E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 99

Witness: Rusty Hudson

Q-99. Provide the amount and date of any asset book value write downs or other valuation write downs since 1997, which exceed $500k, and pertain to Lease Agreement facilities.

A-99.

FUEL BOOK TO PHYSICAL ADJUSTMENT:COAL

COAL		PET COKE	
DATE	AMOUNT	DATE	AMOUNT
Nov-99	$1,396,271.26	Feb-99	($788,785.78)
Dec-00	($504,085.92)	Nov-99	($1,433,447.56)
Nov-01	$847,709.46	Nov-01	$1,157,049.59
Dec-02	$1,522,960.90	Dec-02	$1,959,425.26
Nov-03	$2,291,387.67	Nov-03	($1,950,847.70)
Oct-04	$1,817,145.86	Sep-05	($497,335.91)
Sep-05	$2,821,523.11	Sep-07	($1,077,362.53)
Sep-06	($812,436.50)		
Sep-07	$1,441,268.37		

PP&E DISPOSALS: CONVEYOR BELT REPLACEMENT AT WILSON PLANT

DATE	AMOUNT
Dec-98	$565,622.75

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 100

Witness: Counsel / Paul Thompson / David Sinclair

Q-100. Provide E.ON/LEM current view of operating budgets (cost and revenues, multi-year forward looking) for facilities operated under the Lease Agreement.

a. Calculate and state the extent to which unit costs of power produced by the leased facilities are projected increase or decrease under this operating budget view.

A-100. The information responsive to this request that was provided to Big Rivers is being filed with the Commission pursuant to a Petition for Confidential Treatment.

a. This request requires original work and requests information (i.e., calculate and state the extent to which unit costs of power produced by the leased facilities are projected increase or decrease under this operating budget view) which can be reasonably calculated and identified by Attorney General's consultant from the information provided in the responses to these data requests or is otherwise in the record in this proceeding.

WESTERN KENTUCKY ENERGY

2007-2009

Business Plan

[CONFIDENTIAL INFORMATION REDACTED]

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 101

Witness: Counsel / Paul Thompson / David Sinclair

Q-101. Provide E.ON/LEM current capital budget (multi-year, forward looking) for facilities operated under the Lease Agreement.

a. Calculate and state the extent to which unit costs of power produced by the leased facilities are projected increase or decrease under this capital budget view.

A-101. The information responsive to this request that was provided to Big Rivers is being filed with the Commission pursuant to a Petition for Confidential Treatment.

a. This request requires original work and requests information (i.e., calculate and state the extent to which unit costs of power produced by the leased facilities are projected increase or decrease under this operating budget view) which can be reasonably calculated and identified by Attorney General's consultant from the information provided in the responses to these data requests or is otherwise in the record in this proceeding.

WESTERN KENTUCKY ENERGY

2007-2009

Business Plan

[CONFIDENTIAL INFORMATION REDACTED]

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 102

Witness: Rusty Hudson

Q-102. Provide documents which show the prices of power provided to Big Rivers by E.ON under the relevant purchase power agreements versus the cost of producing that power, for the years 2005 to current.

A-102.

YEAR	BREC PRICING ($/MWH)	COST OF PRODUCTION ($/MWH)
2005	19.48	18.61
2006	19.57	18.66
2007	19.88	19.10

Note:
BREC Pricing includes revenues for the base sales, revenues for volumes in excess of the maximum on-peak take of 597 MW, and any penalties for volumes below the minimum off-peak take of 297 MW, divided by total BREC sales volumes.

Cost of production includes fuel costs, pet coke, fuel oil, natural gas, propane, fuels department, fuel handling, scrubber reagent, other cost of sales, and transmission, divided by total generation. It does not include the cost of SO2 and NOx emission allowances. The exchanges of current and future vintage allowances in 2005, 2006 and 2007 resulted in the expense numbers for SO2 and NOx emissions not being meaningful by year from a true production cost perspective.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 103

Witness: Dan Arbough

Q-103. Provide all reports or presentations prepared by investment banking advisors for E.ON pertaining to the Unwind Transaction/Lease Agreement termination.

A-103. There are no reports that are responsive to this request.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 104

Witness: Counsel / Paul Thompson / David Sinclair

Q-104. Provide all E.ON management reports and analyses prepared internally pertaining to the Unwind Transaction/Lease Agreement termination which is the subject of this application.

A-104. E.ON U.S. objects to this request on the basis that it seeks documents and information that are confidential and proprietary; that are privileged; and that are the property of unregulated entities (rather than utilities) whose financial affairs and internal memoranda are not subject to discovery absent an indication that they are relevant to the public interest inquiry in the present case. The public interest inquiry here concerns whether Big Rivers can provide service on a going forward basis on the terms and conditions of the proposed transaction. The internal documents and business strategy of E.ON's unregulated businesses have no relevance to this inquiry.

Without waiver of this objection, please see the response to Attorney General Request for Information Nos. 26(d) and 87 for a detailed description of why the current contracts are not economic.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 105

Witness: Paul Thompson / David Sinclair

Q-105. Please reference the Application at page 11, paragraph 21. Explain in detail why the transactions with Big Rivers "had not proven to be advantageous to E.ON US."

