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May 30, 2008

RECEIVED
JUN 02 2008
PUBLIC SERVICE COMMISSION

Via Fed-Ex

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

Re: The Applications of Big Rivers Electric Corporation for: (1) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (II) Approval of Transactions, (III) Approval to Issue Evidences of Indebtedness, and (IV) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing, Inc. for Approval of Transactions, PSC Case No. 2007-00455

Dear Ms. Stumbo:

Enclosed for filing on behalf of Big Rivers Electric Corporation ("Big Rivers") are an original and ten copies of updates to previously filed data request responses. The information contained in the updated data request responses relate in large part to the draft settlement concepts that Big Rivers presented at the informal conference on May 15, 2008, and the updated responses indicate the draft settlement concepts to which they apply. Two of the witnesses for the responses, Robert Mudge and Steven Seelye, were not able to sign verification pages in time for those pages to be included with this filing, but those verification pages will be filed shortly. I certify that a copy of this letter and the responses have been served on the attached service list.

Sincerely yours,

Tyson Kamuf

TK/bh
Enclosures

cc: Michael H. Core
David Spainhoward
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PSC CASE NO. 2007-00455

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VERIFICATION

I verify, state, and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

David Spainhoward
David A. Spainhoward

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David A. Spainhoward on this the 30th day of May, 2008.

Vickie G. King
Notary Public, Ky. State at Large
My Commission Expires 03/03/2010

VERIFICATION

I verify, state, and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

Mark A. Bailey

Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 30th day of May, 2008.

Vickie G. King

Notary Public, Ky. State at Large
My Commission Expires 03/03/2010

VERIFICATION

I verify, state, and affirm that the data request responses filed with this verification and for which I am listed as a witness are true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

C William B Blackburn
C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 30th day of May, 2008.

Vickie G. King
Notary Public, Ky. State at Large
My Commission Expires 03/03/2010

TABLE OF CONTENTS

May 30, 2008

Item 11) In addition to Exhibit 37, provide the complete CPA Audit report for Big Rivers, for 2004 and 2007 when completed.

Response) A copy of Big Rivers' 2007 Independent Auditors' Report is attached.

Witness) C. William Blackburn

Big Rivers Electric Corporation

Financial Statements as of and for the
Years Ended December 31, 2007 and 2006,
and for Each of the Three Years in the Period
Ended December 31, 2007, and
Independent Auditors' Report

Deloitte.

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Big Rivers Electric Corporation:

We have audited the accompanying balance sheets of Big Rivers Electric Corporation (the "Company") as of December 31, 2007 and 2006, and the related statements of operations, equities (deficit), and of cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Big Rivers Electric Corporation as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

In accordance with Government Auditing Standards, we have also issued a report dated April 25, 2008, on our consideration of Big Rivers Electric Corporation's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards and should be read in conjunction with this report in considering the results of our audit.

As discussed in Note 9 to the consolidated financial statements, in 2007 the Company changed its method of accounting for defined benefit pension and other postretirement plans.

Deloitte & Touche LLP

April 25, 2008

BIG RIVERS ELECTRIC CORPORATION

BALANCE SHEETS
AS OF DECEMBER 31, 2007 AND 2006
(Dollars in thousands)

	2007	2006
ASSETS		
UTILITY PLANT — Net	$ 911,634	$ 917,668
RESTRICTED INVESTMENTS UNDER LONG-TERM LEASE	192,932	186,690
OTHER DEPOSITS AND INVESTMENTS — At cost	4,240	3,816
CURRENT ASSETS:		
Cash and cash equivalents	148,914	96,143
Accounts receivable	26,683	17,748
Materials and supplies inventory	768	811
Prepaid expenses	131	3,608
Total current assets	176,496	118,310
DEFERRED CHARGES AND OTHER	28,856	27,905
TOTAL	$1,314,158	$1,254,389
EQUITIES (DEFICIT) AND LIABILITIES		
CAPITALIZATION:		
Equities (deficit)	$ (174,137)	$ (217,371)
Long-term debt	1,022,345	1,041,075
Obligations related to long-term lease	183,891	177,310
Other long-term obligations	-	45
Total capitalization	1,032,099	1,001,059
CURRENT LIABILITIES:		
Current maturities of long-term obligations	39,392	11,959
Purchased power payable	13,038	9,219
Accounts payable	4,932	3,366
Accrued expenses	3,014	2,164
Accrued interest	7,811	7,631
Total current liabilities	68,187	34,339
DEFERRED CREDITS AND OTHER:		
Deferred lease revenue	15,537	17,316
Deferred gain on sale-leaseback	53,480	56,380
Residual value payments obligation	141,370	140,744
Other	3,485	4,551
Total deferred credits and other	213,872	218,991
COMMITMENTS AND CONTINGENCIES (see note 14)		
TOTAL	$1,314,158	$1,254,389

See notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2007, 2006, AND 2005
(Dollars in thousands)

	2007	2006	2005
POWER CONTRACTS REVENUE	$ 271,605	$ 200,692	$ 191,280
LEASE REVENUE	58,265	57,896	57,675
Total operating revenue	329,870	258,588	248,955
OPERATING EXPENSES:			
Operations:			
Power purchased and interchanged	169,768	114,516	114,500
Transmission and other	27,196	21,684	20,309
Maintenance	4,240	3,652	3,195
Depreciation and amortization	30,632	30,408	30,192
Total operating expenses	231,836	170,260	168,196
ELECTRIC OPERATING MARGIN	98,034	88,328	80,759
INTEREST EXPENSE AND OTHER:			
Interest	60,932	60,754	59,639
Interest on obligations related to long-term lease	9,919	9,505	9,109
Other—net	103	111	124
Total interest expense and other	70,954	70,370	68,872
OPERATING MARGIN	27,080	17,958	11,887
NONOPERATING MARGIN:			
Interest income on restricted investments under long-term lease	12,481	12,069	11,670
Interest income and other	7,616	4,515	2,786
Total nonoperating margin	20,097	16,584	14,456
NET MARGIN	$ 47,177	$ 34,542	$ 26,343

See notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

STATEMENTS OF EQUITIES (DEFICIT)
FOR THE YEARS ENDED DECEMBER 31, 2007, 2006, AND 2005
(Dollars in thousands)

	Total Equities (Deficit)	Accumulated Deficit	Other Equities: Donated Capital and Memberships	Other Equities: Consumers' Contributions to Debt Service	Accumulated Other Comprehensive Income
BALANCE — December 31, 2004	$ (278,256)	$ (282,701)	$ 764	$ 3,681	$ -
Net margin	26,343	26,343	-	-	-
BALANCE — December 31, 2005	(251,913)	(256,358)	764	3,681	-
Net margin	34,542	34,542	-	-	-
BALANCE — December 31, 2006	(217,371)	(221,816)	764	3,681	-
Net margin	47,177	47,177	-	-	-
FAS 158 Adoption	(3,943)	-	-	-	(3,943)
BALANCE — December 31, 2007	$ (174,137)	$ (174,639)	$ 764	$ 3,681	$ (3,943)

See notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2007, 2006, AND 2005
(Dollars in thousands)

	2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net margin	$ 47,177	$ 34,542	$ 26,343
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	33,866	33,592	33,386
Increase in restricted investments under long-term lease	(6,242)	(6,040)	(5,955)
Amortization of deferred gain on sale-leaseback	(2,900)	(2,882)	(2,856)
Deferred lease revenue	(1,779)	(4,439)	(4,335)
Residual value payments obligation	(6,591)	(6,187)	(5,969)
Increase in RUS ARVP Note	5,572	5,313	5,077
Increase in New RUS Promissory Note	15,761	13,889	8,205
Increase in obligations under long-term lease	6,580	6,356	6,250
Changes in certain assets and liabilities:			
Accounts receivable	(8,934)	(1,398)	(741)
Materials and supplies inventory	43	(144)	(112)
Prepaid expenses	3,477	(3,517)	257
Deferred charges	(2,429)	(694)	480
Purchased power payable	3,818	(1,513)	1,528
Accounts payable	1,566	972	(516)
Accrued expenses	1,033	81	72
Other — net	(5,465)	(1,170)	351
Net cash provided by operating activities	84,553	66,761	61,465
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(18,682)	(13,189)	(12,904)
Other deposits and investments	(424)	(419)	(151)
Net cash used in investing activities	(19,106)	(13,608)	(13,055)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments on long-term obligations	(12,676)	(24,274)	(36,037)
Net cash used in financing activities	(12,676)	(24,274)	(36,037)
NET INCREASE IN CASH AND CASH EQUIVALENTS	52,771	28,879	12,373
CASH AND CASH EQUIVALENTS — Beginning of year	96,143	67,264	54,891
CASH AND CASH EQUIVALENTS — End of year	$148,914	$ 96,143	$ 67,264
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest	$ 45,600	$ 47,277	$ 46,534
Cash paid for taxes	$ 420	$ 375	$ 271

See notes to financial statements.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General Information — Big Rivers Electric Corporation ("Big Rivers" or the "Company"), an electric generation and transmission cooperative, operates one segment that supplies wholesale power to its three member distribution cooperatives (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation) under all requirements contracts, excluding the power needs of two large aluminum smelters (the "Aluminum Smelters"), sells surplus power under separate contracts to Kenergy Corp. for a portion of the Aluminum Smelters load, and markets power to nonmember utilities and power marketers. The members provide electric power and energy to industrial, residential, and commercial customers located in portions of 22 western Kentucky counties. The wholesale power contracts with the members extend to January 1, 2023. Rates to Big Rivers' members are established by the Kentucky Public Service Commission (KPSC) and are subject to approval by the Rural Utilities Service (RUS). The financial statements of Big Rivers include the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, which was adopted by the Company in 2003, and gives recognition to the ratemaking and accounting practices of KPSC and RUS.

In 1999, Big Rivers Leasing Corporation (BRLC) was formed as a wholly owned subsidiary of Big Rivers. BRLC's principal assets are the restricted investments acquired in connection with the 2000 sale-leaseback transaction discussed in Note 4.

Principles of Consolidation — The financial statements of Big Rivers include the accounts of Big Rivers and its wholly owned subsidiary, BRLC. All significant intercompany transactions have been eliminated.

Estimates — The preparation of the financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities. The estimates and assumptions used in the accompanying financial statements are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

System of Accounts — Big Rivers' accrual basis accounting policies follow the Uniform System of Accounts as prescribed by the RUS Bulletin 1767B-1, as adopted by the KPSC. These regulatory agencies retain authority and periodically issue orders on various accounting and ratemaking matters.

Revenue Recognition — Revenues generated from the Company's wholesale power contracts are based on month-end meter readings and are recognized as earned. In accordance with SFAS No. 13, *Accounting for Leases*, Big Rivers' revenue from the Lease Agreement is recognized on a straight-line basis over the term of the lease. The major components of this lease revenue include the annual lease payments and the Monthly Margin Payments (described in Note 2).

In conjunction with the Lease Agreement, Big Rivers expects to realize the minimum lease revenue for the years ending December 31, as follows:

	Amount
2008	$ 52,332
2009	52,332
2010	52,332
2011	41,291
2012	35,076
Thereafter	385,832
	$ 619,195

Utility Plant and Depreciation — Utility plant is recorded at original cost, which includes the cost of contracted services, materials, labor, overhead, and an allowance for borrowed funds used during construction. Replacements of depreciable property units, except minor replacements, are charged to utility plant.

Allowance for borrowed funds used during construction is included on projects with an estimated total cost of $250 or more before consideration of such allowance. The interest capitalized is determined by applying the effective rate of Big Rivers' weighted-average debt to the accumulated expenditures for qualifying projects included in construction in progress.

In accordance with the terms of the Lease Agreement, the Company generally records capital additions for Incremental Capital Costs and Nonincremental Capital Costs expenditures funded by E.ON U.S. (formerly LG&E Energy Corporation) as utility plant to which the Company maintains title. A corresponding obligation to E.ON U.S. is recorded for the estimated portion of these additions attributable to the Residual Value Payments (see Note 2). A portion of this obligation is amortized to lease revenue over the useful life of those assets during the remaining lease term. For the years ended December 31, 2007 and 2006, the Company has recorded $8,359 and $7,221, respectively, for such additions in utility plant. The Company has recorded $6,591, $6,187, and $5,969 in 2007, 2006 and 2005, respectively, as related lease revenue in the accompanying financial statements.

In accordance with the Lease Agreement, and in addition to the capital costs funded by E.ON U.S (see Note 2) that are recorded by the Company as utility plant and lease revenue, E.ON U.S also incurs certain Nonincremental Capital Costs and Major Capital Improvements (as defined in the Lease Agreement) for which they forego a Residual Value Payment by Big Rivers upon lease termination. Such amounts are not recorded as utility plant or lease revenue by the Company. At December 31, 2007, the cumulative Nonincremental Capital Costs amounted to $6,618 (unaudited).

E.ON U.S completed the construction of a scrubber (Major Capital Improvement) on Big Rivers' Coleman plant. First operation at the Coleman units occurred in February 2006, while commercial acceptance occurred in January 2007. The project was completed at a cost of $97,495 (unaudited), none of which is expected to be recorded as utility plant or lease revenue under the Lease Agreement.

Depreciation of utility plant in service is recorded using the straight-line method over the estimated remaining service lives, as approved by the RUS and KPSC. The annual composite depreciation rates used to compute depreciation expense were as follows:

Electric plant-leased	1.60%–2.47%
Transmission plant	1.76%–3.24%
General plant	1.11%–5.62%

For 2007, 2006, and 2005, the average composite depreciation rates were 1.85%, 1.86%, and 1.86%, respectively. At the time plant is disposed of, the original cost plus cost of removal less salvage value of such plant is charged to accumulated depreciation, as required by the RUS.

Impairment Review of Long-Lived Assets — Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This review is performed in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS No. 144 establishes one accounting model for all impaired long-lived assets and long-lived assets to be disposed of by sale or otherwise. SFAS No. 144 requires the evaluation for impairment involve the comparison of an asset's carrying value to the estimated future cash flows the asset is expected to generate over its remaining life. If this evaluation were to conclude that the carrying value of the asset is impaired, an impairment charge would be recorded based on the difference between the asset's carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations.

Restricted Investments — Investments are restricted under contractual provisions related to the sale-leaseback transaction discussed in Note 4. These investments have been classified as held-to-maturity and are carried at amortized cost.

Cash and Cash Equivalents — Big Rivers considers all short-term, highly-liquid investments with original maturities of three months or less to be cash equivalents.

Income Taxes — As a taxable cooperative, Big Rivers is entitled to exclude the amount of patronage allocations to members from taxable income. Income and expenses related to nonmember operations are taxable to Big Rivers. Big Rivers and BRLC file a consolidated Federal income tax return and Big Rivers files a separate Kentucky income tax return.

Patronage Capital — As provided in the bylaws, Big Rivers accounts for each year's patronage-sourced income, both operating and nonoperating, on a patronage basis. Notwithstanding any other provision of the bylaws, the amount to be allocated as patronage capital for a given year shall not be less than the greater of regular taxable patronage-sourced income or alternative minimum taxable patronage-sourced income.

Derivatives — Management has reviewed the requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted, and has determined that all contracts meeting the definition of a derivative also qualify for the normal purchases and sales exception under SFAS No. 133. The Company has elected the Normal Purchase and Normal Sale exception for these contracts and, therefore, the contracts are not required to be recognized at fair value in the financial statements.

New Accounting Pronouncements — In September 2006, the FASB issued FASB Statement No. 157, *Fair Value Measurements* ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measures. It applies under other accounting pronouncements that require or permit fair value measurements and does not require any new fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating the effect that the adoption of SFAS No. 157 will have on its results of operations and financial condition and does not expect the adoption will have a significant impact on the Company.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FASB Statement No. 115*, which is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. The fair value option established by this Statement permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity shall report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option a) may be applied instrument by instrument; b) is irrevocable (unless a new election date occurs); and c) is applied only to entire instruments and not to portions of instruments. The Company does not expect to elect to record any financial assets or liabilities at fair value under this standard.

2. LG&E LEASE AGREEMENT

On July 15, 1998 ("Effective Date"), a lease was consummated ("Lease Agreement"), whereby Big Rivers leased its generating facilities to Western Kentucky Energy Corporation (WKEC), a wholly owned subsidiary of E.ON U.S. Pursuant to the Lease Agreement, WKEC operates the generating facilities and maintains title to all energy produced. Throughout the lease term, in order for Big Rivers to fulfill its obligation to supply power to its members, the Company purchases substantially all of its power requirements from LG&E Energy Marketing Corporation (LEM), a wholly owned subsidiary of E.ON U.S., pursuant to a power purchase agreement.

Big Rivers continues to operate its transmission facilities and charges LEM tariff rates for delivery of the energy produced by WKEC and consumed by LEM's customers. The significant terms of the Lease Agreement are as follows:

I. WKEC leases and operates Big Rivers' generation facilities through 2023.

II. Big Rivers retains ownership of the generation facilities both during and at the end of the lease term.

III. WKEC pays Big Rivers an annual lease payment of $30,965 over the lease term, subject to certain adjustments.

IV. On the Effective Date, Big Rivers received $69,100 representing certain closing payments and the first two years of the annual lease payments. In accordance with SFAS No. 13, *Accounting for Leases*, the Company amortizes these payments to revenue on a straight-line basis over the life of the lease.

V. Big Rivers continues to provide power for its members, excluding the member loads serving the Aluminum Smelters, through its power purchase agreements with LEM and the Southeastern Power Administration, based on a pre-determined maximum capacity. When economically feasible, the Company also obtains the power necessary to supply its member loads, excluding the Aluminum Smelters, in the open market. Kenergy Corp.'s retail service for the Aluminum Smelters is served by LEM and other third-party providers that may include Big Rivers. To the extent the power purchased from LEM does not reach pre-determined minimums, the Company is required to pay certain penalties. Also, to the extent additional power is available to Big Rivers under the LEM contract, Big Rivers may sell to nonmembers.

VI. LEM will reimburse Big Rivers an additional $58,862 for the margins expected from the Aluminum Smelters through 2011, being defined as the net cash flows that Big Rivers anticipated receiving if the Company had continued to serve the Aluminum Smelters' load, as filed in the Rate Hearing (the "Monthly Margin Payments").

VII. WKEC is responsible for the operating costs of the generation facilities; however, Big Rivers is partially responsible for ordinary capital expenditures ("Nonincremental Capital Costs") for the generation facilities over the term of the Lease Agreement, generally up to predetermined annual amounts. This cumulative amount is not expected to exceed $148,000 over the entire 25 1/2 year Lease Agreement. At the end of the lease term, Big Rivers is obligated to fund a "Residual Value Payment" to E.ON U.S. for such capital additions during the lease, currently estimated to be $125,880 (see Note 1). Adjustments to the Residual Value Payment will be made based upon actual capital expenditures. Additionally, WKEC will make required capital improvements to the facilities to comply with a new law or a change to existing law ("Incremental Capital Costs") over the lease life (the Company is partially responsible for such costs: 20% through 2010) and the Company will be required to submit another Residual Value Payment to LEC for the undepreciated value of WKEC's 80% share of these costs, at the end of the lease, currently estimated to be $16,017. The Company will have title to these assets during the lease and upon lease termination.

VIII. Big Rivers entered into a note payable with LEM for $19,676 (the "LEM Settlement Note") to be repaid over the term of the Lease Agreement, which bears interest at 8% per annum, in consideration for LEM's assumption of the risk related to unforeseen costs with respect to power to be supplied to the Aluminum Smelters and the increased responsibility for financing capital improvements. The Company recorded this obligation as a component of deferred charges with the related payable recorded as long-term debt in the accompanying balance sheets. This deferred charge is being amortized on a straight-line basis over the lease term.

IX. On the Effective Date, Big Rivers paid a nonrefundable marketing payment of $5,933 to LEM, which has been recorded as a component of deferred charges. This amount is being amortized on a straight-line basis over the lease term.

X. During the lease term, Big Rivers will be entitled to certain "billing credits" against amounts the Company owes LEM under the power purchase agreement. Each month during the first 55 months of the lease term, Big Rivers received a credit of $89. For the year 2011, Big Rivers will receive a credit of $2,611 and for the years 2012 through 2023, the Company will receive a credit of $4,111 annually.

In accordance with the power purchase agreement with LEM, the Company is allowed to purchase power in the open market rather than from LEM, incurring penalties when the power purchased from LEM does not meet certain minimum levels, and to sell excess power (power not needed to supply its jurisdictional load) in the open market (collectively referred to as "Arbitrage"). Pursuant to the New RUS Promissory Note and the RUS ARVP Note, the benefit, net of tax, as defined, derived from Arbitrage must be divided as follows: one-third, adjusted for capital expenditures, will be used to make principal payments on the New RUS Promissory Note; one-third will be used to make principal payments on the RUS ARVP Note; and the remaining value may be retained by the Company.

Management is of the opinion that the Company is in compliance with all covenants of the Lease Agreement.

The Company, LEM, and WKEC have entered into an agreement that would allow for a mutually acceptable early termination of the Lease Agreement (see Note 15).

3. UTILITY PLANT

At December 31, 2007 and 2006, utility plant is summarized as follows:

	2007	2006
Classified plant in service:		
Electric plant — leased	$ 1,524,421	$ 1,506,822
Transmission plant	209,547	208,760
General plant	15,772	15,581
Other	114	67
	1,749,854	1,731,230
Less accumulated depreciation	853,290	826,647
	896,564	904,583
Construction in progress	15,070	13,085
Utility plant — net	$ 911,634	$ 917,668

Interest capitalized for the years ended December 31, 2007, 2006, and 2005, was $391, $236, and $160 respectively.

The Company has not identified any material legal obligations, as defined in SFAS No. 143, *Accounting for Asset Retirement Obligations*, which was further interpreted by FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*. In accordance with regulatory treatment, the Company records an estimated net cost of removal of its utility plant through normal depreciation. As of December 31, 2007 and 2006, the Company had a regulatory liability of approximately $29,771 and $26,670, respectively, related to nonlegal removal costs included in accumulated depreciation.

4. SALE-LEASEBACK

On April 18, 2000, the Company completed a sale-leaseback of two of its utility plants, including the related facilities and equipment. The sale-leaseback provides Big Rivers a $1,089,000 fixed price purchase option, at the end of each lease term (25 and 27 years), which, together with future contractual interest receipts, will be fully funded.

This transaction has been recorded as a financing for financial reporting purposes and a sale for Federal income tax purposes. In connection therewith, Big Rivers received $866,676 of proceeds and incurred

$791,626 of related obligations. Pursuant to a payment undertaking agreement with a financial institution, Big Rivers effectively extinguished $656,029 of these obligations with an equivalent portion of the proceeds. The Company also purchased investments with an initial value of $146,647 to fund the remaining $135,597 of the obligations. These amounts are reflected as restricted investments under long-term lease and obligations related to long-term lease in the accompanying balance sheets. Interest received and paid will be recorded to these accounts over the life of the lease. Currently, the Company is paying 7.57% interest on its obligations related to long-term lease and receiving 6.89% on its related investments. The Company made a $64,000 principal payment on the New RUS Promissory Note with the remaining proceeds. The $75,050 gain was deferred and will be amortized over the respective lease terms, of which the Company recognized $2,900, $2,881, and $2,856, in 2007, 2006, and 2005, respectively. The following are the scheduled principal payments on the long-term lease as of December 31:

Year	Amount
2008	-
2009	5,669
2010	
2011	
2012	508
Thereafter	177,714
Total	$ 183,891

Amounts recognized in the statement of financial position related to the sale-leaseback as of December 31, 2007 and 2006, are as follows:

	2007	2006
Restricted investments under long-term lease	$ 192,932	$ 186,690
Obligations related to long-term lease	183,891	177,310
Deferred gain on sale-leaseback	53,480	56,380

Amounts recognized in the statement of operations related to the sale-leaseback for the years ended December 31, 2007, 2006, and 2005, are as follows:

	2007	2006	2005
Power contracts revenue (revenue discount adjustment — see Note 6)	$ (3,680)	$ (3,680)	$ (3,680)
Interest on obligations related to long-term lease:			
Interest expense	12,819	12,386	11,965
Amortize gain on sale-leaseback	(2,900)	(2,881)	(2,856)
Net interest on obligations related to long-term lease	9,919	9,505	9,109
Interest income on restricted investments under long-term lease	12,481	12,069	11,670
Interest income and other	778	777	772

5. DEBT AND OTHER LONG-TERM OBLIGATIONS

A detail of long-term debt at December 31, 2007 and 2006, is as follows:

	2007	2006
New RUS Promissory Note, stated amount of, $807,556, stated interest rate of 5.75%, with an interest rate of 5.81%, maturing July 2021	$ 804,098	$ 799,789
RUS ARVP Note, stated amount of $249,456, no stated interest rate, with interest imputed at 5.81%, maturing December 2023	99,290	94,391
LEM Settlement Note, interest rate of 8.0%, payable in monthly installments through July 2023	16,204	16,707
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 3.74% and 3.49% in 2007 and 2006, respectively), maturing in October 2022	83,300	83,300
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 3.74% and 3.49%% in 2007 and 2006, respectively), maturing in June 2013	58,800	58,800
Total long-term debt	1,061,692	1,052,987
Current maturities	39,347	11,912
Total long-term debt — net of current maturities	$ 1,022,345	$ 1,041,075

The following are scheduled maturities of long-term debt at December 31:

Year	Amount
2008	$ 39,347
2009	39,391
2010	41,440
2011	47,492
2012	65,561
Thereafter	828,461
Total	$ 1,061,692

RUS Notes — On July 15, 1998, Big Rivers recorded the New RUS Promissory Note and the RUS ARVP Note at fair value using the applicable market rate of 5.81%. The RUS Notes are collateralized by substantially all assets of the Company.

Pollution Control Bonds — The County of Ohio, Kentucky, issued $83,300 of Pollution Control Periodic Auction Rate Securities, Series 2001, the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate. These bonds bear interest at a variable rate and mature in October 2022.

The County of Ohio, Kentucky, issued $58,800 of Pollution Control Variable Rate Demand Bonds, Series 1983, the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate as the bonds. These bonds bear interest at a variable rate and mature in June 2013.

The Series 1983 bonds are supported by a liquidity facility issued by Credit Suisse First Boston, which was assigned to Dexia Credit in 2006. Both Series are supported by municipal bond insurance and surety policies issued by Ambac Assurance Corporation. Big Rivers has agreed to reimburse Ambac Assurance Corporation for any payments under the municipal bond insurance policies or the surety policies.

Due to current market conditions, the variable interest rates incurred on the Series 1983 and Series 2001 Pollution Control Bonds' have increased. These instruments are subject to maximum interest rates of 13% and 18%, respectively.

LEM Settlement Note — On the Effective Date, Big Rivers executed the Settlement Note with LEM. The Settlement Note requires Big Rivers to pay to LEM $19,676, plus interest at 8% per annum over the lease term. The principal and interest payment is approximately $1,822 annually. This payment is consideration for LEM's assumption of the risk related to unforeseen costs with respect to power to be supplied to the Aluminum Smelters and the increased responsibility for financing capital improvements.

Other Long-Term Obligations — During 1997, Big Rivers terminated two unfavorable coal contracts. In connection with that settlement, the Company paid $47, $345, and $351 during 2007, 2006, and 2005, respectively. At December 31, 2007, the Company has a remaining liability of $45 payable in 2008 which is included in current maturities of long-term obligations.

Notes Payable — Notes payable represent the Company's borrowing on its line of credit with the National Rural Utilities Cooperative Finance Corporation. The maximum borrowing capacity on the line of credit is $15,000. There were no amounts outstanding on the line of credit at December 31, 2007. The line of credit bears interest at a variable rate. Each advance on the line of credit is payable within one year.

6. RATE MATTERS

The rates charged to Big Rivers' members consist of a demand charge per kW and an energy charge per kWh consumed as approved by the KPSC. The rates include specific rate designs for its members' two classes of customers, the large industrial customers and the rural customers under its jurisdiction. For the large industrial customers, the demand charge is generally based on each customer's maximum demand during the current month. The remaining customers demand charge is based upon the maximum coincident demand of each member's delivery points. The demand and energy charges are not subject to adjustments for increases or decreases in fuel or environmental costs. Big Rivers' current rates will remain in effect until changed by the KPSC.

Effective since September 1, 2000, the KPSC has approved Big Rivers' request for a $3,680 annual revenue discount adjustment for its members through August 31, 2008, effectively passing the benefit of the sale-leaseback transaction (see Note 4) to them. The extent to which Big Rivers requests KPSC approval to continue the adjustment depends upon its planned environmental compliance costs and its overall financial condition. In 2008 Big Rivers plans to pursue KPSC approval to extend the adjustment, at minimum, through August 31, 2009.

7. INCOME TAXES

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an Interpretation of FASB Statement No.109 ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes by prescribing the recognition threshold a tax position is required to meet before being recognized in the financial statements. It also provides guidance on derecognition, classification, interest and penalties, disclosures and transition. The cumulative effects of applying FIN 48 are to be recorded as an adjustment to retained earnings as of the beginning of the period of adoption. FIN 48 was effective for fiscal years beginning after December 15, 2006. The Company adopted the provisions of FIN 48 on January 1, 2007. The Company files a federal income tax return, as well as several state income tax returns. The years currently open for federal tax examination are 2004 through 2007 and 1990 through 1997, due to unused net operating loss carryforwards. The major state tax jurisdiction currently open for tax examination is Kentucky for years 2001 through 2007 and years 1990 through 1997, also due to unused net operating loss carryforwards. As a result of implementing FIN 48, the Company made no adjustment to the liability for unrecognized tax benefits. The Company did not have any unrecognized tax benefits recorded related to federal or state income taxes. Upon adoption of FIN 48, the Company adopted a financial statement policy of classification of interest and penalties as an operating expense on the income statement and accrued expense in the balance sheet. No interest or penalties have been recorded as of the adoption or during 2007.

The components of the net deferred tax assets as of December 31, 2007 and 2006, were as follows:

	2007	2006
Deferred tax assets:		
Net operating loss carryforward	$ 60,972	$ 68,696
Alternative minimum tax credit carryforwards	5,035	4,790
Sale-leaseback	142,807	136,598
Fixed asset basis difference	7,764	-
Other accruals	2,844	2,465
Total deferred tax assets	219,422	212,549
Deferred tax liabilities:		
Lease agreement	(27,359)	(21,270)
Fixed asset basis difference	-	(827)
Total deferred tax liabilities	(27,359)	(22,097)
Net deferred tax asset (prevaluation allowance)	192,063	190,452
Valuation allowance	(187,028)	(185,662)
Net deferred tax asset	$ 5,035	$ 4,790

Big Rivers was formed as a tax-exempt cooperative organization described in Internal Revenue Code Section 501(c)(12). To retain tax-exempt status under this section, at least 85% of the Big Rivers' receipts must be generated from transactions with the Company's members. In 1983, sales to nonmembers resulted in Big Rivers failing to meet the 85% requirement. Until Big Rivers can meet the

85% member income requirement, the Company is a taxable cooperative. Big Rivers is also subject to Kentucky income tax.

