1	1.3	1.4	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
42	AMT NOLs Used	27.8	0.3	50.2	0.3	0.6	0.7	1.0	1.2	1.3	-	-	-	-	-	-	-	-	-	-
43	Net Taxable Income	3.1	0.0	5.6	0.0	0.1	0.1	0.1	0.1	0.1	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
44	TMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
46	Net AMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																			
48	BB	4.7	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2
49	Additions	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
51	EB	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
52																				
53	Total Tax	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
54																				
55	Est. Book Tax	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	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	0.331	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	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	-	0.5	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	-	0.8	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	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
64	Incremental Generation		-																	
65	WKE Total	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
66	Plant Maintenance	-	-	-	5.7	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
67	Environmental	-	-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Shared HQ Building	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Intellectual Property	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
71	8/07 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Total	11.0	7.1	-	23.2	49.2	36.4	38.8	36.3	23.3	25.0	24.3	23.3	24.0	28.7	29.6	27.1	28.8	27.8	29.0
73																				
74	Cumulative Balance	167.5	174.6	174.6	197.9	247.0	283.4	322.3	358.6	381.9	406.8	431.2	454.5	478.4	507.1	536.7	563.7	592.5	620.2	649.3
75																				
76	Book Depreciation @ 60 Years	2.8	1.0	-	3.3	4.1	4.7	5.4	6.0	6.4	6.8	7.2	7.6	8.0	8.5	8.9	9.4	9.9	10.3	10.8
77																				
78	Tax Depreciation @ 20 Years	8.4	2.9	-	9.9	12.4	14.2	16.1	17.9	19.1	20.3	21.6	22.7	23.9	25.4	26.8	28.2	29.6	31.0	32.5
79																				
80	Timing Difference (Tax Deduction)	(5.6)	(1.9)	-	(6.6)	(8.2)	(9.4)	(10.7)	(12.0)	(12.7)	(13.6)	(14.4)	(15.1)	(15.9)	(16.9)	(17.9)	(18.8)	(19.7)	(20.7)	(21.6)

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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	(11,132,402)	(32,499,597)	0	0
1996	12,713,387	0	(1,675,643)	(11,037,744)	0	0
1997	29,946,372	0	(1,747,361)	(28,199,011)	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	(31,833,276)	31,833,276	0	0	0	0
2008	(627,320)	627,320	0	0	0	0
Transaction	(55,780,912)	55,780,912	0	0	0	0
2008	(1,002,760)	1,002,760	0	0	0	0
2009	(1,540,918)	1,540,918	0	0	0	0
2010	(1,606,869)	1,606,869	0	0	0	0
2011	(1,675,643)	1,675,643	0	0	0	0
2012	(1,747,361)	1,747,361	0	0	0	0
2013	(1,822,148)	0	0	0	0	0
2014	(1,900,136)	0	0	0	0	0
2015	(1,981,462)	0	0	0	0	0
2016	(2,066,268)	0	0	0	0	0
2017	(2,154,705)	0	0	0	0	0
2018	(2,246,926)	0	0	0	0	0
2019	(2,343,094)	0	0	0	0	0
2020	(2,443,379)	0	0	0	0	0
2021	(2,547,955)	0	0	0	0	0
2022	(2,657,008)	0	0	0	0	0
2023	(2,770,728)	0	0	0	0	0
				(94,924,476)		
Total Carryforward to 2024	69,990,667	434,844,837	(434,844,837)	185,791,428	0	0