A-105. An explanation of the reasons why E.ON U.S. LLC's transactions with Big Rivers "had not proven to be advantageous to E.ON US." is described at page 18 of Mr. Thompson's testimony (i.e., the performance of an uneconomic set of contracts and their associated exposure of E.ON U.S. LLC to uncertain and unfavorable financial results through 2023). Please also see response to Attorney General Request for Information No. 87 for a detailed description of why the current contracts are not advantageous to E.ON U.S. LLC.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 106

Witness: Paul Thompson / David Sinclair

Q-106. Explain in detail why the Joint Applicants chose not to include the Attorney General, who represents consumers in matters before the Commission, in the unwind transaction presently filed.

A-106. The negotiations were conducted between the persons who are parties to the commercial contracts. The Attorney General is not a contract party to these commercial arrangements.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 107

Witness: Paul Thompson / David Sinclair

Q-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.

A-107. Shortly after Big Rivers and E.ON U.S. signed the Letter of Intent (LOI) on November 28, 2005, the parties provided Henderson with a copy of the LOI and met with Henderson and its legal counsel. HMPL identified several issues involving the existing contracts that needed to be resolved prior to closing. These discussions continued through 2006 and into early 2007 with many issues being resolved. Shortly after the Transaction Termination Agreement (TTA) was signed by Big Rivers and E.ON U.S. on March 26, 2007, Henderson was provided a copy of the TTA and the parties met with Henderson and its legal counsel. All three parties have subsequently met on several occasions in an attempt to reach agreement on the terms and conditions under which Henderson will consent to the unwind transaction. The most recent meeting took place between E.ON U.S. and Henderson on February 1, 2008.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 108

Witness: Paul Thompson / David Sinclair

Q-108. Please reference the Application at page 17, paragraph 33e. Explain what the Joint Applicants mean when they state that the negotiations are "on-going."

A-108. The term "on-going" means the negotiations have not been concluded at this time. E.ON U.S. LLC anticipates that the negotiations will be concluded and the resulting consent filed with the Commission consistent with the procedural schedule in this case.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 118

Witness: Paul Thompson / David Sinclair

Q-118. Please reference the testimony of Burns E. Mercer, page 4, regarding "absent the rate path offered by Big Rivers through the capacity restored to it by the Unwind Transaction there would be a higher chance that the Smelters could discontinue operations." Please explain in detail why E.ON/LEM would not be able to offer the smelters the same or similar "rate path" under the current status and structure, including the Lease Transaction and Purchase Power agreements.

A-118. WKE /LEM would not be able to offer the smelters the same or similar "rate path" under the current status and structure, including the Lease Transaction and Purchase Power agreements for two reasons. First, WKE does not expect to have adequate capacity to serve the smelter load when the smelter contracts expire due to the increase in sales volumes for Big Rivers' distribution cooperatives. Secondly, WKE/LEM are unregulated entities and have no obligation to serve the smelter customers following the expiration of the current contracts at cost based rates. For the reasons stated in response to other requests for information from the Attorney General (e.g., Response to No. 26(d)), WKE/LEM will have every economic reason to sell any excess power at market based prices to mitigate their losses on sales to Big Rivers and under their Lease obligations.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 122

Witness: Paul Thompson / David Sinclair

Q-122. Please reference the testimony of Burns E. Mercer, page 9, regarding "fuel and environmental costs will fluctuate up or down depending on actual costs."

a. Provide documents which show the variation in fuel costs, by type of fuel, that has been experienced by E.ON since the inception of the Lease Transaction; and,

A-122. Response to 122(a):

DOLLARS PER MMBTU

YEAR	COAL	PET COKE	COMBINED
1998	$0.94	$0.77	$0.92
1999	$0.89	$0.74	$0.86
2000	$0.89	$0.58	$0.83
2001	$0.94	$0.75	$0.88
2002	$1.07	$0.73	$0.96
2003	$1.04	$0.78	$0.95
2004	$1.11	$0.71	$0.98
2005	$1.35	$0.78	$1.17
2006	$1.48	$0.90	$1.32
2007	$1.54	$0.80	$1.36

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 125

Witness: Dan Arbough

Q-125. Provide the current credit ratings for E.ON U.S. Parties.

A-125. E.ON U.S. LLC is the only E.ON U.S. Party that has a credit rating. E.ON U.S. LLC has a rating of BBB+ from S&P and a rating of A3 from Moody's.

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 126

Witness: Rusty Hudson

Q-126. Provide the most current SFAS No. 144 impairment review pertaining to the Big Rivers generation facilities.

A-126. See attached.