Under the provisions of SFAS No. 109, *Accounting for Income Taxes*, Big Rivers is required to record deferred tax assets and liabilities for temporary differences between amounts reported for financial reporting purposes and amounts reported for income tax purposes. The Company has not recorded any income tax expense for the years ended December 31, 2007, 2006, and 2005, as the Company has utilized federal net operating losses to offset any taxable income during those years. Had the Company not had the benefit of a net operating loss carryforward, the Company would have recorded $7,724, $10,599, and $7,995 in current tax expense for the years ended December 31, 2007, 2006, and 2005, respectively. Deferred tax assets and liabilities are determined based upon these temporary differences using enacted tax rates for the year in which these differences are expected to reverse. Deferred income tax expense or benefit is based on the change in assets and liabilities from period to period, subject to an ongoing assessment of realization.

A reconciliation of the Company's effective tax rate for 2007, 2006 and 2005 follows:

Federal rate	35.0 %	35.0 %	35.0 %
State rate, net of federal benefit	4.5	4.5	4.5
Patronage allocation to members	(28.0)	(20.5)	(21.7)
Tax benefit of operating loss carryforwards and other	(11.5)	(19.0)	(17.8)
Effective tax rate	0.0 %	0.0 %	0.0 %

At December 31, 2007 and 2006, Big Rivers had a nonpatron net operating loss carryforward of approximately $148,713 and $167,551, respectively, for tax reporting purposes expiring through 2014, and an alternative minimum tax credit carryforward at December 31, 2007 and 2006, of approximately $5,035 and $4,790, respectively, which carries forward indefinitely.

Big Rivers has a net deferred tax asset, against which a valuation allowance has been provided based upon the fact that it is presently uncertain whether such asset will be realized. The resulting net deferred tax asset at December 31, 2007 and 2006, is approximately $5,035 and $4,790, respectively, which represents the alternative minimum tax credit carryforward, against which no allowance has been provided.

8. POWER PURCHASED

In accordance with the Lease Agreement, Big Rivers supplies all of the members' requirements for power to serve their customers, other than the Aluminum Smelters. Contract limits were established in the Lease Agreement and include minimum and maximum hourly and annual power purchase amounts. Big Rivers cannot reduce the contract limits by more than 12 MW in any year or by more than a total of 72 MW over the lease term. In the event Big Rivers fails to take the minimum requirement during any hour or year, Big Rivers is liable to LEM for a certain percentage of the difference between the amount of power actually taken and the applicable minimum requirement.

Although Big Rivers will be required by the Lease Agreement to purchase minimum hourly and annual amounts of power from LEM, the lease does not prevent Big Rivers from paying the associated penalty in certain hours to purchase lower cost power, if available, in the open market or reselling a portion of its purchased power to a third party. The power purchases made under this agreement for the years ended December 31, 2007, 2006, and 2005, were $96,295, $97,999, and $96,795, respectively, and are included in power purchased and interchanged on the statement of operations.

9. PENSION PLANS

Big Rivers has noncontributory defined benefit pension plans covering substantially all employees who meet minimum age and service requirements. The plans provide benefits based on the participants' years of service and the five highest consecutive years' compensation during the last ten years of employment. Big Rivers' policy is to fund such plans in accordance with the requirements of the Employee Retirement Income Security Act of 1974.

On December 31, 2007, the Company adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158"). SFAS No. 158 required the Company to recognize the funded status of its pension plans and other postretirement plans (see Note 11 - Postretirement Benefits Other Than Pensions). SFAS No. 158 defines the funded status of a defined benefit pension plan as the fair value of its assets less its projected benefit obligation, which includes projected salary increases, and defines the funded status of any other postretirement plan as the fair value of its assets less its accumulated postretirement benefit obligation.

SFAS No. 158 also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet and requires disclosure in the notes to the financial statements certain additional information related to net periodic benefit costs for the next fiscal year. The Company's pension and other postretirement benefit plans are measured as of December 31, 2007 and 2006.

The following provides an overview of the Company's noncontributory defined benefit pension plans.

A reconciliation of the Company's benefit obligations of its noncontributory defined benefit pension plans at December 31, 2007 and 2006 follows:

	2007	2006
Benefit obligation, beginning of period	$ 17,464	$ 16,550
Service cost - benefits earned during the period	958	838
Interest cost on projected benefit obligation	1,058	926
Benefits paid	(124)	(852)
Actuarial (gain) or loss	533	2
Benefit obligation, end of period	$ 19,889	$ 17,464

The accumulated benefit obligation for all defined benefit pension plans was $14,789 and $12,421 at December 31, 2007 and 2006, respectively.

A reconciliation of the Company's pension plan assets at December 31, 2007 and 2006 follows:

	2007	2006
Fair value of plan assets, beginning of period	$ 16,416	$ 11,868
Actual return on plan assets	1,006	716
Employer contributions	4,522	4,684
Benefits paid	(124)	(852)
Fair value of plan assets, end of period	$ 21,820	$ 16,416

The funded status of the Company's pension plans at December 31, 2007 and 2006 follows:

	2007	2006
Benefit obligation, end of period	$ (19,889)	$ (17,464)
Fair value of plan assets, end of period	21,820	16,416
Funded status	$ 1,931	$ (1,048)

Components of net periodic pension costs for the years ended December 31, 2007, 2006, and 2005, were as follows:

	2007	2006	2005
Service cost	$ 958	$ 838	$ 824
Interest cost	1,058	926	931
Expected return on plan assets	(1,167)	(828)	(840)
Amortization of prior service cost	19	19	19
Amortization of actuarial (gain) or loss	285	212	224
Net periodic benefit cost	$ 1,153	$ 1,167	$ 1,158

A reconciliation of the pension plan amounts in accumulated other comprehensive income at December 31, 2007 follows:

	2007
Prior service cost	$ (97)
Unamortized actuarial gain/(loss)	(4,861)
Accumulated other comprehensive income	$ (4,958)

In 2008, $13 of prior service cost and $29 of actuarial loss is expected to be amortized to periodic benefit cost.

At December 31, 2006, the unrecognized prior service cost was $116 and the unrecognized actuarial loss was $4,452. These amounts net of the funded status were recorded as a prepaid benefit cost of $3,520 in the statement of financial position.

At December 31, 2007 and 2006, amounts recognized in the statement of financial position were as follows:

	2007	2006
Prepaid Benefit cost	$ -	$ 3,520
Noncurrent assets	1,931	-
Net amount recognized	$ 1,931	$ 3,520

Assumptions used to develop the projected benefit obligation and determine the net periodic benefit cost were as follows:

	2007	2006	2005
Discount rate - projected benefit obligation	6.25 %	5.75 %	5.75 %
Discount rate - net periodic benefit cost	5.75	5.75	5.75
Rates of increase in compensation levels	4.00	4.00	4.00
Expected long-term rate of return on assets	7.25	7.25	7.25

The expected long-term rate of return on plan assets for determining net periodic pension cost for each fiscal year is chosen by the Company from a best estimate range determined by applying anticipated long-term returns and long-term volatility for various asset categories to the target asset allocation of the plans, as well as taking into account historical returns.

Using the asset allocation policy adopted by the Company noted in the paragraph below, we determined the expected rate of return at a 50% probability of achievement level based on (a) forward-looking rate of return expectations for passively-managed asset categories over a 20-year time horizon and (b) historical rates of return for passively-managed asset categories. Applying an approximately 80%/20% weighting to the rates determined in (a) and (b), respectively, produced an expected rate of return of 7.28%, which was rounded to 7.25%.

The general investment objectives are to invest in a diversified portfolio, comprised of both equity and fixed income investments, which are further diversified among various asset classes. The diversification is designed to minimize the risk of large losses while maximizing total return within reasonable and prudent levels of risk. The investment objectives specify a targeted investment allocation for the pension plans of up to 65% equities. The remaining 35% may be allocated among fixed income or cash equivalent investments. Objectives do not target a specific return by asset class. These investment objectives are long-term in nature. As of December 31, 2007 and 2006, the investment allocation was 49% and 0%, respectively, in equities and 51% and 100%, respectively, in fixed income.

Expected retiree pension benefit payments projected to be required during the years following 2007 are as follows:

Years Ending December 31	Amount
2008	$ 1,258
2009	846
2010	1,495
2011	1,326
2012	2,471
2013–2017	12,528
Total	$ 19,924

In 2008, the Company expects to contribute $1,010 to its pension plan trusts.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying value of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to their short maturity.

The fair value of restricted investments is determined based upon quoted market prices and rates. The carrying value of the investments is recorded at accreted value and the terms of the investment are within Note 4. The estimated fair values of the restricted investments are as follows:

	2007		2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Restricted investments	$ 192,932	$ 250,088	$ 186,690	$ 233,418

It was not practical to estimate the fair value of patronage capital included within other deposits and investments due to these being untraded companies.

It was not practical to estimate the fair value of long-term debt due to Big Rivers' inability to obtain long-term debt from outside parties.

11. POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

Big Rivers provides certain postretirement medical benefits for retired employees and their spouses. As of July 1, 2001, Big Rivers pays 85% of the cost from age 62 to 65 for all retirees. For salaried employees who retired prior to December 31, 1993, Big Rivers pays 100% of Medicare supplemental costs. For salaried employees who retire after December 31, 1993, Big Rivers pays 25% plus $25 per month of the Medicare supplemental costs.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act") was enacted. The Medicare Act created Medicare Part D, a new prescription drug benefit that is available to all Medicare-eligible individuals, effective January 1, 2006. National Rural Electric Cooperative Association (NRECA), the provider of Big Rivers' health plan coverage through the NRECA Group Benefits Trust, chose to become a Medicare Part D provider. Effective January 1, 2006, Part D coverage is the only drug coverage available to Big Rivers' Medicare-eligible retirees.

The discount rates used in computing the postretirement benefit obligation and net periodic benefit cost were as follows:

	2007	2006	2005
Discount rate - projected benefit obligation	5.85 %	5.75 %	5.75 %
Discount rate - net periodic benefit cost	5.75	5.75	6.25

The health care cost trend rate assumptions as of December 31, 2007 and 2006 were as follows:

	2007	2006
Initial trend rate	9.00 %	9.00 %
Ultimate trend rate	5.50 %	5.50 %
Year ultimate trend is reached	2012	2011

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	2007	2006
One-Percentage-Point Decrease		
Effect on total service and interest cost components	$ (28)	$ (32)
Effect on year end benefit obligation	(268)	(254)
One-Percentage-Point Increase		
Effect on total service and interest cost components	$ 34	$ 38
Effect on year end benefit obligation	313	296

A reconciliation of the Company's benefit obligations of its postretirement plan at December 31, 2007 and 2006 follows:

	2007	2006
Benefit obligation, beginning of period	$ 2,695	$ 2,578
Service cost - benefits earned during the period	85	145
Interest cost on projected benefit obligation	153	143
Participant contributions	45	61
Benefits paid	(170)	(232)
Actuarial (gain) or loss	54	-
Benefit obligation, end of period	$ 2,862	$ 2,695

A reconciliation of the Company's postretirement plan assets at December 31, 2007 and 2006 follows:

	2007	2006
Fair value of plan assets, beginning of period	$ -	$ -
Employer contributions	125	171
Participant contributions	45	61
Benefits paid	(170)	(232)
Fair value of plan assets, end of period	$ -	$ -

The funded status of the Company's postretirement plan at December 31, 2007 and 2006 follows:

	2007	2006
Benefit obligation, end of period	$ (2,862)	$ (2,695)
Fair value of plan assets, end of period	-	-
Funded status	$ (2,862)	$ (2,695)

The components of net periodic postretirement benefit costs for the years ended December 31, 2007, 2006, and 2005, were as follows:

	2007	2006	2005
Service cost	$ 85	$ 145	$ 94
Interest cost	153	143	182
Amortization of prior service cost	2	2	2
Amortization of actuarial (gain) or loss	(70)	(80)	(23)
Amortization of transition obligation	31	31	31
Net periodic benefit cost	$ 201	$ 241	$ 286

A reconciliation of the postretirement plan amounts in accumulated other comprehensive income at December 31, 2007 follows:

	2007
Prior service cost	$ (9)
Unamortized actuarial gain/(loss)	1,177
Transition obligation	(153)
Accumulated other comprehensive income	$ 1,015

In 2008, $2 of prior service cost, $64 of actuarial gain, and $31 of the transition obligation is expected to be amortized to periodic benefit cost.

At December 31, 2006, the unrecognized prior service cost was $11, unrecognized accumulated gain was $1,287, and unrecognized transition obligation was $184. These amounts net of the funded status were recorded as a noncurrent liability of $3,787 in the statement of financial position.

At December 31, 2007 and 2006, amounts recognized in the statement of financial position were as follows:

	2007	2006
Accounts payable	$ (138)	$ -
Other deferred credits	(2,724)	(3,787)
Net amount recognized	$ (2,862)	$ (3,787)

Expected retiree benefit payments projected to be required during the years following 2007 are as follows:

Year	Amount
2008	$ 138
2009	168
2010	194
2011	212
2012	224
2013–2017	1,325
Total	$ 2,261

In addition to the postretirement plan discussed above, in 1992 Big Rivers began a postretirement benefit plan which vests a portion of accrued sick leave benefits to salaried employees upon retirement or death. To the extent an employee's sick leave hour balance exceeds 480 hours such excess hours are paid at 20% of the employee's base hourly rate at the time of retirement or death. The accumulated obligation recorded for the postretirement sick leave benefit is $345 and $294 at December 31, 2007 and 2006, respectively. The postretirement expense recorded was $51, $44, and $27 for 2007, 2006, and 2005, respectively, and the benefits paid were $0, $20, and $16 for 2007, 2006, and 2005, respectively.

12. BENEFIT PLAN — 401(k)

Big Rivers has two defined contribution retirement plans covering bargaining and salaried employees. Big Rivers matches up to 60% of the first 6% of eligible employees' wages contributed. Employees generally become vested in Company matching contributions based upon years of service as follows:

Years of Vesting Service	Vested Percentage
1	20 %
2	40
3	60
4	80
5 or more	100

Employees are also permitted to make pre-tax contributions of up to 75% of eligible wages. Big Rivers' expense under this plan was $215 and $193 for the years ended December 31, 2007 and 2006, respectively.

13. RELATED-PARTIES

For the years ended December 31, 2007, 2006, and 2005, Big Rivers had tariff sales to its members of $113,281, $108,737, and $109,439, respectively. In addition, for the years ended December 31, 2007, 2006, and 2005, Big Rivers had certain sales to Kenergy for the Aluminum Smelters and Domtar Paper (formerly Weyerhaeuser) loads of $123,094, $57,374, and $46,372, respectively.

At December 31, 2007 and 2006, Big Rivers had accounts receivable from its members of $20,052 and $13,015, respectively.

In October 2005, Big Rivers made a lump sum payment of $221 to Kenergy for the lease of office space in a building owned by Kenergy. The charge for the lump sum payment was deferred and is being amortized over the life of the agreement.

14. COMMITMENTS AND CONTINGENCIES

Big Rivers is involved in litigation arising in the normal course of business. While the results of such litigation cannot be predicted with certainty, management, based upon advice of counsel, believes that the final outcome will not have a material adverse effect on the financial statements.

15. TERMINATION OF THE LG&E LEASE AGREEMENT

The Big Rivers board of directors adopted resolutions on February 23, 2007, authorizing management, among other things, to execute a Transaction Termination Agreement among Big Rivers Electric Corporation, LG&E Energy Marketing Inc., and Western Kentucky Energy Corp. (the "Termination Agreement"). The Termination Agreement establishes the terms on which Big Rivers, on the one hand, and LG&E Energy Marketing Inc. and Western Kentucky Energy Corp. on the other hand, agree to terminate a series of contractual relationships established in 1998 under which, among other things, LG&E Energy Marketing Inc. and Western Kentucky Energy Corp. currently lease and operate the generating units owned or previously operated by Big Rivers, and sell power to Big Rivers to use in meeting the requirements of its system. Those resolutions additionally authorize management to sign various agreements under which Big Rivers agrees to sell its member, Kenergy Corp., 850 MW in the aggregate for resale to Alcan Primary Products Corporation and Century Aluminum of Kentucky General Partnership, contingent upon the closing of the transaction contemplated in the Termination Agreement. Applications seeking the necessary state regulatory approvals and tariff revisions required to implement these transactions were filed with the Kentucky Public Service Commission on December 28, 2007, in P.S.C. Case Nos. 2007-00455 and 2007-00460.

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BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S
INITIAL INFORMATION REQUESTS
PSC CASE NO. 2007-00455
(May 30, 2008)

Item 37) Please reference the testimony of C. William Blackburn, page 19, lines 5-7, consent fees, "discussions with those creditors remain ongoing". Provide all documents to and from Big Rivers' creditors regarding consent fees, restructure of debt to accomplish and support the Unwind Transaction, etc.

Response) See attached chart.

Witness) C. William Blackburn

Unwind Consent and Transaction Fees

$ (000's)

	Big Rivers	E.ON US	Smelters	Total
Ambac				
Consent Fee	1,000	1,000	1,000	3,000
Transaction Costs	58	58	58	175
Bank of America				
Consent Fee	1,000	4,000	1,000	6,000
Transaction Costs	33	33	33	100
PMCC				
Consent Fee	-	-	-	-
Transaction Costs		2,000		2,000
Year 1 Letter of Credit Costs (1)		2,000		2,000
HMP&L				
Consent Fee	-	2,000	-	2,000
Transaction Costs	467	467	467	1,400
RUS				
Consent Fee				-
Transaction Costs				-
Big Rivers' Transaction Costs				
Cumulative Cost	8,851	18,998		27,849
May 2008 Through July 31 Closing	6,256	-	-	6,256
Other Creditors				
Consent Fee				-
Transaction Costs	40			40
Unit Capacity Tesing	150	150		300
IT Vendors				
Consent Fee				-
Transaction Costs	1,300	2,771		4,071
TOTAL	19,155	33,477	2,558	55,191

(1) Letter of credit costs continue through 2027 - this represents only year 1 costs

Item 60) Please reference the testimony of Mark W. Glotfelty, pages 4-6, regarding "key credit factors the rating agencies will focus".

a. State the extent to which the list of factors presented here is a complete and total list. If not, state and describe any other factors the ratings agencies will likely focus on.

b. State whether the ratings agencies will also focus on leverage rations, e.g., not debt/EBITDA.

c. Provide any documents to which you have access which provide and describe the ratings agencies' (e.g., Moody's, S&P, Fitch) key credit ratings factors and methodologies for determining credit ratings for:

i. Utilities;
ii. Electric distribution companies; and
iii. Generation and Transmission companies.

Response) In response to an inquiry at the May 15, 2008, Informal Conference, Big Rivers supplements its response to this information request as follows:

There are many factors the rating agencies will consider when assigning a rating to Big Rivers. A primary factor will be the Unwind Financial Model, which the rating agencies will rely on for the projection of how Big Rivers will perform financially post Unwind. The rating agencies will focus on the assumptions used in the financial model, and make their own assessment as to the reasonableness of each assumption. It is very important to the rating process that all of Big Rivers' stakeholders have reviewed the Unwind Financial Model and the assumptions, and are comfortable that Big Rivers can meet or exceed its financial projections. Anything short of a united endorsement by Big Rivers' stakeholders of the financial forecast will likely be viewed as a negative, will likely generate additional inquiries and could potentially adversely impact the rating. Should the Commission approve the Unwind but be critical of the Financial Model, Big Rivers believes it will raise some concerns for the rating agencies to consider in their evaluations.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE ATTORNEY GENERAL'S
INITIAL INFORMATION REQUESTS
PSC CASE NO. 2007-00455
(May 30, 2008)

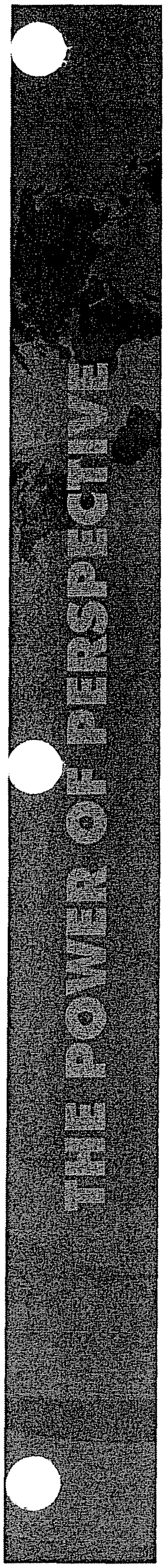
Item 64) Please reference the testimony of David A. Spainhoward, page 13, line 4 at "Big Rivers projects that it will realize $14.487 million in revenues from the sale of excess 2008 SO_2 allowances, with this amount declining to $4.065 million for 2012 SO_2 allowances".

a. Provide workpapers and associated supporting documents to support these estimations.

b. Please state the extent to which the estimated declining revenues can be characterized by Big Rivers as "best case", "worst case", or "base case".

Response) As an update to the Attorney General's First Data Request Item 64, Big Rivers is attaching its most recent Global Insight forecast.

Witness) C. William Blackburn



GLOBAL INSIGHT

Price Outlook for Coal Delivered to BREC Plants

Prepared for:
Big Rivers Energy Company

Prepared by:
Global Insight, Inc.
Global Energy Services

April 2008

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Price Outlook for Coal Delivered to BREC Plants

This report provides a forecast of delivered coal prices to the various BREC plants and describes the rationale behind their trends. The report also contains projections of SO2 and NOx prices.

Background: Pressure from the International Coal Sector

In a rare occurrence, much of the pressure on the US coal industry this year is coming from the international arena. For a country that exports only about 0.5% of its coal production, that may appear to be something of an anomaly, but US coal supplies are sufficiently tight that even small changes in demand can create upward price pressures.

The crisis in the global coal industry that is being felt in the US derives from two sources. The first cause, that of high international demand for coal, is well-known. China has cut back on its exports in order to serve increasingly higher coal demand within its own borders and is moving closer to the point of becoming a net importer. India, in spite of being the third largest coal producer in the world, continues to fall short of its goal of self-sufficiency and relies to a considerable degree on imports, particularly of met quality coal. Expanding demand elsewhere in the developing world is further fueling this situation.

The second source of international pressure stems from supply side problems. The long-standing port congestion in Australia and high ocean freight rates have now been supplemented by a host of other problems that arrived early in 2008, including (but not limited to) idled loaders at Richards Bay (South Africa), insufficient train sets in western Colombia to carry (predominantly met) coal to ports, and flooding in Australia causing *force majeure* by 6 companies. With regard to Australia, that flooding has resulted in the permanent loss of about 20 million tons of 2008 scheduled production.

This situation is further complicated by high ocean freight rates that have played an enormous role in severely limiting competition in the Atlantic area. Normally, there is a small deficit among Atlantic Basin producers (South Africa, Colombia, Venezuela, Poland, and part of Russia) in meeting Atlantic Basin demand (largely from Europe). The difference is normally made up by production from Pacific Basin producers (historically Australia, and more recently Indonesia). The delivered cost in Europe from these Pacific sources usually sets the price of coal for the entire Atlantic Basin, but over the last decade the difference between that delivered price and the Atlantic Basin coal delivered to Europe has been quite small (averaging about $2/metric ton), so the impact on the market has been negligible. As freight rates began their dramatic rise in mid-2003, the replacement price escalated dramatically. The average freight rate differential between July 2003 and the summer of 2007 rose to $7/mt, and by the end of the year had skyrocketed to over $20/mt. The impact of this rising rate was that it allows the producers in the Atlantic region to effectively raise their fob prices to the level where their delivered price to Europe is at or just below the now elevated Australian and Indonesian price into the Atlantic.

The final dimension of this unusual international pressure on US markets is explained by yet two additional factors. First, the supply tightness in the Pacific Rim (caused by both high demand and producer difficulties there) has severely eroded the historic surplus that this region always shipped to the Atlantic Basin. This, in turn, has forced European buyers to look to the United States. The rapid decline in the value of the dollar has facilitated this development (from the vantage point of the Europeans) by offsetting much of the rising price of coal delivered to Europe by the fact that the Euro is worth an increasing number of dollars as the dollar falls in value.

The weak dollar has made steam exports from the eastern US highly attractive into Europe, helping pare down excess inventories in the East. The flight of coal from the East to meet international demand is aggravated further by the high demand for US metallurgical coal on a global scale, with some shipments even going to India. This has attracted coal from Central Appalachia (typically low vol) and from Northern Appalachia (typically high vol) away from the US steam market into the much more lucrative met market, where prices of high quality lo vol coal are now close to $300/mt. Even the Illinois Basin and western US basins are finding buyers in the export market, but they are similarly being drawn to power plants in the eastern US to replace the Appalachian coal heading to Europe.

Supply

The Illinois Basin, the source of coals for BREC, is in a state of transition. After having lost over one-third of its production since 1990, registering a 52 million ton decline down to about 89 million tons, output has begun to improve. Production reached over 95 million in both 2006 and 2007.

The cause for the decline in Illinois Basin coal production was due both to tighter environmental standards and to strong competitive pressure from the Powder River Basin. Increasingly more stringent SO2 standards under the Acid Rain legislation implemented first in 1995 made it increasingly difficult to meet those standards using the higher sulfur coal that dominates this basin. At the same time, however, the standards were not so restrictive as to mandate FGD use. As a result, the low BTU but very low sulfur coal from the PRB made significant inroads into the traditional Illinois Basin market areas. Similarly, much of the Illinois Basin coal used in the Southeast was displaced by low sulfur Central Appalachian coal.

The major driver for higher production in the future from the Illinois Basin has long been understood to be the massive FGD retrofits which began in 2006 and are gaining more momentum. In addition, as noted in the section above, the Illinois Basin is one of the locations trying to provide replacement coal for eastern coals moving to the export market. Thus far in 2008, production in the Illinois Basin is about 2.9% above 2007. Most of the increase is coming from western Kentucky (about 1 million tons), while Indiana and Illinois are canceling each other out (the former is up by about 730 thousand tons, the latter down by about 850 thousand tons).

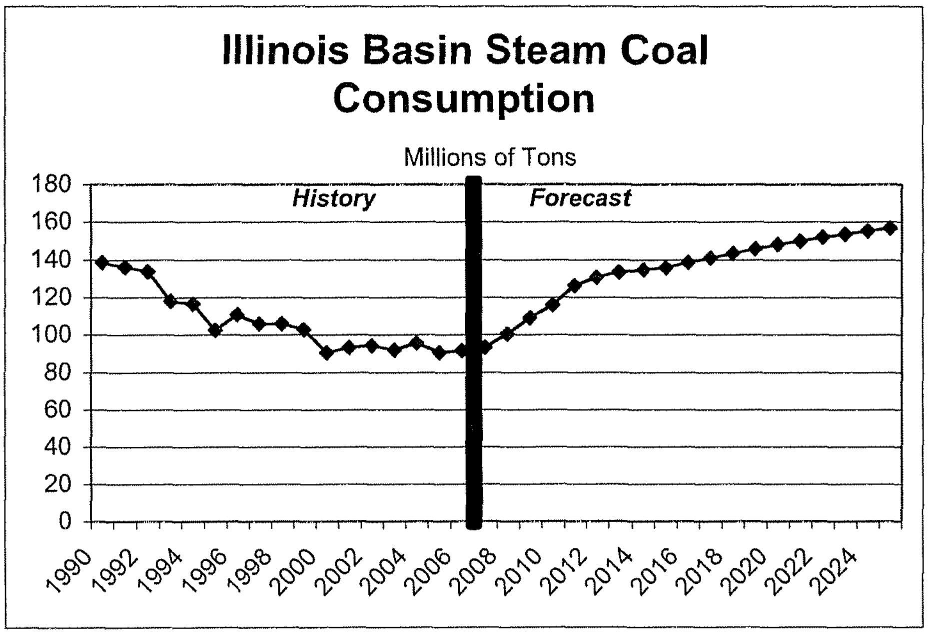
There is considerable new mine activity in the Illinois Basin, most of it in Illinois. Alliance Resource Partners broke ground on the new River View mine late last year and hopes to produce about 6.4 million tons-per-year (mmtpy) by 2011. It has also added a fifth continuous miner at the Warrior mine and plans to build the new Gibson South mine. Chris Cline's Pond Creek is looking to move from 1.1mmtpy to 7mmtpy, while plans other mines are underway (e.g., Deer Run, Sugar Camp, and Locust Grove).

In spite of these additions, oversupply does not appear to be a problem. There have been a number of mine closures---Monterey, Wabash and Crown 2---although in part these were due to the declining need for non-scrubbing coal (Monterey was a low sulfur mine, Wabash a mid-sulfur mine).

As noted in the next section, Global Insight foresees a considerable increase in Illinois Basin coal production over the forecast period. There is a likely preference for much of this demand to be directed towards the western Kentucky mines, for two reasons. First, they are in closer proximity (than Illinois coal) to many of the plants likely to use Illinois Basin coal. Second, the lower chlorine content of the western Kentucky coal (compared to Illinois coal) renders that coal a more suitable match for units not designed for the higher chlorine coal from this region.

Demand

As noted above, much of the higher demand for Illinois Basin coal is anticipated to result from the large number of FGD retrofits now in progress. Already, companies such as Duke and Dayton Power & Light have moved away from sourcing their coal out of Central Appalachia to opt instead for Illinois Basin producers. All in all, Global Insight is now estimating that about 85GW of retrofits will have occurred between 2006-2010, with another 30GW scheduled by 2015. This translates into about two-thirds of the entire coal-fired generating fleet being scrubbed by that latter date.



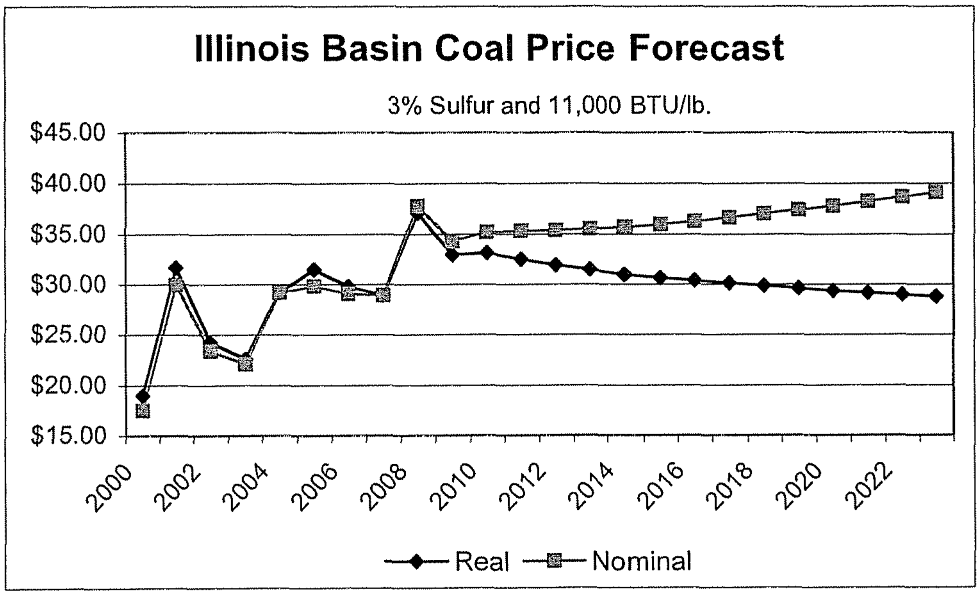
Higher demand in the short-term is stemming from the international pressures discussed at the outset of this section. The Illinois Basin has only rarely exported coal in the past, and in spite of the strong interest, we do not expect this region to send more than about 4 million tons abroad this year. The primary opportunity for Illinois Basin coal in this regard will come as producers from this region try to fill gaps left in the East, largely by Northern Appalachian coal being shipped overseas for both steam and met purposes.