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	158,906,259	370,863,054	(370,863,054)	(23,188,124)	135,718,135	135,718,135
Total Carryforward to Transactio	158,278,939	371,490,374	(371,490,374)	(23,188,124)	135,090,815	135,090,815
Total Carryforward to H2 2008	102,498,027	427,271,286	(427,271,286)	(23,188,124)	79,309,903	79,309,903
Total Carryforward to 2009	101,495,267	428,274,046	(428,274,046)	(23,188,124)	78,307,143	78,307,143
Total Carryforward to 2010	99,954,349	429,814,964	(429,814,964)	(23,188,124)	76,766,225	76,766,225
Total Carryforward to 2011	98,347,480	431,421,833	(431,421,833)	(55,687,721)	42,659,759	42,659,759
Total Carryforward to 2012	96,671,837	433,097,476	(433,097,476)	(66,725,465)	29,946,372	29,946,372
Total Carryforward to 2013	94,924,476	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2014	93,102,328	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2015	91,202,192	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2016	89,220,730	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2017	87,154,462	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2018	84,999,757	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2019	82,752,831	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2020	80,409,737	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2021	77,966,358	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2022	75,418,402	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2023	72,761,394	434,844,837	(434,844,837)	(94,924,476)	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	(21,087,586)	(12,930,658)	0	0
1996	9,443,662	0	0	(968,129)	(8,475,533)	0	0
1997	32,657,152	0	0	(1,184,282)	(31,472,870)	0	0
1998	44,897	0	0	(44,897)	0	0	0
1999	8,082,161	0	0	(1,254,439)	(6,827,722)	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	(30,915,813)	27,824,231	(3,091,581)	0	0	0	0
2008	(324,006)	291,606	(32,401)	0	0	0	0
Transaction	(55,780,912)	50,202,821	(5,578,091)	0	0	0	0
2008	(388,611)	349,750	(38,861)	0	0	0	0
2009	(647,037)	582,333	(64,704)	0	0	0	0
2010	(730,767)	657,691	(73,077)	0	0	0	0
2011	(1,075,699)	968,129	(107,570)	0	0	0	0
2012	(1,315,869)	1,184,282	(131,587)	0	0	0	0
2013	(1,443,707)	1,299,336	(144,371)	0	0	0	0
2014	(1,638,356)	0	(1,638,356)	0	0	0	0
2015	(1,883,882)	0	(1,883,882)	0	0	0	0
2016	(2,042,669)	0	(2,042,669)	0	0	0	0
2017	(2,149,181)	0	(2,149,181)	0	0	0	0
2018	(2,241,548)	0	(2,241,548)	0	0	0	0
2019	(2,337,861)	0	(2,337,861)	0	0	0	0
2020	(2,437,831)	0	(2,437,831)	0	0	0	0
2021	(2,542,573)	0	(2,542,573)	0	0	0	0
2022	(2,651,791)	0	(2,651,791)	0	0	0	0
2023	(2,765,676)	0	(2,765,676)	0	0	0	0
Total Carryforward to 2024	101,158,829	330,506,313	(55,339,977)	(330,506,313)	(156,498,806)	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 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 H1 2008	185,556,805	274,970,366	(26,477,948)	(274,970,366)	(96,792,024)	115,242,730	115,242,730
Total Carryforward to Transacti	185,232,799	275,261,971	(26,510,348)	(275,261,971)	(96,792,024)	114,951,124	114,951,124
Total Carryforward to H2 2008	185,232,799	325,464,792	(32,088,440)	(325,464,792)	(96,792,024)	120,529,215	120,529,215
Total Carryforward to 2009	129,063,276	325,814,542	(32,127,301)	(325,814,542)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	128,416,240	326,396,875	(32,192,004)	(326,396,875)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	127,685,472	327,054,566	(32,265,081)	(327,054,566)	(109,722,681)	FALSE	FALSE
Total Carryforward to 2012	126,609,773	328,022,695	(32,372,651)	(328,022,695)	(118,198,214)	FALSE	FALSE
Total Carryforward to 2013	125,293,904	329,206,977	(32,504,238)	(329,206,977)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2014	123,850,198	330,506,313	(32,648,609)	(330,506,313)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2015	122,211,841	330,506,313	(34,286,965)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2016	120,327,959	330,506,313	(36,170,847)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2017	118,285,290	330,506,313	(38,213,516)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2018	116,136,109	330,506,313	(40,362,697)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2019	113,894,562	330,506,313	(42,604,244)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2020	111,556,701	330,506,313	(44,942,105)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2021	109,118,869	330,506,313	(47,379,937)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2022	106,576,296	330,506,313	(49,922,510)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2023	103,924,506	330,506,313	(52,574,301)	(330,506,313)	(156,498,806)	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:	2005/ Othe	2006	2007	2008H1	Transaction 4/30/2008	2008 H2	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	2.396	0.762		1.632	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%	64.32%	60.17%		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	425	145		310	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 (		0.957	0.974	0.323		0.691	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%	80.16%	78.09%		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	139	47		101	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																						
11	TWH	Contract Stipulated			0	0		2.106	3.138	3.138	3.138	3.146	3.138	3.138	3.138	3.146	3.138	3.138	3.138	3.146	3.138	3.138	3.138
12	LF	Contract Stipulated			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				-	-		294	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439
14	Century																						
15	TWH	Contract Stipulated						2.792	4.159	4.159	4.159	4.171	4.159	4.159	4.159	4.171	4.159	4.159	4.159	4.171	4.159	4.159	4.159
16	LF	Contract Stipulated			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							390	581	581	581	581	581	581	581	581	581	581	581	581	581	581	581
18																							
19	Offsystem (TWh)	file: annual output - 12-15-07.xls		1.93	1.16	0.71		1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
20																							
21	Purchases & Production																						
22	Purchases (TWh)																						
23	Market	file: annual output - 12-15-07.xls		0.07	0.02	0.01		0.13	0.29	0.19	0.46	0.38	0.54	0.37	0.42	0.42	0.72	0.47	0.66	0.53	0.55	0.62	0.71
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10		0.17	0.30	0.31	0.31	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 - 12-15-07.xls			-	-		8.07	11.80	12.10	11.63	11.71	11.65	11.88	11.87	11.95	11.56	11.97	11.58	11.86	11.94	11.90	11.92
26	Loss Rate (%)	Stated			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 (MMBtu)	file: annual output - 12-15-07.xls						89.9	131.5	134.0	129.1	129.4	128.1	130.5	130.5	131.2	127.3	131.6	127.3	130.4	131.3	130.7	131.1
29																							
30	Startup Costs (M$)	file: annual output - 12-15-07.xls			-	-		4.36	6.54	6.84	7.89	6.54	6.91	7.01	6.17	6.97	8.06	6.81	8.66	7.68	7.68	8.42	8.22
31																							
32	Emissions																						
33	SO2																						
34	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		14,032	18,797	19,882	18,824	19,356	18,296	19,317	20,336	20,806	19,359	20,823	18,767	19,356	20,501	20,755	20,354
35	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		32,653	48,979	24,489	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	17,125	17,125	18,352	18,352	18,352
36	NOX																						
37	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		4,932	13,610	13,606	12,916	12,895	13,063	12,974	13,115	12,988	13,014	13,060	12,813	13,164	13,188	12,936	13,288
38	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		4,651	11,072	11,072	11,071	11,057	11,056	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)				-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																							
41	Rates																						
42	Fuel ($/ MMBtu)	file: annual output - 12-15-07.xls						1.48	1.50	1.64	1.70	1.71	1.81	1.82	1.84	1.88	1.92	1.90	1.92	1.95	1.97	1.99	2.01
43	Power Purchases ($/ MWh)																						
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		22.44	22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
45	Market	file: annual output - 12-15-07.xls		67.8347	77.90	200.00		47.55	53.53	53.88	51.18	48.73	43.89	46.92	48.93	48.57	49.27	46.27	48.71	52.10	59.38	55.96	59.64
46	Variable Production ($/ MWh sales)	file: annual output - 12-15-07.xls			-	2.27		2.27	2.45	2.60	2.83	3.07	3.13	3.19	3.53	3.62	3.74	3.81	3.92	4.01	4.18	4.23	4.40
47	SO2 Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	778		778	853	881	818	792	747	787	907	759	618	357	146	137	134	111	105
48	NOX Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	763		763	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
49																							
50	Coal used (ktons)	file: annual output - 12-15-07.xls	100%					4,072	5,970	6,085	5,813	5,881	5,811	5,909	5,919	5,933	5,752	5,963	5,777	5,913	5,958	5,922	5,958
51																							
52	Sales Rates & Related																						
53																							
54	General Rate Adjustments (%)							0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	1.02%	0.00%	9.98%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
55	Shadow 2010 Rate (0=start 2011)		1	0.02																			
56	Market ($/ MWh)	file: annual output - 12-15-07.xls		43.30	42.91	37.82		48.40	51.34	49.47	50.22	48.34	51.48	51.92	53.69	52.59	53.75	54.70	57.55	57.70	56.11	59.94	59.12
57																							
58	Rural																						
59	Demand ($/ KW-mo.)			7.37	Escalated by GRAs																		
60	Energy ($/ MWh)			20.4	Escalated by GRAs																		
61																							
62	Large Industrial																						
63	Demand ($/ KW-mo.)			10.15	Escalated by GRAs																		
64	Energy ($/ MWh)			13.715	Escalated by GRAs																		
65																							
66	Smelters																						
67	Margin ($/ MWh)	Contract Stipulated						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 ($/ MWh)							-	-	0.00	1.81	2.64	2.40	2.26	3.16	2.88	3.14	0.15	3.17	2.16	3.46	2.50	3.69
69	Surcharge 1 (M$)	Contract Stipulated						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 ($/MWh)	Contract Stipulated	0					1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15						4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
72	Surcharge 2 (M$)	line 70 * line 71						5.88	5.22	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76
73																							
74	Member Revenue Discount Adjustment (M$)			3.68	3.68000	1.21661		2.46	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.74	0.24		0.74	0.73	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.71	0.71	0.71	0.71
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)			0.19	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77																							
78	TIER Rebate Related to Rurals ($M)							0.41	1.36	2.33	-	-	0.00	-	-	-	-	-	-	-	-	-	-
79	TIER Rebate Related to Large Industrials ($M)	Methodology Contract Stipulated			-			0.15	0.51	0.89	-	(0.00)	(0.00)	-	-	-	-	-	-	-	-	-	-
80	TIER Rebate Related to Smelters ($M)							1.18	3.91	6.55	-	-	-	-	-	-	-	-	-	-	-	-	-
81	FAC Base, 12/2004 ($/ MWh Sold)																						
82	W/o Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	10.72																				
83	W/ Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	12.47																				
84																							
85	Total																						
86	NOx + SO3	annual output - 12-15-07.xls																					
87	VOM	annual output - 12-15-07.xls						0.99	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	annual output - 12-15-07.xls						0.21	7.23	6.10	3.97	3.65	3.81	3.66	7.80	7.07	7.35	7.47	7.04	7.93	8.34	8.31	8.96
89	SO2	annual output - 12-15-07.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	annual output - 12-15-07.xls						17.35	25.66	27.66	29.29	32.11	32.82	33.78	37.85	38.87	39.23	40.97	40.87	42.83	45.04	45.17	47.38
91	Net Allowances	annual output - 12-15-07.xls						(14.49)	(25.74)	(4.06)	(4.64)	(4.06)	(4.63)	(4.07)	1.80	1.86	0.62	0.88	0.24	0.31	0.29	0.27	0.21
92	Total	annual output - 12-15-07.xls						4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
93	**Allowed in Environmental Surcharge**																						
94	NOx + SO3	annual output - 12-15-07.xls																					
95	VOM	annual output - 12-15-07.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.88	5.17	5.05
96	Allowances	annual output - 12-15-07.xls						0.21	7.23	6.10	3.97	3.65	3.81	3.66	7.80	7.07	7.35	7.47	7.04	7.93	8.34	8.31	8.96
97	SO2	annual output - 12-15-07.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	VOM in Excess of 2009	annual output - 12-15-07.xls						17.35	25.66	27.66	29.29	32.11	32.82	33.78	37.85	38.87	39.23	40.97	40.87	42.83	45.04	45.17	47.38
99	Net Allowance Costs in Excess of 2009	annual output - 12-15-07.xls						(14.49)	(25.74)	(4.06)	(4.64)	(4.06)	(4.63)	(4.07)	1.80	1.86	0.62	0.88	0.24	0.31	0.29	0.27	0.21
100	Total	annual output - 12-15-07.xls						4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
101																							
102	Smelter Rate Structure																						
103	Bandwidth	Contract Stipulated						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	Fixed/ Insured							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%
110	Fixed/ Non-Insured							0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
111	RUS							3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
112	Variable							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)							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							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	Fixed/ Insured	Goldman						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%
118	Fixed/ Non-Insured	Goldman						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							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	Goldman						5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
121	PCB (Swapped to Fixed/ Refi)							3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
122	ARVP (Accretion/ Refi)		0.059144					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							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	Fixed/ Insured						181																
127	Fixed/ Non-Insured						82																
128	Variable						-																
129	PCB						142																
130	ARVP					249.89	102																
131	RUS -- GAAP						351																
132	Remarketing on Variable	Goldman	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman	1.75%																				
136	Bond Insurance	Goldman	0.80%																				
137																							
138	Capitalized Interest			(0.24)	(0.73)	(0.24)		(0.48)	(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			0.90	0.84	0.79	0.77	0.77	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-
141	Amortization			0.05	0.05	0.02	-	0.04	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	0.05	-
142	Ending Balance			0.84	0.790	0.772	0.772	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-	-
143	AMBAC Amortization (PCB) A/C 165																						
144	Amortization			0.42	0.42	0.14	-	0.28	0.42	0.42	0.42	0.42	0.30	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.16	-
145	Balance			4.69	4.27	4.13	4.13	3.85	3.43	3.00	2.58	2.16	1.86	1.65	1.44	1.22	1.01	0.80	0.59	0.37	0.16	-	-
146	Settlement Note/Marketing Payment																						
147	Amortization			1.00	1.00	0.33	-	0.67	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			17.08	16.07	15.74	15.74	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	0.03	0.03	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
150	Other			(0.21)	(0.34)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)
151	Line of Credit		0.50%	100.00																			
152	Prepayment on Transaction Date			-	-	-	195.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
153	Pre-Transaction Debt Service																						
154	Principal			26.43	12.47	13.05																	
155	Interest (Cash Flow)			36.93	36.724	16.944																	
156	Interest (Income Statement)			60.72	59.98	19.27																	
157	Amortization of RUS/PCB Account					-	1.75	1.67	1.54	1.41	1.28	1.15	3.64	3.37	3.10	2.82	2.55	2.28	2.00	1.73	1.46	4.26	3.79
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal			812.23	803.60	807.60	794.71	352.00	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-
161	Base Payment			54.48	42.64	27.99	-																
162	Interest Expense			45.88	46.80	14.93	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
163	Interest Payment			31.57	31.14	15.10	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
164	Accrued Interest			7.16	7.32	6.98	7.15																
165	Principal Payment			22.91	11.50	12.89	-	11.93	18.33	19.38	20.50	21.67	22.92	24.24	25.63	27.11	28.66	30.31	32.06	33.90	35.36	-	-
166	Ending Principal			803.60	807.60	794.71	794.71	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-	-
167	Orig Scheduled Principal Payment			24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance			938.60	912.60	878.61	878.61																
169																							
170	New RUS Promissory Note (GAAP)																						
171	Beginning Principal - RUS New Note			815.30	807.04	811.56	798.62	798.62															
172	Interest Expense			46.21	47.16	15.05	-	30.48															
173	Interest Payment			32.29	31.24	15.23	-	30.83															
174	Accrued Interest			7.25	7.41	7.24	7.24	6.89															
175	Principal Payment			22.19	11.41	12.77	-	25.85															
176	Principal Balance			799.79	804.14	791.38	791.38	765.53															
177	Imputed Interest			0.00	0.00	-	-	0.00															
178																							
179	**Receipts (M$)**																						
180																							