Support
5065-2301-1207
No Entry
Viewed FIT
SZI
1/7/08

LG&E FAS 144 Quarterly Asset Impairment Questionnaire – Part A

(To be completed by Plant Budget Analyst, Mtc Manager, and IT Ops Manager)

Location: **Reid/Henderson Station Two**

Completed by: **Dawna Ralph** Dawna Ralph

Plant Maintenance Manager approval: **Larry Baronowsky** See Below for DCA Signature

IT Operations Manager approval: **Phil Waggoner** Phil Waggoner

Date Completed: **December 18, 2007**

Reports are due to Accounting by the last business day of each quarter.
Since the date of the last questionnaire:

(A1) Has there been a significant decrease in the market value of an individual long-lived asset or asset group? If yes, please describe:
No

(A2) Has there been a significant change in the extent or manner in which an individual long-lived asset or asset group is used? If yes, please describe:
No

(A3) Has there been a significant change in the physical condition of an individual long-lived asset or asset group? If yes, please describe:
No

(A4) Has there been an accumulation of costs significantly in excess of the amount originally expected to acquire or construct an individual long-lived asset or asset group? If yes, please describe:
No

A5) Is there a current expectation that, more likely than not, an individual long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life? If yes, please describe:
No

Ralph, Dawna

m: E.ON U.S. DOA Website [lgeproc@eon-us.com]
nt: Wednesday, December 19, 2007 3.04 PM
ɔ: Ralph, Dawna
Subject: Delegation Of Authority Notification For Lawrence Baronowsky to James Hawkins
Importance: High

This delegation of authority is effective with the start of the work day 12/20/2007 through the end of the work day 1/31/2008.
The Reason for this delegation of authority is Vacation.

Delegation of Authority for	
Name	Lawrence Baronowsky
Location	WKE Station 2
Department	WKE Reid/Stion Two Operations
Company	Western Kentucky Energy Corp.
Phone	270/844-5524
E-Mail	LARRY.BARONOWSKY@EON-US.COM
Cell Phone	N/A
Pager	N/A

Authority being delegated to	
Name	James Hawkins
Location	WKE Station 2
Department	WKE Reid/Station Two Maintenan
Company	Western Kentucky Energy Corp.
Phone	270/844-5924
E-Mail	JIM.HAWKINS@EON-US.COM
Cell Phone	N/A
Pager	N/A

ɔmments :

Committee for final copy

1. 2007

LG&E FAS 144 Quarterly Asset Impairment Questionnaire - Part A

(To be completed by Plant Budget Analyst, Maintenance Manager, and IT Operations Manager)

Location: **Wilson Station**

Completed by: **Jeff Williams/Ron Gregory**

Plant Maintenance Manager approval: Ron Gregory 12/17/07

IT Operations Manager approval: Phil Waggoner 12/21/07

Date Completed: **12/14/07**

Reports are due to Accounting by the last business day of each quarter.

Since the date of the last questionnaire:

(A1) Has there been a significant decrease in the market value of an individual long-lived asset or asset group? If yes, please describe:
No

(A2) Has there been a significant change in the extent or manner in which an individual long-lived asset or asset group is used? If yes, please describe:
No

(A3) Has there been a significant change in the physical condition of an individual long-lived asset or asset group? If yes, please describe:
No

(A4) Has there been an accumulation of costs significantly in excess of the amount originally expected to acquire or construct an individual long-lived asset or asset group? If yes, please describe:
No

A5) Is there a current expectation that, more likely than not, an individual long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life? If yes, please describe:
No

LG&E FAS 144 Quarterly Asset Impairment Questionnaire - Part A

(To be completed by Plant Budget Analyst, Maintenance Manager, and IT Operations Manager)

Location: WKE Green Station

Completed By: Jennifer Polivick, Budget Analyst Jennifer Polivick

Plant Maintenance Manager Approval: Larry Rideout Larry J. Rideout

IT Operations Manager Approval: Phil Waggoner Phil Waggoner 12/21/07

Date Completed: 12/14/07

Reports are due to Accounting by the last business day of each quarter.

Since the date of the last questionnaire:

(A1) Has there been a significant decrease in the market value of an individual long-lived asset or asset group? If yes, please describe:
No

(A2) Has there been a significant change in the extent or manner in which an individual long-lived asset or asset group is used? If yes, please describe:
No

(A3) Has there been a significant change in the physical condition of an individual long-lived asset or asset group? If yes, please describe:
No

(A4) Has there been an accumulation of costs significantly in excess of the amount originally expected to acquire or construct an individual long-lived asset or asset group? If yes, please describe:
No

(A5) Is there a current expectation that, more likely than not, an individual long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life? If yes, please describe:
No

LG&E FAS 144 Quarterly Asset Impairment Questionnaire - Part A

(To be completed by Plant Budget Analyst, Maintenance Manager, and IT Operations Manager)

Location: WKE Coleman Station

Completed by: Vicky Livingston VL

Plant Maintenance Manager approval:

IT Operations Manager approval: 12/21/07

Date Completed: 12/10/2007

Reports are due to Accounting by the last business day of each quarter.