Pricing

Coal prices for the Illinois Basin high sulfur coal used in most of the BREC plants have, as is the case with most other coals, surged since the beginning of 2008. While this forecast reflects an average price of $38/ton for the year for a 3% sulfur 11,000 BTU/lb. coal, the price at the beginning of the year was slightly below $30/ton and is now well into the $45-$50 range.

There is a widespread perception (at least among coal companies) that the price pressures on the US coal market caused by the international situation will remain with us for many years to come. There are strong reasons why this could occur, including the weak dollar, the seeming inability of the Australians to improve their port situation, and the relentless demand of developing countries for coal.

At the same time, Global Insight perceives that the US coal market could see prices decline by this summer or next year. Uncertainty among key variables in the situation remains high, holding out the prospect that demand for US coal could falter badly. The US dollar will probably weaken again given the April 30th rate cut by the Fed, but this looks to be the end of such moves and we in fact expect the dollar to strengthen over the next year or two. Global demand for virtually everything is still strong, but economists continue to debate whether or not international economies---the source of much of the higher coal pricing we have seen--- might retreat in the face of a US economic slowdown. A major decline in ocean freight rates could introduce significantly stronger competition in European coal markets, leading to falling mine prices. Finally, and perhaps most importantly, a significant retrenchment in the US economy could result in another inventory buildup on top of the more-than-adequate supply most power companies already have today.



Global Insight is anticipating that prices will decline modestly over the long-term for the benchmark 3% sulfur coal. The major driver in the short-run will be the easing in the market that occurs as international pressures begin to lessen. Over the longer-term, the strong level of investment, both in upgrading existing mines as well as a large number of new mine openings with state-of-the-art mining equipment, will permit a significant improvement in mine productivity in the region, allowing the selling cost to decline (in real terms) along with costs but concurrently allowing producers a strong profit margin.

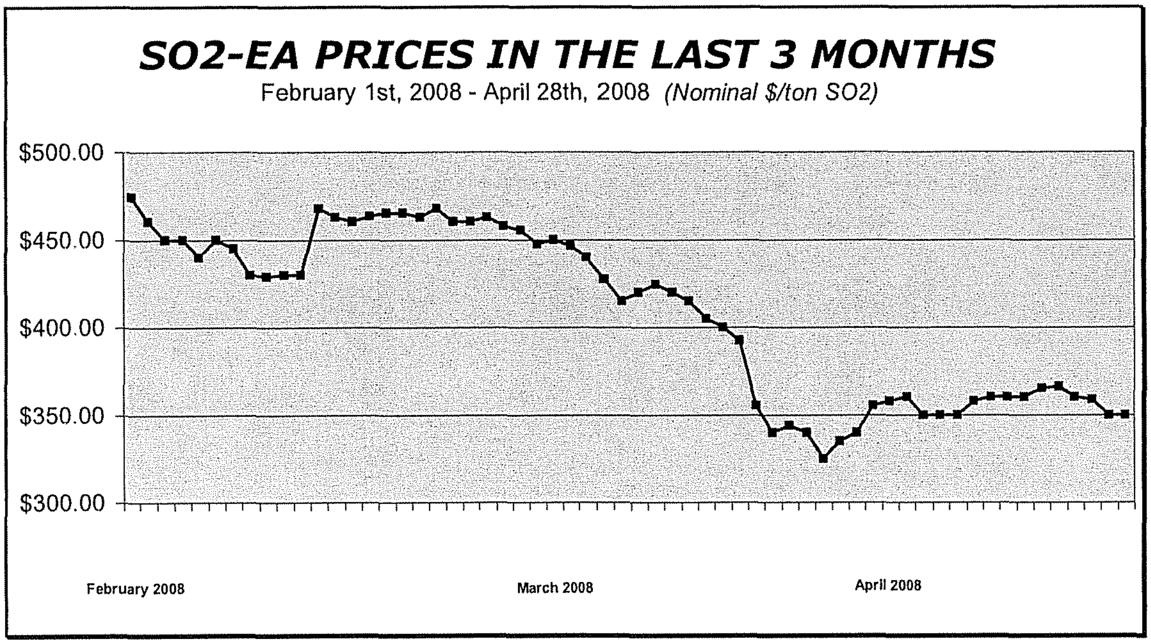
Delivered Coal Prices

The tables for each of the plants are included in the Appendix.

SO2 Prices

The Short-term SO2 Outlook

The SO2 market continued to trade below $400/ton for the entire month of April, at low prices not seen in a number of years. The spot market had been trading in the mid-$400/ton range for much of 2008 before prices plummeted after EPA's Annual SO2 auction in late March into the mid-$300/ton range. Current year vintage allowances entered the month on April 1st trading at $340/ton before gradually drifting higher late in the month to end on April 28th at $350/ton, down slightly from its April high of $366/ton reached on April 22nd.



The SO2 market has maintained a slight, but gradual recovery now since reaching a post-auction low of $325/ton on April 2nd, suggesting that the market has probably reached its short term floor. Global Insight strongly believes that allowances are significantly undervalued at these prices with the marginal cost of scrubbing closer to $700-800/ton. The actions this month of Constellation Energy, one of the larger naturals in the market, suggests that it agrees the market is underpriced. Constellation was a major player in last month's auction, picking up 27,500 allowances, and since then has remained active in the market, purchasing an additional 36,625 spot allowances this month along with 50,000 vintage 2010 allowances. A number of smaller naturals have also stepped into the market to take advantage of the lower prices, such as South Carolina Electric & Gas and DTE Coal Services, but have come away with far fewer allowances than behemoth Constellation.

That said, activity in the spot market still remains relatively tepid overall, likely on account of continued regulatory uncertainty on a number of fronts combined with very little demand from compliance-buyers for current year vintage allowances.

In the Shadow of Mercury, CO2, and CAIR

The relatively low level of activity in the spot SO2 market results from a combination of factors. First, naturals have relatively little concern about meeting their obligations under the Acid Rain Program for 2008 as the industry is on pace to fall within the SO2 cap again this year (preliminary 1st Quarter numbers show SO2 levels already down 6.8% for the year versus the same period in 2007) after emitting fewer than 9 million tons of SO2 for the first time in 2007. On top of this, the industry has a bank of nearly 6.8 million allowances to fall back on for compliance. In short, market fundamentals are on solid ground.

On the other hand, regulatory uncertainty looms large over the SO2 market in a number of areas: mercury, CO2, and CAIR. What ultimately happens with these three issues will significantly impact the direction of the SO2 market as participants face decisions over FGD retrofit and the degree to which they will rely on coal-fired generation to meet demand.

Mercury…
Global Insight has been closely following the legal maneuvers concerning mercury regulation, particularly in response to the decision of the D.C. Circuit Court of Appeals in February to vacate the Bush Administration's Clean Air Mercury Rule (CAMR). With a petition for a re-hearing *en banc* of the CAMR decision already filed, the D.C. Circuit Court of Appeals is expected to make a decision within the next month on whether or not to re-hear the case before the entire court.

If the court agrees to re-hear the case, CAMR will immediately become active again pending the court's new decision. At the same time, EPA may also choose to appeal the lower court's decision to the U.S. Supreme Court. This *may* be done concurrently with the petition for a re-hearing, but *must* be done within 90 days of the lower court either denying the petition for a re-hearing or issuing a new decision after re-hearing the case.

The timing of these legal proceedings should be of great interest to our clients and the industry at large for a number of reasons. Effective immediately, in the void left by CAMR, the industry now faces a nebulous requirement to conduct a MACT analysis before constructing any new coal-fired power plant. If this requirement were not troublesome enough, matters are complicated by general uncertainty over what precisely constitutes MACT for mercury removal.

In the absence of CAMR, EPA's December 2000 decision to classify mercury as an air toxic under Section 112 of the Clean Air Act now governs the industry. The problem is that while EPA conducted public hearings earlier this decade to develop MACT guidelines for mercury, the agency never finalized its rule. It is unclear whether EPA intends to continue its previously started rule-making process (which Global Insight notes fails to take into account the rapid adoption rate of FGD technology in recent years) to finalize a MACT rule, or whether it plans to re-start the process and issue a schedule for new public hearings. If EPA were to continue with its previously started rule-making, the agency could likely promulgate a MACT standard in a matter of months, but the rule would be susceptible to legal challenges for relying on outdated baseline measurements. On the other hand, a new rule-making process would require a new detailed baseline survey of the industry to determine the Top 12% of plant performers and a new round of public hearings in a process that would necessarily last a number of years.

This uncertainty is already having a short-term impact on the electric power sector. Entergy Louisiana announced this month that it will have to now delay the start of construction of its 530MW Little Gypsy 3 coal- and petroleum coke-fired unit on account of the CAMR decision. Entergy is already in negotiations with both state and federal agencies to develop a strategy for conducting the now required MACT analysis for mercury on the new plant. While Entergy, who was planning to fit the plant with both FGD and activated carbon injection, is convinced that it will pass any MACT analysis, it is as yet unclear how long the plant will be delayed as a result and how much of an impact this type of uncertainty could have on the industry as a whole.

In conclusion, Global Insight believes that it is unlikely the industry will get a final answer on mercury regulations before this fall at the very earliest, and even that is extremely unlikely. If either the D.C. Circuit Court of Appeals overturns its previous decision (and considering that its original decision was a 3-to-0 vote against CAMR, this seems unlikely), or if the U.S. Supreme Court overturns the lower court's ruling, then CAMR might survive to fight another day. But even in such an instance, what appears to be the strong likelihood of a Democrat-controlled Congress in 2009 with a new President could quickly alter this calculus yet again by legislating a MACT standard.

Global Insight has come to the conclusion that a 90% MACT standard for mercury is *ultimately* inevitable. While 2008 is poised to be inconclusive on the mercury front, we believe that by the end of 2009 a MACT standard will be foisted on the industry either by Congress or by the new Administration's EPA, with implementation to take effect in the 2013-2015 timeframe. We are sufficiently confident of our projection for this type of mercury regulation that we have adopted just such a MACT standard for our 2008 Base Case forecast. This result, of course, will have a deep impact on both new and existing coal-fired generation, particularly the latter where the economics of installing FGD (and ACI) on older, smaller coal-fired units will undergo considerable scrutiny. Combined with CAIR, this should keep pressure on the industry at intense levels to continue retrofitting scrubbers on existing coal capacity, thus helping to relieve compliance demand pressures on the SO2 market into the next decade.

CO2...

Similar to mercury, uncertainty over the prospect of federal CO2 regulation is also weighing on the SO2 markets. Executives at both NRG and Dominion made public statements this month to the effect that their companies are hesitant about increasing coal-fired generation in the future. Among the reasons cited were uncertainty about future carbon legislation combined with growing public interest in global climate change and the impacts of coal generation on CO_2 levels. It remains to be seen to what extent companies will begin to internalize these concerns – will they simply begin shifting new generation builds away from coal? Or, until federal CO_2 legislation arrives, will companies be forced by state agencies to retire existing facilities as a trade-off for building new coal-fired units?

There has even been some discussion on Capitol Hill about trying to pass legislation to require any new coal-fired plant to meet some type of "carbon capture ready" requirement even before actual CO_2 regulations are passed. Moreover, momentum has continued to build yet again this month for the prospect of having federal CO_2 regulation. In a highly publicized event, President Bush gave a speech in April calling for a stabilization of U.S. greenhouse gas levels by 2025, but provided no detailed proposals for reaching this goal. A number of Democratic Congressional leaders took this opportunity to criticize the President for not being nearly aggressive enough in his approach, and have increased talk about trying to build a bi-partisan majority in Congress to pass the Lieberman-Warner cap-and-trade climate bill currently introduced. Some are even suggesting that enough Republicans may support the legislation to make its passage possible in 2008, but it remains unclear whether (1) the President would sign a climate bill similar to Lieberman-Warner, or (2) whether Congress would be able to build veto-proof majorities to pass the legislation in both houses. Global Insight does not believe that either will occur, however, and thus no federal CO_2 regulation will become law in 2008. At the earliest, the industry should expect passage of CO_2 legislation by the end of 2009.

The passage of CO_2 regulation would have a dramatic impact on SO_2 markets. Depending on the timelines and stringency of the eventual regulation, the industry could face an accelerated retirement schedule for existing coal-fired generation and/or could face the need to increase FGD capacities and efficiency levels as it is expected that carbon capture technology will require 99% SO_2 removal for efficient operation. Again, like mercury, adoption of this type of regulation would result in lower SO_2 levels and lower demand for allowances into the next decade.

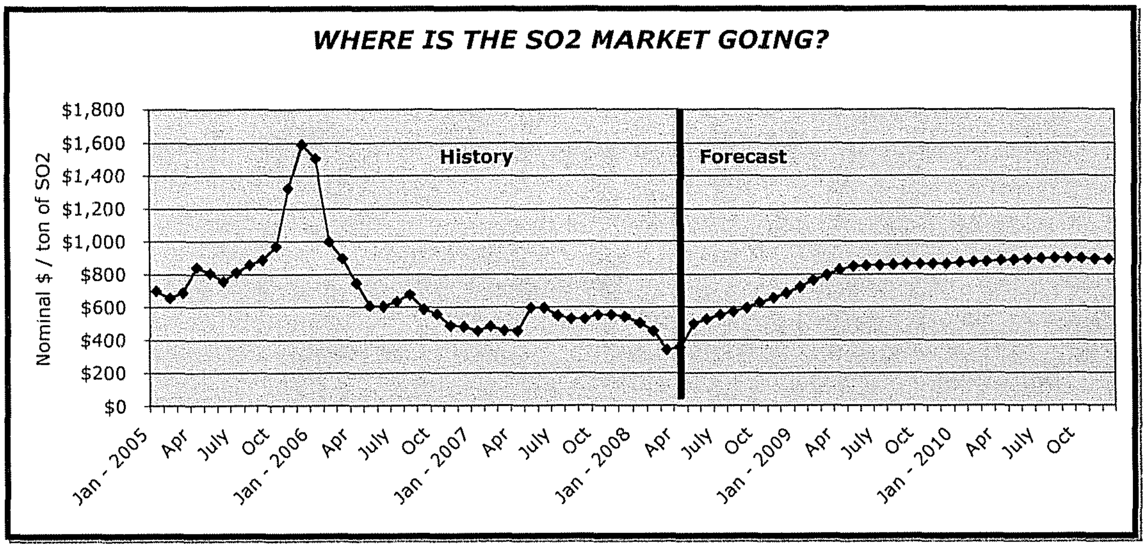
CAIR…

The industry is also still playing wait-and-see on the issue of allowance devaluation under the Clean Air Interstate Rule (CAIR) scheduled to take effect for SO_2 in January 2010. Oral arguments in the case were heard before the D.C. Circuit Court of Appeals in March, but no decision has yet been rendered. The market continues to value 2010-2014 vintage allowances at approximately 50% of the value of current year vintage allowances, strongly suggesting that the market continues to expect the court to uphold the CAIR devaluation scheme as originally promulgated. Global Insight has likewise made this assumption in our forecast, and believes that any court decision to the contrary would come as a real surprise not only to us, but to the SO_2 market as well. Some companies, however, have started to hedge their bets as buying activity has increased in recent weeks for out-year vintages as participants try to stockpile allowances just in case the courts come back with a surprising ruling in the coming months that causes forward year prices to jump.

In the short term, uncertainty over CAIR is likely to have little dramatic impact on the market. Should the Court overturn CAIR's devaluation scheme, however, forward year vintages would, of course, be expected to jump dramatically, to levels closer to parity with current year vintages. Such a decision would also likely result in a short-term spike in pre-CAIR vintage SO_2 allowance prices that would prove short-lived.

Where the SO_2 Market is Headed

A number of factors are driving the short-term SO_2 market, as discussed in some detail above. The market is severely undervalued and Global Insight, as a result, expects continued interest in the coming months from buyers looking to meet current-year compliance needs and/or to cushion their bank of allowances. This desire for companies to cushion their positions ahead of the coming Phase I CAIR caps in 2010 will ultimately take prices higher by 2010. The issue of rising construction and material costs for FGD will also likely add to the demand for allowances and push prices higher ahead of CAIR as some units hoping to have scrubbers online in time for Phase I of CAIR may be delayed. In the immediate short-term, the coming summer months, and the higher demand for electricity that comes with warmer temperatures, will also likely provide some upward price pressure on the market as some concern about increased SO2 levels creeps into the market.



At the same time, however, the wide reach of regulatory uncertainty outlined above should keep a lid on prices from spiking too high or too quickly as market naturals will be uncomfortable enough about the future regulatory landscape (and the potential for stiff regulation of both mercury and CO2) to hold relatively steady. Global Insight forecasts the spot market to climb steadily into the summer months from its early April low of $325/ton and to continue its bullish run through the end of this year and into 2009 as the start of CAIR draws ever nearer.

The Long-term SO2 Outlook

Technology and Cost Issues

From an overview perspective, flue gas desulfurization (FGD) technology continues to perform incredibly well, allowing electric power companies to efficiently mitigate significant quantities of SO2 emissions. Over the past decade, important developments have been made on the technology front, allowing for 99% removal efficiencies at high levels of reliability across a wide variety of coal types at relative costs that have been bearable by the market. Currently, the SO2 removal systems of choice for the industry are dry FGD units for plants burning low-sulfur coals, and wet limestone forced oxidation (LSFO) units for plants burning high-sulfur coals with sulfur levels greater than 2%.

These technologies have allowed the industry to successfully meet the national annual SO2 caps set by the Acid Rain Program. Preliminary data released by the EPA shows that the industry emitted

8,949,450 tons of SO_2 in 2007, far below the cap of 9.5 million tons. The technologies have performed so well, in fact, that the industry has also accrued a sizeable bank of excess emission allowance credits as it has met its annual cap in recent years. There are approximately 6.75 million SO_2 allowances in the bank for use in 2008. The Clean Air Interstate Rule (CAIR) will be implemented as a two phase program for further reducing national SO_2 levels, with Phase I of the program beginning in 2010.

The reality of further tightening regulations on the not-too-distant horizon has kept demand for new FGD units high as the industry seeks to continue lowering SO_2 levels. This ongoing effort to ratchet down emissions is also occurring in other nations, particularly in China. This skyrocketing global demand for FGD has led to labor and engineering shortages that are driving the capital costs for installation of these technologies ever higher in many parts of the world.

With relatively few technology companies able to provide the expertise to design and construct these units—such as the Shaw Group, Alstom, Foster Wheeler, and Babcock & Wilcox—electric utilities are seeing projected costs for new FGD units soar. Allegheny Energy has seen its initial projection of $550 million to install FGD units at its Fort Martin and Hatfield's Ferry plants swell to over $700 million. FirstEnergy has encountered similar cost run-ups—from a projected $1.3 billion to over $1.6 billion—in its project to install FGD on seven units at its Sammis Plant.

American Electric Power has reported some minor delays, on the order of a few months, with some of its FGD projects. Officials at AEP cite global demand for cranes as one key roadblock, again pointing towards demand from China as weighing down the industry.

At the same time, increasing costs do not seem to be deterring many companies from moving forward with plans to increase scrubber capacity at their plants. The following is a list (by no means a complete one) of a number of companies moving forward with scheduled FGD installations regardless of cost run-ups as a result of global demand pressures:

- The Tennessee Valley Authority (TVA) expects its FGD work at its Bull Run plant to be completed on schedule in time for full operation beginning in 2009. Additionally, TVA expects to scrub nine units at its Kingston Plant in 2010.

- Southern Company expects to bring eight new scrubbed units totaling 4,445MW online in 2008. The technology will be installed on three units at its Gorgas Station Plant; two at its Bowen Plant; two at its Hammond Plant; and one at its Wansley Plant. Southern has additional plans for another seven units to be scrubbed in 2009; five in 2010; two in 2011; and eighteen in 2012.

- American Electric Power expects to have two units scrubbed at its Amos Plant in 2009, with another unit at the same plant on schedule for 2010. The scrubber installation at its Big Sandy 2 Plant is scheduled for operation by 2014.

As these examples demonstrate, electric utilities are not backing down in the face of increasing FGD costs. As some of our clients have expressed to Global Insight privately, many industry participants appear willing to accept the risk of increasing construction costs in light of still fresh memories of $1,500+/ton SO_2 allowance prices from 2006.

Another trend impacting demand for FGD units is increased pressure by environmental groups and others to negotiate pre-settlements with electric utilities for increased pollution controls in lieu of filing lawsuits in an attempt to halt construction of new plants. In many cases, power companies are finding it to their advantage to avoid the costs (in time and money) of legal delays by negotiating such settlements to allow construction to proceed. The following chart displays recently negotiated SO2 requirements at four electric power utilities. In each of the four cases below, the negotiated settlements essentially require the installation of Best Available Control Technology (BACT) in the form of FGD.

	Xcel's Comanche Plant		CWLP's Dallman Plant		Seminole's Seminole Plant		KCP&L's Iatan Plant	
	Unit 3 (new)	*Units 1 & 2*	*Unit 4 (new)*	*Units 1-3*	*Unit 3 (new)*	*Units 1 & 2*	*Unit 2 (new)*	*Unit 1*
SO2 (lb/mmBtu)	0.10	0.12 each; 0.10 together	99% Removal	0.24, decreasing to 0.10	98% Removal	95% Removal	0.06	0.07

[Source: Andracsek, Robynn. "Dollars vs. Delays: The Trend Toward Intervener Settlements." Power Engineering Magazine. November 2007. Page 18.]

These settlements are increasingly going beyond negotiated emission rates for new plants to also include increased SO2 removal efficiencies from existing units. In some cases, this results in a new retrofit of an existing un-scrubbed plant. In other instances, however, electric utilities are beginning to turn their attention to increasing the removal efficiencies of existing FGD units on existing plants.

Most new FGD units are capable of 95-99% removal efficiency, whereas some older units are still operating in the 65-80% removal efficiency range. There are two major reasons why FGD efficiencies are so low at some existing units. First, many FGDs were built in the early-to-mid 1970s, prior to the 1977 Clean Air Act Amendments (CAAA) that required that specified, minimum percentages of SO2 removal be achieved (90% in the case of bituminous coal-fired units, and 70% in the case of sub-bituminous coal-fired units). Many units where FGDs were installed during this pre-1977 period burned bituminous coals, but only designed them initially for removal efficiencies in the low 70% range. Secondly, as noted with regard to the sub-bituminous units, many boilers in the West burning this type of coal simply installed the bare minimum removal efficiency required under the 1977 CAAA.

As both the value of SO2 emission allowances and the value to the company of removing additional SO2 have risen over the past few years, some companies have embarked on upgrading the removal efficiency of FGD units at these plants. Depending on the type of upgrade planned, the main improvement sought for existing FGDs involves improving plant infrastructure to handle larger quantities of reagent and by-product removal. The following table displays a number of plants that have publicly announced plans to upgrade their FGD removal efficiencies, or have recently done so.

Recent & Planned Upgrades to Existing FGDs							
Census Region	Plant Name	State	Unit	Size (MW)	Original FGD	Upgrade FGD	Comment
MTN2	Cholla	AZ	1	113.6	1973	n/a	Scrubber being upgraded during installation on 3 & 4
MTN2	Cholla	AZ	2	288.9	1978	n/a	Scrubber being upgraded during installation on 3 & 4
MTN2	Springerville	AZ	1	424.8	1985	2004	Upgraded in 2004
MTN2	Springerville	AZ	2	424.8	1990	2005	Upgraded in 2005
MTN1	Craig	CO	C2	446.4	1979	2008	Plans to upgrade scrubber in spring of 2008
MTN1	Craig	CO	C1	446.4	1980	2008	Plans to upgrade scrubber in spring of 2008
MTN1	Craig	CO	C3	446.4	1984	2008	Plans to upgrade scrubber in spring of 2008
SATL	Seminole-FL	FL	1	652.0	1983	2008	Plans to upgrade the scrubbers along w/ new unit
ENC	Duck Creek	IL	1	416.0	1978	2008	Possible upgrade by 2008
ENC	Gibson	IN	5	668.0	1982	2008	Upgrades planned for 2008
ENC	Gibson	IN	4	668.0	1995	2005	Upgrades planned for 2005
WNC	La Cygne	KS	1	893.0	1973	2011	Upgrading scrubber from 2009 to 2011/2012
WNC	Jeffrey Energy Center	KS	1	720.0	1978	2010	Plans to upgrade
WNC	Jeffrey Energy Center	KS	2	720.0	1980	2010	Plans to upgrade
WNC	Jeffrey Energy Center	KS	3	720.0	1984	2010	Plans to upgrade
ESC	East Bend	KY	2	669.3	1981	2005	Upraded in 2005
ESC	Trimble County	KY	1	566.1	1991	n/a	Utility plans to improve controls
ESC	Spurlock	KY	2	508.0	n/a	2008	Replacing old scrubber by 2008
WNC	Clay Boswell	MN	3	364.5	1973	2009	Plans to upgrade scrubber by 2009
WNC	Milton R Young	ND	B2	440.0	1977	2010	Plans to upgrade scrubber by 2010
MTN2	San Juan	NM	1	361.0	1999	n/a	Plans for upgrades
MTN2	San Juan	NM	2	350.0	1999	n/a	Plans for upgrades
MTN2	San Juan	NM	3	534.0	1999	n/a	Plans for upgrades
MTN2	San Juan	NM	4	534.0	1999	n/a	Plans for upgrades
ENC	Conesville	OH	5	375.0	1977	2009	Upgrades mandated by 2009
ENC	Conesville	OH	6	375.0	1978	2009	Upgrades mandated by 2009
ENC	W.H. Zimmer	OH	1	1425.0	1991	2006	Upgraded in 2006
ENC	Niles	OH	1	125.0	1995	2011	Plans to upgrade the scrubbers through 2011
ENC	Niles	OH	2	125.0	1995	2011	Plans to upgrade the scrubbers through 2011
MATL	Elrama	PA	1	100.0	1975	2007	Scrubber uprgrade completed in June 2007
MATL	Elrama	PA	2	100.0	1975	2007	Scrubber uprgrade completed in June 2007
MATL	Elrama	PA	3	125.0	1975	2007	Scrubber uprgrade completed in June 2007
MATL	Elrama	PA	4	185.3	1975	2007	Scrubber uprgrade completed in June 2007
MATL	Bruce Mansfield	PA	1	913.8	1976	2012	Upgrade by 2012
MATL	Bruce Mansfield	PA	2	913.8	1977	2012	Upgrade by 2012
MATL	Bruce Mansfield	PA	3	913.8	1980	2012	Upgrade by 2012
SATL	Winyah	SC	3	280.0	1977	2012	Upgrade by 2012
SATL	Winyah	SC	4	280.0	1981	2012	Upgrade by 2012
SATL	Cross	SC	2	450.0	1984	2012	Upgrade by 2012
SATL	Cross	SC	1	540.0	1995	2012	Upgrade by 2012
SATL	Jefferies	SC	4	173.0	n/a	n/a	Plans to upgrade
SATL	Granger	SC	1	82.0	n/a	n/a	Plans to upgrade
SATL	Granger	SC	2	82.0	n/a	n/a	Plans to upgrade
SATL	Jefferies	SC	3	173.0	n/a	n/a	Plans to upgrade
WSC	J.K. Spruce	TX	1	546.0	1992	2013	Scrubber will be upgraded by 2013
MTN1	Hunter (Emery)	UT	1	446.4	1979	n/a	Plans to upgrade
MTN1	Hunter (Emery)	UT	2	445.4	1980	n/a	Plans to upgrade
SATL	Pleasants	WV	1	684.0	1980	2003	Upgraded w/new chimney & duct work
SATL	Pleasants	WV	2	684.0	1980	2003	Upgraded w/new chimney & duct work

Source: JD Energy, Inc.

Alternatives to Conventional FGD Scrubbing

It is also worth noting that there are a few alternative methods for reducing SO2 emissions. Some companies are beginning to explore some of these options, a overview of which is offered below.

- ***Partial Scrubbing:*** The use of partial scrubbing is gaining significant attention as more stringent federal and state requirements and high SO2 prices force power companies to explore alternatives for smaller, older plants that can not economically justify large investment dollars in full scrubbing systems.

  Significant progress has occurred in this area by dry injection, dry sorption of SO_2 using the plentiful, natural mineral, "trona" supplied from Green River, Wyoming. At in-duct flue gas temperatures in excess of 300˚F, such as in high-load unit operation, the highly chemically hydrated, sodium carbonate-bicarbonate compound is rapidly calcined to anhydrous sodium carbonate with a "popcorn-like" particle shape of high specific surface. With a stoichiometric feed rate of 350% and higher SO_2 removal efficiency, even upstream of an ESP (rather than a fabric filter) is greater than 75%. While its efficient simultaneous removal of SO_3/H_2SO_4(v) tends to disadvantageously increase the fly ash resistivity, the added sodium salts counteract that effect and ESP particulate removal efficiency is not impaired by this ultra-low-capital-cost means of flue gas desulfurization.

A major drawback to use of trona (and other sodium alkates) to substantially collect SO_2 for throwaway disposal is the highly water-soluble nature of sodium compounds.

Mirant Corporation will reportedly be employing partial scrubbing using trona in at least one of its three Maryland plants (Chalk Point, Morgantown, and Dickerson) as a means of complying the that state's Healthy Air Act, legislation with SO2, NOx, and mercury standards considerably more stringent than that of the federal government.

- ***Fuel-Switching:*** Another method for reducing SO2 emissions among a company's fleet is to switch from coal to natural gas generation, which emits less SO2 on a Btu-basis compared to coal. SO2 allowance prices have not been high enough, nor the SO2 caps stringent enough, at this point to trigger any kind of fuel-switching to natural gas in a sizeable way. This could become a more viable option under the more stringent requirements of CAIR---particularly with regard to some older and smaller units--- or should SO2 prices spike to unexpectedly high levels.

- ***CFB Scrubbing:*** Another alternative method for SO2 removal is the use of a circulating fluidized bed FGD unit, as opposed to a post-combustion unit that removes SO2 directly from the flue gas stream. This method for SO2 removal has been employed internationally and is currently being used at AES's Greenidge Plant in New York.

FGD Installations

Global Insight closely monitors the installation of FGD technology on both existing and new plants. In this section, we seek to provide an overview of existing and planned installations.

Existing FGD Retrofits

Beginning in the late 1960s and early 1970s, electric power plants began to install scrubbers to reduce SO2 emissions. The federal government issued New Source Performance Standards (NSPS) which mandated a certain threshold level of SO2 removal efficiency on all newly constructed coal plants. And since 1990, the industry has seen a rapid adoption of FGD technology to reduce SO2 emissions and comply with the national caps placed on emissions by the Acid Rain Program.

As of the end of 2007, approximately 110GW of existing coal capacity in the United States operating with a scrubber for SO2 removal. This currently constitutes about one-third of the entire operating coal-fired fleet in the United States.

The following table shows the total scrubbed capacity (measured in GW) in each region of the nation. Additionally, it shows the approximate percentage of total coal capacity in each region that has an FGD unit installed.