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Inputs

December 2007

#	Item	Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease			47.89	47.97	15.79		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Transmission			5.95	5.15	1.70		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
183	Smelter - Tier 3 Transmission (Cash Flow)			1.70	1.74	0.58		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)			1.78	1.82	0.60		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)			-	-	-	301.50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
186	Cobank Patronage Capital & Other			0.57	0.53	0.18	(0.26)	0.36	0.54	0.51	0.52	0.53	0.53	0.53	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55
187	Interest Earnings			3.73	6.59	1.96																	
188	Net Confomring Receipts			-	15.00	-																	
189	Cobank Patronage Capital - Balance Sheet		2.19	2.59	2.97	3.10	3.36	3.36	3.75	4.11	4.48	4.84	5.21	5.57	5.92	6.28	6.63	6.97	7.32	7.66	7.99	8.32	8.64
190	Lease Related & Other			5.04	5.35	2.02		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Cobank Patronage Capital (Income Statement)			0.96	0.92	0.31		0.62	0.93	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.88	0.87
192																							
193																							
194	**Fixed Production (M$)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	2008 Fact	66.7%				27.54	33.83	36.48	36.13	33.21	40.91	33.06	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						29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
201	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
202	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
203	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
204	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
205	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.10	0.07	0.19	0.20	0.20	0.20	1.56	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
206	Fixed Environmental O&M, Clear Skies (Real Basis)																						
207	NOx ongoing	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		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)	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0.3				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	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 Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	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																						
221	W-1 stack repair	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223	SCR catalyst replacement	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combine	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls		6.59	7.38	1.89		3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K				0.52		1.06	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			-	-	0.08		0.16	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			-	-	0.01		0.02	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.			-	-	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	0.01
231																							
232	A&G																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
234	Non-Labor	2004 actual escalated @ 3%						6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
235	Intellectual Property (Nominal Basis)	Unwind spreadsheet -- 8-29-07_Rev1.xls						3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
236	Intellectual Property Contingency	Assumption						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total			13.81	13.80	4.86		17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
238																							
239	APM, L/C, Cogen, CW & TVA Trans	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		4.66	3.83	3.63		3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
240																							
241	Property Insurance	2004 actual escalated @ 3%		0.40	0.40	0.14		2.63	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
242																							
243	Property Tax			3.94	3.94	-																	
244	*Baseline*	*BREC Property Taxes Schedule in the 1998 LG&E Contract Deal*		1.10	1.08	0.37		1.18	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			0.74	0.77	0.26		0.57	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			0.14	0.11	0.04		0.11	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	13.95																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	08 Factor:	0.61				22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
253	Adjustment for Station 2 (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254																							
255	Gross Incremental			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
256																							
257	Transmission (Nominal)	Per Crockett Memo dated 11/12/07		5.91	9.62	5.19		6.21	9.56	9.19	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	0.43		0.86	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			51%	51%	84%		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 Nov-07 w outage shift.xls		-	-	-		3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
265	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
266	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
267	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
268	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
269	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		0.44	0.41	0.26	1.89	1.26	-	1.12	-	-	-	-	0.28	0.28	-	-	-
270																							
271	Plant Maintenance Claim Amount			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