Since the date of the last questionnaire:

(A1) Has there been a significant decrease in the market value of an individual long-lived asset or asset group? If yes, please describe:
NO

(A2) Has there been a significant change in the extent or manner in which an individual long-lived asset or asset group is used? If yes, please describe:
NO

(A3) Has there been a significant change in the physical condition of an individual long-lived asset or asset group? If yes, please describe:
NO

(A4) Has there been an accumulation of costs significantly in excess of the amount originally expected to acquire or construct an individual long-lived asset or asset group? If yes, please describe:
NO

(A5) Is there a current expectation that, more likely than not, an individual long-lived asset or asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life? If yes, please describe:
NO

E.ON U.S. LLC

Response to the AG's Request for Information
Dated February 1, 2008

Case No. 2007-00455

Question No. 134

Witness: Ralph Bowling

Q-134. Regarding the "Environmental Matters" and "significant financial impacts on the use of fossil fuels for power generation" referenced in the Big Rivers 2005 Annual Report to Members (Exhibit 41), please provide any documents or studies performed by or for E.ON since January 2005 which address and/or estimate costs associated with the Big Rivers generating facilities and compliance with:

a. The EPA's Clean Air Mercury Rule (CAMR);

b. The EPA's Clean Air Interstate Rule (CAIR);

c. Performance goals of the Clean Water Act Section 316(b);

d. Regulation of carbon dioxide as a pollutant under the Clean Air Act; and,

e. Any other state or federal rules likely to cause additional cost in order to meet pollution standards or otherwise comply with those rules.

A-134. See attached for responses to Question No. 134, parts a, b, and e.

There are no reports that are responsive to the request in parts c and d.

Multi Pollutant Plan Study

by

Engineering

E.ON Reference No. 2005117

January 18th, 2006 Rev.5

INDEX

1. ABSTRACT

This March, the U.S. EPA announced two additional air pollution rules that apply to coal-fired utility boilers: the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR).

The intent of the CAIR is to reduce ground-level concentrations of criteria pollutants ($PM_{2.5}$, ozone) to National Ambient Air Quality Standards (NAAQS) levels under Title I of the Clean Air Act. This rule applies to states in which the EPA's atmospheric chemistry and transport models have demonstrated that NOx and SO_2 emissions contribute to levels of ground-level ozone and PM2.5 that exceed the NAAQS.

For compliance, the EPA has directed states in the affected regions to cap their industrial emissions and revise their State Implementation Plans. The CAIR will set caps on NOx emissions for the entire year as well as for the ozone season, enabling NOx emissions credits to be traded. Additionally, emissions of SO_2 will be reduced by changing the current surrender ratio of one allowance per ton of emission, thereby creating economic pressure to reduce emissions as well as effectively reducing the allowance supply.

As for the CAMR, the EPA estimates that U.S. power plants emit 48 tons of mercury annually. The new rule seeks to reduce these emissions to 38 tons per year by 2010 and to 15 tons per year starting 2018. Like the CAIR, the CAMR establishes a cap-and-trade program to facilitate reaching its goals.

The CAIR and CAMR of March 2005 are likely to have a significant impact on all the Units operated by WKE.

Based upon data, predictions and assumptions generated by WKE with respect to their long-term operating objectives (load, capacity factors and heat rates), the current level of performance in terms of emissions reductions of the various pollutants (SO_2, NOx, Particulate, SO_3 and Mercury) and the impact of CAIR and CAMR on the emission allowances available to the WKE system,

E.ON Engineering were commissioned to undertake a comprehensive fleet-wide study of their existing emission reduction capability. Additionally, E.ON were commissioned to evaluate the viability and applicability of various system upgrades and new equipment technologies available to WKE to comply with the predicted implications and requirements of CAIR and CAMR.

Furthermore E.ON were commissioned to estimate the costs and schedule of the wide range of available alternatives and to make a composite recommendation as to which overall approach and modifications/equipment installations WKE should proceed with.

2. OBJECTIVE

The objectives of the study were:

- Provide information on the performance, cost, implementation schedule and lead times of the alternative upgrades and plant additions available to comply with CAIR and CAMR.
- To develop composite fleet-wide strategy options for WKE's consideration detailed on a unit by unit basis.
- To make a recommendation as to the most viable composite compliance strategy for WKE, complete with an implementation schedule and predictive levels of emissions reduction or performance improvement.

3. APPROACH

This report utilizes information from various sources to predict WKE's multi pollutant position relative to the CAIR and CAMR, including:

1) A Predictive Model, developed by WKE, is the primary basis of the predictions in this report. This WKE Predictive Model is discussed further in Section 4.2 of this report.

2) Knowledge of the current and proposed status of the Units within the existing WKE fleet, including:

   - Operational issues, limitations and difficulties
   - Equipment performance

3) Input from the Plant Management Staff and visits to each Unit.

4) E.ON Engineering experience and evaluation of information collected.

Using this knowledge and information, potential upgrades or plant modifications are discussed on a per Unit basis, strategy options for the system are developed and recommendation are made for compliance with CAIR/CAMR.