Census Region	FGD Capacity (GW)	% of Coal Capacity w/FGD
NENG	0.3	6.3%
MATL	9.8	36.7%
ENC	15.7	19.4%
WSC	3.3	9.2%
ESC	16.0	36.6%
SATL	29.9	40.1%
WNC	6.2	16.5%
MTN1	14.2	65.0%
MTN2	7.5	73.1%
PAC1	2.1	95.1%
PAC2	0.1	16.6%

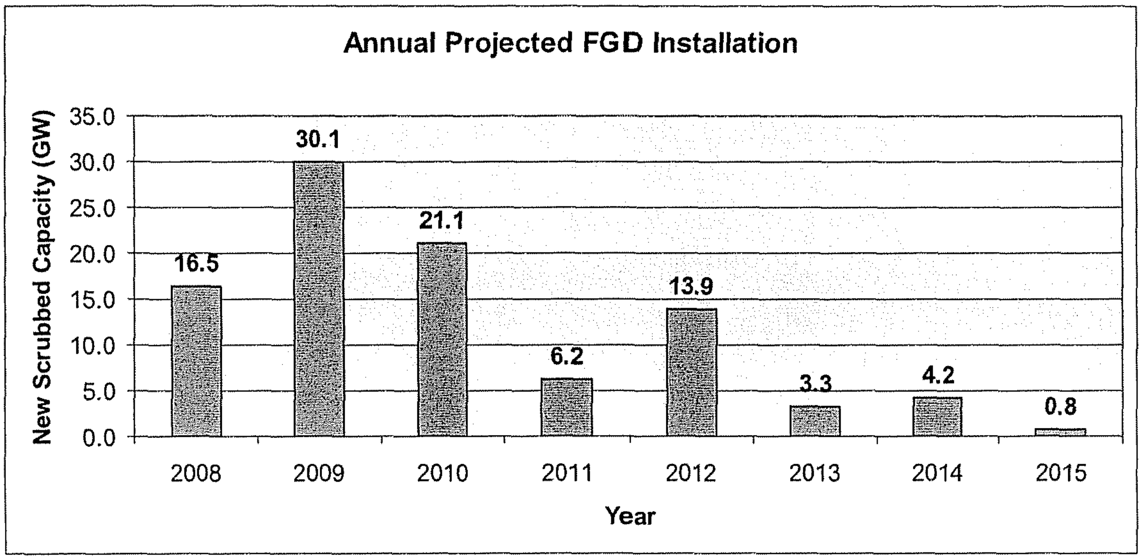
As shown above, the South Atlantic region is home to the largest capacity of scrubbed coal units, followed by the East South Central and East North Central.

The following table compiled by Global Insight displays the estimated weighted average FGD removal efficiency levels of all the scrubbers operating in each region of the nation. The national average removal efficiency is approaching 90%.

Census Region	Average FGD Removal Efficiency
NENG	90.0%
MATL	95.2%
ENC	90.3%
WSC	94.8%
ESC	90.7%
SATL	88.9%
WNC	68.3%
MTN1	79.9%
MTN2	84.2%
PAC1	93.5%
PAC2	96.8%
Total:	87.5%

Projected FGD Installations

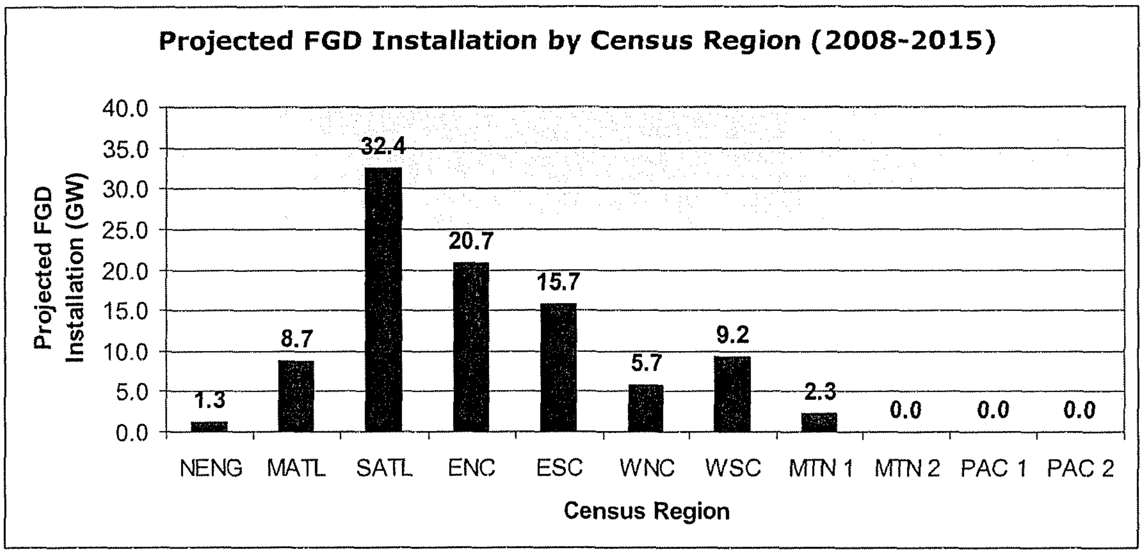
Global Insight has compiled a detailed regional list of publicly announced plans to install scrubbers on existing coal plants. Our data projects a significant wave of FGD capacity to come online between 2008 and the end of the first year of CAIR's tighter SO2 standard in 2010. A year-by-year projection of total expected FGD expansion across the United States is displayed below.



Source: Global Insight, Inc.

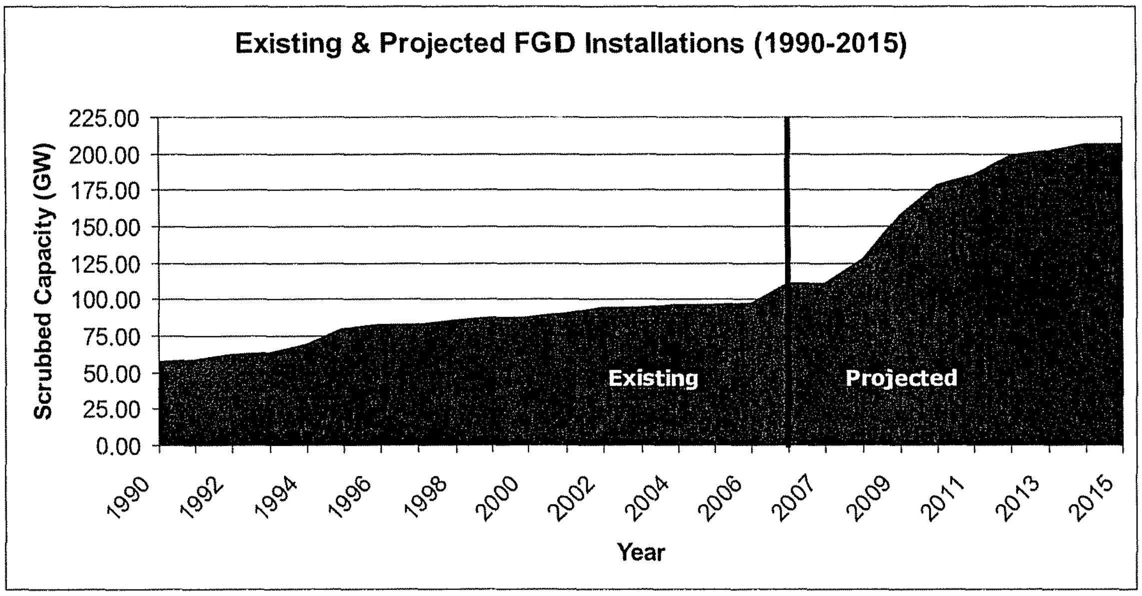
As referenced above, the 67.7GW of projected FGD installation between now and the end of 2010 is primarily driven by the implementation of Phase I of CAIR. The up-tick in FGD installations scheduled for 2012 is likely driven by an anticipation of CAIR's Phase II implementation in 2015.

The following graph illustrates the regional break-down of these same projected FGD installations between 2008 and 2015. The regional installation of new scrubbing capacity, it might be noted, closely resembles the regional distribution of existing FGD as shown above.



Source: Global Insight, Inc.

When looking at the issue of projected FGD installations in the aggregate, Global Insight finds that the total capacity of scrubbed coal should nearly double by 2015, to over 206GW of scrubbed capacity by 2015. The following chart displays Global Insight's summary of total existing FGD capacity combined with our projection for future FGD capacity out to 2015.



Source: Global Insight, Inc.

The Long-Term SO2 Allowance Price Forecast

Global Insight evaluates the outlook for future SO2 pricing based on four critical factors. Each of these factors have played a dominant role at different times, and it is the interplay of these variables that directs our forecast outcome. Below we evaluate these key considerations and then explain the forecast price trends.

Key Considerations

♦ The Marginal Cost of Scrubbing - Any analysis of SO2 prices must begin with the marginal cost of scrubbing---the cost of the next scrubber to be retrofit on an existing unit represented by the SO2 price at which the FGD installation becomes economic. As discussed previously in this report, the cost of scrubbing has increased substantially over the past few years, due to several factors. These include the rising cost of components, which in turn is a function of higher global demand for key elements such as steel, as well as the weakening dollar that is rendering the cost higher for US companies. Other causes have been previously discussed in the section entitled "FGD Installations."

In 2006, Global Insight viewed the marginal cost of scrubbing to be about $650/ton. This cost has risen due not only to the factors previously cited, but also to the rising difficulty of the units where scrubbers are to be installed. As the massive scrubbing effort that has occurred since 2006 has proceeded (and will continue for many years) situations will be increasingly encountered where site limitations and smaller unit sizes make the effort increasingly difficult and costly. This trend validates the so-called "low hanging fruit" theory where most of the less expensive and easier FGD retrofits are occurring first. As a result, we foresee the marginal cost of scrubbing to rise to about $890/ton by 2010 (in 2008 dollars). As noted previously, this is significantly above the current market price.

In the outer years of our forecast, however, the cost actually begins to fall. This is contradictory to conventional wisdom that, as described above, assumes that each installation is more costly than the previous one. The decline in the marginal cost of scrubbing occurs in our forecast for two reasons.

First, the current congestion---both in terms of demand for scrubber installations and, to a lesser extent, the supply/demand imbalance for materials that currently exists---will subside. Second, improvements in the technology (particularly with regard to the widespread use of multi-pollutant integrated systems) will concurrently raise performance and reduce pollutant-specific capital and O&M costs. This, in our assessment, leads to the marginal cost of scrubbing falling (in 2008 dollars) to $755/ton by 2015 and $730/ton by 2020.

As a final note, these costs also are constrained by our forecast assumption that many of the smaller and older coal-fired generating units will be retired instead of retrofitted. This assumption is being driven primarily by the cumulative impact of (1) the upcoming requirements to reduce SO2 and NOx under CAIR, (2) state-initiated mercury policies (in more than 20 states) that will render the cost of retrofitting these units excessive and (3) state-initiated CO2 policies (largely in RGGI) that will, in many instances, force the cost of operating less efficient units to be infeasible.

♦ The Size of the SO2 Bank - The presence, or lack, of a sizeable SO2 bank can have a profound effect on market pricing. An extremely large bank can cushion the impact of high marginal FGD costs to the point where the SO2 price is driven back below the marginal scrubbing cost. Conversely, a very small bank could lead to severe concerns that a shortage of SO2 allowances might ensue, leading to considerable premiums placed above and beyond the marginal FGD cost.

The bank remains sizeable in our forecast, such that the power sector will enter CAIR in 2010 with a bank of about 11.8 million tons. Once CAIR begins in 2010 with its reduced allocations, the bank begins to fall and continues to do so until 2013 before it starts rebuilding again. Nevertheless, it never falls below 9.4 million tons in the forecast, leaving plenty of breathing room.

Some analysts have suggested that the failure of CAMR in the courts or the sheer volume of scheduled FGD retrofits could lead companies to begin canceling scrubbing plans. Global Insight highly doubts these claims will materialize to any significant extent, as CAMR by itself really was to have no impact until 2018 and many FGD retrofits are in fact being driven by state mercury and environmental policies, not CAMR..

♦ Liquidity - Several factors can influence liquidity, including state or regional governmental programs restricting the use of allowances for emissions trading, the degree of willingness of naturals to freely trade their excess allowances, and the actions of speculators as they seek to maximize profits. Liquidity is an element that can be closely linked to the impact of the size of the bank. The potentially depressive impact of a large bank on SO2 pricing can be negated by an illiquid market (as was the case in 2005); conversely, even a relatively small bank will exercise less upward SO2 price pressure if there is a high degree of liquidity in the market. As a result, the concept of liquidity and the size of the SO2 bank must be considered in tandem when projecting the likely direction of SO2 pricing.

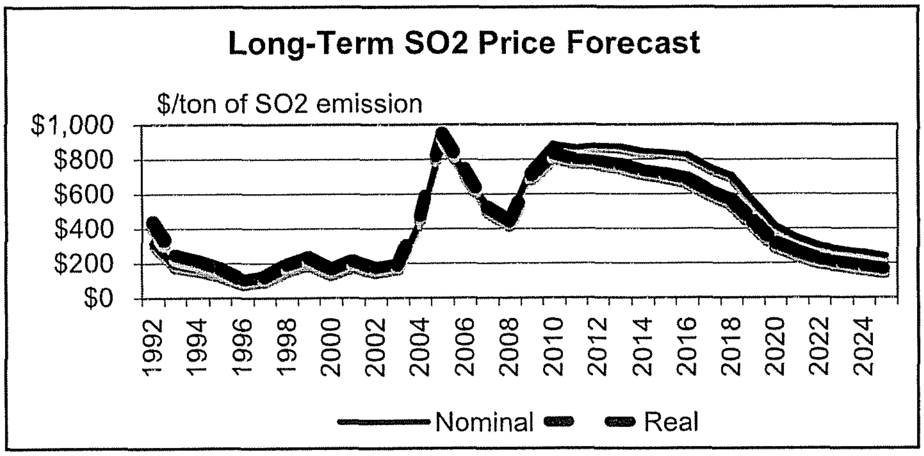
The kind of illiquidity that was a major cause of the 2005 price spike to the $1,500/ton area is not deemed by Global Insight to pose a problem in the future. The magnitude of the size of the bank, as discussed in the previous section, argues strongly against the likelihood that speculators or anyone else could garner control of sufficient allowances to significantly influence the market.

♦ Market Expectations - In addition to the three factors discussed previously, the impact of the expectations of market participants plays a formidable role in the development of SO2 prices. Clearly, there are anxieties at present regarding a number of issues (CO2, mercury MACT, RPS), but they do not have a major market effect in the 2008-2010 time frame because traders and planners do not know whether they will come to pass or not, or in what form. The most noticeable impact in this period, however, is to restrict most trading to relatively low levels aimed at meeting near-term compliance objectives, leaving limited trading of future vintage allowances given the high degree of uncertainty.

SO2 Price Forecast

In the forecast, the price of SO2 allowances effectively peaks in real terms in 2010 and never recovers. Our forecast assumes no change in legislation that is not already on the books, but even without the pervasive impact of issues such as federal CO2 legislation or Mercury MACT, the wave of scrubbing that is underway now will create a strong bank of allowances that should provide considerable liquidity and a ready supply of allowances in the market in the next decade.

The vast majority of coal units are scrubbed by 2020 in the forecast, leading sellers to let go of allowances at reduced prices in an oversupplied market as we work our way through the 2010-2020 decade. Other factors in our forecast serving to depress SO2 prices include a moderately higher renewables contribution and declining electricity demand, each of which lowers overall demand for coal.

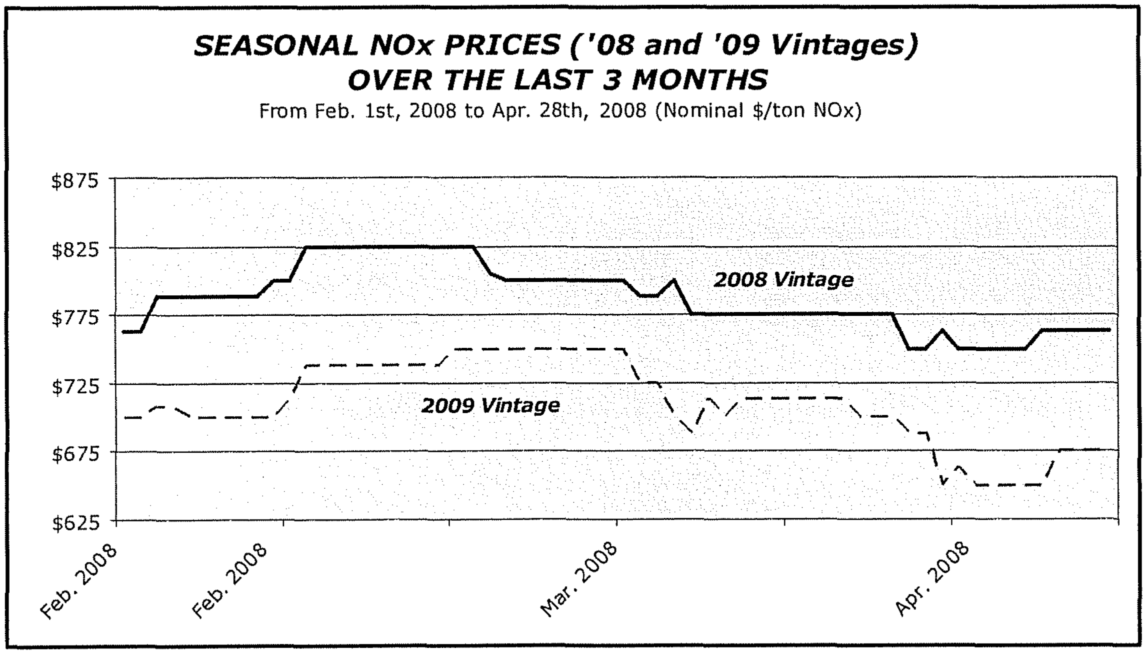


NOx Prices

The Short-Term NOx Outlook

Seasonal NOx Market

The Seasonal NOx market has seen yet another month pass it by with little activity. Prices have held steady now in the mid- to upper-$700/ton range since the first of the year. Current year Seasonal NOx vintage allowances entered the month trading at $775/ton before falling slightly through the month to close on April 28th at $763/ton.



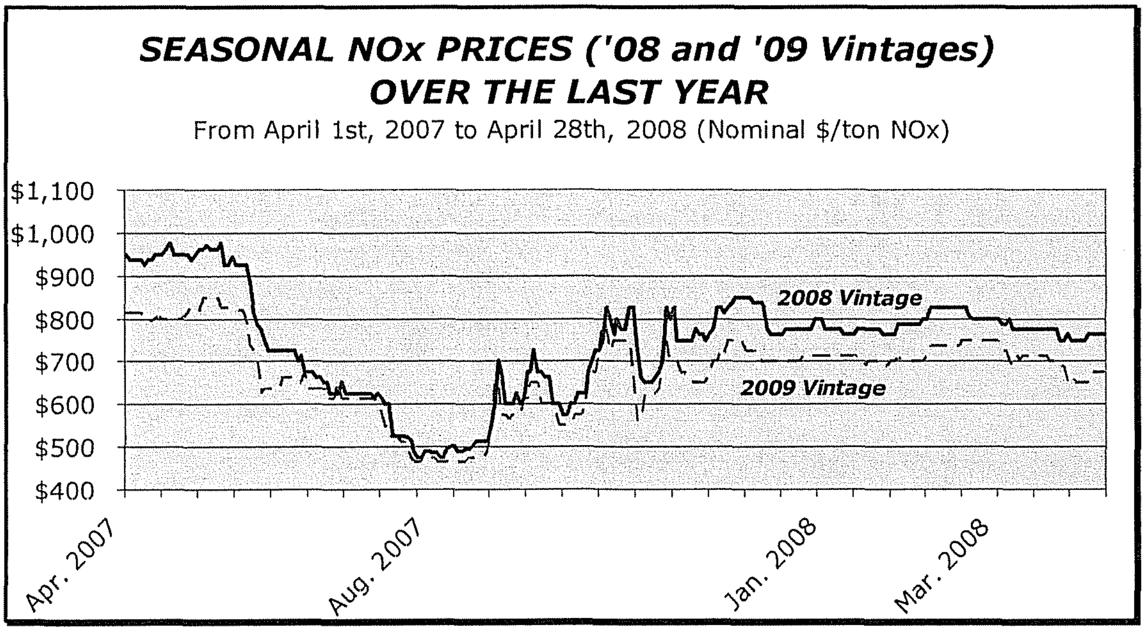
The Seasonal NOx market has remained quiet again in the month of April with incredibly low volumes trading as has been the story now for a number of months. Electric generators are finding little reason to buy allowances as the market has easily fallen within the cap levels for the summer ozone season and should have no problem doing so once again in 2008. Additionally, the large bank of allowances is providing participants with a useful insurance policy to fall back on. Another interesting consideration is that 2008 marks the last year during which progressive flow control (PFC) will discount the use of banked allowances for compliance purposes. Any banked seasonal allowances carried over into 2009's Phase I of CAIR will be available for use at a one-to-one ratio.

Ozone Lawsuits?

EPA finalized its new 8-hour ozone NAAQS at the end of March. The new standard is 0.075ppm, down from the previous level of 0.084ppm. It is expected that a number of states and environmental groups will ultimately file a lawsuit against the new standard, particularly considering that the EPA's own scientific advisory council recommended a lower standard than the new rule to protect the public health. As of this publication, however, no lawsuits have yet been filed to challenge the rule.

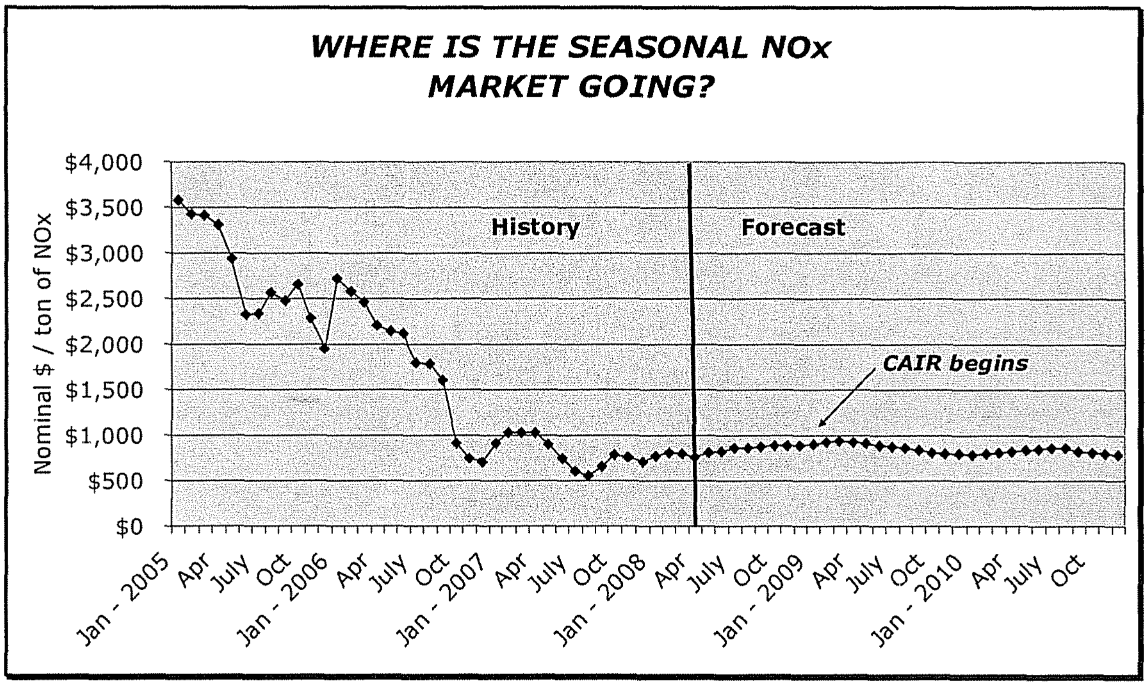
The Seasonal NOx market, however, has proceeded unfazed by the promulgation of the new standard. The failure of the market to respond to this new ozone standard is a clear indication that the industry does not expect to have much difficulty meeting the stricter limit. By EPA's own calculus, fewer than 30 counties by 2020 are expected to be in non-attainment for the new standard.

If lawsuits against the new rule are filed and prove successful, it is possible that the EPA will need to re-visit ozone once again in the coming year or two. In such an instance, it is possible that a tighter standard could ultimately be promulgated by EPA that would prove more difficult for the industry to meet. The impact of this, however, would be simply to add even more to the inventory of NOx control equipment, because plants caught in or affecting non-attainment areas would likely lose the option to purchase allowances and be forced, instead, to install de-NOx equipment. This, in turn, would lower the demand for NOx allowances, placing additional downward pressure on the price.



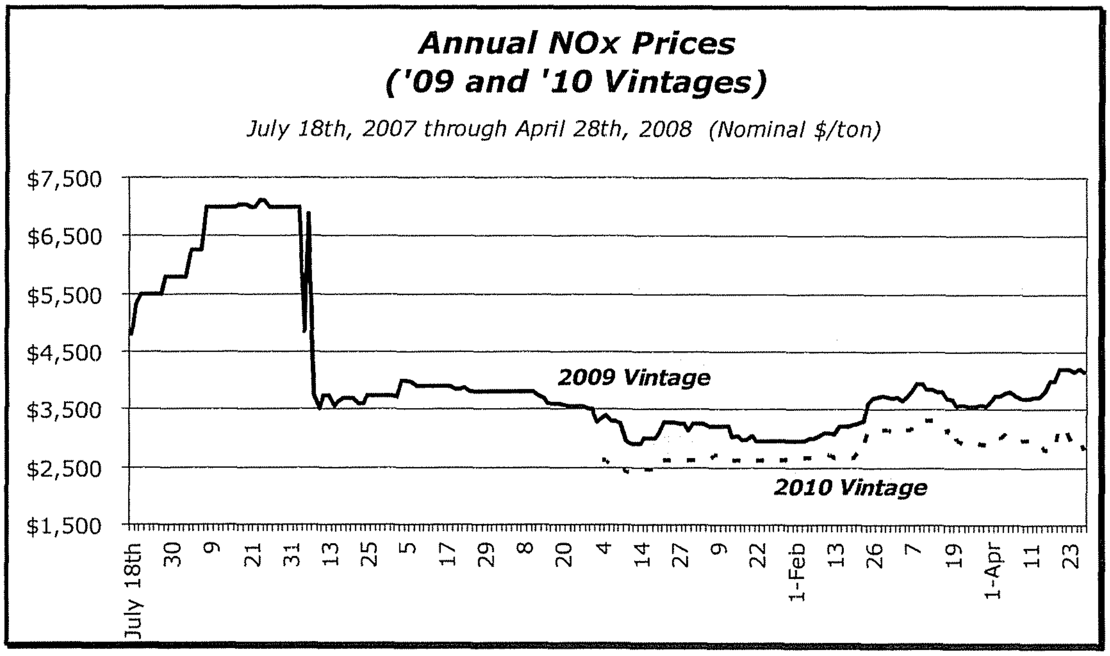
Where is the Seasonal NOx market headed?

Barring an unexpected development, the Seasonal NOx market is unlikely to change course much in the short-term. The market should track slightly higher through the end of 2008 as the start of CAIR's Phase I nears in January 2009. But even with that, the Seasonal NOx limits for CAIR's Phase I are no more stringent than those already in place under the NOx SIP Call trading program; rather, it is the expansion of this program to now cover a total of 28 states, many of which were not previously subject to seasonal restrictions, that creates any interest whatsoever. As a result, even the typical run-up in prices ahead of the start of a new trading program is expected to be severely tempered in this case.



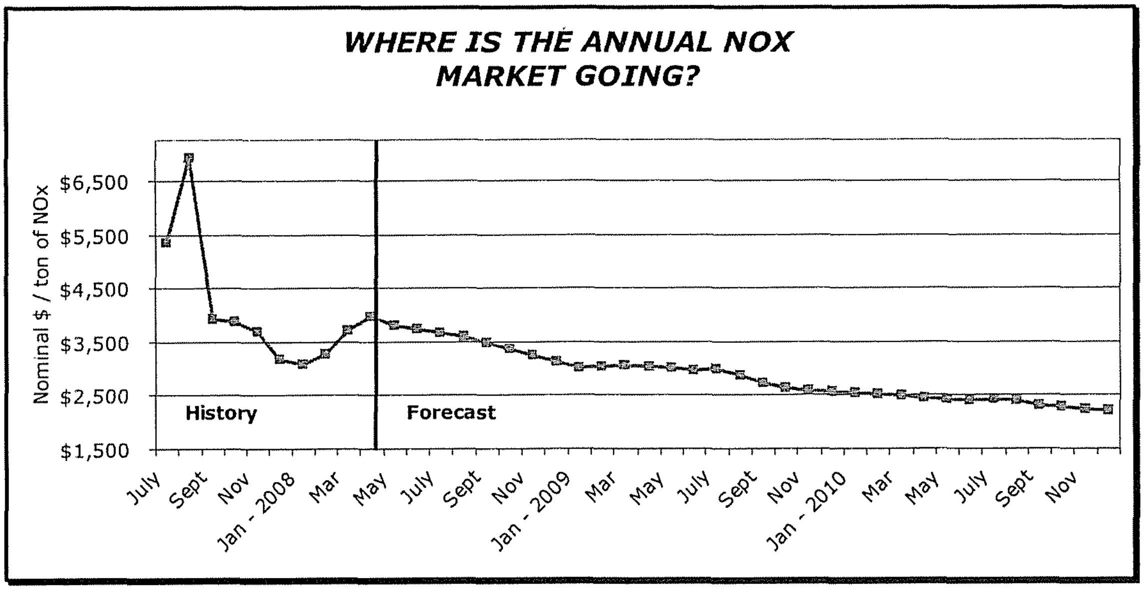
Annual NOx Market

In what is becoming the normal course of events, the Annual NOx market saw significantly more activity in April than the Seasonal NOx market. The Annual market has seen not only more activity this month than in recent months, but also significantly more volatility. 2009 vintage Annual NOx allowances entered the month trading at \$3,650/ton before spiking late in the month to \$4,200/ton on April 24th, a price point not seen in the market since early April 2008. Prices dropped off slightly, however, to close on April 28th at \$4,150/ton.



Where is the Annual NOx market headed?

The volatility this month may be a sign of things to come in the Annual NOx market as concerns emerge over the historic nature of the market to jump in advance of a new program and as fears over the reliability of operating SCRs year-round weighs on the market. Many in the industry expect that SCRs will have little trouble operating year-round and that these reliability issues will be quickly assuaged after a successful first year of the Annual NOx market. Until that point, however, the market could expect to undergo some short-lived volatile price swings like the one seen at the end of April. In the long-term, however, we believe the prices to be significantly overvalued at $3,000-4,000/ton. Global Insight pegs the marginal cost of annual NOx removal to be nearer to $1,700-2,000/ton. As a result, prices should fall off precipitously after a successful 2009 and come closer into line with the marginal cost of annual NOx removal. The lack of a bank for the annual market, however, should provide some upward price pressure on the market through 2009 and 2010 as compliance demand fundamentals generally push the market lower.



The Long-Term NOx Outlook

Technology Issues

Technology Options

1. ***SCR (Selective Catalytic Reduction)***
SCR technology has been used commercially in Japan since 1980 and in Germany since 1986. Applications have principally been in power stations primarily burning low-sulfur coal and in some cases medium-sulfur coal. As recently as the late 1990s, there was only about 15GW of coal-fired SCR capacity in Japan and nearly 30 GW in Germany out of a total of more than 60 GW worldwide. Since the 1990s, SCR demonstration and full-scale systems have been installed in U.S. coal-fired power plants burning diverse coals. Their commercial use has followed the introduction of stringent limits on ozone-season NO_x emissions.