#	Item	Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	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 Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Mercury Monitoring	file: Fin Model Inputs BREC Nov-07 w outage shift.xls		-	-	-		3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Clmn FGD Equipment Capital	file: Fin Model Inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	FGD ongoing upkeep capital (0.10%)	file: Fin Model Inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
278	Additional FGD thickener & filter drum	file: Fin Model Inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	R-CT reliability study & upgrades	file: Fin Model Inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Wilson super heater tubes replacment	*file: Fin Model Inputs BREC Nov-07 w outage shift.xls*		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Adjustment for Station 2	file: Fin Model Inputs BREC Nov-07 w outage shift.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		-	-			3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
286																							
287	Shared HQ Building																						
288	Phase I			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
289	Phase II			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
290																							
291	Intellectual Property																						
292	Capex Purposes	Unwind spreadsheet -- 8-29-07_Rev1.xls		-	-	-		4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
293	Depreciation Purposes			-				0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
294	Trial Balance Adjust		101.0%																				
295																							
296	Cash Adder			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
297																							
298	**Other Disbursements (M$)**																						
299																							
300	PPA			98.00	87.89	34.07																	
301	Environmental			0.41	0.68	0.25																	
302	PCB Restructuring			-	-	-		-	-	-	-	-	2.77	-	-	-	-	-	-	-	-	3.28	-
303	LEM Settlement Note			1.82	1.82	0.60		1.22	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'			0.14	0.12	0.08		(1.22)	(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			(0.05)	(0.05)	(0.02)		(0.04)	(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)	(0.05)	-
307	*Green River Coal Settlement*			0.35	0.05	0.01		0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
308	MISO Credit Fee		1	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Deferred Tax Asset Write-Down			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
310	Payment to City of Henderson			-			-	0.19	0.31	0.31	0.31	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
311	Smelter Payment (Assurances Agreement)			-	-	-	4.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
312	Lease-Equity Consent Fees/ Smelter Exit			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
314	Economic Reserve			-	-	-	75.00	(5.54)	(12.52)	(19.12)	(20.45)	(24.16)	(4.38)	-	-	-	-	-	-	-	-	-	-
315	Working Capital Adj.			1.09	0.21	0.02																	
316	CoBank Patronage Capital		2.25	2.64	3.03	3.16		3.42	3.81	4.17	4.53	4.90	5.26	5.62	5.98	6.33	6.68	7.03	7.37	7.71	8.05	8.38	8.70
317	Amortization of RUS/PCB Charges						-	0.09	0.13	0.13	0.13	0.13	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.47	0.47
318	**Other Assumptions**																						
319																							
320	Interest Earnings Rate on Cash Balances		4.28%																				
321																							
322	Inflation		3.00%																				
323																							
324	Receivables (days)		30.00																				
325																							
326	Payables (days)		52.50																				
327																							
328	Non-Patronage Taxable Allocation (Transaction)		15%																				
329																							
330	Sequestered Cash Ending Balance		35.00		0																		
331																							
332																							
333	**Balance Sheet (2005)**																						
334																							
335	Assets																						
336	Property																						
337	Total Utility Plant in Service		1,714.8	1,731.2	1,760.4	1,780.2																	
338	Construction in Progress		12.7	13.1	13.1	13.1	13.1	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	5.0
339	Depreciation & Amortization		798.7	826.6																			
340	Other Property		184.0	190.7																			
341	Current																						
342	Cash General Funds & Special Deposits		0.0	0.0	0.0	0.0	0.0																
343	Ending Cash Balance		67.8	96.5																			
344	Accounts Receivable		16.3	17.5	17.7	17.7																	
345	Fuel Stock & Related		-	-																			
346	Credit Escrow		-	.	-	-	75.0	71.6	62.1	45.7	27.2	4.2	-	-	-	-	-	-	-	-	-	-	-
347	Materials and Supplies Other		0.7	0.8	0.8	0.8																	
348	*Other Current Assets*		0.3	4.1	4.7	4.7	4.7																
349	Credits																						
350	AMBAC/Credit Suisse July '98		5.1	4.7	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
351	Deferred Tax		4.3																				
352	Other Deferred Debits/PCB Refunding 10/01																						
353	LEM Settlement Note/Marketing Payment		18.1	17.1	16.1	15.7																	
354	Total Assets																						
355																							
356	Liabilities																						
357	Margins & Equities		(251.9)	(217.4)																			
358	Long-Term Debt																						
359	Existing Debt		1,058.2	1,053.1	1,062.1	1,051.1																	
360	Sale-Leaseback Obligation		171.0	177.3																			
361	Total Long-Term Debt																						
362	Current & Accrued Liabilities																						

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		Source:	2005/ Othe	2006	2007	2008H1	Transactioı	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable		13.1	12.6	11.7																		
364	Taxes Accrued		0.4	0.2	0.2																		
365	Deferred Revenue (Credit Escrow)																						
366	Interest Accrued		7.5	7.6	7.8	7.6	0.4	0.4															
367	Other Accrued Liabilities		5.9	6.0	6.2	6.3	6.3	6.4															
368	WKEC Lease (Resid. Value Obligation)*			158.1																			
369	Sale-Leaseback Gain																						
370	Other Deferred Credits & Century Reactive Power		1.0	0.4	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
371	Total Liabilities & Equity																						
372																							
373	Misc included in Other Property		1																				
374																							
375																							
376	**Sale-Leaseback**																						
377																							
378	BOY Deferred Gain		62.12																				
379	Amortization (I/S)		2.86	2.88	2.90	0.97		1.96	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)		180.65																				
382	Adder		0.50	0.73	0.74	0.24		0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
383																							
384	Liability - Long-Term Debt (B/S)		170.95																				
385																							
386	Interest Income (I/S)		11.67	12.07	12.48	4.27		8.65	13.02	13.56	14.13	14.68	15.27	15.90	16.58	17.30	18.08	18.91	19.81	20.76	21.78	22.88	24.05
387	Interest Expense (I/S)		11.97	12.39	12.82	4.39		8.89	13.33	13.90	14.60	15.07	15.68	16.33	17.03	17.78	18.58	19.43	20.35	21.33	22.38	23.50	24.70
388																							
389	Cash Flow (Investment and Liability)		5.72	6.03	6.24	2.06		4.18	11.91	5.27	5.45	6.36	6.36	6.36	6.35	6.35	6.35	6.34	6.34	6.33	6.33	6.32	6.31
390																							
391	Sale-Leaseback - LeaseCo.																						
392	Defeasance Income		63.53	64.06	64.47	21.31		64.91	61.26	62.10	62.92	63.14	63.36	63.60	63.86	64.13	64.42	64.73	65.06	65.41	65.79	66.19	66.62
393	Rent Expense		(48.87)	(48.87)	(48.87)	(16.16)		(48.87)	(48.87)	(48.87)	(48.87)	(50.65)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)
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			40.2	45.3	50.3	61.2	-	-	-	-	-	-	-									
402	WKE Share of Non-Incremental Capex			6.7	6.8	11.7	-	-	-	-	-	-	-	-									
403	Amortization of WKE Share			1.6	1.8	0.9	-	-	-	-	-	-	-	-									
404	Unattributed Plugs			(145.1)																			
405	Incremental																						
406	Beginning Balance			100.2	95.6	90.9	89.4	-	-	-	-	-	-	-									
407	WKE Share of Non-Incremental Capex			0.8	-	-	-	-	-	-	-	-	-	-									
408	Amortization of WKE Share			5.4	4.6	1.6	-	-	-	-	-	-	-	-									
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow			47.9	48.0	15.8	-	-	-	-	-	-	-	-									
412	Income Statement			52.3	52.3	17.3	-	-	-	-	-	-	-	-									
413	Balance			(17.3)	(13.0)	(11.4)	(11.4)	-	-	-	-	-	-	-									
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories			-	-	-	55.0	-	-	-	-	-	-	-									
418																							
419	Coleman Scrubber Completion			-	.	-	97.5	-	-	-	-	-	-	-									
420																							
421	Cancellation of Settlement Prom. Note			-	-	-	16.0	-	-	-	-	-	-	-									
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment			-	-	-	4.3	-	-	-	-	-	-	-									
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						-	75.0	71.6	62.1	45.7	27.2	4.2	-	-	-	-	-	-	-	-	-	-
431	IE						-	2.1	3.1	2.7	2.0	1.2	0.2	-	-	-	-	-	-	-	-	-	-
432	Contribution						75.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	(5.5)	(12.5)	(19.1)	(20.4)	(24.2)	(4.4)	-	-	-	-	-	-	-	-	-	-
434	EB						75.0	71.6	62.1	45.7	27.2	4.2	-	-	-	-	-	-	-	-	-	-	-
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance																						
439	Volume (tons)						14,000																
440	Price ($/ton)						778																
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		1																				
453	**Depreciation**																						