4. REGULATORY BACKGROUND

4.1. Impact of Clean Air Interstate Rule (CAIR)

The EPA issued the Clean Air Interstate Rule (CAIR) on March 10th, 2005. CAIR will permanently cap emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) across 28 eastern States, including Kentucky. Emission caps for the affected region will be implemented in two phases for each pollutant, as follows:

Annual SO_2:	3.6 million tons (2010)
	2.5 million tons (2015)
Annual NOx:	1.5 million tons (2009)
	1.3 million tons (2015)
Seasonal NOx	0.58 million tons (2009)
	0.48 million tons (2015)

CAIR will set an emission reduction requirement for each State. This will be based on capping power plant emissions collectively at the levels set by the EPA. As a method to implement the necessary reductions, CAIR will provide an optional cap and trade program. This will allow States flexibility on how to achieve the required reductions, including which sources to control and whether to join the trading program.

The cap and trade mechanism will require both the EPA and State involvement in different roles. The EPA will set the State budgets, establish trading program and market procedures, administer trading systems, and define allowance allocation parameters. The State role will be to identify sources for reduction and to establish a voluntary trading program. The latter will require rules/programs to be adopted within 18 months, determination of a trading program budget, and allocation of NOx allowances (SO_2 already allocated).

CAIR could potentially impact the following stations within the WKE fleet:

Coleman:	(3 Units)
Station Two:	(2 Units)
Green:	(2 Units)
Reid:	(1 Unit, 1 Gas Turbine)
Wilson:	(1 Unit)

It is uncertain at this time as to how the Kentucky Division for Air Quality (KYDAQ) will allocate statewide pools of allowances. Additionally, there are other unknowns including the amount of new generation in the State that could affect the allocations.

4.2. NOx Allocation

In order to develop a fleet-wide approach for NOx reduction the following assumptions have been made to estimate the allocation of allowances for both the Ozone Season NOx and CAIR Annual NOx.

4.2.1. Ozone Season NOx

Based on the NOx SIP Call, actual allocations are already provided for 2004 – 2008. In 2009 the latest allocations proposed from KYDAQ can be considered as probable. These include a 2% set-aside[1]. From 2010 onwards, the regulations will have to be rewritten for the CAIR ozone season. The following assumptions were made to develop a model which predicts the impact of CAIR on NOx:

2007 – 2009:	2% set-aside (base case set-aside)
2010 – 2012:	5% total set-aside (3% additional)
2013 – 2015:	10% total set-aside (8% additional)
2016 – 2018:	12% total set-aside (10% additional)

---

[1] Set-aside means allowances which the issuing regulatory agency reserves for use by future facilities and existing plants which do not receive a direct allocation. These are typically sold by auction.

2019 – 2021:	14% total set-aside (12% additional)
2022 – 2024:	16% total set-aside (14% additional)

4.2.2. CAIR Annual NOx

This report assumes that Kentucky will not apply a fuel type factor that reduces allowances awarded to non-coal units. The following assumptions are made, starting in 2009:

2009 – 2012:
- KYDAQ allocates 4 years of allowances to be in alignment with NOx SIP Call
- Assume 5% set-aside

2013 – 2015:
- Assume 10% total withheld (a combination of NSSA[2] and roll-ins)

2016 – 2018:
- Assume 12% reduction from 2015 unratcheted allocation or a total of 22% withheld

2019 – 2021:
- Assume 14% reduction from 2015 allocation or a total set-aside of 24%

2022 – 2024:
- Assume 16% reduction from 2015 allocation or a total set-aside of 26%

4.2.3. Predictive Model for NOx Allocation

A predictive model was developed by WKE and expanded by E.ON Engineering using the assumptions outlined in Sections 4.1.1 and 4.1.2 that calculates the NOx credit balance for each Unit at each Station within the WKE fleet, annually from 2005 until the end of the lease period in 2023. This model incorporates a monthly forecast of the total heat input (in MMBtu) to each boiler in the WKE fleet, and based on the anticipated NOx emissions (in lb/MMBtu) calculates the annual tons of NOx

[2] NSSA – New Source Set Aside

emitted. The difference between the NOx emitted and the predicted allowances available for each Unit is then calculated as the credit balance. The sum of the annual credit balances for all the Units in the WKE fleet then yields the net annual credit balance for the system. The predictive results are divided for the Ozone Season NOx and the CAIR Annual NOx. Cumulative balances are then calculated and plotted in Figure 1 (WKE NOx Allowance Balance {Ozone Season and Annual CAIR} vs. Calendar Year) to indicate surplus or deficit of NOx allowances for any given year. Based on a forecast of cost for NOx credits a plot (Figure 2) of WKE NOx Emissions Expense vs. Calendar Year is also developed. This procedure results in the "base case", predicting the impacts of the rule without any additional action