The installation of SCR technology has proven the primary method by which electric power companies have chosen to reduce NOx emissions from the stack. By and large, the technology has worked very well over the last decade and has made a significant contribution to reducing NOx emissions from the electric power sector.

The following chart shows estimated SCR installations on electric power plants in the United States on a regional basis as of 2007:

SCR Installations by Capacity by Region (through 2007)			
Census Region	Coal Capacity (GW)	Capacity w/SCR (GW)	% of Capacity w/SCR
NENG	4.8	0.5	9.6%
MATL	30.9	7.5	24.4%
SATL	79.5	26.4	33.2%
ESC	44.7	13.1	29.4%
ENC	82.6	21.7	26.3%
WNC	39.8	4.2	10.6%
WSC	35.6	4.8	13.6%
MTN1	22.9	0.1	0.4%
MTN2	10.3	0.0	0.0%
PAC1	2.3	0.0	0.0%
PAC2	0.9	0.0	0.0%
TOTAL:	*354.2*	*78.4*	*22.1%*

SO3 Formation
The oxidation of SO2 to SO3 in the SCR continues to trouble electric utility operators seeking to increase NOx removal efficiencies. Particularly with higher sulfur coals, from which greater quantities of SO2 are produced during combustion, the formation of SO3 has proven more troublesome. The SO3 reacts with unreacted ammonia catalyst from the SCR resulting in the formation of sulfuric acid vapor. This byproduct of SCR operation on high-sulfur coals especially can cause corrosion and can combine with the flyash to form a sticky deposit that is difficult to remove. One of the primary methods to combat SO3 formation is to operate a unit's SCR at a lower removal efficiency and thus use less of the ammonia catalyst that leads to the SO3 formation.

SCR manufacturers have been trying to mitigate this problem by developing new catalysts that reduce the oxidation of SO2 to SO3 in the first place. There are, as yet, no silver bullet solutions to this problem, particularly when operating SCRs with high sulfur coals. Most current research is focused on optimizing SCR catalyst regeneration to reduce the oxidation of SO3[i]. The Department of Energy's National Energy Technology Laboratory (NETL) is also funding research into a novel approach whereby CO emissions directly from the boiler can be used to reduce NOx without the need of an ammonia catalyst. It is not yet clear, however, whether this research will result in a commercially viable ammonia-free SCR process.

This could become more of an issue as CAIR's more stringent NOx regulations take effect and operators are faced with needing to increase the removal efficiencies of their installed SCRs to meet the tighter standards. SCR operators will need to continue to pursue a multi-pronged approach to minimizing the impacts of SO3 formation.

Removal Efficiency
New SCR installations are technically capable of removing 90% of NOx emissions from the flue gas stream with mid-to-low sulfur coals. As a result of the problems addressed above with SO3 formation, new SCR installations are operating at lower removal efficiencies, typically 78-80%, with high sulfur coals. These efficiencies with high sulfur coals, however, are improving and are expected to continue to do so in the coming years as industry further develops processes for injecting alkalis and other sorbents upstream of the air preheater to remove SO3.

The current NOx SIP Call standard and the coming Phase I cap of the Clean Air Interstate Rule (CAIR) require a NOx output of 0.15lb NOx/mmBtu or lower. Ultimately, There is speculation that the industry will be required to tighten those emission rates down even further to 0.01lb NOx/mmBtu by the end of the next decade. Any widespread federal effort to regulate CO2 would certainly provide the impetus for this, as a pure flue gas stream not contaminated by NOx allows for the most efficient capture of CO2 emissions.

That said, the following displays the current distribution of removal efficiencies across existing SCR installations operating today in the United States:

Distribution of Removal Efficiency on Installed SCR Capacity		
Removal Efficiency	*Capacity (GW)*	*% of SCRs*
90%+	11.2	15.49%
87-90%	19.8	27.37%
80-86%	26.2	36.30%
70-80%	15.0	20.84%

ii

Additionally, the following table shows the regional breakdown of removal efficiencies for currently installed SCRs:

Average SCR Removal Efficiency By Census Region	
NENG	69.6%
MATL	72.4%
ENC	61.7%
WSC	83.9%
ESC	61.2%
SATL	72.9%
WNC	52.6%
MTN1	65.5%
MTN2	96.1%
PAC1	0.0%
PAC2	0.0%

2. SNCR (Selective Non-Catalytic Reduction)
SNCR technologies came into commercial use on oil- and gas-fired power plants in Japan in the middle of the 1970's. In Western Europe, SNCR systems have been used commercially on

coal-fired power plants since the end of the 1980s. In the USA, SNCR systems have been used commercially on coal-fired power plants since the early 1990's. As recently as the late 1990s, the total installed capacity of SNCR throughout the world on coal-fired plants only amounted to more than 2 GW.

SNCR have not been able to achieve the same removal efficiency levels for NOx reduction as have SCRs. While the SNCR option is typically not as capital intensive, the lower removal efficiencies make it a less economical choice for most electric power companies.

The following chart shows estimated SNCR installations in the United States through 2007:

SNCR Installations by Capacity by Region (through 2007)			
Census Region	Coal Capacity (GW)	Capacity w/SNCR (GW)	% of Capacity w/SNCR
NENG	4.8	0.7	13.93%
MATL	30.9	3.7	12.03%
SATL	79.5	2.4	3.02%
ESC	44.7	0.9	1.99%
ENC	82.6	1.4	1.73%
WNC	39.8	0.1	0.35%
WSC	35.6	0.0	0.00%
MTN1	22.9	0.0	0.00%
MTN2	10.3	0.0	0.00%
PAC1	2.3	0.0	0.00%
PAC2	0.9	0.5	47.87%
TOTAL:	*354.2*	*9.7*	*2.74%*

3. Major Primary Measures

Due to stringency of emission standards for NO_x control, utility and industrial plant operators have to include NO_x control equipment in their new plant designs and costing. In most cases, existing power plants have been retrofitted with measures to reduce NO_x emissions. Using new and improved low-NO_x burner design in new plants and modifying combustion condition in existing units are generally the first options investigated and used to control NO_x emissions. However, retrofitting a boiler with primary measures may be difficult in terms of space availability, and limitations in boiler orientation and operation. In general, utilizing primary measures for NO_x control requires relatively little capital investment and does not entail the use of any additives. Therefore the total investment, capital and operational, is lower per ton of NOx abatement compared to post combustion (secondary) NO_x flue gas treatment processes.

Common primary measures for NO_x control are as follows:

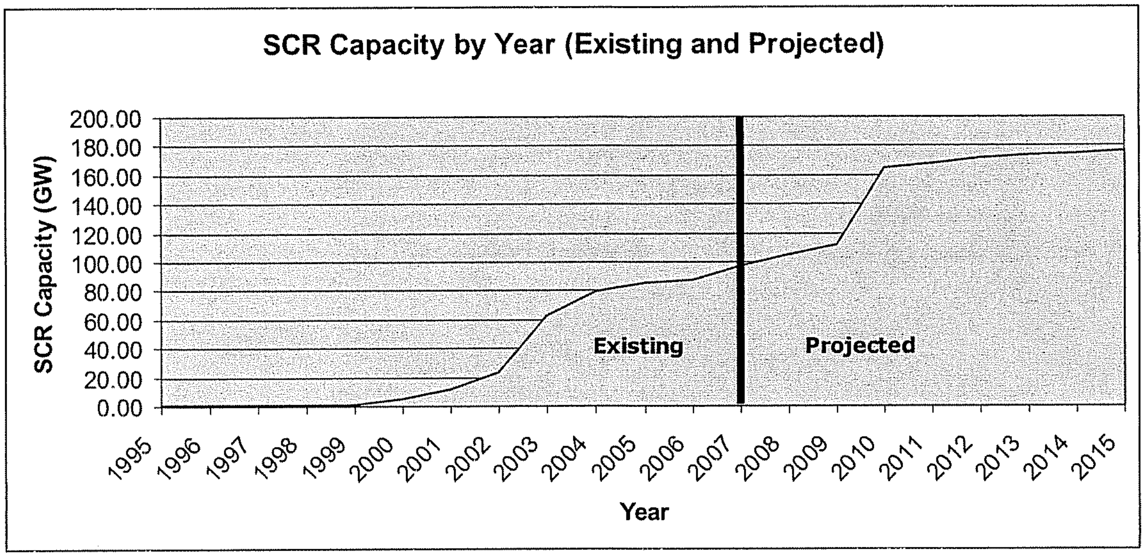
- burner optimization (excess air control, burner fine turning)
- air staging (overfire air or two-stage combustion)
- flue gas recirculation
- fuel staging (burner out of service, fuel biasing, reburning, i.e. three-stage combustion)
- low NO_x burners

These primary measures for NOx removal are fairly well understood and little has changed technologically in recent years. And again, due to their lower removal efficiencies versus SCRs, primary measures are not the first line of defense for the electric industry in its attempts to cut NOx emissions to comply with clean air regulations.

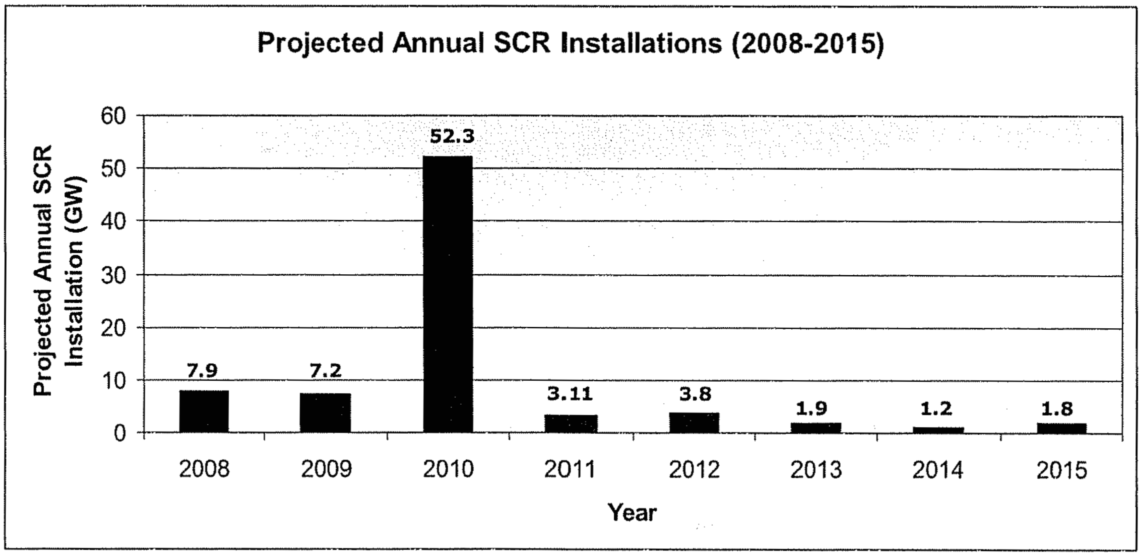
Future SCR and SNCR Installations

Global Insight closely monitors the electric power industry for any public announcements of planned SCR installations, either retrofitted on existing plants or built onto new and proposed plants. As a result of the coming CAIR regulations, the industry is on schedule to install a significant new wave of SCRs. Global Insight projects the total installed capacity of SCRs to more than double by the start of CAIR's Phase II caps in 2015.

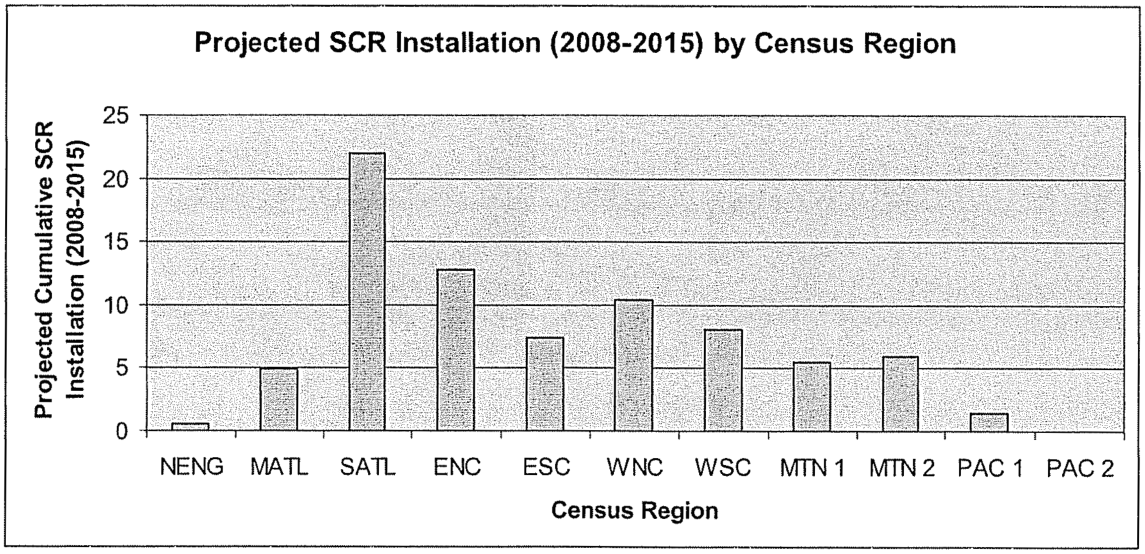
The following chart displays our projected cumulative SCR capacity until 2015:



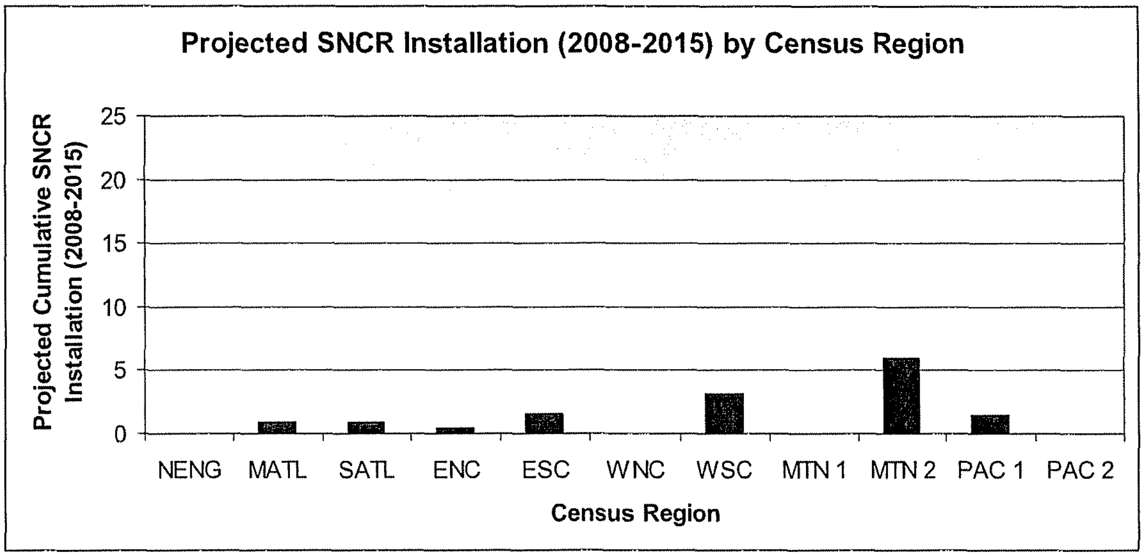
The following table breaks down the data displayed in the aggregate above and shows the annual projected SCR installation nationwide between 2008 and 2015. As is clearly evident below, a significant wave of SCRs are expected to come online in 2010 as the industry prepares for the first year of CAIR's new regulation:



The next graph displays the regional breakdown of these projected SCR installations, with the South Atlantic region on track to install over 20GW of SCR capacity between today and 2015:



And lastly, the following graph displays the relatively small projected installation of new SNCR capacity compared to the projected SCR installations. As evident below, what small quantities of SNCR that are expected to come online are projected to be concentrated in West South Central and in Arizona and New Mexico (Mountain 2):



Long-Term NOx Price Forecast

Key Considerations

♦ The Marginal Cost of SCRs – The annual market will serves as the focus for cost allocation when CAIR begins in 2009, a significant departure from previous NOx regulatory programs that focused on the seasonal market. Our assessment is that the marginal cost of SCRs in 2009 will range from $1,650-$1,930. The lower range of that estimate reflects units burning high sulfur bituminous coals, while the upper end of the range is illustrative of the growing number of units that use sub-bituminous coals, principally from the Powder River Basin.

The actual cost range for all units is actually much wider, at least at the lower end of the scale. The lowest costs are incurred by units burning low-to-mid sulfur bituminous coals. Their cost is below the marginal cost range because they can operate at close to a 90% removal efficiency, using a coal (bituminous) with relatively large emissions (that renders the "cost per ton of NOx removed" lower because total costs are divided by a larger number of tons removed). Typically, these fully allocated costs will fall below $1,500/ton.

For the previous two cases mentioned, however, the costs are higher. For units using high sulfur coal, the removal efficiency is scaled back to prevent the formation of SO3. That technique effectively lowers the number of tons removed, raising the overall cost per ton. Yet it is the units using sub-bituminous coals that incur the highest cost per ton. Even though units burning these low BTU coals can generally operate close to the 90% level, the amount of NOx emitted from this type of coal is substantially (approximately 40%) less than is the case for bituminous coals, thereby increasing the cost per ton removed.

As is the case with SO2, the marginal cost actually declines over time. In spite of higher penalties as the industry moves to the more difficult to retrofit units, improved technology overcomes these higher costs. Specifically, the major areas of improvement at this time appear to be improving the ability of units using high sulfur coals to raise their removal efficiencies without creating SO3 difficulties and the development of integrated multi-pollutant removal systems that lower both capital and operating costs.

♦ The Size of the NOx Bank – The bank of seasonal allowances under the SIP Call has already grown to the point where it is depressing prices. When CAIR is initiated in 2009, this large bank will no longer be subjected to the discounting under the PFC system, so the bank will simply grow even larger. This will tend to keep seasonal prices in the forecast quite low.

The fact that the Annual Market will commence for the first time in 2009 means that there will be no bank upon which to draw upon. This will have the effect of inflating the price, as many power companies will be inclined to take a year or two to begin building their own buffer before selling to other companies. Our assessment is that after the first two years, the technology will have once again proven itself and a large bank of NOx allowances will exist.

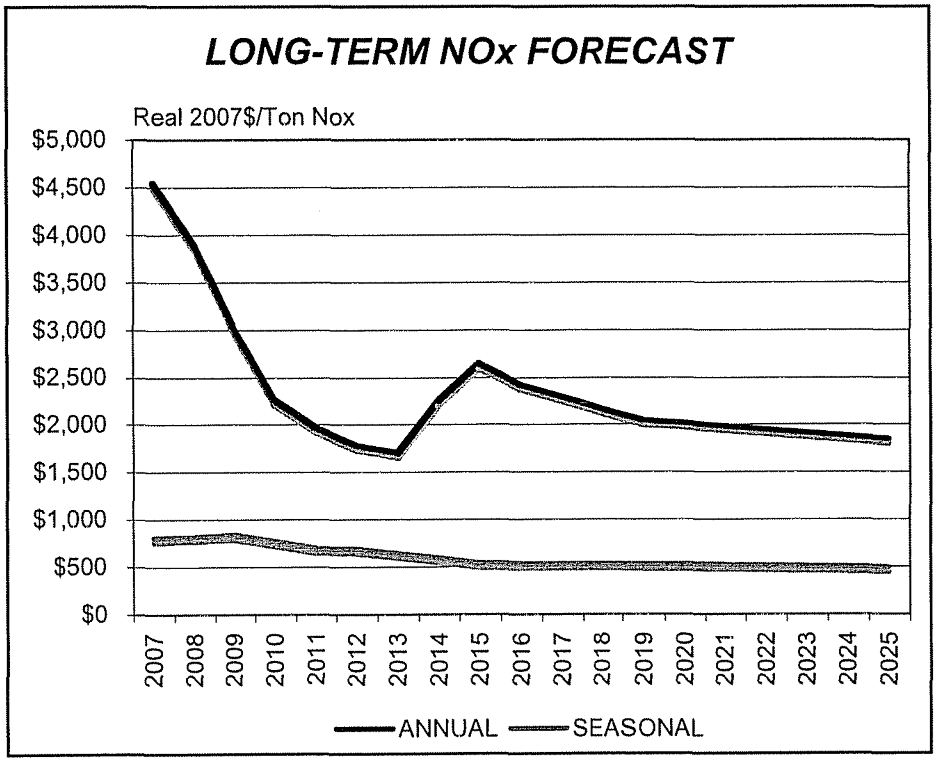
♦ Liquidity – As discussed above in the discussion regarding the size of the bank, the Seasonal and Annual markets will experience very different situations. The large bank that will already exist as CAIR begins in 2009 will make for a highly liquid Seasonal market, with few impediments to trading. The Annual Market, however, will experience considerable liquidity issues in the first two years before most companies feel sufficiently comfortable to freely sell their allowances. We suspect some companies, particularly those with considerable experience in the SIP Call, will feel quite confident in the ability of the technology to deliver and will enter the market very early as sellers in order to maximize profits during this period when prices will be the highest.

♦ Market Expectations – Most market participants are not extremely concerned that there will be severe allowance shortages or high volatility in this market. Given the past history of the NOx market, however, many observers are anticipating prices well above the marginal costs in the first and perhaps second year of the program in the Annual Market. As noted in the SO2 portion of the report, it is also clear that many participants are closely watching developments regarding a federal CO2 program and regarding the initiation of a Mercury MACT program, either of which would likely result in the accelerated retirement of older, smaller coal-fired units that would be the most likely to need to purchase allowances. Hence, these could act as a deterrent against companies purchasing allowances for use considerably beyond a few years until the outcome of these potential new programs becomes clearer.

NOx Price Forecast

In the Annual Market forecast, the price begins quite high (close to $4,000), but then subsides quickly over the next two years as the technology operates well and more sellers enter the market, having created first a buffer for their own use. The price tilts up in 2015 with the second phase of CAIR reducing allowable emissions to 0.125#NOx per million Btu.

The Seasonal Market simply declines given the nature of this more limited market. Prices in this market are also depressed due to the large bank that exists as CAIR begins and which continues to grow throughout the forecast period.


LONG-TERM NOx FORECAST
Real 2007$/Ton Nox
$5,000
$4,500
$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
2007
2008
2009
2010
2011
2012
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2017
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2019
2020
2021
2022
2023
2024
2025
ANNUAL
SEASONAL

Forecasts of Delivered Coal Prices: Coleman

COLEMAN 3-4% S, 11000 BTU

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
Nominal $/ton						
2007	$28.91	$9.12	$38.03	$28.91	$5.55	$34.47
2008	$37.81	$10.08	$47.88	$37.81	$6.02	$43.83
2009	$34.28	$9.67	$43.94	$34.28	$5.85	$40.13
2010	$35.18	$9.44	$44.62	$35.18	$5.77	$40.95
2011	$35.27	$9.33	$44.60	$35.27	$5.74	$41.01
2012	$35.37	$9.44	$44.81	$35.37	$5.82	$41.19
2013	$35.52	$9.58	$45.10	$35.52	$5.91	$41.43
2014	$35.66	$9.71	$45.37	$35.66	$6.01	$41.66
2015	$35.92	$9.85	$45.78	$35.92	$6.10	$42.03
2016	$36.27	$9.97	$46.24	$36.27	$6.20	$42.47
2017	$36.65	$10.08	$46.73	$36.65	$6.29	$42.95
2018	$37.02	$10.21	$47.23	$37.02	$6.40	$43.43
2019	$37.42	$10.33	$47.76	$37.42	$6.50	$43.93
2020	$37.78	$10.46	$48.24	$37.78	$6.61	$44.39
2021	$38.23	$10.59	$48.81	$38.23	$6.71	$44.94
2022	$38.66	$10.72	$49.39	$38.66	$6.82	$45.48
2023	$39.10	$10.87	$49.98	$39.10	$6.93	$46.03
2024	$39.50	$11.04	$50.53	$39.50	$7.04	$46.54
2025	$39.92	$11.21	$51.13	$39.92	$7.16	$47.08
Real 2007 $/ton						
2007	$28.91	$9.12	$38.03	$28.91	$5.55	$34.47
2008	$37.09	$9.88	$46.97	$37.09	$5.90	$42.99
2009	$32.96	$9.30	$42.26	$32.96	$5.63	$38.59
2010	$33.12	$8.89	$42.01	$33.12	$5.44	$38.56
2011	$32.51	$8.60	$41.11	$32.51	$5.29	$37.80
2012	$31.93	$8.52	$40.46	$31.93	$5.25	$37.19
2013	$31.44	$8.48	$39.92	$31.44	$5.23	$36.67
2014	$30.97	$8.44	$39.40	$30.97	$5.22	$36.18
2015	$30.62	$8.40	$39.02	$30.62	$5.20	$35.83
2016	$30.35	$8.35	$38.70	$30.35	$5.19	$35.54
2017	$30.11	$8.28	$38.39	$30.11	$5.17	$35.28
2018	$29.86	$8.24	$38.10	$29.86	$5.16	$35.02
2019	$29.64	$8.18	$37.82	$29.64	$5.15	$34.79
2020	$29.38	$8.14	$37.52	$29.38	$5.14	$34.52
2021	$29.19	$8.08	$37.28	$29.19	$5.13	$34.32
2022	$28.99	$8.04	$37.03	$28.99	$5.11	$34.11
2023	$28.79	$8.01	$36.80	$28.79	$5.10	$33.89
2024	$28.56	$7.98	$36.54	$28.56	$5.09	$33.65
2025	$28.35	$7.96	$36.31	$28.35	$5.08	$33.43

Forecasts of Delivered Coal Prices: Green

GREEN	3.3% S, 10500 BTU					
	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
Nominal $/ton						
2007	$27.60	$4.79	$32.39	$27.60	$3.42	$31.02
2008	$36.09	$5.29	$41.38	$36.09	$3.67	$39.76
2009	$32.72	$5.08	$37.80	$32.72	$3.59	$36.31
2010	$33.58	$4.96	$38.54	$33.58	$3.56	$37.14
2011	$33.67	$4.90	$38.57	$33.67	$3.55	$37.22
2012	$33.76	$4.96	$38.73	$33.76	$3.60	$37.36
2013	$33.91	$5.03	$38.94	$33.91	$3.65	$37.56
2014	$34.03	$5.10	$39.14	$34.03	$3.71	$37.74
2015	$34.29	$5.18	$39.47	$34.29	$3.77	$38.06
2016	$34.62	$5.24	$39.86	$34.62	$3.82	$38.44
2017	$34.99	$5.30	$40.28	$34.99	$3.87	$38.86
2018	$35.34	$5.37	$40.71	$35.34	$3.93	$39.27
2019	$35.72	$5.43	$41.15	$35.72	$3.98	$39.70
2020	$36.06	$5.50	$41.56	$36.06	$4.04	$40.10
2021	$36.49	$5.56	$42.05	$36.49	$4.09	$40.58
2022	$36.91	$5.63	$42.54	$36.91	$4.15	$41.06
2023	$37.32	$5.71	$43.04	$37.32	$4.21	$41.54
2024	$37.70	$5.80	$43.50	$37.70	$4.28	$41.98
2025	$38.11	$5.89	$44.00	$38.11	$4.35	$42.46
Real 2007 $/ton						
2007	$27.60	$4.79	$32.39	$27.60	$3.42	$31.02
2008	$35.40	$5.19	$40.59	$35.40	$3.60	$39.00
2009	$31.46	$4.89	$36.35	$31.46	$3.45	$34.91
2010	$31.62	$4.67	$36.29	$31.62	$3.35	$34.97
2011	$31.03	$4.52	$35.55	$31.03	$3.27	$34.31
2012	$30.48	$4.48	$34.96	$30.48	$3.25	$33.73
2013	$30.01	$4.45	$34.47	$30.01	$3.24	$33.25
2014	$29.56	$4.43	$33.99	$29.56	$3.22	$32.78
2015	$29.23	$4.41	$33.65	$29.23	$3.21	$32.44
2016	$28.97	$4.39	$33.36	$28.97	$3.20	$32.17
2017	$28.74	$4.35	$33.09	$28.74	$3.18	$31.92
2018	$28.50	$4.33	$32.83	$28.50	$3.17	$31.67
2019	$28.29	$4.30	$32.59	$28.29	$3.15	$31.44
2020	$28.05	$4.28	$32.32	$28.05	$3.14	$31.19
2021	$27.87	$4.25	$32.12	$27.87	$3.13	$30.99
2022	$27.68	$4.23	$31.90	$27.68	$3.11	$30.79
2023	$27.48	$4.21	$31.69	$27.48	$3.10	$30.59
2024	$27.26	$4.19	$31.46	$27.26	$3.09	$30.36
2025	$27.06	$4.18	$31.24	$27.06	$3.09	$30.15

Forecasts of Delivered Coal Prices: Henderson

HENDERSON 3-4% S, 11000 BTU

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
Nominal $/ton						
2007	$28.91	$4.79	$33.70	$28.91	$3.42	$32.33
2008	$37.81	$5.29	$43.10	$37.81	$3.67	$41.48
2009	$34.28	$5.08	$39.36	$34.28	$3.59	$37.87
2010	$35.18	$4.96	$40.14	$35.18	$3.56	$38.74
2011	$35.27	$4.90	$40.17	$35.27	$3.55	$38.82
2012	$35.37	$4.96	$40.33	$35.37	$3.60	$38.97
2013	$35.52	$5.03	$40.55	$35.52	$3.65	$39.17
2014	$35.66	$5.10	$40.76	$35.66	$3.71	$39.37
2015	$35.92	$5.18	$41.10	$35.92	$3.77	$39.69
2016	$36.27	$5.24	$41.51	$36.27	$3.82	$40.09
2017	$36.65	$5.30	$41.95	$36.65	$3.87	$40.52
2018	$37.02	$5.37	$42.39	$37.02	$3.93	$40.95
2019	$37.42	$5.43	$42.85	$37.42	$3.98	$41.40
2020	$37.78	$5.50	$43.28	$37.78	$4.04	$41.82
2021	$38.23	$5.56	$43.79	$38.23	$4.09	$42.32
2022	$38.66	$5.63	$44.30	$38.66	$4.15	$42.81
2023	$39.10	$5.71	$44.82	$39.10	$4.21	$43.32
2024	$39.50	$5.80	$45.30	$39.50	$4.28	$43.78
2025	$39.92	$5.89	$45.82	$39.92	$4.35	$44.27
Real 2007 $/ton						
2007	$28.91	$4.79	$33.70	$28.91	$3.42	$32.33
2008	$37.09	$5.19	$42.28	$37.09	$3.60	$40.69
2009	$32.96	$4.89	$37.85	$32.96	$3.45	$36.41
2010	$33.12	$4.67	$37.80	$33.12	$3.35	$36.47
2011	$32.51	$4.52	$37.03	$32.51	$3.27	$35.78
2012	$31.93	$4.48	$36.41	$31.93	$3.25	$35.18
2013	$31.44	$4.45	$35.90	$31.44	$3.24	$34.68
2014	$30.97	$4.43	$35.40	$30.97	$3.22	$34.19
2015	$30.62	$4.41	$35.04	$30.62	$3.21	$33.83
2016	$30.35	$4.39	$34.74	$30.35	$3.20	$33.55
2017	$30.11	$4.35	$34.46	$30.11	$3.18	$33.29
2018	$29.86	$4.33	$34.19	$29.86	$3.17	$33.03
2019	$29.64	$4.30	$33.94	$29.64	$3.15	$32.79
2020	$29.38	$4.28	$33.66	$29.38	$3.14	$32.52
2021	$29.19	$4.25	$33.44	$29.19	$3.13	$32.32
2022	$28.99	$4.23	$33.22	$28.99	$3.11	$32.11
2023	$28.79	$4.21	$33.00	$28.79	$3.10	$31.90
2024	$28.56	$4.19	$32.75	$28.56	$3.09	$31.66
2025	$28.35	$4.18	$32.53	$28.35	$3.09	$31.43