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	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			12.83	13.12	4.43																	
457	Average of Transmission and A&G			6.38	10.88	5.29																	
458	Depreciation as a Percentage of Gross PPE			0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)		1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)		38																				
461	Capital Depreciation Rate (Environmental)		38																				
462																							
463																							
464	HMP&L Station Two																						
465	Prior year non-incremental			12.83	13.12	4.43																	
466	Depreciation as a Percentage of Gross PPE			0.00	0.00	0.00		0.00															
467																							
468	Other																						
469	Prior year			6.00	6.77	4.96																	
470	Depreciation as a Percentage of Gross PPE			0.00	0.00	0.00		0.00															
471																							
472	Book Depreciation & Amortization																						
473	Generation																						
474	Big Rivers' Plants			25.36	25.39	8.58		26.58	9.01														
475	HMP&L Station Two			1.58	1.64	0.54		0.93	0.31														
476	Other			5.05	5.25	1.75		5.06	1.69														
477																							
478	Adjustment to Depreciation		0																				
479	9/24/07 Blended Depreciation Amount							0.019757	0.020404	0.021031	0.021553	0.021668	0.021221	0.020901	0.021226	0.021501							
480	**Income Tax Related**																						
481																							
482	Previously Expensed Marketing Payment			0	0	0	4.196																
483																							
484	Status Quo Depreciation		23.69																				
485																							
486	WKE Share of Capex																						
487	Non-Incremental			51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental			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		149.87																				
492	Other Temporary Differences		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		35%																				
499	AMT		20%																				
500																							
501	ACE																						
502	ACE Deduction			(1.23)	(1.22)	(0.40)	-	(0.82)	(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			0.41	0.89	0.13	-	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	5.58	5.70																
507																							
508	Nonpatronage MWH		1	38%	0.256522	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales		PE																				
510	Interest Income on Unrestricted Cash		PE																				
511	Interest on Transition Reserve		NP																				
512	Interest on Economic Reserve		PE																				

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

EXHIBIT 9

Direct Testimony of Robert S. Mudge

December 2007

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

DIRECT TESTIMONY OF
ROBERT S. MUDGE

ON BEHALF OF
APPLICANTS

DECEMBER 2007

DIRECT TESTIMONY OF
ROBERT S. MUDGE

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Robert S. Mudge. I am a Principal with CRA International, Inc. (formerly, Charles River Associates, Inc.) ("CRA"). My business address is 1201 F St., NW, Washington, D.C. 20004.

Q. Please briefly describe your business and educational background.

A. I have been a banker or a consultant in the energy finance area since 1988. Since commencing work with CRA in the fall of 2002, I have advised on financial structuring issues including lease and other financing initiatives for the Tennessee Valley Authority, project financing for a $1.2 billion new-build coal generation project, asset divestiture on behalf of an IOU affiliate, and construction contract issues for an IPP owner, as well as extensive work on behalf of Big Rivers in connection with the Unwind Transaction, as further described below. I have also provided expert testimony in connection with contract disputes and regulatory hearings relating to combined cycle generation and a proposed LNG terminal. From 1997 to 2002, I was a Director in the Energy and Utilities group of Rothschild, Inc. ("Rothschild"), the U.S. arm of a global investment banking firm advising energy clients on strategic transactions, with a focus on IOUs and their affiliates. In addition to advising on corporate M&A and asset sales and acquisitions in the energy industry, I played a central role in the development of financeable contract structures in connection with privatization initiatives of the U.S. Department of Energy, including the evaluation of proposed multi-billion dollar financing plans from a broad spectrum of Wall Street and other financial institutions. Prior to joining Rothschild, I was a Group Vice President in the Project and Utilities Group at ABN AMRO, where I led numerous energy project financings and conducted advisory engagements in the United States and abroad through the early- and mid-1990s. A copy of my resume is attached as Exhibit RSM-1.

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

A. Big Rivers Electric Corporation ("Big Rivers") has asked me to present a financial model (the "Financial Model") depicting the transaction (the "Unwind Transaction", as referenced in the testimony of Michael H.

Core and others), under which Big Rivers has proposed to terminate a 1998 power purchase and lease transaction with E.ON U.S. LLC ("E.ON") (the "Lease Transaction), and the financial impact of operations thereafter, through the period of the existing arrangements which terminate in 2023. The following is a general description of the Financial Model, its applications over time, key assumptions and data sources, and key outcomes and metrics.

II. DESCRIPTION OF THE FINANCIAL MODEL

Q. Please describe the Financial Model depicting the Unwind Transaction.

A. The Financial Model projects Big Rivers' financial statements -- Income Statement, Cash Flows, and Balance Sheet -- from the currently projected Transaction Closing Date of April 30, 2008 ("Transaction Closing Date") through year-end 2023. It also contains a number of supporting schedules indicating projected energy sales, energy production and related costs, fixed costs, capital expenditures and depreciation, taxes, and projected debt service. Importantly, the Financial Model presents detailed projections of rates to be paid by Big Rivers' existing distribution cooperatives' members and Kenergy

Corp.'s two aluminum smelter customers, Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, (the "Smelters"). The Financial Model also projects key measures of financial performance and solvency at Big Rivers, as presented below. Except for the 8 month period of 2008, the Financial Model is presented on an annualized, calendar-year basis.

Q. Please describe how the Financial Model has been used to date.

A. At the outset of negotiations relating to the Unwind Transaction in 2003, Big Rivers retained CRA to prepare a financial spreadsheet projection depicting the Unwind Transaction in detail, largely for purposes of calculating appropriate compensation for termination of the Lease Transaction. The Financial Model has been used since that time to track the development of input assumptions, projected corporate operations, transaction elements and contractual provisions with Kenergy on behalf of the Smelters, and to reflect the impact of these items on Big Rivers' member non-Smelter rates and the financial performance of Big Rivers through 2023. The Financial Model has thus formed the basis for quantitative assessment of the Unwind Transaction by Big Rivers' management, board of directors, and member distribution cooperatives.

III. RESULTS OF THE FINANCIAL MODEL

Q. Can you please summarize key results of the Financial Model?

A. The Financial Model shows that, as a result of the Unwind Transaction, Big Rivers' equity will immediately grow by approximately $550 million, from approximately negative 13% of assets to positive 24%. Equity is projected to increase to 38% of assets by the end of 2023. Big Rivers' member revenue requirements for their rural and large industrial consumers ("non-Smelter members") can be achieved with Big Rivers' existing tariffs until 2011, when Big Rivers projects that a first rate adjustment could reasonably be expected to take effect. Even accounting for certain new riders to recover fuel and environmental costs, which are proposed prior to 2011, member non-Smelter rates are projected to remain approximately at current levels ($34.40 per MWh, on a blended basis) through 2010. Member non-Smelter member rates are projected to average $34.71 per MWh through 2012 and $44.56 per MWh through 2023, again, on a blended basis. Smelter rates are projected to average $39.07 per MWh through 2012 and $46.79 through 2023. Their projected rates and their components are detailed below.

Interest coverage (Times Interest Earned Ratio, or "TIER", as defined in the Smelter agreements) is targeted at 1.24x through 2023 by the revenue requirement provisions of Big Rivers' wholesale agreements with Kenergy Corp. for service to the Smelters. Average cash balances are projected to remain greater than $84 million in any year through 2023. Big Rivers is projected to have not less than 136 days of operating cash available to it, including a $100 million line of credit proposed to be secured upon financial closing, in every year through 2023.