Figure 1

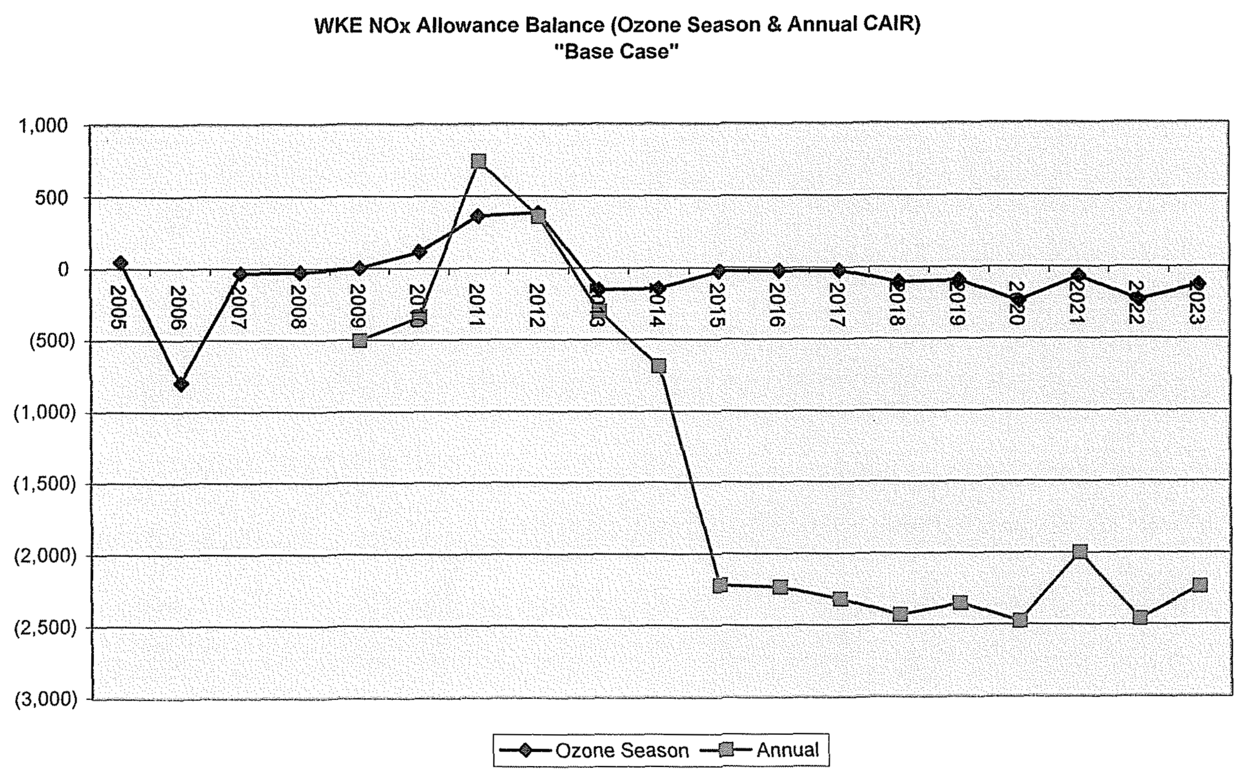
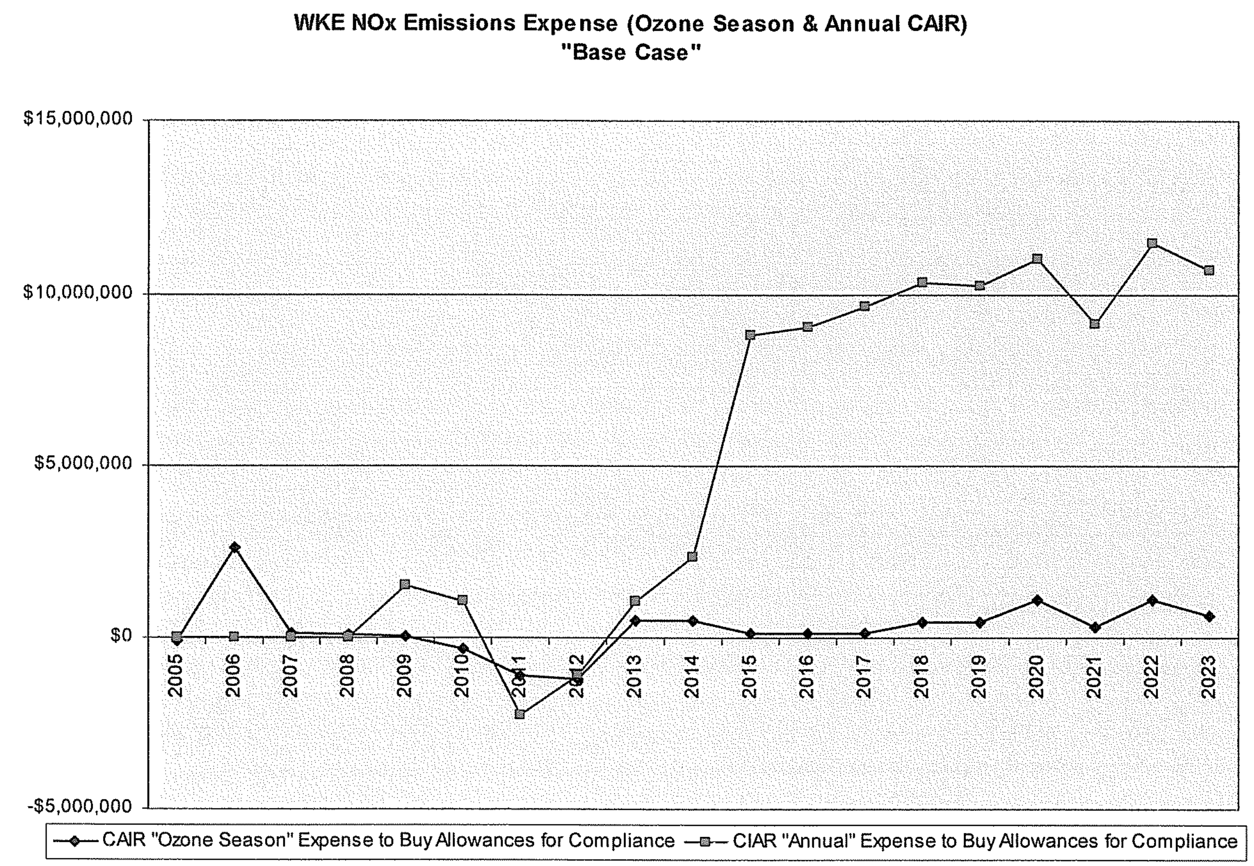