Forecasts of Delivered Coal Prices: Reid

REID	<2.7% S, 11000 BTU					
	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
Nominal $/ton						
2007	$33.10	$5.35	$38.45	$33.10	$5.82	$38.92
2008	$44.61	$6.21	$50.83	$44.61	$6.31	$50.93
2009	$40.27	$5.96	$46.24	$40.27	$6.13	$46.40
2010	$41.16	$5.82	$46.98	$41.16	$6.03	$47.19
2011	$41.22	$5.75	$46.98	$41.22	$6.00	$47.22
2012	$41.29	$5.82	$47.12	$41.29	$6.08	$47.37
2013	$41.42	$5.91	$47.33	$41.42	$6.17	$47.59
2014	$41.53	$5.99	$47.52	$41.53	$6.26	$47.79
2015	$41.80	$6.08	$47.88	$41.80	$6.35	$48.15
2016	$42.15	$6.15	$48.30	$42.15	$6.43	$48.59
2017	$42.55	$6.22	$48.77	$42.55	$6.51	$49.06
2018	$42.93	$6.30	$49.23	$42.93	$6.60	$49.54
2019	$43.35	$6.37	$49.72	$43.35	$6.69	$50.04
2020	$43.71	$6.45	$50.16	$43.71	$6.78	$50.49
2021	$44.18	$6.53	$50.71	$44.18	$6.87	$51.05
2022	$44.63	$6.61	$51.25	$44.63	$6.96	$51.60
2023	$45.09	$6.71	$51.79	$45.09	$7.07	$52.15
2024	$45.49	$6.81	$52.30	$45.49	$7.17	$52.67
2025	$45.93	$6.91	$52.85	$45.93	$7.29	$53.22
Real 2007 $/ton						
2007	$33.10	$5.35	$38.45	$33.10	$5.82	$38.92
2008	$43.76	$6.10	$49.86	$43.76	$6.19	$49.95
2009	$38.73	$5.73	$44.46	$38.73	$5.89	$44.62
2010	$38.75	$5.48	$44.24	$38.75	$5.68	$44.44
2011	$38.00	$5.30	$43.30	$38.00	$5.53	$43.52
2012	$37.28	$5.26	$42.54	$37.28	$5.49	$42.76
2013	$36.67	$5.23	$41.89	$36.67	$5.46	$42.12
2014	$36.07	$5.20	$41.27	$36.07	$5.43	$41.51
2015	$35.63	$5.18	$40.81	$35.63	$5.41	$41.04
2016	$35.27	$5.15	$40.42	$35.27	$5.38	$40.66
2017	$34.95	$5.11	$40.06	$34.95	$5.35	$40.31
2018	$34.63	$5.08	$39.71	$34.63	$5.33	$39.95
2019	$34.33	$5.05	$39.38	$34.33	$5.30	$39.63
2020	$33.99	$5.02	$39.01	$33.99	$5.27	$39.27
2021	$33.74	$4.99	$38.73	$33.74	$5.25	$38.99
2022	$33.47	$4.96	$38.43	$33.47	$5.22	$38.69
2023	$33.20	$4.94	$38.14	$33.20	$5.20	$38.41
2024	$32.90	$4.92	$37.82	$32.90	$5.19	$38.08
2025	$32.61	$4.91	$37.52	$32.61	$5.17	$37.79

Forecasts of Delivered Coal Prices: Wilson

WILSON	3.3% S, 10700 BTU					
	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
Nominal $/ton						
2007	$28.12	$6.59	$34.71	$28.12	$3.54	$31.66
2008	$36.78	$7.28	$44.06	$36.78	$3.80	$40.58
2009	$33.34	$6.99	$40.33	$33.34	$3.72	$37.06
2010	$34.22	$6.82	$41.04	$34.22	$3.68	$37.90
2011	$34.31	$6.74	$41.05	$34.31	$3.67	$37.98
2012	$34.41	$6.82	$41.23	$34.41	$3.72	$38.13
2013	$34.55	$6.92	$41.47	$34.55	$3.78	$38.33
2014	$34.68	$7.02	$41.70	$34.68	$3.84	$38.52
2015	$34.94	$7.12	$42.07	$34.94	$3.90	$38.84
2016	$35.28	$7.21	$42.49	$35.28	$3.95	$39.23
2017	$35.65	$7.29	$42.94	$35.65	$4.00	$39.66
2018	$36.01	$7.38	$43.39	$36.01	$4.06	$40.08
2019	$36.40	$7.47	$43.87	$36.40	$4.12	$40.52
2020	$36.75	$7.56	$44.31	$36.75	$4.18	$40.93
2021	$37.18	$7.65	$44.83	$37.18	$4.24	$41.42
2022	$37.61	$7.75	$45.36	$37.61	$4.30	$41.91
2023	$38.03	$7.86	$45.89	$38.03	$4.36	$42.40
2024	$38.42	$7.98	$46.40	$38.42	$4.43	$42.85
2025	$38.84	$8.10	$46.94	$38.84	$4.50	$43.34
Real 2007 $/ton						
2007	$28.12	$6.59	$34.71	$28.12	$3.54	$31.66
2008	$36.07	$7.14	$43.22	$36.07	$3.73	$39.80
2009	$32.06	$6.72	$38.78	$32.06	$3.57	$35.63
2010	$32.22	$6.42	$38.64	$32.22	$3.47	$35.69
2011	$31.63	$6.21	$37.84	$31.63	$3.38	$35.01
2012	$31.06	$6.16	$37.22	$31.06	$3.36	$34.42
2013	$30.59	$6.13	$36.71	$30.59	$3.35	$33.93
2014	$30.12	$6.10	$36.22	$30.12	$3.33	$33.46
2015	$29.79	$6.07	$35.86	$29.79	$3.32	$33.11
2016	$29.52	$6.03	$35.55	$29.52	$3.31	$32.83
2017	$29.29	$5.99	$35.28	$29.29	$3.29	$32.58
2018	$29.05	$5.95	$35.00	$29.05	$3.28	$32.32
2019	$28.83	$5.91	$34.74	$28.83	$3.26	$32.09
2020	$28.58	$5.88	$34.46	$28.58	$3.25	$31.83
2021	$28.40	$5.84	$34.24	$28.40	$3.24	$31.64
2022	$28.20	$5.81	$34.01	$28.20	$3.22	$31.43
2023	$28.01	$5.79	$33.80	$28.01	$3.21	$31.22
2024	$27.78	$5.77	$33.55	$27.78	$3.20	$30.99
2025	$27.58	$5.75	$33.33	$27.58	$3.20	$30.77

SO2 Allowance Price Forecast

SO2 ALLOWANCE PRICE FORECAST

Year	Nominal $/Ton	% Change	Real 2007 $/Ton	% Change
1992	$320		$438	
1993	$187	-41.72%	$249	-43.03%
1994	$164	-12.20%	$214	-14.02%
1995	$133	-19.08%	$170	-20.71%
1996	$84	-36.86%	$105	-38.02%
1997	$99	18.43%	$123	16.49%
1998	$157	58.90%	$193	57.15%
1999	$194	23.53%	$235	21.77%
2000	$141	-27.37%	$167	-28.92%
2001	$186	31.51%	$214	28.43%
2002	$153	-17.62%	$174	-19.04%
2003	$174	13.88%	$193	11.52%
2004	$438	151.30%	$473	144.36%
2005	$906	106.96%	$950	100.88%
2006	$731	-19.35%	$744	-21.65%
2007	$524	-28.32%	$524	-29.58%
2008	$454	-13.33%	$444	-15.18%
2009	$747	64.57%	$716	61.11%
2010	$887	18.64%	$833	16.31%
2011	$868	-2.11%	$799	-4.05%
2012	$878	1.16%	$792	-0.88%
2013	$875	-0.33%	$774	-2.27%
2014	$850	-2.92%	$737	-4.78%
2015	$842	-0.85%	$717	-2.71%
2016	$825	-2.13%	$688	-4.04%
2017	$757	-8.19%	$620	-9.88%
2018	$706	-6.77%	$567	-8.55%
2019	$561	-20.50%	$442	-22.05%
2020	$413	-26.36%	$319	-27.83%
2021	$350	-15.33%	$265	-16.93%
2022	$302	-13.81%	$224	-15.47%
2023	$279	-7.63%	$203	-9.38%
2024	$262	-5.99%	$187	-7.88%
2025	$240	-8.34%	$168	-10.16%

NOTE: The price depicts the cost of reducing one ton of emissions.
Under CAIR, 2 allowances generated after 2009 will be needed
to reduce one ton of emissions, and in 2015 the ratio will rise to 2.86:1
As a result, reducing a ton of emissions in 2013 would take one
pre-2010 allowance priced at $728 (nominal $), or two 2010-2012
allowances priced at $364 each.

NOx Allowance Price Forecast

NOx ALLOWANCE PRICE FORECAST (SEASONAL)

Year	Nominal $/Ton	% Change	Real 2007 $/Ton	% Change
2001	$4,976		$5,740	
2002	$4,699	-5.56%	$5,328	-7.18%
2003	$3,655	-22.22%	$4,058	-23.83%
2004	$2,250	-38.45%	$2,429	-40.15%
2005	$2,768	23.05%	$2,901	19.42%
2006	$1,814	-34.46%	$1,847	-36.32%
2007	$808	-55.49%	$808	-60.73%
2008	$837	3.66%	$819	2.50%
2009	$870	3.92%	$842	2.72%
2010	$816	-6.16%	$775	-2.04%
2011	$752	-7.92%	$699	-1.05%
2012	$759	0.93%	$692	-1.05%
2013	$715	-5.74%	$640	-1.05%
2014	$681	-4.75%	$598	-1.04%
2015	$627	-7.89%	$540	-1.04%
2016	$637	1.50%	$538	-1.04%
2017	$646	1.46%	$535	-1.04%
2018	$656	1.48%	$533	-1.04%
2019	$665	1.43%	$531	-1.04%
2020	$675	1.43%	$528	-1.03%
2021	$678	0.51%	$521	-1.91%
2022	$681	0.46%	$514	-1.92%
2023	$684	0.45%	$507	-1.94%
2024	$687	0.44%	$500	-1.95%
2025	$690	0.44%	$493	-1.97%

NOTE: Prices for 2001-2003 are for the OTC market; Prices from 2004-2008 are for the SIP Call; prices for 2009-2025 are for CAIR

NOx ALLOWANCE PRICE FORECAST (ANNUAL)

Year	Nominal $/Ton	% Change	Real 2007 $/Ton	% Change
2007	$4,543		$4,543	
2008	$3,956	-12.92%	$3,892	-14.33%
2009	$3,117	-21.21%	$3,015	-22.53%
2010	$2,383	-23.55%	$2,261	-25.01%
2011	$2,120	-11.03%	$1,972	-12.78%
2012	$1,951	-7.97%	$1,779	-9.77%
2013	$1,909	-2.18%	$1,708	-4.00%
2014	$2,570	34.64%	$2,256	32.08%
2015	$3,071	19.51%	$2,644	17.22%
2016	$2,863	-6.76%	$2,418	-8.55%
2017	$2,764	-3.46%	$2,291	-5.27%
2018	$2,665	-3.60%	$2,166	-5.44%
2019	$2,564	-3.78%	$2,046	-5.57%
2020	$2,574	0.41%	$2,016	-1.46%
2021	$2,578	0.13%	$1,981	-1.71%
2022	$2,581	0.11%	$1,948	-1.69%
2023	$2,584	0.11%	$1,915	-1.70%
2024	$2,586	0.11%	$1,882	-1.72%
2025	$2,589	0.11%	$1,849	-1.73%

NOTE: Prices for 2007-2008 are for pre-CAIR trading; prices for 2009-2025 are for the actual time period covered by CAIR

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[i] http://www.netl.doe.gov/publications/proceedings/06/ecc/pdfs/Harrison_Summary.pdf

[ii] http://www.netl.doe.gov/publications/proceedings/06/ecc/pdfs/Licata.pdf

Item 107) Please reference the Application at page 17, paragraph 33. Describe the negotiations to date with Henderson. In the description include dates, people involved, and all matters discussed.

Response) For purposes of expediting approval of any minor amendments that may be required to the Station Two Contracts in connection with a settlement with Henderson, Big Rivers proposed that it would seek a finding from the Commission in its order authorizing Big Rivers to execute any amendments to the Station Two Contracts between and among Big Rivers, City of Henderson Utility Commission and City of Henderson, which the parties may enter into prior to the closing of the Unwind Transaction, that do not materially adversely affect the Unwind Financial Model or Big Rivers' operating risks following the closing of the Unwind Transaction. This concept was the subject of Draft Settlement Concept No. 3 presented at the May 15, 2008, Informal Conference.

Based on discussions at the May 15, 2008, Informal Conference, Settlement Concept No. 3 has been revised as follows:

Big Rivers would seek a finding from the Commission in its order authorizing Big Rivers to execute any amendments to the Station Two Contracts between and among Big Rivers, City of Henderson Utility Commission and City of Henderson, which the parties may enter into prior to the closing of the Unwind Transaction, that do not "materially adversely affect" the Unwind Financial Model or Big Rivers' operating risks following the closing of the Unwind Transaction. Proposed amendments to the Station Two Contracts would be considered "not to materially adversely affect the Unwind Financial Model or Big Rivers' operating risks following the closing of the Unwind Transaction" if Big Rivers files the proposed amendments with the Commission, and after a period of consideration set by the Commission, the Commission has not objected to the proposed amendments becoming effective under the terms of the order, and no intervenor has filed a written objection to the proposed amendments becoming effective under the terms of the order.

This proposal leaves the Commission and each party free to require further examination of any amendments, yet preserves the opportunity to avoid further delays if no party objects to the amendments.

Witness) Counsel
David A. Spainhoward

Item 33) Refer to the Blackburn Testimony, page 74 of 130.

a. Provide Schedule 3.15 to the Coordination Agreements with the Smelters.

b. Explain in detail why the Coordination Agreements address how Big Rivers will account for and capitalize the assets received from the E. ON-U.S. Parties.

c. Would Big Rivers agree that the accounting for assets and capitalization requirements should conform to the provisions of the RUS USoA and CAAP? Explain the response.

d. Explain in detail how Big Rivers concluded that it was premature to perform a new depreciation study in conjunction with the Unwind Transaction and why it is reasonable to perform the new depreciation study at the time of the 2010 general rate case.

Response) Big Rivers supplements this data request response and its rebuttal testimony to address in more detail the concerns expressed at the May 15, 2008, Informal Conference (i) that the Smelter Agreements unreasonably shift risks to Big Rivers and 'front-end load' benefits for the Smelters (see Draft Settlement Concept No. 4 presented at the May 15, 2008, Informal Conference); (ii) relating to Big Rivers' agreement with the Smelters regarding depreciation (see Draft Settlement Concept No. 4 presented at the May 15, 2008, Informal Conference); and (iii) relating to the prohibition in the Smelter Agreements on rate adjustments that become effective prior to January 1, 2010 (see Draft Settlement Concept No. 7 presented at the May 15, 2008, Informal Conference).

Risk-Shifting

Big Rivers does not believe that the Smelter Agreements unreasonably shift risks to Big Rivers. In fact, the Smelter Agreements significantly buffer Big Rivers and its Members against costs they would otherwise bear in an Unwind. Big Rivers acknowledges that the chief risks of the Unwind Transaction include load concentration in serving the Smelter load and fuel risks, and that its Members will be exposed to those risks under the Unwind Transaction. *See* Big Rivers' Responses to the Attorney General's Initial Request for Information, Item 32(b). But the Smelters assume a disproportionate share of that risk exposure, while mitigating those risks to the Members. *Id.*

The Smelters assume a disproportionate share of the risk exposure through the various rate mechanisms contained in the Smelter Agreements. It should be noted that "the Smelter rates are higher than a traditional cost-based tariff." Direct Testimony of Henry W. Fayne at 13. In the aggregate, Smelter rates in excess of comparable large industrial rates increase the present value of the Unwind Transaction to Big Rivers by approximately $327 million,[1] which additional value offsets the risks Big Rivers will assume in operating the plants. *See* Application, Ex. 14, Direct Testimony of Michael H. Core at 7; Big Rivers' Responses to the Attorney General's Initial Request for Information, Item 67; Direct Testimony of Henry W. Fayne at 12-13.

The Smelters' Base Energy Charge is equivalent to $0.25/MWh above the large industrial rate (assuming a 98% load factor). Direct Testimony of Henry W. Fayne at 6-7; Application ¶ 43; Application, Ex. 9, Direct Testimony of Robert S. Mudge, Application at 19. In addition to their base rates, the "Smelters will also pay, among other amounts, the fuel adjustment clause charges and environmental surcharge amounts applicable to all Big Rivers' Member sales, the TIER Adjustment Charge… and the Smelter Surcharges."

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[1] The numbers used in this response are based on the April 22, 2008, version of the Unwind Financial Model.

Application P 43; *see also* Application, Ex. 9, Direct Testimony of Robert S. Mudge, at 19. Unlike the non-Smelter Members, the Smelters will pay Big Rivers for additional purchased power costs not covered by the fuel adjustment clause. Application, Ex. 10, Direct Testimony of C. William Blackburn, at 57, 80-81; Application ¶ 48.

The TIER Adjustment Charge can move the Smelter's payments upward within a contractually specified bandwidth. Application ¶ 46. Within that bandwidth, the Smelters pay 100% of the additional amounts required to enable Big Rivers to maintain a 1.24 TIER as defined." Application ¶ 46. So, under the TIER Adjustment Charge, "the Smelters support Big Rivers' earnings by paying an amount above base rates in order to cover 100% of Big Rivers' cost increases, under certain circumstances and within certain limitations." Application ¶ 44; *see also* Application, Ex. 10, Direct Testimony of C. William Blackburn, at 51-57. While there is an upper bound on the amount that the Smelters are required to pay as part of the TIER Adjustment Charge, if Big Rivers chose to collect additional revenue through an increase in Member Base Rates, there would be a corresponding increase in the Smelter Base Rates because the Smelter Base Rates are explicitly tied to Big Rivers' Large Industrial Customer rate. Rebuttal Testimony of C. William Blackburn at 17; Rebuttal Testimony of Henry W. Fayne at 4.

The Smelters have also agreed to pay a Smelter Surcharge. Application, Ex. 10, Direct Testimony of C. William Blackburn, at 58. Through the Smelter Surcharge, the Smelters pay additional amounts to help offset fuel and environmental charges the non-Smelter Members would otherwise have to pay. *Id.* at 58-61; Application ¶ 47; Direct Testimony of Henry W. Fayne at 6-7. The "Smelter Surcharges are meant to offset Member payments dollar for dollar." Big Rivers' Responses to the Commission Staff's First Data Request, Item 12. The "monthly Surcharge is flowed back to the Members through the Unwind Surcredit." The Smelter Surcharge will preserve the Economic Reserve and will reduce Member rates for service to non-Smelter customers. *See* Application, Ex. 10, Direct Testimony of C. William Blackburn, at 79-80.

The amount that the Smelters pay under the Smelter Agreements is in excess of what other large industrial customers with a similar load factor would pay, and is summarized in the attached Figure 1 for the periods 2008 – 2012 and 2013 – 2023.

Equally important, the Smelters are bearing additional risk not shown in the Base Case numbers above. Year-to-year, should there be costs in excess of budget not covered under the fuel adjustment clause, the environmental surcharge, or the PPA, those costs may be absorbed by the Smelters in the form of lost Rebates or additional TIER Adjustment Charges, prior to any rate increases for the non-Smelter Members. Contingent cost coverage by the Smelters is shown in the attached Figure 2.

Note that, for the period 2008 – 2012, the Smelter Agreements provide that the Smelters provide $1.47/MWh in contingent price coverage for a total potential contribution of $4.52/MWh in excess of comparable large industrial rates.

Of course, the above-described payments are dependent upon the Smelters remaining on the Big Rivers system, and Big Rivers has taken numerous steps to mitigate against the risk of the Smelters leaving the Big Rivers system. *See* Application ¶ 53. A Smelter is only allowed "to terminate its retail agreement following the commencement of service thereunder in two circumstances: (1) the termination and cessation of all aluminum smelting operations at its smelting facilities, and (2) following the occurrence of an event of default by Kenergy." Big Rivers' Responses to the Attorney General's Initial Request for Information, Item 78; Application, Ex. 10, Direct Testimony of C. William Blackburn at 66; Application, Ex. 19, Summary of New Smelter Service Arrangements, at 7. But even if it is assumed that both Smelters cancel their contracts at the earliest possible date allowed, alternative sales into the market are more than adequate to replace the lost revenues associated with the loss of the Smelter load. Big Rivers' Responses to the Commission Staff's First Data Request, Item 10. This is true even if a ten percent reduction in market prices is assumed. *Id.*

Front-End Loading

Big Rivers likewise does not believe that the benefits to the Smelters are unreasonably "front-end loaded." Big Rivers' believes that the Smelters' rationale for entering into the Smelter Agreements is to obtain benefits that occur primarily after 2012, not before. This is because a large portion of the Smelter load is served by E.On affiliates at an average rate below $25/MWh into 2011. As shown in the attached Figure 3, all-in costs to the Smelters after 2012 are projected to be significantly less in the Unwind than in the existing arrangement.[2]

Moreover, while it is true that the premia paid by the Smelters under the Smelter Agreements grow over time, this does not diminish the absolute level of Smelter contribution from 2008 - 2012, averaging $3.05 per MWh in excess of comparable large industrial rates. *See* Figure 1, attached. Also, as noted in the rebuttal testimony of C. William Blackburn, the backloading of the Smelter premia is not extreme, with approximately 26% of the present value benefit being achieved by the end of 2012, a similar proportion of the overall Unwind period (2008 – 2023). Rebuttal Testimony of C. William Blackburn at 18. So, while more of the benefits fall in the early years, it is not a dramatic difference. *Id.*

Although Big Rivers has agreed not to propose an increase in its depreciation rates through 2016, that does not change the fact that the benefits to the Smelters are not unreasonably front-end loaded. In exchange for the risks and rates that the Smelters agreed to, Big Rivers agreed not to seek a change in depreciation rates through 2016 or an increase in base rates through 2009 to give the Smelters some assurance that their costs for energy in the early years of the Unwind will not be significantly different than they expected during the negotiations. Application, Ex. 19, Summary of New Smelter Service Arrangements, at 7. These measures were aimed at providing some certainty,

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[2] Assumes market electricity prices available to the Smelters at $47/MWh in 2008, escalating approximately at inflation.

because changes in those values in the first years of the Unwind would have a significant effect on the economics of the transaction for each party. Rebuttal Testimony of Michael H. Core at 8-9. However, Big Rivers was careful to include specific exceptions to the covenant not to propose a change in depreciation rates to make sure its depreciation rates were able to change if necessary. *Id.* at 9. The depreciation rates projected in the Unwind Financial Model constitute an increase over the status quo. *Id.* And they intended to represent a plausible outcome of a depreciation study, based on the results of an approved 1994 depreciation study performed for Big Rivers. Application, Ex. 9, Direct Testimony of Robert S. Mudge, at 15-16.

One item that indicates both how the benefits to the Smelters are not unreasonably front-end loaded and how Big Rivers' is mitigating the risk of serving the Smelters is the Transition Reserve Account. Big Rivers will segregate at least $35 million of the consideration it is receiving under the Unwind Transaction to hold in this account to be available to offset any temporary revenue shortfalls that could arguably occur if one or both Smelters cease operations and terminate their contracts. Application ¶ 53. This money could have been used to provide additional front-end benefits. Instead, Big Rivers will set it aside as a risk mitigation measure, and the Smelters will receive no benefit from the account. *Id.*; Application, Ex. 10, Direct Testimony of C. William Blackburn, at 85-88.

Finally, Big Rivers is formulating a proposed schedule for selling SO_2 allowances that will further reduce the perceived front-end loading of benefits. *See* Big Rivers' updated response to Item 43 of the Commission Staff's Supplemental Data Request (filed with this updated response).

Depreciation

Big Rivers has considered the concerns expressed regarding the need for a review of its depreciation rates, and related to the need for a depreciation study. Big Rivers' position on this issue has not changed from its original position in filed testimony. In the testimony of Robert S. Mudge, he states, "[T]he depreciation rates are intended to represent a plausible outcome of such a depreciation study." Application, Exhibit 9, at 16. Big Rivers believes that it has sufficient depreciation rates in the financial model to recover cost. Big Rivers does intend to prepare a new depreciation study and submit it to the RUS and this Commission in late 2015 or early 2016.

As stated in Big Rivers' response to Commission Staff's First Data Request Item 19, "Big Rivers has agreed with the Smelters that, through 2016, it will not affirmatively seek an increase in depreciation rates beyond depreciation rates agreed by the parties prior to finalization of the Financial Model (Section 3.10 of the Coordination Agreement)." This is a material term of the agreement with the Smelters. Changes in depreciation rates obviously directly impact rates, and the depreciation rates adopted by Big Rivers are intended to maintain the rate levels contemplated in the Unwind Financial Model.

Effects of Franklin Circuit Court Order Appeal

Several concerns were expressed at the May 15, 2008, informal conference regarding the potential effect on the Smelter Agreements of the possibility that the August 1, 2007, opinion and order of the Franklin Circuit Court in *Commonwealth of Kentucky ex rel. Gregory D. Stumbo, Attorney General v. Public Service Comm'n and Union Light, Heat and Power Co.*, Franklin Circuit Court, C.A. No. 06-CI-269 (the "Franklin Circuit Court Order") could be affirmed on appeal. For example, the Smelter Retail Agreements state that no increase in the Non-Smelter Member Rates will take effect before January 1, 2010. See, for example, Section 13.1.1 of the Alcan Retail Agreement, Application Exhibit 20. During the informal conference, members of the Commission Staff expressed concern that this restriction could have devastating consequences for Big Rivers if an earlier need for revenue arises, or if the final disposition of the appeal of the Franklin Circuit Court Order requires curative rate action before January 1, 2010.

Big Rivers and the Smelters have agreed to attempt to allay those concerns by amending the Smelter Agreements to provide that if any provision of the agreements is found illegal or unenforceable as a result of that appeal, the parties will negotiate in good faith to revise the agreements to preserve the rights, benefits and economics of the parties. They have also agreed that the prohibition on a rate increase that becomes effective before January 1, 2010, will not apply to any rate increase that is required as a result of the disposition of the Franklin Circuit Court Order. These concepts are being incorporated into the Smelter Agreements and will be filed with the Commission in the next few days.

In addition, the proposed Smelter contracts are valid, even assuming that the Franklin Circuit Court order is affirmed in its entirety on appeal. First, even assuming the Smelters had an interest in attacking the Smelter Agreements (which is counter-intuitive considering the motivations of the parties), they have expressly agreed that they will not do so. The proposed Smelter Retail Electric Service Agreements provide:

> Neither Kenergy nor [Alcan/Century] will support or seek, directly or indirectly, from any Governmental Authority, including the KPSC, any challenge to or change in the rate formula set forth in this Agreement or other terms and conditions set forth herein, including the relationship of the Large Industrial Rate to amounts payable by [Alcan/Century] pursuant hereto, except that any Party may initiate or intervene in a proceeding to (i) clarify, interpret or enforce this Agreement, or (ii) challenge the applicable rate for Transmission Services should those services be unbundled for purposed of calculating the Large Industrial Rate.

Smelter Retail Electric Service Agreement § 13.1. Similarly, the proposed coordination agreements provide:

[Alcan/Century] shall...(v) not terminate or repudiate the [Alcan/Century] Retail Agreement (including by rejection or similar termination in a bankruptcy proceeding involving [Alcan/Century]) other than in accordance with the provisions thereof without the prior written consent of Big Rivers;...(vii) not take any action or support any action by others that in any manner would impede [Alcan's/Century's] ability to fulfill its obligations to Kenergy or Big Rivers under the [Alcan/Century] Retail Agreement or this Agreement or act in any manner that could reasonably be expected to materially adversely affect it ability to perform or discharge its obligations under this Agreement. Neither Big Rivers nor [Alcan/Century] will support or seek, directly or indirectly, from any Governmental Authority, including the KPSC, any challenge to or change in the rate formula set forth in the [Alcan/Century] Wholesale Agreement or the [Alcan/Century] Retail Agreement or other terms and conditions set forth therein, including the relationship of the Large Industrial Rate to amounts payable by [Alcan/Century] pursuant the [Alcan/Century] Retail Agreement, except that any Party may initiate or intervene in a proceeding to (a) clarify, interpret or enforce the [Alcan/Century] Wholesale Agreement or the [Alcan/Century] Retail Agreement, or (b) challenge the applicable rate for Transmission Services should those services be unbundled for purposed of calculating the Large Industrial Rate.

[Alcan/Century] hereby represents and warrants to Big Rivers as follows:

(b) This Agreement, the [Alcan/Century] Retail Agreement and other agreements entered into by [Alcan/Century] in connection therewith constitute [Alcan's/Century's] valid and binding obligation enforceable against it in accordance with their terms, except as enforceability may be affected by bankruptcy, insolvency or other similar laws affecting creditors' rights generally and by general equitable principles.

Coordination Agreements §§ 3.1, 3.8, 6.2. By agreeing to this language, the Smelters have clearly waived any right they would have had to challenge the contracts. *See Kraus* *v. Kentucky State Senate*, 872 S.W.2d 433, 438 (Ky. 1993) ("The right to object to a defect in a contract may be waived"); *Weil v. B.E. Buffaloe & Co.*, 251 Ky. 673, 65 S.W.2d 704, 710 (Ky. App. 1933).

Second, the Smelters are unlikely to challenge the contracts. Even if they were able to get over the waiver hurdle, the Smelters have agreed to enter into the contracts to ensure a long-term source of wholesale power at non-market rates. If they were to challenge the contracts, they would face the prospect of relying on prohibitively-priced market power, which is what they were trying to avoid through their participating in the Unwind Transaction.

Third, the Franklin Circuit Court order should not affect the Smelter contracts. The Franklin Circuit Court Order concerned a tariff rate, and it should not be extended to limit the ability of a utility and a customer to agree to a variable rate in a special contract. In the Franklin Circuit Court case, the Court was concerned with a utility passing on an expense to all customers through a surcharge without the Commission having the information or opportunity to judge the reasonableness of that expense in the context of the utility's overall financial picture. The charges contained in the Smelter contracts do not present such a concern because in the Unwind Transaction case, the Commission has virtually Big Rivers' entire financial picture before it, and the Commission is able to review the Smelter contracts in context. Further, the charges in question are contracted for by two individual, highly sophisticated customers who have expressly negotiated for those charges, and are not imposed on tens of thousands of customers who have not individually agreed to the rates.