Q. Please describe the key inputs and assumptions underlying the Financial Model.

A. The following describes the assumptions, data sources, and methodologies for key model inputs:

1. <u>Transaction Economics</u> - The Unwind Transaction is modeled to close on April 30, 2008. The terms of the Unwind Transaction stipulate the following compensation is to be paid and/ or provided by E.ON for termination of the 1998 Lease Transaction, with an immediate impact on Big Rivers' financial statements:

Transaction Date Income

	$ Millions
Cash	301.5
Residual Value Payment	150.4
LG&E Rental Income Advance	11.4
Fuel Inventory & Other	55.0
Settlement Promissory Note	16.0
Coleman Scrubber	97.5
SO2 Allowances & Other	10.9
Expense Unamortized Mktg Payment/ Settlement Note	(15.7)
Assurances Agreement Payment	(4.3)
Total	622.7

The elements of compensation listed above are discussed in the testimony of C. William Blackburn, Exhibit 10. Cash derived from the Unwind Transaction will be applied to debt reduction (an assumed $195.8 million) and reserves for the benefit of non-Smelter members will be funded ($110 million), as shown below:

Transaction Closing Date Cash Flows:

	$ Millions
Cash Balances Pre-Transaction	134.9
Transaction Proceeds	301.5
Debt Reduction	(195.8)
Misc. Transaction	(5.6)
Net Flow to Unrestricted Cash	100.1
Cash Balances Post-Transaction	235.0
Less Funding of Member Rate Stabilization Account	(75.0)
Less Funding of Member Transition Reserve	(35.0)
Cash Balances	125.0

2. Debt Reduction and Ongoing Financing - On the Transaction Closing Date, the existing United States Rural Utilities Service ("RUS") New Note is projected to be reduced by $440 million (GAAP basis) from both the net proceeds of the Unwind Transaction equal to $195.8 million and the issuance of additional capital markets debt equal to $263.5 million, less transaction costs, accrued interest and other items. Below is a summary of the Sources and Uses of Funds as they relate to debt reduction on the Transaction Closing Date:

Sources and Uses of Funds in Reduction of the RUS New Note:

	$ Millions
Sources of Funds	
Net Transaction Proceeds	195.8
Net New Issuance Proceeds	263.5
Total	459.3
Uses of Funds	
Reduce RUS New Note (GAAP Basis)	440.7
Accrued Interest and Other	9.0
Transaction Costs	9.6
Total	459.3

Financing has been modeled to minimize costs, reduce RUS exposure to the maximum degree, and reasonably extend debt maturities. The RUS New Note balance remaining after the reduction described above ($351 million) is modeled to amortize on a level debt service basis through its current maturity of 2021. Similarly, the existing RUS ARVP Note, entered into as part of the Lease Transaction, is assumed to be refinanced upon maturity at the end of 2023. The balance of the debt consisting of tax-exempt pollution control bonds and new capital markets issuances is modeled to be repaid and/or refinanced on a 30-year schedule, through April 2038. Assumptions concerning new and extended debt facilities were provided by Big Rivers' underwriter Goldman Sachs. The specifics of the financing plan currently reflected in the Financial Model may be changed to optimally meet the objectives above as market conditions change prior to closing.

3. Production and Variable Costs - Following the Unwind Transaction and Big Rivers' reassuming control of the plants, the Financial Model derives assumptions for (i) energy sales revenues, (ii) costs of energy production and purchases, and (iii) net costs for fuel, non-fuel variable inputs, and emissions allowances, from a Production Cost Model prepared by ACES Power Marketing ("APM"). In turn, the Production Cost Model is based on the Henwood market "dispatch" model (the "Henwood Model"). The Henwood Model combines input assumptions about Big Rivers and market costs of production, other electric generation resources, transmission constraints and other factors to determine anticipated sales, production and costs as further described below.

Projected non-Smelter member, Smelter, and market sales are generally based on current member load forecasts, expected Smelter load, and the dispatch modeling described above. Projected sales (and transmission line losses) are covered by production based on anticipated plant availability and performance, with the balance covered by purchases from the Southeast Power Administration

("SEPA") and from the market. Pursuant to the Production Cost Model, the Financial Model reflects average annual member sales of 4,089,675 MWh each year, average annual Smelter sales of 7,302,078 MWh and market sales of 1,077,477 MWh. Plant capacity factors average 81.9% with average production available to Big Rivers of 11,835,439 MWh.

Offsystem sale revenues are based on offsystem sales determined in the Henwood Model, referenced above, and market electricity prices derived from assumptions about fuel prices, competing resources, transmission constraints, and other items. Offsystem sales average $52.71/ MWh, or $56.8M in average annual revenue.

Input assumptions for projected fuel costs are derived from a forecast of market costs per MMBtu of delivered Illinois Basin coal prepared by the consulting firm Global Insight, Inc., blended with terms of existing contracts to be assumed by Big Rivers as part of the Unwind Transaction. Heat rates are then stipulated by Big Rivers as inputs to the Production Cost Model to derive fuel costs per MWh. Fuel costs average $1.88/ MMbtu, or $19.64/ MWh, generating $245.1M in average annual expenditure.

Non-fuel variable operation and maintenance ("O&M") costs consist primarily of reagent for emissions control. Input assumptions for reagent are derived from the terms of existing contracts to be assumed by Big Rivers as part of the Unwind Transaction. Non-fuel variable O&M costs average \$3.28/ MWh, generating \$38.8M in average annual expenditure.

Power purchase costs are based on contract rates with SEPA and otherwise on market rates derived in the Production Cost Model (consistent with market assumptions underlying offsystem sale revenues). Power purchase costs average \$28.33/ MWh for SEPA and \$51.30/ MWh for market purchases, or \$32.0M in average annual expenditure.

Emissions Allowance Net Costs represent the cost of procuring allowances to offset emissions of SO_2 or NOx by the plants. In some years where United Stated Environmental Protection Agency ("EPA") allocations of SO_2 allowances exceed those required to offset plant emissions, such excess allowances are modeled to be sold in the market, generating revenues rather than costs. Emissions Allowance Net Costs average \$(0.28)/ MWh for SO_2 and \$0.51/ MWh for NOx, or \$2.7 million in average annual expenditure. As noted above, a quantity of SO_2 allowances will be contributed by E.ON as part of the Unwind Transaction consideration, the accounting for which is described in the testimony of C. William Blackburn, Exhibit 10.

Projections of power production, power sales, and variable costs have been made under the assumption that current environmental regulations will be in place.

4. Fixed Operating Costs. Fixed O&M cost inputs have been developed by Big Rivers and encompass production, transmission, and administrative and general ("A&G") costs. Each of these categories is further broken down into labor -- based on specific estimates of payroll and overhead -- and non-labor components. Production cost inputs are based on Big Rivers' adoption of work plans prepared by Western Kentucky Energy Corporation ("WKEC"), an E.ON affiliate, covering the years 2008 – 2010 as discussed in the testimony of Mark A. Bailey (Exhibit 5), with costs beyond that period projected by Big Rivers. Transmission costs are derived from Big Rivers' estimates based on recent actual costs and anticipated requirements for marketing offsystem energy after Big Rivers re-assumes control of the plants. A&G costs have also been estimated by Big Rivers on the basis of recent actual costs and anticipated costs of re-acquiring the plants,

with notable expenditures for information technology ("IT") systems. Other fixed costs include property taxes and insurance.

On average, fixed operating costs break out as follows:

	$Million
Production	
Labor	53.15
Non-Labor	58.16
Transmission	
Labor	7.21
Non-Labor	2.39
A&G	
Labor	13.46
Non-Labor	15.43

5. <u>Depreciation and Amortization</u> - Current average book depreciation rates in Big Rivers' financial statements amortize gross assets over a period in excess of 50 years. This depreciation, which was established in connection with the Lease Transaction, is based on an approved 1998 depreciation study performed for Big Rivers by Burns and McDonnell on plant in service as of December 31, 1997, that concluded that assets had been over-depreciated in prior periods. It is therefore a more extended schedule than might reasonably be expected to result from a more current analysis of remaining useful life.