Moreover, the variable rate in the Smelter contracts is analogous to the variable rates for the Smelters that were approved in *National-Southwire Aluminum Co. v. Big Rivers Elec. Corp.*, 785 S.W.2d 503 (Ky. App. 1990). In that case (the "*NSA Case*"), the Commission approved, and the Court of Appeals affirmed (both over the Smelters' objections), variable rates for the Smelters that were tied to the market price of aluminum. *NSA Case* at 514. The Court held that those rates did not violate Kentucky statutes. *See id.* ("NSA and Alcan next attack the imposition of a variable rate. They argue that it violates Kentucky statutes and that it discriminates against them. We conclude that there is no statutory violation and that any discrimination is either too uncertain or that it is within acceptable limits").

The Franklin Circuit Court broadly concluded that the Commission could not approve a system-wide tariff surcharge even in a general rate case without specific statutory authority. But the circumstance in the present case is more like the NSA Case, where rates were applicable only to the two Smelters, rather than the Franklin Circuit Court case, where the surcharge rates were applicable to all tariff customers. In fact, in the present case the charges are not being imposed on the Smelters, as in the NSA Case, but are being accepted with the agreement of the Smelters, making an even stronger case for enforceability.

Finally, the Kentucky Revised Statutes specifically recognize that utilities and customers enter into special contracts, and that the rates in special contracts can be different than tariff rates, like those that are the subject of the Franklin Circuit Court appeal. *See, e.g.,* KRS 278.160(3) ("The provisions of this section do not require disclosure or publication of a provision of a special contract that contains rates and conditions of service not filed in a utility's general schedule if such provision would otherwise be entitled to be excluded from the application of KRS 61.870 to 61.884 under the provisions of KRS 61.878(1)(c)"). If special contract rates were legally required to be the same as general published tariff rates, there would be no need (or basis) for confidential treatment of those rates, as is provided for in KRS 278.160(3). The fact that special contracts are recognized by the KRS Chapter 278, and the fact that the statutes do not prevent utilities and their customers from agreeing to surcharges in their special contracts (so long as they are fair, just, reasonable, not unduly discriminatory, and otherwise comply with the requirements of KRS Chapter 278), are further indications that the Franklin Circuit Court opinion's general prohibition of surcharges should not be applied to special contracts.

Witness) C. William Blackburn
Counsel

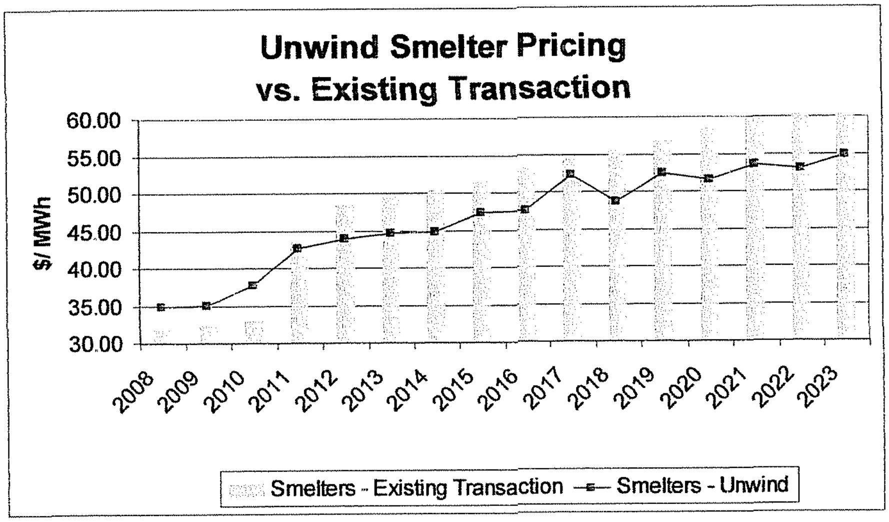
Figure 1

	Avg. $/ MWh 2008 - 2012	2013 - 2023
Large Industrial Rate @ 98% LF+FAC+PPA+ES-Rebate	36.17	44.89
Base Case Contribution:		
Margin	0.25	0.25
TIER Adjustment Charge	0.94	2.55
Surcharge 1	0.76	1.25
Surcharge 2	1.10	1.20
Total	3.05	5.25
Effective Smelter Rate - Base Case	39.22	50.15

Figure 2

	Avg. $/ MWh	
	2008 - 2012	2013 - 2023
Effective Smelter Rate - Base Case	39.22	50.15
Contingent Contribution:		
Rebate	0.25	-
TIER Adjustment Charge	1.22	1.38
Total	1.47	1.38
Max Smelter Rate - Within Bandwidth	40.69	51.53

Figure 3


Unwind Smelter Pricing
vs. Existing Transaction
$/ MWh
60.00
55.00
50.00
45.00
40.00
35.00
30.00
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Smelters - Existing Transaction
Smelters - Unwind

Item 34) Refer to the Blackburn Testimony, page 80 through 84 of 130.

a. Given the complexity of the proposed Purchased Power Account ("PPA"), the need to adjust Smelter rates to avoid double counting, and Big Rivers' apparent willingness to apply the non-Fuel Adjustment clause ("FAC") PPA to non-Smelter sales, explain in detail why Big Rivers proposed the PPA mechanism including the establishment of regulatory asset and regulatory liability accounts.

b. Explain how Big River would apply the non-FAC PPA to non-Smelter sales. Include a description of how this charge would be presented in the Unwind Model.

c. Would the other parties to the Unwind Transaction accept a change to charging the non-FAC PPA to non-Smelter sales rather than establishing regulatory asset and regulatory liability accounts as originally proposed? Explain the response.

Response) Based on discussions at the May 15, 2008, Informal Conference, Big Rivers supplements its response with the following.

Replacing the regulatory account for power purchases with a PPA clause would increase cash on Big Rivers' balance sheet, and would increase reserves from Member reserves by \$0.37/ MWh, on average from 2008 - 2023.

This would occur as a result of reversing the deferral of power purchase expense for the Members and accelerating the cash recovery of power purchase costs through the PPA component of Member rates. Except for the very early years of the financial projection, this would result in greater cash balances.

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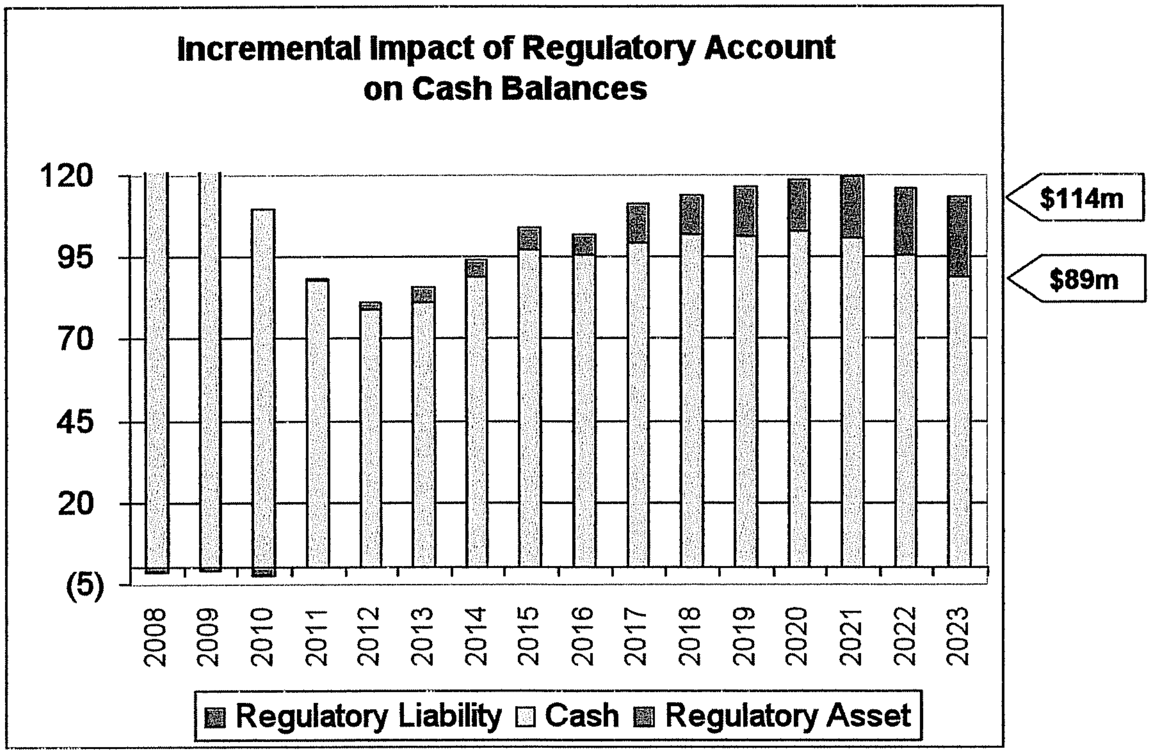
As indicated below, increased cash would displace the Regulatory Account balances reflected in filed financial models to date, with cash balances at year end 2023 rising from $89 million to $114 million.



This change in cash can be further summarized by key components, below (in millions of dollars, unless otherwise indicated):

1	**2023 Cash Balance With Regulatory Account**		88.6
2	Member PPA		57.8
3	Member Regulatory Account Charges		(33.0)
4	Net (equal to EOY 2023 Regulatory Asset Balance)		24.8
5			
6	Incremental Interest Earnings		4.9
7	Less Smelter Share (via TIER Adjustment)		(4.1)
8	Less Member Share (via Avoided GRAs)		(0.8)
9	Net		(0.0)
10			
11	Economic Reserve		(0.1)
12	Working Capital		0.4
13	**2023 Cash Balance With PPA**		113.8
14			
15	**Average Member Rate Impact**		
16	$M	Lines 4 + 8 + 11	23.8
17	TWh		64.3
18	$/ MWh		0.37
19			
20	**Average Smelter Rate Impact**		
21	$M	Line 7	(4.1)
22	TWh		114.4
23	$/ MWh		(0.04)

Witness) Robert S. Mudge
C. William Blackburn

Item 43) Refer to the Spainhoward Testimony, page 40 of 48.

a. Provide an analysis of Big Rivers' SO2 emission allowance inventory. This analysis should cover the years 2008through 2023 and include the following information for each year of the analysis.

(1) Total SO_2 emission allowances in inventory as of the beginning of the year.

(2) Total SO_2 emission allowances received from the Environmental Protection Agency ("EPA").

(3) Total SO_2 emission allowances surrendered to EOA to cover emissions.

(4) Number of SO_2 emission allowances Big Rivers anticipates it will sell.

(5) Number of SO_2 emission allowances Big Rivers anticipates it will sell.

(6) Total SO_2 emission allowances in inventory as of the end of the year.

b. Mr. Spainhoward states that during the period from 2008 through 2012 Big Rivers plans to sell any excess SO_2 emission allowances and use the revenues from these sales to reduce the level of the environmental surcharge. The Unwind Model shows that beginning in 2015 Big Rivers expects its SO_2 emissions to exceed its allocation of emission allowances. In light of this situation and the fact that SO_2

emission allowances can be banked, explain in detail why Big Rivers believes that its proposal to sell excess allowances over the next 4 years is reasonable.

c. Assume for purposes of this question that the Commission required Big Rivers to bank its excess SO_2 emission allowances during 2008 through 2012 rather than allowing the allowances to be sold. Explain in detail the effect of such a requirement on the Unwind Transaction.

Response) Big Rivers' Unwind Financial Model (Application Exhibit 8) contemplates emission allowances being sold from its inventory in the early years of the period after the Unwind Transaction Closing, and purchased in later years to meet the requirements of environmental laws regarding emissions. During an informal conference in this matter, Commission Staff expressed concern that evidence of shifting prices in the allowance market made the wisdom of this plan questionable. Staff suggested the possibility of imposing limitations on the percentage of Big Rivers' allowance inventory that could be sold in any year, subject to that limitation being removed, if found appropriate by the Commission, upon motion by Big Rivers in its first general rate case following the Unwind Transaction Closing. Draft Settlement Concept No. 29 submitted at the May 15, 2008, Informal Conference.

The Staff's concerns arose from emission allowance price forecasts they had seen in other cases that contradicted the forecasts used by Big Rivers in 2007 when the Unwind Financial Model was prepared. The latest forecast obtained is attached to Item 64 of the Attorney General's Initial Data Request. The emission allowance prices in that forecast continue to be different than those referred to by Staff.

Big Rivers believes that decisions about managing emission allowance inventories are fundamentally decisions that should be left to management of the utility, using information available at the time the decision is made. Based upon the latest allowance forecast information available to Big Rivers, and if allowance values are the same as the forecast, it would not sell emission allowances at that time, unless the allowance prices change dramatically between the then-current year and the first Big Rivers general rate case, Big Rivers would sell allowances during that period. In any event, decisions to buy or sell allowances will be based upon all facts available to management at the time the decision is made.

Witness) C. William Blackburn
David A. Spainhoward

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Item 45) Refer to the Application, Exhibit 25, the Direct Testimony of William Steven Seelye ("Seelye Testimony"), pages 6 and 7 of 34. Big Rivers states that the initial value of the Economic Reserve is expected to be $75 million, although Big Rivers is able to add to this amount of closing. Clarify the statement "although Big Rivers is able to add to this amount at closing".

a. Does Big Rivers expect the Economic Reserve to be greater than $75 million: If yes, can Big Rivers estimate the anticipated value of the Economic Reserve?

b. If Big Rivers expects the Economic Reserve to be greater than $75 million, explain the factors that determine whether the Economic Reserve will be greater than $75 million.

Response) This subject relates to Draft Settlement Concept No. 11 from the proposal discussed at the May 15, informal conference. Big Rivers, E.ON and the Smelters have reached resolution to the increased fuel issue. E.ON will increase its termination payment to Big Rivers by $152 million. Big Rivers will use a portion of these proceeds to increase its Economic Reserve account by $82 million so that the Economic Reserve will be funded at closing of the Unwind Transaction by an amount no less than $157 million. Big Rivers will establish a new Economic Reserve - Smelter account with the remaining $70 million received from E.ON. In addition, Big Rivers will fund the Economic Reserve - Smelter account with an additional $7 million for a total or $77 million. The additional $7 million from Big Rivers is approximately equal to the margins that Big Rivers will receive from its Tier 3 Energy sales to the Smelters from May through July. This time period is beyond the modeled closing date of April 30, 2008.

In order to accomplish the accounting for the new Economic Reserve - Smelter account, Big Rivers will be requesting the establishment of an additional regulatory account similar to the existing Economic Reserve account. This request will be filed with the financial model next Tuesday.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE COMMISSION STAFF'S
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Item 47) Refer to the Seelye Testimony, page 18 of 34. Big Rivers proposes that the monthly unit environmental costs to be used in the environmental surcharge for the first two or three months reflect estimates utilized in the Unwind Model rather than actual costs. Explain why the actual applicable environmental costs are not available.

Response) Big Rivers had proposed to use its projected cost in preparation of its first two months calculation for the Fuel Adjustment Clause (FAC) and Environmental Surcharge (ES). In response to the Commission Staff's concern about Big Rivers' use of projected costs, Big Rivers has asked WKEC to provide it with actual costs for the two months prior to the closing, which in turn will be used by Big Rivers to calculate its first two months of adjustments. Through the normal process of calculation of future FAC and ES charges, these first two months will be trued up to Big Rivers' actual cost of operation.

WKEC has provided actual historical data for March and April for Big Rivers to review in preparation of its FAC and ES filings with the Commission. WKEC will continue to provide historical data until closing. Therefore, Big Rivers will have the actual cost to utilize when it prepares its first two months of FAC and ES calculations. WKEC is an unregulated utility in Kentucky, and it has not been required to report this type of cost information in the past. Thus, Big Rivers will not be able to duplicate the FAC and ES detailed calculation in the exact manner that it will do so going forward. As an example, Big Rivers will have the total system average fuel cost for March and April, but it will not have the information to calculate any fuel associated with a forced outage or an economic purchase. Big Rivers proposed to use the system wide average actual fuel cost $/kWh as the basis for calculating its first monthly FAC. Again, through the normal process of calculation of future FAC and ES charges, these first two months will be trued up to Big Rivers' actual cost of operation.

Witness) C. William Blackburn/W. Steven Seelye

Item 51) Provide the final due diligence report on the physical condition of the Big Rivers generating units.

Response) The attached CD contains additional reports performed by Stanley Consultants for Big Rivers.

Witness) Mark A. Bailey

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE INITIAL DATA REQUEST OF
HENDERSON MUNICIPAL POWER & LIGHT
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Item 3) What is the estimated cost to address the repairs, replacements, upgrades or other deficiencies related to Station Two as so identified by BR?

Response) Attached is an updated 2009 O&M Non-Labor Budget to replace the 2009 O&M Non-Labor Budget originally filed in the response to this Item 3.

Witness) Mark A. Bailey

BREC - Reid/Station Two

2009 O&M Non-Labor Budget (Gross)

Number	Description	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	TOTAL
RDMAIR	RDM Air System	5,000	3,420	5,000	26,650	4,270	4,290	1,830	5,800	4,350	3,520	3,920	950	69,000
STMPAS	STM Air System	4,660	3,590	3,050	2,100	18,500	3,100	2,750	3,050	3,300	3,650	1,950	2,800	52,500
RDMASH	RDM Ash Handling	6,250	5,300	3,954	6,750	755	12,960	5,880	3,435	8,166	3,450	10,200	4,400	71,500
STMASH	STM Ash Handling	9,300	18,600	14,850	11,250	2,850	18,700	12,100	18,050	13,000	10,800	17,800	10,200	157,500
RDMSGU	RDM Boilers & Burners	10,300	12,500	11,300	6,500	2,580	3,350	4,790	3,900	2,850	12,800	12,500	9,200	92,570
STMSGU	STM Boilers & Burners	36,650	27,800	28,050	29,050	29,050	18,250	20,350	27,325	18,225	27,050	29,450	24,350	315,600
RDMFOS	RDM Fuel Oil System	900	600	400	800	650	665	575	500	210	700	500	900	7,400
STMFOS	STM Fuel Oil System	1,100	900	1,200	850	650	1,300	1,100	1,200	800	400	800	1,300	11,600
RDMCDS	RDM Condensate System	1,000	1,250	1,000	1,600	600	700	600	500	850	1,500	1,500	1,100	12,200
STMCDS	STM Condensate System	1,900	1,200	1,600	1,650	1,700	1,500	1,625	2,175	10,600	2,050	2,250	1,250	29,500
RDMDWS	RDM Demineralized Water System	900	1,300	1,500	1,000	1,800	800	900	1,000	400	1,800	1,300	1,300	14,000
RDMBFW	RDM Feedwater System	1,400	2,200	1,200	1,550	200	400	400	300	850	900	1,200	1,400	12,000
STMBFW	STM Feedwater System	5,000	5,900	9,600	6,700	4,500	6,000	5,200	5,200	7,000	7,000	7,900	5,500	75,500
RDMSGUFDE	RDM Fans/Draft System	1,500	3,400	1,600	3,600	750	1,000	2,550	1,100	1,900	600	2,500	5,500	26,000
STMSGUFDE	STM Fans/Draft System	1,000	4,750	6,250	5,500	4,000	8,500	3,200	3,500	7,350	2,600	3,700	1,600	51,950
RDMFPS	RDM Fire Protection	400	1,200	1,200	2,700	650	1,800	200	700	1,100	2,800	800	800	14,350
STMFPS	STM Fire Protection	1,000	1,000	3,500	1,500	3,000	1,000	1,500	1,500	2,500	1,000	3,500	1,000	22,000
RDMPLS	RDM Plant Lighting System	1,700	4,200	200	4,400	200	4,400	1,850	4,600	350	5,700	900	350	28,850
STMPLS	STM Plant Lighting System	9,300	5,800	10,450	5,600	8,600	4,750	5,500	6,200	4,700	8,100	8,000	6,500	83,500
RDMOHC	RDM Overhead Cranes & Hoists	3,000	600	3,000	1,900	0	5,500	2,000	400	3,700	800	1,000	0	21,900
STMOHC	STM Overhead Cranes & Hoists	0	2,500	3,600	4,000	0	1,000	0	0	4,000	1,600	1,500	1,000	19,200
RDMPCM	RDM Plant Communications	1,350	1,800	1,000	1,850	1,500	1,600	1,700	1,950	1,600	2,200	1,500	1,250	19,300
STMPCM	STM Plant Communications	1,600	1,600	1,800	1,500	1,950	2,150	2,300	1,800	1,800	1,000	2,100	1,300	20,900
RDMPST	RDM Bldgs & Grounds Site Mtce/Impr	3,100	3,600	2,300	2,800	2,800	4,500	7,400	2,500	3,300	3,550	4,450	3,700	44,000
RDMEL	RDM Bldgs & Grounds: Elevators	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,925	46,550
STMEL	STM Bldgs & Grounds: Elevators	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,875	3,925	46,550
RDMWTS	RDM Bldgs & Grounds: Sumps	3,250	1,650	8,050	4,250	1,050	5,150	15,150	9,450	3,650	4,050	1,250	3,150	60,100
RDMHVC	RDM Bldgs & Grounds: HVAC	580	3,980	1,980	3,680	2,680	3,460	5,075	3,600	5,050	340	3,260	2,040	35,725
STMHVC	STM Bldgs & Grounds:HVAC	1,200	3,630	3,750	3,750	5,750	5,760	6,275	4,250	4,100	2,050	5,000	2,285	47,800
RDMPFP	RDM Bldgs & Grounds:Winterization	1,510	1,000	600	500	500	0	0	410	1,050	15,410	410	610	22,000
RDMCW	RDM Cooling Water System	400	350	125	400	200	150	330	400	350	150	170	0	3,025
STMCW	STM Cooling Water System	1,000	700	950	1,000	1,500	1,700	1,500	1,150	750	700	1,150	1,500	13,600
RDMCWS	RDM Circulating Water/Cooling Tower	1,000	1,000	1,000	1,000	1,900	1,350	1,400	1,450	600	1,700	0	1,700	14,100
STMCWS	STM Circulating Water/Cooling Towers	5,400	4,550	6,650	6,350	6,700	8,050	5,550	5,550	6,000	15,900	5,200	5,200	81,100
RDMPCS	RDM Controls/Computer Systems	1,000	1,000	16,000	500	1,000	1,100	1,000	1,000	500	1,100	1,000	500	25,700
STMPCS	STM Plant Controls	1,800	2,000	1,900	1,700	1,800	1,800	1,000	1,200	1,900	2,000	1,300	1,300	19,700
STMPLC	STM Controls/Computer Systems	3,100	3,800	163,340	4,900	3,500	17,850	2,800	4,250	2,800	3,000	3,500	2,750	215,590
RDMRID	RDM Recording/Indicating Devices	1,000	1,500	750	600	225	450	740	450	180	900	1,000	500	8,295
STMRID	STM Recording/Indicating Devices	900	1,150	3,350	1,800	500	0	500	1,000	1,500	1,500	1,500	0	13,700
RDMMBBLU	RDM Plant Lubrication	3,000	3,000	3,000	3,000	3,000	3,500	3,500	3,000	3,000	3,000	3,000	3,000	37,000
STMCSM	STM Consummables	18,670	16,920	16,420	18,820	16,920	19,620	17,620	21,570	23,320	19,320	22,320	17,320	228,840

BREC - Reid/Station Two

2009 O&M Non-Labor Budget (Gross)

Number	Description	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	TOTAL
RDMENV	RDM Emission Controls: CEM	3,500	1,570	2,100	2,550	820	1,050	600	900	1,700	4,200	3,100	1,910	24,000
STMEVS	STM Emission Controls:CEM	6,100	7,050	9,050	5,700	14,000	4,200	7,500	5,250	5,200	11,850	4,200	5,400	85,500
RDMSGUPCP	RDM Emission Controls:Precipitators	500	500	5,800	500	700	1,100	1,500	500	1,100	200	200	700	13,300
STMSGUPRP	STM Emission Controls: Precipitators	4,000	6,500	7,000	4,000	8,000	6,000	5,500	5,000	6,500	5,000	3,500	500	61,500
STMFGXMEW	STM Emission Controls: SDRS Mist El	0	1,500	4,300	500	0	3,100	800	2,000	2,000	500	2,000	900	17,600
STMFGXPWS	STM Emission Controls:SDRS Potable	400	200	100	200	500	200	100	200	100	200	100	500	2,800
STMFGXSAB	STM Emission Controls:SDRS Absorb	1,500	5,000	1,000	1,500	2,500	1,000	3,100	1,300	1,500	1,500	2,400	1,200	23,500
STMFGXSBB	STM Emission Controls:SDRS Scrubb	100	150	100	150	100	150	700	150	150	150	150	250	2,300
STMFGXSTK	STM Emission Controls:SDRS Scrubb	500	0	1,000	400	0	1,400	0	500	1,700	500	700	700	7,400
STMFGXTRW	STM Emission Controls:SDRS Thicker	750	750	750	750	900	7,750	800	750	1,050	750	1,150	750	16,900
STMFGD	STM Emission Controls: Scrubbers	7,250	7,800	22,700	10,450	6,650	14,225	2,900	5,700	12,300	9,675	13,100	2,200	114,950
STMSCR	STM Nox Reduction-SCR Maintenance	1,000	1,000	28,200	44,500	2,000	5,000	3,000	22,200	10,680	8,100	1,000	1,000	127,680
RDMWWS	RDM Effluent Control(Waste Water Tre	750	13,000	750	1,000	750	1,000	750	1,000	750	1,000	750	1,000	22,500
STMWWS	STM Effluent Control(Waste Water Tre	500	400	350	400	500	400	500	400	500	400	350	400	5,100
RDMCHS	RDM Fuel Feed: Fuel Conveying Syste	11,400	30,320	22,800	42,620	25,420	41,020	27,420	35,520	27,320	28,880	17,400	23,420	333,540
STMCHS	STM Fuel Feed: Fuel Conveying Syste	3,975	6,200	6,175	6,275	9,075	6,175	8,900	7,475	7,875	5,525	3,550	7,025	78,225
RDMSGUFPE	RDM Fuel Feed: Mills and Feeders	2,500	5,800	2,500	6,400	600	2,700	1,000	1,400	500	5,100	1,400	2,150	32,050
STMSGUFPE	STM Fuel Feed: Mills and Feeders	6,100	8,250	12,500	9,500	5,500	7,400	6,000	4,500	9,000	7,000	8,500	3,900	88,150
RDMCHSBUS	RDM Fuel Handling:Coal Unloading Ba	4,000	3,500	14,750	4,500	7,000	14,250	12,500	10,100	4,000	7,800	15,400	5,000	102,800
RDMCWSINT	RDM Screenwell Maintenance	2,500	7,050	13,500	12,000	2,800	1,800	5,400	4,300	3,550	1,600	2,500	4,000	61,000
RDMPWS	RDM Potable Water System	800	350	370	500	1,100	620	900	450	500	850	450	600	7,490
STMPWS	STM Service Water System	100	100	100	100	100	100	100	100	100	100	100	100	1,200
RDMEDT	RDM Switchgear/Bus	250	1,300	450	150	1,400	6,000	300	7,700	6,000	200	500	100	24,350
STMEDT	STM Switchgear/Bux	1,400	7,900	7,500	2,400	6,500	6,700	7,850	450	8,250	1,200	12,400	1,200	63,750
STMTGNDGS	STM Diesel/Generator	100	70	0	600	200	0	200	500	0	1,500	0	800	3,970
RDMGEU	RDM General Use Equipment	1,700	1,700	2,700	1,700	1,700	2,700	2,200	1,200	3,200	1,700	1,200	2,700	24,400
STMTR	STM Tool Room	3,500	3,400	4,050	3,250	3,600	4,000	4,700	6,000	5,500	4,500	5,500	4,500	52,500
RDMTGN	RDM Turbine/Generator	2,500	2,500	2,600	1,750	700	850	1,100	800	1,100	1,750	2,100	2,250	20,000
STMTGN	STM Turbine/Generator	4,000	5,000	3,100	4,750	3,500	3,500	5,400	4,600	4,150	5,500	4,000	3,000	50,500
RDMMEQ	RDM Non-Fuels Equipment	200	500	200	500	200	500	200	500	200	500	200	500	4,200
RDMPVE	RDM Vehicles	3,400	4,900	2,900	4,050	5,050	4,950	3,450	2,800	4,450	6,000	4,100	2,350	48,400
RDMMBBMT	RDM Maintenance Training	1,250	3,250	1,250	1,250	1,250	24,250	6,250	3,250	1,250	1,250	3,250	1,250	49,000
RDMEDGT	RDM Combustion Turbine-Electrical D	400	400	800	300	500	900	500	500	400	0	600	300	5,600
RDMFSPGT	RDM Combustion Turbine-Fire Protect	1,000	450	600	500	500	200	600	400	200	400	3,000	200	8,050
RDMGT	RDM Combustion Turbine	0	1,000	7,000	3,200	2,000	0	1,000	0	3,000	17,700	61,100	1,000	97,000
RDMMEQCLE	RDM Mobile Fuels Equipment	6,700	6,700	6,700	6,700	59,700	6,700	6,700	6,700	6,700	46,700	6,700	6,700	173,400
STOMEQ	STO Mobile Fuels Equipment - Fuel Ha	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	8,600	103,200
STOCHSBUS	STO Coal Unloading Barge - Fuel Hand	0	0	12,000	0	12,000	0	12,000	22,000	0	12,000	0	0	70,000
STCHPST	STO Buildings & Grounds - Fuel Hand	5,750	5,750	2,750	5,900	5,150	11,275	5,150	5,150	6,275	3,275	2,750	5,750	64,925
STCHCSM	STO Consummables - Fuel Handling	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
STCHTR	STO Tool Room - Fuel Handling	700	700	700	700	700	700	700	700	700	700	700	700	8,400

BREC - Reid/Station Two

2009 O&M Non-Labor Budget (Gross)

Number	Description	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	TOTAL
STCHOIS	ST Outside Industrial Service - Fuel Hε	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	66,000
STOSCR	STO HMPL SCR Operation	6,250	6,250	30,250	6,250	6,250	126,250	6,250	6,250	6,250	82,250	84,250	6,250	373,000
STMFGX	STM Limestone Grinding/Processing	4,888	14,588	21,388	18,188	12,988	11,988	10,688	8,688	7,189	13,189	10,189	6,189	140,160
STOMEQCVH	STO Vehicles (Mtc, Gas, Oil)	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	3,300	39,600
STOFGD	STO HMPL FGD Shared Equipment	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	38,638	463,656
STOADM	STO Administrative	16,104	16,104	14,131	15,103	15,964	6,175	16,995	18,405	17,657	7,694	5,254	16,129	165,713
STOLAB	STO Laboratory	13,050	15,350	30,400	18,750	22,300	33,700	13,200	15,450	36,880	16,250	15,900	23,700	254,930
STDREDGE	ST Dredging Ash Ponds	0	0	0	0	0	5,000	0	0	10,000	0	0	0	15,000
STOPST	STO Buildings & Grounds - Operation:	11,640	14,640	11,640	19,595	10,595	12,095	12,095	35,595	10,595	10,595	19,595	11,695	180,375
STOCSM	STO Consummables - Operations	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
RDOSGUFPE	RDO Mills and Feeders	5,000	5,000	5,000	5,000	0	0	0	0	0	5,000	5,000	5,000	35,000
STOSGUFPE	STO Mills and Feeders	13,500	13,500	13,500	7,000	13,500	13,500	13,500	13,500	13,500	13,500	13,500	13,500	155,500
STOTR	STO Tool Room - Operations	0	0	2,550	0	1,000	0	1,500	0	350	1,000	0	1,000	7,400
STOTGN	STO Turbine/Generator	5,330	5,330	5,340	5,330	5,330	5,340	5,330	5,330	5,340	5,330	5,330	5,340	64,000
STOIS	ST Outside Industrial Service - Operati	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	156,000
STOSGU	STO Boilers and Burners	27,000	33,000	25,500	0	19,200	42,000	18,000	0	27,800	33,000	18,000	0	243,500
RD109xxx	R1 - Major Initiatives	0	0	0	18,000	0	19,500	95,000	10,000	19,500	0	0	0	162,000
RD09xxx	RD - Major Initiatives	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	371,315
ST109xxx	H1 - Major Initiatives	0	80,000	150,000	0	0	0	0	0	30,000	0	0	0	260,000
ST209xxx	H2 - Major Initiatives	0	0	0	0	0	0	30,000	0	0	0	0	0	30,000
ST09xxx	H0 - Major Initiatives	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	30,943	371,315
RD109USO	R1 - Unscheduled Outages	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	17,500	210,000
ST109USO	H1 - Unscheduled Outages	7,000	7,000	0	0	7,000	7,000	7,000	7,000	7,000	7,000	7,000	7,000	70,000
ST209USO	H2 - Unscheduled Outages	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	360,000
RD109XXO	R1 - Planned Outage (Ops)	0	0	0	0	0	0	0	0	0	0	0	0	0
ST109SPO	H1 - Spring Planned Outage (Ops)	0	0	157,000	0	0	0	0	0	0	0	0	0	157,000
ST209XXO	H2 - Planned Outage (Ops)	0	0	0	0	0	0	0	0	0	0	0	0	0
RD109XXX	R1 - Planned Outage (Mtc)	0	0	0	0	0	0	0	0	0	0	0	0	0
ST109SPG	H1 - Spring Planned Outage (Mtc)	0	0	2,159,755	0	0	0	0	0	20,000	0	0	0	2,179,755
ST209XXG	H2 - Planned Outage (Mtc)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total 2009 R/STII Non-Labor O&M (Gross)		541,130	712,685	3,371,292	677,634	634,746	842,742	714,742	636,751	707,336	765,427	733,571	510,486	10,848,544
HMPL Allocation		122,841	167,245	975,049	157,445	153,606	209,641	149,083	150,244	167,731	179,869	164,333	114,938	2,712,025
Total 2009 R/STII Non-Labor O&M (Net)		418,289	545,440	2,396,243	520,189	481,140	633,101	565,659	486,507	539,605	585,558	569,239	395,549	8,136,519

Item 88) Provide any and all internal E. ON documents which address the subject of existing agreements which are the subject of the "Unwind Transaction" and "Termination Transaction", including any financial analyses and strategic analyses.

Response) Big Rivers files this supplement to its response to Item 88 of the Attorney General's Supplemental Request for Information in response to requests by the Attorney General and the Commission Staff for more information regarding the generating plant and plant site due diligence Big Rivers is performing in anticipation of the Unwind Transaction closing. For the convenience of the Commission and the parties, Big Rivers has assembled in this supplemental response references to most of the information on its due diligence that has been filed in the record in this matter. This Supplemental Response also relates to Draft Settlement Concept No. 1 presented at the May 15, 2008, Informal Conference in this matter.

Big Rivers believes that its knowledge of the condition of its owned-leased and previously operated plants at the closing of the Unwind Transaction will be substantially greater than the knowledge of facility conditions most utilities would have upon the acquisition of generating plants. The due diligence conducted by Big Rivers on its generating units and sites did not commence at the time the Unwind Transaction began to appear viable. Big Rivers constructed those units and operated them until 1998. It employs persons who have institutional history and memory regarding the condition of those units through 1998. Robert Berry, the person who will be the Vice President and Chief Production Officer of Big Rivers after the Unwind Transaction closing is a former Big Rivers employee, and the current plant manager of the Green/Reid/Station Two operations. Testimony of Mark Bailey, Application Exhibit 5, page 8. "Almost every Western Kentucky-based employee of WKEC will [also] become an employee of Big Rivers, including the plant managers and personnel, most of whom were employees of Big Rivers prior to 1998, bringing with them a thorough knowledge of the operation of the Big Rivers' generating stations and Station Two." Application, pages 32 and 33.

Since 1998, subsidiaries of E.ON have had the obligation to operate and maintain the generating units owned by Big Rivers, or operated by Big Rivers under agreements with Henderson. Application, p. 8. During that period, WKEC has made millions of dollars of capital improvements to the plants under budgets reviewed, investigated and contributed to by Big Rivers in connection with the budgeting and cost-sharing processes established under the 1998 Transaction agreements. See Big Rivers' Response to Item 141 of Attorney General Initial Request for Information, Big Rivers' Response to Item 8 of Commission Staff Initial Request for Information and E.ON Entities' Response to Item 8 of Commission Staff Initial Request for Information.

Big Rivers also engaged Stanley Consultants Inc. ("Stanley") in 2000 to begin making an annual review of generating plant condition, including physical inspection of the plants, review of plant inspection reports prepared by vendors and consultants and review of plant operating and performance data. Beginning in 2006, when Big Rivers thought a closing of the Unwind Transaction might be imminent, Stanley's reports to Big Rivers were condensed to data that could be included in an annual report in the future without the expense of preparing a full report should the Unwind not occur. Stanley's role changed somewhat from outage visits and once a year on-site walk-down, to having two full-time people who are stationed on-site. The Stanley reports, which have been reviewed by Big Rivers as part of its due diligence, are filed in the record. Big Rivers' Response to Item 51 of the Commission Staff's Initial Information Requests.

Big Rivers has made additional, in-depth due diligence of generating plant condition a priority in the terms of the Termination Agreement itself (Application, Exhibit 3), in part because there are no warranties in the Termination Agreement by the E.ON entities regarding plant condition that extend beyond the Unwind Transaction closing. For example, Big Rivers required warranties and representations from the E.ON parties regarding environmental conditions (Section 11.1(k)), correctness of diligence materials (Section 11.1(l)) and the obligation to deliver diligence materials (Section 11.1(m)).

The Termination Agreement deals with a number of issues that would not have been known to Big Rivers but for its ongoing diligence efforts prior to the date the Termination Agreement was negotiated. For example, the closing conditions expressly require resolution or satisfaction before closing of issues related to: the Station Two H1 boiler event (Section 10.3(l)); gypsum facilities removal (Section 10.3(cc)); status of gypsum offtake agreement (Section 10.3(hh)); and cleaning of Wilson ponds (Section 10.3(jj)). The closing conditions also protect Big Rivers from the implications of due diligence problems that Big Rivers discovers prior to closing, such as: casualty damage to the generating plants (Section 10.3(w)); environmental conditions (Section 10.3(y)); condition of generating plants (Section 10.3(dd)); testing of generating plant capability (Section 10.3(ee), and see also Section 12.7); forced outages (Section 10.3(ff)); requirements that WKEC comply with its own operating plans, including expenditures (Section 10.3(ii), and see also Section 12.2); compliance of plants with reliability standards (Section 10.3(ll)); and unresolved disputes (Section 10.3(mm))
The Termination Agreement specifically provides the methodology for certain due diligence issues, such as determination of the quantities and value of inventory and personal property (Article 4), receiving notice of forced outages prior to closing (Section 12.2(b)) and procedures to address noncompliance by WKEC with its operating plan (Section 12.5(c)). Article 15 of the Termination Agreement contains extensive terms regarding an environmental audit and environmental indemnities, which cover subjects for which due diligence is difficult.

Big Rivers' representatives have made hundreds of due diligence requests of the E.ON Entities. Each due diligence request is separately tracked, and the product of the request is placed on a Big Rivers FTP site, where those who need access to the information can retrieve it.

Big Rivers and others have filed in this proceeding in response to information requests a number of items Big Rivers has considered in connection with its due diligence. Big Rivers has filed a copy of 74 different reports and studies (under a Petition for

Confidential Treatment) that it has produced or collected with respect to the generating facilities and sites. Big Rivers' Response to Item 6 of Henderson's Initial Data Request. The Stanley reports have been filed, as noted above. The Smelters have filed the Stone & Webster report, which Big Rivers has also considered (Big Rivers' Response to Item 83 of Attorney General's Second Request for Information), although neither Big Rivers nor the Smelters consider the Stone & Webster report to be a "work plan" for Big Rivers going forward. Rebuttal Testimony of Henry Fayne, page 4. Although not filed in this case, and protected by confidentiality agreements, Big Rivers has also reviewed engineering reports produced by Henderson regarding the Station Two units. Information on the recent operation performance of the units regarding heat rate, net capacity factor, equivalent availability factor and equivalent forced outage rate are filed with Big Rivers' Response to Item 3 of the Commission Staff's Second Supplemental Information Request.

As Big Rivers has explained in its responses to information requests in this proceeding, due diligence is a process, not an end in itself. See the rebuttal testimonies of Mark Bailey, pages 2-5 (due diligence efforts of Big Rivers are more than adequate), and Michael Core, pages 5-7 (due diligence is a process; a single, comprehensive "due diligence report" not contemplated or required); see also Big Rivers' Response to Items 109 and 110 of the Attorney General's Initial Request for Information, and to Item 88 of Attorney General's Supplemental Request for Information. The components of Big Rivers' due diligence plan include: (i) inspection of O&M records at each site; (ii) engineering evaluation of condition of plants by Big Rivers and Stanley Consultants; (iii) review E.ON's operating plans; and (iv) physical test of operating capability of the generating facilities to be conducted prior to closing. Big Rivers' Response to Item 1 of the Commission Staff's Initial Request for Information.

With respect to the due diligence process at the generating plants and sites, since 2005, Big Rivers has employed a person whose duties include visiting each generating plant each week to monitor the condition of the plant and the performance by WKEC of its obligations under the existing transaction. After the Termination Agreement was signed in March of 2007, Big Rivers added two Stanley employees/consultants to this task, assigning one person full-time to each of the generating plant sites. These persons became part of the Termination Agreement Execution Team ("TAE"). In addition to their preexisting duties, members of the TAE track performance by Big Rivers and the E.ON entities of their respective obligations under the Termination Agreement. This includes monitoring the condition of the generating plants so that Big Rivers' management can determine on the date of closing whether, "[s]olely in the reasonable judgment of Big Rivers, each Generating Plant shall be in all material respects in good condition and state of repair, ordinary wear and tear excepted, consistent with Prudent Utility Practice." Termination Agreement, Section 10.3(dd). In the Termination Agreement Big Rivers obtained expanded rights to have these representatives present in the plants performing due diligence activities prior to closing. Termination Agreement, Section 12.2(a).

The TAE team members report at least weekly to a supervisor, who tracks compliance with the Termination Agreement on a Gaant chart, and reports any due diligence issues to a Big Rivers vice president. Issues are evaluated and, as deemed appropriate, an issue could be put on a list for resolution with the E.ON entities pursuant to a closing condition, or added to the Production Work Plan for correction after closing. Any material issues with the condition of a generating plant will be resolved before closing, which could include a revision to the Production Work Plan with the cost of resolution appropriately reflected in the Unwind Financial Model. Issues that arise may also be reviewed by other Big Rivers employees, and Big Rivers' consultants and counsel as appropriate. Big Rivers' Response to Items 127, 131 and 133 of Attorney General's Initial Request for Information.

The Big Rivers Production Work Plan, filed in response to Item 1 of the Commission Staff's Second Supplemental Request for Information, has been included in the Unwind Financial Model, and will allow Big Rivers to meet the generation and reliability levels anticipated by the Unwind Financial Model. Big Rivers' Response to Commission Staff's Second Supplemental Request, Item 2 and Item 92 of Attorney General's Supplemental Request for Information. This includes capital expenditures for environmental compliance that are anticipated and included in the Unwind Financial Model. Big Rivers' Response to Item 5 of the Commission Staff's Second Supplemental Request for Information. Some of the items in the Big Rivers Production Work Plan and capital budget were not and are currently not in the WKEC capital budget. Testimony of Mark Bailey, Application Exhibit 5, page 16; Big Rivers' Response to Item 94 of Attorney General's Supplemental Request for Information. The projections in the Production Work Plan are consistent with the projections in the Unwind Financial Model. Big Rivers' Response to Item 2 of Commission Staff's Second Supplemental Request for Information. In addition to assessing the physical condition of plants, Big Rivers has also performed economic modeling on the reliability of Reid I, and included the results in the Unwind Financial Model. Big Rivers' Response to Item 96 of Attorney General's Supplemental Request for Information.

Ultimate management responsibility for evaluation of any generating plant and site due diligence issues rests with Mark Bailey, who will succeed Michael Core as president and CEO of Big Rivers at some point after the Unwind Transaction closing. Mr. Bailey is an electrical engineer with over 34 years of experience in the utility industry, including 10 years in coal-fired generating plants. He is the person who will have responsibility for operating Big Rivers post-closing, and for securing the funds to correct any issues with the generating plants that are not resolved prior to closing and included in the Production Work Plan at closing. He accordingly has an intense interest in detecting and resolving any generating plant condition issues prior to closing.

Big Rivers has not planned to generate a "due diligence report," as such. Big Rivers' Response to Item 51 of the Commission Staff's Initial Request for Information. Mr. Bailey, however, has previously and as recently as on May 16, 2008, reported to the Big Rivers board of directors verbally and in a follow-up memorandum on his current satisfaction that Big Rivers will be taking back generating plants that, in the end, are in appropriate condition to perform as anticipated under the Unwind Financial Model. A copy of his memorandum to the Big Rivers board of directors on this subject dated May 29, 2008, is attached. Big Rivers will also create a post-closing memorandum on disposition of closing conditions, including those related to the condition of the generating plants. Rebuttal Testimony of Michael Core, page 12.

The Smelters have also expressed their comfort with the plans of Big Rivers for operating and maintaining the generating units. Response of Smelters to Item 4 of Attorney General's Supplemental Request for Information. Their consultant on the condition of the generating units, Stone & Webster, concluded that Big Rivers' system is in "reasonable condition, and capable of performing on a reliable basis, consistent with industry standards." *Id.* Ultimately, however, a determination of whether the plants are in all material respects in good condition and state of repair is a business judgment only Big Rivers can make.

Witness) Mark A. Bailey

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MEMORANDUM

TO: Big Rivers' Board of Directors

FROM: Mark Bailey

DATE: May 29, 2008

SUBJECT: Condition of Big Rivers' Generating Plants

I am writing in follow-up to various conversations we have had over the past several years, including at the most recent May 16, 2008 board meeting, regarding the condition of Big Rivers' generating plants. As Big Rivers' President & CEO-Elect, I recognize that following the "unwind," I will be ultimately accountable and responsible to see that the company safely delivers low-cost, reliable power to its members. Based on my engineering education along with 34 years engineering and management experience in the electric utility industry including many years involving various operation and maintenance management assignments at a number of AEP power plants, I further recognize that reliable, low-cost generating facilities are the key to fulfilling that responsibility.

Because of their importance, I have paid close attention to our power plants, both while I was CEO of Kenergy as well as after joining Big Rivers last June as Executive Vice President. As you know, Big Rivers has utilized Stanley Consultants to monitor the plant conditions since the early 2000s through the present. We also have employees assigned to the plants to observe plant operations and maintenance and regularly communicate with local plant management. These individuals regularly review plant conditions and maintenance work that is performed, and also monitor plant budgets and expenditures.

I have examined the various reports produced by Stanley as well as reports prepared by Henderson Municipal Power & Light's engineering consultants. In addition, I have reviewed the Stone & Webster draft and final reports produced for the aluminum smelters as part of their due diligence of the "unwind" transaction. In general, it has been my observation that many of the items documented in many of these reports should have very little impact on the ability of the plants to produce low-cost, reliable electricity. I have also found that when major areas of concern have arisen, as they do in facilities as complex as generating stations, WKE addressed them in an effective manner.

In addition to these activities, I have examined the historical operating performance of the units. You may recall I have said on numerous occasions, both while I was with Kenergy as well as after joining Big Rivers, that based on my experience, a generating unit's performance will deteriorate rather quickly (e.g., 3–5 years) if it is not adequately maintained. In studying WKE expenditures since it began operating the units, I have found that base annual gross (including HMP&L's share of Station Two) capital and O&M expenditures have steadily increased from approximately $36.5 million in 1999 to nearly $65 million in 2007; a 78 percent increase which is nearly triple the rate of inflation (CPI) over that period. Given this information, combined with the fact that the Big Rivers' units are still performing well after ten years of WKE oversight, it is difficult to conclude they have not been adequately maintained. I have also recently walked down all the units and spoken with local plant management about the condition and operation and maintenance of the facilities, and am comfortable with what I have seen and heard.

As you know, Bob Berry, currently the plant manager of the Reid-Green plant and a 27-year veteran of both Big Rivers and WKE, who has also worked in various maintenance and management positions at the Coleman Plant, will assume the position of Vice President of Power Production following the "unwind." Since Bob has agreed to re-join Big Rivers in this capacity, I have worked closely with him and am quite comfortable with his knowledge, experience and management philosophy. Together, we have worked with the current Big Rivers' personnel who have primary plant monitoring responsibilities to develop a Production Work Plan which Bob and I believe will enable Big Rivers to safely meet the generation and reliability levels included in the "unwind" financial model.

Based on the activities described earlier as well as my experience with generating facilities of various design, size and age including some with similar characteristics as the Big Rivers' units, I am comfortable with the current condition of the generating facilities with the exception of the Coleman Unit 1 low pressure (LP) turbine rotor which is currently undergoing repairs found necessary during its regularly scheduled routine outage. Assuming that turbine is properly repaired, demonstrates it can operate normally and generate its rated output following its return to service prior to close of the "unwind" transaction, I will be comfortable with it as well.

Even though I am presently comfortable with the plant situation, there are still a number of conditions that must be met between now and the "unwind' closing before I will be completely satisfied that the plant due diligence portion of the Termination Agreement closing conditions are satisfied. For example, the plants must continue to operate without any significant abnormalities arising between now and the closing that would impact their ability to reliably generate at their rated levels and at their predicted cost profile. In addition, WKE must complete the 2008 Production Work Plan scheduled to occur up to closing and spend the budgeted funds necessary to complete that work. The units must also demonstrate their ability to operate at their rated output under normal conditions for eight continuous hours. Other due diligence items found, if any, will also need to be addressed to Big Rivers' satisfaction. If these conditions are not met, then WKE will either need to make satisfactory corrections similar to what I described earlier in the case of the Coleman 1 LP turbine and/or agree to other remedies which will permit Big Rivers to satisfactorily correct the deficiencies post-close and recover any modeled revenue lost in the process.

In closing, I want to reiterate a point noted earlier. Power plants are complex facilities with many things that can go wrong which will occasionally occur even in the best-managed operations. While Big Rivers' plant management plans to rely heavily on condition- based maintenance practices designed to detect, predict, and permit correction of major problem areas before they occur to minimize significant unplanned situations, they will still likely happen occasionally as they have in the past. If the "unwind" proceeds and these unexpected situations arise, Big Rivers will be much stronger financially and thus much better positioned to deal with them than we are at present.

I hope you find this information helpful in understanding how I have become and why I am currently comfortable with the plant conditions and also in understanding what must occur between now and closing for the plant portions of the Termination Agreement closing conditions to be satisfied.

c: Burns Mercer
Kelly Nuckols
Sandy Novick

Item 119) Please refer to the Response of OAG # 41. Provide a summary of outcomes and action steps and associated timelines/milestones from the "scheduled meetings".

Response) Big Rivers provided the following documents to Standard & Poor's or to Moody's. The documents which have not previously been filed with the Public Service Commission are contained on the attached CD.

1. The following wholesale power contracts between Big Rivers and its Member Cooperatives, all of which have been filed with the Public Service Commission.

A. JPEC Contracts

1. Amendment 1 to Wholesale Power Contract, dated May 9, 1980
2. Supplemental Agreement, dated October 14, 1977
3. Letter Agreement, dated October 14, 1977
4. Agreement, dated October 14, 1977

B. Kenergy (Henderson Union) Contracts

1. Wholesale Power Contract, dated June 11, 1962
2. Supplemental Agreement, dated June 11, 1962
3. Supplemental Agreement, dated July 22, 1970
4. Amendment to Wholesale Power Agreements, dated July 15, 1998 (filed in Appendix A to Application)
5. Agreement of Big Rivers Electric Corporation with respect to Future Policies and Procedure regarding Big Rivers' Transmission System, dated July 15, 1998 (filed in Appendix A to Application)

6. RUS-Member Agreement

C. Kenergy (Green River) Contracts

1. Wholesale Power Contract, dated June 11, 1962
2. Supplemental Agreement, dated June 11, 1962
3. Supplemental Agreement No. ___ to Wholesale Power Contract
4. Agreement, dated October 12, 1974
5. Amendment to Wholesale Power Agreement, dated December 12, 1975
6. Amendment No. 2, dated March 9, 1976
7. Amendment No. 3, dated May 9, 1980
8. Wholesale Power Agreement, dated February 16, 1988
9. Agreement of Big Rivers Electric Corporation with respect to Future Policies and Procedure regarding Big Rivers' Transmission System, dated July 15, 1998 (filed in Appendix A to Application)
10. RUS-Member Agreement

D. Meade County Contracts

1. Wholesale Power Contract, dated June 11, 1967
2. Amendment to Wholesale Power Contract, dated December 15, 1975
3. Amendment 2 to Wholesale Power Contract, dated May 9, 1980

2. Transaction Termination Agreement (Exhibit 3 to the Application).

3. The Guarantee of E.ON US LLC of the obligations of its subsidiaries under the Transaction Termination Agreement and the other operative documents in connection with the Unwind (contained on the attached CD).

4. Indenture (Exhibit 49 – filed April 11, 2008, with Second Amendment and Supplement to Application).

5. Intercreditor Agreement (Exhibit 65 – filed April 23, 2008, with Third Amendment and Supplement to Application).

6. 12 Unwind Financial Models and a table of contents for the models (contained on the attached CD.

7. Spreadsheet of generating unit performance statistics (contained on the attached CD as the file titled "Performance Indicators 2002-2007.xls").

8. Financial and Statistical Reports for the Member Cooperatives for 2003-2007 (contained on the attached CD).

9. Power Point Presentation entitled "Discussion with Standard and Poor's" (contained on the attached CD).

Witness) C. William Blackburn

Item 120) Please refer to Big Rivers' Power Point presentation, "Discussion of Unwind Financial Model" dated January 2008. Please update this presentation to incorporate revised data from the 2.14.08 version of the Unwind Model as provided to the parties, where the newer version changes the data in the original presentation.

Response) Big Rivers proposed in Draft Settlement Concept No. 12 presented at the May 15, 2008, Informal Conference, that it would commit to filing with the Commission on or before June 30 of each year, through the date on which it files a case for a general adjustment of its rates, the "Big Rivers New Financial Model". The Big Rivers New Financial Model would supplement Big Rivers' monthly filing of its RUS Form 12, its Financial and Statistical Report (Annual Report) required by the Commission and the Big Rivers annual report (containing audited financial statements). The Big Rivers New Financial Model would contain actual financial results for the prior year, the current year's budget, and three forecasted years beyond the current year.

In response to concerns about this information not being filed until June 30 of each year, Big Rivers has determined that it can file the information on or before April 30 of each year, through the date on which it files a case for a general adjustment of its rates.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
SUPPLEMENTAL RESPONSE TO THE COMMISSION STAFF'S
SUPPLEMENTAL INFORMATION REQUESTS
PSC CASE NO. 2007-00455
(May 30, 2008)

Item 9) Refer to the Application, Exhibit 8, the Unwind Model.

a. Does the version of the Unwind Model submitted as Exhibit 8 reflect a "base case" scenario for Big Rivers?

b. Has Big Rivers performed any sensitivity analyses for the Unwind Model? If yes, describe all sensitivity analyses performed, specifically noting the variable or variables examined in each analysis.

c. Explain why the results of any performed sensitivity analyses were not included in the Application.

Response) Big Rivers supplements this information request and its rebuttal testimony to describe in more detail why the $200 million reduction in the Maximum Allowed Balance in the RUS 2008 Promissory Note, Series A before the end of 2015 does not materially affect Big Rivers' risk exposure. This information also relates to Draft Settlement Concept No. 2 presented at the May 15, 2008, Informal Conference in this matter.

The maximum allowed balance of the RUS Note reduces by $200,000,000 in 2016. Big Rivers is not required to refinance this amount. It could instead make voluntary prepayments of $200,000,000 over the period from the Unwind closing until 2016. In the financial model Big Rivers has assumed that it would refinance its $200,000,000 and that it would make no voluntary prepayments prior to 2016 but instead would use its excess cash flow to pay for new capital expenditures rather than financing them. There is a total of $392.5 million going into capital expenditures in the model through 2015 so, if Big Rivers were to finance about half of those capital expenditures, it would not need to refinance any debt in 2016. Assuming, however, as the model does, that none of those capital expenditures are financed, Big Rivers would refinance the $200,000,000 by 2016. This is not a particular risk to Big Rivers as there are a wide variety of financial instruments and financing sources that might be used to accomplish this financing. Among those are:

the issuance of long-term, fixed rate bonds in the capital markets based on Big Rivers credit;

the issuance of long-term, fixed rate credit enhanced bonds in the capital markets;

the issuance of long-term, floating rate, enhanced or un-enhanced debt in the capital markets;

the issuance of long-term bonds with periodic resets and puts in the capital markets, again with or without enhancement;

the private placement of securities with insurance companies or other institutional investors;

the use of bank credit facilities; and

debt financing with either or both of CFC and/or CoBank.

It is a condition to closing of the Unwind that Big Rivers has an investment grade credit rating and as an investment grade entity Big Rivers will have all of the foregoing sources of financing available to it. It will be up to Big Rivers to pick the time to refinance and the type of security and source of financing that it believes is the most economical. However, Big Rivers believes that there is virtually no risk that it will be unable to accomplish the refinancing by 2016. In the event Big Rivers were to lose its investment grade rating prior to the completion of the refinancing, it would still be able to accomplish the refinancing, although at higher interest costs. There is a well-established market for non-investment grade debt. Another alternative would be to renegotiate with RUS to obtain a further modification of the allowed balance schedule.

Witness) C. William Blackburn

Item 13) Refer to the response to the Staff's First Request, Item 28.

a. Does Big Rivers agree that the RUS USoA provides that utilities owning emission allowances shall account for those allowances at cost?

b. Does Big Rivers agree that while the market value of the 14,000 sulfur dioxide ("SO2") emission allowances may represent a portion of the consideration being provided by E. ON to Big Rivers as part of the Unwind Transaction, the market value does not necessarily reflect the cost of those emission allowances? Explain the response.

Response) Big Rivers would account on its books for emission allowances it acquires in the Unwind Transaction in accordance with the RUS Uniform Systems of Accounts. [Draft Settlement Concept No. 12 from 5/15/08].

According to the RUS' Uniform System of Accounts, "Cost is the amount of money actually paid for property or services. When the consideration given is other than cash...the value of such consideration shall be determined on a cash basis." Uniform System of Accounts - Electric, RUS Bulletin 1767B-1. Recently, the Federal Energy Regulatory Commission ("FERC") adopted provisions governing accounting treatment of allowances as part of its own Uniform Systems of Accounts, and the regulation containing the "at cost" requirement is identical to the RUS provision. *Compare* 18 C.F.R. Pt. 101, General Instruction 21.A. (2007) *with* 17 C.F.R. § 1767.15(u)(1) (2008). In its order adopting the allowance provisions, FERC determined that allowances should be accounted for at "historical cost," defined as "the amount of cash or its equivalent paid to acquire an asset, *i.e.*, its historical exchange price." *Revisions to Uniform Systems of Accounts to Account for Allowances Under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A*, 1991-1996 FERC Stats. & Regs. [Regs. Preambles] ¶¶ 30, 803 and 30,967 (1993). FERC went on to distinguish between allowances obtained from the

Environmental Protection Agency ("EPA") at no cost to the recipient, and allowances obtained in what FERC characterized as "package purchases" in which the purchaser obtained allowances along with commodities, such as fuel or electricity. In the former instance, since there is no cost to the recipient, FERC directed that the allowances be recorded at zero cost. *Id.* at 30, 803. In the latter instance, FERC concluded that the historical cost of the allowances for accounting purposes should be their fair market value at the time of the purchase, to be determined by direct reference to market prices. *Id.* at 30,807-08. In providing for fair market value accounting treatment in the "package purchase" scenario, FERC recognized the distinction between allowances that are conferred upon a utility by the government at no cost to the utility and allowances that are obtained by a utility as part of bargained-for consideration in a transaction.

Witness) C. William Blackburn

Item 13) Refer to the Unwind Model, page 9 and 10 of 37.

a. Compare the conventional TIER and "DSCR" calculations with the determination of TIER and Debt Service Coverage requirements in Big Rivers' Rural Utilities Service ("RUS") Mortgage. Explain all differences between the calculations.

b. Does Big Rivers intend for the Conventional TIER to reflect the TIER awarded for rate-making purposes ("rate-making TIER") by the Commission. Explain the response.

c. In previous electric cooperative rate cases, the Commission has determined rate-making TIER by dividing the sum of the net margins and interest on long-term debt by interest on long-term debt. Comparing rate-making TIER with the Conventional TIER as shown in the Unwind Model reveals several additional components in the Conventional TIER determination. For each additional component in the Conventional TIER, explain in detail why it is reasonable to include the component.

d. Explain in detail why the Economic Reserve Account, Taxes, and the Sale-Leaseback interest should be included in the determination of the DSCR.

Response) Big Rivers supplements its response to Item 13 of the Commission Staff's Second Supplemental Request for Information to explain in more detail the table of rates in that data requests response. This information was also the subject of Draft Settlement Concept No. 5 from the May 15, 2008, Informal Conference.

The following is intended to provide more context to Big Rivers' response to Item 13 of the Commission Staff's Second Supplemental Data Request, and, by extension, to Big

Rivers' Response to Items 3 and 128 of the Attorney General's Initial Request for Information.

Big Rivers submitted a comparison of expected future cash flows under 1) continuation of the existing Lease Agreement/ Power Purchase Agreement versus 2) expected future cash flows in the Unwind Transaction on March 5, 2008. That data was the basis for Big Rivers' response to Item 13 of the Commission Staff's 2nd Supplemental Data Request. It is updated below in Exhibit 1 to reflect the financial model submitted on April 23, 2008 and expanded to show Non-Smelter Member rates year-by-year.

In accordance with the purpose of the Economic Reserve/ MRSM, Member rates in the Unwind scenario closely track those in the No Unwind scenarios in the early years (and are identical through 2010).

Importantly, the data shows the "No Unwind" scenario under two differing assumptions for the period 2012 - 2023:

-Arbitrage Sales:

- For reference, Big Rivers is assumed to sell into the market the entirety of purchases available under the existing agreements with E.ON.U.S. affiliates and SEPA in excess of Member load ("Excess Energy"), approximately 36% of total sales.

- Under this assumption, Member rates would be below those of the Unwind on average.

-Sales to Smelters:

- Big Rivers is assumed to serve 200MW of Smelter load at the large industrial rate (load factor adjusted) plus $0.25 per MWh.

- This would require the diversion of approximately 16% of total sales, or less than half of Excess Energy.

- Under this assumption, Member rates would be higher than Member rates in the Unwind.

Witness) C. William Blackburn
Robert S. Mudge