Thus more accelerated average depreciation rates have been projected in the Financial Model, starting concurrent with the first rate increase in 2011. For the years 2011 – 2016, depreciation is shortened to an approximately 47-year basis, on average. Thereafter, through 2023, a 37-year depreciation rate is applied. Any actual change in depreciation will await an updated depreciation study. However, for conservatism, the above depreciation rates are intended to represent a plausible outcome of such a depreciation study. As a reference point, Big Rivers has looked to the results of an approved 1994 depreciation study performed for Big Rivers by Management Resources International on plant in service as of December 31, 1993.

6. Income Taxes - Taxation in the Financial Model is minimal, both because the bulk of transaction and operating revenues are treated as patronage sourced, and because of extensive accumulated Net Operating Losses ("NOLs"). Transaction proceeds are treated as 85% patronage sourced in nature, while operating revenues are treated as fully patronage sourced, with the exception of interest earnings on certain long-term cash funds. Income taxes average $.55 million per year from 2008 – 2023.

7. Capital Expenditures - Capital expenditure assumptions have been developed by Big Rivers, and, like fixed O&M, encompass production, transmission, A&G, and other costs. Again, like fixed O&M, capital expenditures related to production are primarily based on Big Rivers' adoption of work plans prepared by WKEC covering the years 2008 – 2010, as discussed in the testimony of Mark A. Bailey (Exhibit 5), with costs beyond that period projected by Big Rivers.

Annual capital expenditures average $32.9M for production, $4.9M for transmission and $1.6M for A&G.

Q. **Can you summarize the modeling of key rate mechanisms applicable to the non-Smelter members and to the Smelters?**

Yes. Pursuant to the agreement with Kenergy for wholesale service to the Smelters, revenue requirements are set to cover all system costs, net of projected sales of market electricity, interest income, emissions allowances, and other items, plus a margin sufficient to support 1.24 times interest coverage, as defined in the Smelter agreements.

Rates for the non-Smelter members are based on existing tariff rates for demand and energy, less the Member Discount Adjustment ("MDA"). Added to the tariff rates are energy-based charges for fuel (the "FAC Factor") and environmental costs (reagent and the net costs of disposal and emissions allowances -- the "Environmental Surcharge"). Importantly, the FAC Factor and Environmental Surcharge are offset by 1) fuel surcharges payable by the Smelters through the term of their Purchase Contracts and 2) a Member Rate Stability Mechanism ("MRSM"), funded from proceeds of the Unwind Transaction. (See Transaction Cash Flows, above, on page 9.) The combination of the fuel surcharges and the MRSM fully offset the impact of the FAC Factor and Environmental Surcharge through 2012. With respect to certain purchase power costs projected to be paid by the Smelters through a Purchased Power Adjustment ("PPA", see below), but not by the non-Smelter members, a PPA Regulatory Accounts is modeled to account for such power costs attributable to the non-Smelter members, accelerating or deferring expense recognition to correspond to revenues. Periodically, and as part of a rate adjustment application, Big Rivers will seek to amortize, and pass back or recover through rates such accumulated accelerated or deferred costs.

As described above, no changes in demand and energy rates are projected to take effect until 2011, and then pursuant to a rate case. Rate increases are projected to be needed in 2011, and periodically thereafter, to preserve the target TIER (see also the "TIER Adjustment

Charge" payable by the Smelters, below). In some years, rate increases include amortization of the PPA Regulatory Accounts referenced above. Note that, for transparency in modeling, the FAC Factor, Environmental Surcharge, and amortization of the PPA Regulatory Account are presented as distinct from Base Rates through 2023, and not rolled in.

By agreement, the Smelter rates are based on the large industrial rate at any time, adjusted for the projected Smelter load factor of 98%, plus $0.25/ MWh (the Smelter "Base Rate"). The Smelters also pay the FAC Factor, the Environmental Surcharge, and an additional energy-based charge for power purchases, the Non-FAC Power Purchase Adjustment. As noted above, the Smelters also pay fuel surcharges. Additionally, however, the Smelters contribute whatever additional revenues may be needed in a billing period to achieve the 1.24x TIER referenced above, the ("TIER Adjustment Charge"). Note that TIER and TIER Adjustment are specifically defined calculations under the Smelter Agreements. Alternative definitions of TIER may result in interest coverage somewhat different than 1.24x (note that a "Conventional" TIER calculation is supplied in Exhibit RSM-2). The TIER Adjustment Charge is capped in accordance with a schedule stipulated in the Smelter Agreements, ranging from $1.95 per MWh in

2008 to $4.75 per MWh in 2023. To the degree net system costs in a given period, accounting for all other components of the Smelter rate, would allow for a downward adjustment in revenues while still achieving the 1.24x TIER (the "Excess TIER Amount"), this reduction may be shared by the Smelters and the non-Smelter members.

Q. Can you provide some further detail on key measures and outcomes shown in the Financial Model?

Yes. The results of the Financial Model projection can be summarized in terms of balance sheet components, rates, interest coverage (TIER, as defined in the Smelter Agreements), and cash balances, among others. These results are summarized on Exhibit RSM-2, which is attached.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

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

Robert S. Mudge

District of Columbia)
City of Washington)

Subscribed and sworn to before me by Robert S. Mudge on this the 11 day of December, 2007.

Notary Public, District of Columbia
My Commission Expires: __________

Notary Public District of Columbia
Brian Combs
My Commission Expires June 30, 2009

INTERNATIONAL

ROBERT MUDGE
Principal

MBA, University of Chicago

BA, Harvard University

2004–Present *Principal,* CRA International Inc., Washington, D.C.
2002–2004 *Senior Consultant*

Member of CRA's Energy and Environment Practice, Enterprise and Asset Investment Group. Key engagements have included the following:

Restructuring of Electric Cooperative (Current) – Managing financial analysis in connection with transformative restructuring of $1.2 billion generation and transmission electric cooperative, reporting to CEO, CFO, and transaction counsel. Restructuring includes termination of complex power supply arrangements, lease unwind, acquisition of generating assets, acquisition of new customers, and related financing arrangements. Brief includes:

- Analysis, presentation, and testimony for management, board, customers, Rural Utilities Service, state utility commission, and rating agencies
- Valuation and risk analysis
- Interface with bond underwriters
- Oversight of comprehensive financial modeling

Bid Support in Power Plant Sale Process (2007) – Managed a multidisciplinary team in providing market analysis and financial modeling in support of successful bid for $300 million generating plant asset.

Regulatory Hearing Re: Financial Capacity for LNG Developer (2007) – Provided analysis and expert testimony before state Board of Environmental Protection on project financial capacity to support environmental permitting and compliance.

Project Financing of Government Contract (2007) – Financeability analysis relating to $2.5 billion capital project proposed to operate under long term contract with the US Department of Energy (DOE). For prospective project owner, work included:

- Review of debt and contract structures and related financial modeling

- Identification of relevant precedents and threshold feasibility assessment
- Assessment of trade offs between investor returns and government cost

Arbitration Relating to Construction Contract Dispute (2005–2006) – Provided analysis and expert testimony before arbitration panel relating to costs incurred in delayed startup of 1,000 MW merchant power plant. Issues included:

- Analysis of economic projections and contract damage provisions for delay
- Assessment of actual costs occasioned by delay

Project Financing of Consortium-Owned Power Project (2005–2006) – For project counsel, developed working finance plan and analysis to optimize construction cost for a $1.2 billion new-build power project proposed to be owned by a consortium including IOUs, municipalities, and an electric cooperative. Issues included:

- Optimizing corporate vs. project-based debt structures
- Optimizing complementary strengths of consortium members in financing

Capital Financing Alternatives for the Tennessee Valley Authority (2002–2003) – Evaluated diverse financing options for the Tennessee Valley Authority (TVA) relating to nuclear repowering initiatives and investment in emissions control equipment, reporting to the CFO. Work included:

- Cost of capital and liability assessment
- Benchmarking of diverse debt and lease financing proposals

2002–2003 *Member of Advisory Board*, Advanced Renewables, LLC, Philadelphia, PA

For start-up venture focused on acquisition, development, and operation of renewable-fuel generation projects, consultation on structuring, acquisition prospects, and capitalization.

1997–2002 *Director*, Energy and Utilities, Rothschild Inc., Washington, D.C.

Senior member of team spearheading Rothschild's entry into US utility, independent power, and other infrastructure markets.

Mergers and Acquisitions – For US utility and independent energy clients, identification and implementation of asset and corporate acquisitions.

- Advice on valuation, due diligence, approach, and negotiations

- Assessment of key drivers: commercial, financial, regulatory, and other

Privatization/Project Finance – For major contractor to US Department of Energy (DOE), project finance structuring and sourcing for privatized environmental projects.

- Creation of financeable contract structure
- Assembly of top-tier financing syndicate

Sell-Side Advice – Valuation, market canvassing, tax analysis, and negotiation support.

- **Cross-Border** – Support on acquisitions/ financings into and out of the US
- **Restructuring** – Support on bankruptcy/ restructuring work in the utility industry

1991–1997 *Group Vice President* and *Director*, Project Finance Group, ABN AMRO North America, Inc., Chicago, IL

Senior transactor with responsibility for advising and participating in project financings.

- **Project Financing** – Numerous transactions domestically and abroad in electric power generation, oil and gas pipelines, and other infrastructure
- **Financial Advisory** – Engagements on electric generating projects in Brazil and Mexico for major bank clients
- **Fund Structuring** – With major multi-lateral agency, structuring of debt and equity investment fund for emerging markets power projects

1988--1991 *Vice President* and *Manager*, Public and Project Finance Group, The Sanwa Bank, Ltd., Chicago, IL

Led Sanwa's first US project finance underwriting in 1989.

Balance Sheet (in $Millions, unless otherwise indicated)

		T *	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	*Assets*																	
2	Net Utility Plant	1,029	1,035	1,074	1,095	1,107	1,115	1,105	1,097	1,087	1,076	1,053	1,035	1,016	995	974	951	929
3	Sale-Leaseback	195	200	201	209	218	226	235	244	255	266	277	290	303	318	333	350	368
4	Cash & Investments	125	136	98	73	53	41	40	44	48	53	64	74	82	92	99	104	109
5	Transition Reserve	35	36	38	39	41	43	44	46	48	50	52	55	57	60	62	65	68
6	MRSM	75	72	62	46	27	4	-	-	-	-	-	-	-	-	-	-	-
7	Receivables, inventories & Other	116	138	138	143	148	150	160	162	165	166	175	173	177	179	183	188	194
8	Assets	1,567	1,616	1,611	1,605	1,594	1,579	1,585	1,593	1,603	1,611	1,622	1,627	1,636	1,643	1,652	1,658	1,667
9																		
10	*Liabilities & Equities*																	
11	Equities	377	387	403	417	433	448	464	480	496	512	529	545	561	577	593	610	626
12	Sale-Leaseback	239	241	240	246	252	258	265	272	279	288	297	307	319	331	344	358	373
13	Debt	858	850	838	825	811	797	782	766	749	731	712	692	671	649	625	600	574
14	Payables & Other	94	138	130	118	98	76	74	75	78	79	84	82	86	86	90	90	94
15	Liabilities & Equities	1,567	1,616	1,611	1,605	1,594	1,579	1,585	1,593	1,603	1,611	1,622	1,627	1,636	1,643	1,652	1,658	1,667
16																		
17	*Equity/ Assets*	24%	24%	25%	26%	27%	28%	29%	30%	31%	32%	33%	33%	34%	35%	36%	37%	38%

* Transaction Date

Rates ($/ MWh)

		Wtd Avg	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Member Non-Smelters																	
2	Base (Net of MRDA)	36.97	34.44	34.40	34.39	35.10	35.09	35.08	35.08	35.44	35.44	39.06	39.05	39.05	39.05	39.04	39.04	39.04
3	Regulatory Account Charge	0.51	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
4	FAC	8.95	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
5	Environmental Surcharge	3.61	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
6	Surcredit	(4.05)	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
7	Rebate:																	
8	Accrued	(0.09)	(0.24)	(0.54)	(0.90)	-	0.00	(0.00)	-	-	-	-	-	-	-	-	-	-
9	Realized	(0.09)	(0.00)	(0.16)	(0.52)	(0.88)	0.00	(0.00)	-	-	-	-	-	-	-	-	-	-
10	MRSM	(1.34)	(2.39)	(3.58)	(5.34)	(5.56)	(6.42)	(1.14)	-	-	-	-	-	-	-	-	-	-
11	Effective Rate - Cash	44.56	34.44	34.40	34.39	35.10	35.09	41.15	43.18	44.77	45.64	48.65	49.20	49.55	50.29	50.73	51.36	51.64
12																		
13	Smelters																	
14	Lg. Industrial Rate @ 98% LF	29.09	27.07	27.08	27.09	27.67	27.65	27.71	27.72	28.03	28.01	30.93	30.94	30.96	30.93	30.99	31.00	31.01
15	Additional Smelter Charge	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	0.25
16	Base	29.34	27.32	27.33	27.34	27.92	27.90	27.96	27.97	28.28	28.26	31.18	31.19	31.21	31.18	31.24	31.25	31.26
17	TIER Adjustment	2.13	-	-	0.00	1.81	2.64	2.40	2.26	3.16	2.88	3.14	0.15	3.17	2.16	3.46	2.50	3.69
18	FAC	8.81	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
19	Environmental Surcharge	3.50	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
20	PPA	0.83	(0.54)	0.05	(0.37)	0.73	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
21	Surcharge	2.28	1.90	1.42	1.90	1.90	2.20	2.20	2.20	2.20	2.20	2.60	2.60	2.60	2.59	2.60	2.60	2.60
22	Rebate (accrued)	(0.10)	(0.24)	(0.54)	(0.90)	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Effective Rate	46.79	34.82	34.94	37.70	42.58	43.90	44.56	44.75	47.34	47.42	52.22	48.61	52.37	51.61	53.73	53.05	55.05

TIER

		2008*	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Earnings	10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
2	Interest & Related **	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
3	Adjust. Per Smelter Agreements	(1.0)	(1.5)	0.9	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
4	Total	49.6	73.8	73.7	73.5	73.4	73.1	72.7	72.5	72.3	71.9	71.7	71.4	71.2	70.9	70.8	70.3
5	Interest & Related **	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
6	Income Tax	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
7	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	1.24
8	Conventional TIER	1.27	1.27	1.22	1.27	1.27	1.28	1.28	1.29	1.29	1.29	1.29	1.29	1.30	1.30	1.30	1.31

* *Partial year*

** Includes Sale-Leaseback Interest

Cash Balances (in $ Millions, unless otherwise indicated)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Average Cash Balance	166	154	124	103	89	84	87	93	100	110	123	134	145	156	165	173
2	Line of Credit	67	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
3	Total	233	254	224	203	189	184	187	193	200	210	223	234	245	256	265	273
4	Total Operating Expense	294	439	451	477	481	494	501	518	524	554	538	558	561	582	583	601.9
5	Days Cash on Hand:																
6	Including Line of Credit	290	211	181	156	143	136	136	136	139	138	151	153	159	161	166	165
7	Excluding Line of Credit	207	128	101	79	68	62	63	66	70	72	83	88	94	98	104	105

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

EXHIBIT 10

Direct Testimony of C. William Blackburn

December 2007

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2007-00455

DIRECT TESTIMONY OF
C. WILLIAM BLACKBURN

ON BEHALF OF
APPLICANTS

DECEMBER 2007