WKE NOx Allowance Balance (Ozone Season & Annual CAIR)
"Base Case"
1,000
500
0
(500)
(1,000)
(1,500)
(2,000)
(2,500)
(3,000)
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Ozone Season
Annual

Figure 2



Basis: NOx Value $/ton (see Table 1)

4.2.4. CAIR Impact for NOx

As shown in Figure 1 starting in 2006, for the CAIR Ozone Season, the WKE system will be slightly deficient for NOx allowances for the remainder of the lease term, except for a short period between 2009 – 2012 following the retirement of Reid 1 in 2010, considering that all Units in the system will meet their ozone season target values, as follows:

	lb NOx / MMBtu
Coleman:	0.30 per Unit
Station Two:	0.09 Unit 1, 0.065 Unit 2
Green:	0.220 per Unit
Reid:	0.410 Unit 1, 1.200 Gas Turbine
Wilson:	0.045 Unit 1

From a base case projection (starting in 2009), Figure 1 shows that the system will be deficient for CAIR Annual NOx allowances for the remainder of the lease term except for 2011 and 2012 following the retirement of Reid 1 in 2010.
This assumes that all WKE Units will maintain the Ozone Season emission values for the shoulder months. This can be accomplished by integrating for each Unit a catalyst management program that includes catalyst testing.

Using the outcome (Figure 1) from the Predictive Model, and estimating the $/ton of NOx emissions from 2005 – 2023 inclusive (Table 1), the annual emission costs can be calculated (Figure 2).

Table 1

Year	$/ton NOx Emissions	$/ton SO_2 Emissions
2005	2856	793
2006	3275	790
2007	2838	782
2008	2906	761
2009	2976	725
2010	3047	1385
2011	3120	1398
2012	3195	1412
2013	3272	1427
2014	3351	1441
2015	3946	1741
2016	4040	1776
2017	4137	1812
2018	4237	1849
2019	4338	1885
2020	4442	1923
2021	4549	1962
2022	4658	2001
2023	4770	2041

Therefore, the cost impact, on the basis of the Predictive Model and the above forecast of allowance values, to the WKE system until the end of the lease term in 2023 is approximately $93 M USD. This value must be adjusted by WKE to a "net present value".

4.3. SO_2 Allocation

Allocation of SO_2 allowances is based on the existing Acid Rain Allowances for each station within the WKE fleet. The surrender of allowances will be based on the vintage year, as follows:

2009 and earlier: 1 allowance for each ton of SO_2 emissions

2010 – 2014: 2 allowances for each ton of SO_2 emissions

2015 +: 2.86 allowances for each ton of SO_2 emissions

Furthermore, starting in 2010 it has been considered that the issuing regulatory agency (KYDAQ) will reserve 5% of the allowances from the existing Acid Rain Program for future use by facilities and existing plants, which do not receive a direct allocation (i.e. 5% set-aside).

With 5% set-aside, the surrender of allowances will increase for each ton of SO_2 emissions, as follows:

2010 – 2014: 2.11 allowances for each ton of SO_2 emissions

2015 +: 3.01 allowances for each ton of SO_2 emissions

Ultimately, this requirement provides incentive to reduce SO_2 emissions and/or bank SO_2 allowances before 2010.

4.3.1. Predictive Model for SO_2 Allocation

A predictive model was developed by WKE and expanded by E.ON Engineering using the assumptions outlined in Section 4.3. The predictive model calculates the SO_2 credit balance for each Unit at each Station within the WKE fleet, annually from 2005. This model incorporates the sulfur content of the fuel and a monthly forecast of the total heat input (in MMBtu) to each boiler in the WKE fleet, and based on the anticipated SO_2 emissions (in lb/MMBtu) calculates the annual tons of SO_2 emitted. The difference between the SO_2 emitted and the predicted allowances available for each Unit is then calculated as the credit balance. The sum of the credit balances annually for all the Units in the WKE fleet then yields the net annual credit balance for the system. The net annual credit balance for any given year also includes forecasted roll-overs of allowances from previous years, as well as consideration for purchased/sold allowances. Cumulative balances are calculated and plotted in Figure 1A (WKE SO_2 Allowance Balance vs. Calendar Year) to indicate surplus or deficit of SO_2 allowances for any given year. Based on a forecast of cost for SO_2 credits, a plot (Figure 2A) of WKE SO_2 Emissions Expense vs. Calendar Year is also developed. This procedure results in the "base case", predicting the impacts of the rule without any additional action, and includes:

- SO_2 removal at all operating units at their current levels of performance.
- New FGD system at Coleman in 2006.
- Purchasing of 23,172 allowances in 2005, and 3000 in 2006.
- Selling SO_2 allowances, as follows:

2006:	10,000 Allowances
2007:	12,500 Allowances
2008:	14,605 Allowances
2009:	15,000 Allowances

4.3.2. CAIR Impact for SO_2

As shown in Figure 1A starting in 2005, the WKE system will be self-compliant, until 2010, assuming that all Units in the system meet their target emission values (Table 2), as follows:

Table 2

	$lbSO_2$/MMBtu		
	2005	2006	2007+
Coleman 1	3.633	0.757	0.331
Coleman 2	3.623	0.757	0.331
Coleman 3	3.639	0.757	0.331
Henderson 1	0.469	0.503	0.503
Henderson 2	0.439	0.503	0.503
Green 1	0.289	0.279	0.279
Green 2	0.289	0.279	0.279
Reid 1	3.471	5.00	5.00
Wilson 1	0.632	0.65	0.636

From a base case projection (starting in 2010), Figure 1A shows that the system will be deficient for CAIR Annual SO_2 Allowances for the remainder of the lease term. Using the outcome (Figure 1A) from the Predictive Model, and estimating the $/ton of SO_2 emissions from 2005 – 2023 inclusive (Table 1), the cumulative annual emission cost can be calculated (Figure 2A). Therefore, the cost impact, on the basis of the Predictive Model and the forecast of allowance values, to the WKE system over the lease term until 2023 is approximately $534million USD. This value must be adjusted by WKE to a “net present value”.

WKE Multi Pollutant Plan Study
E.ON Reference No. 2005117 Rev.5
January 18th, 2006

Figure 1A

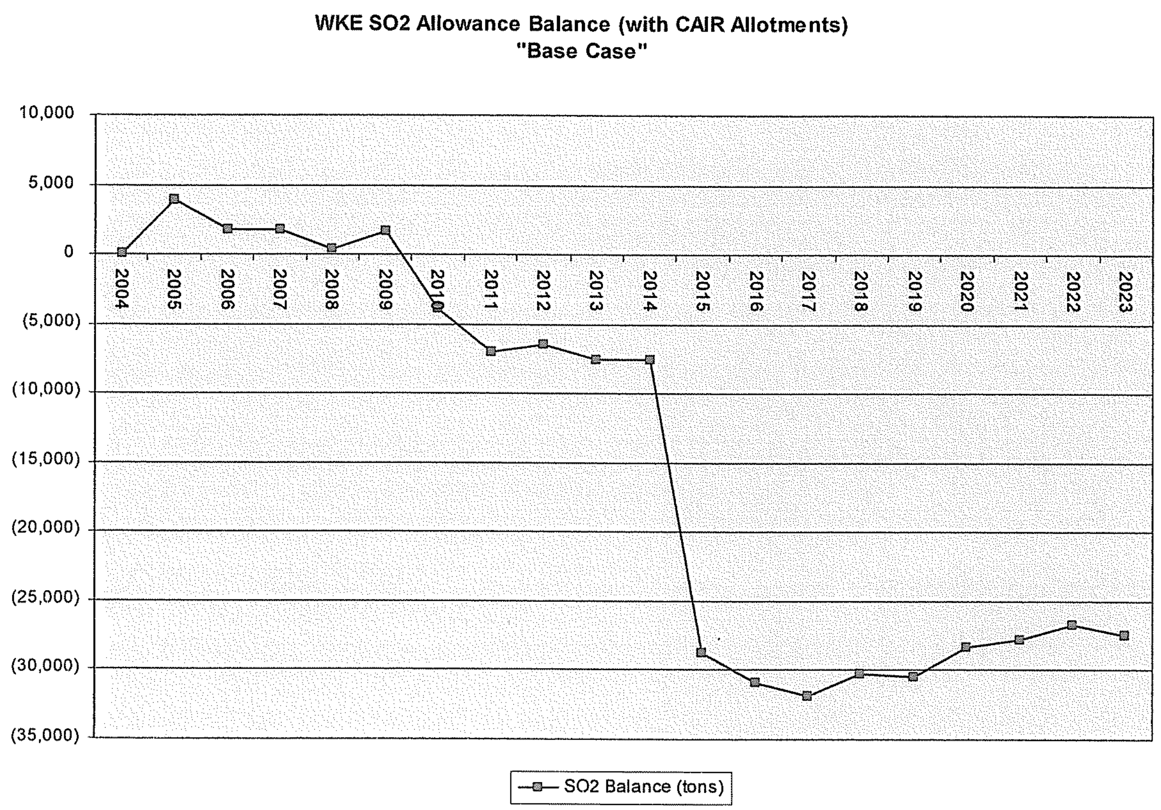
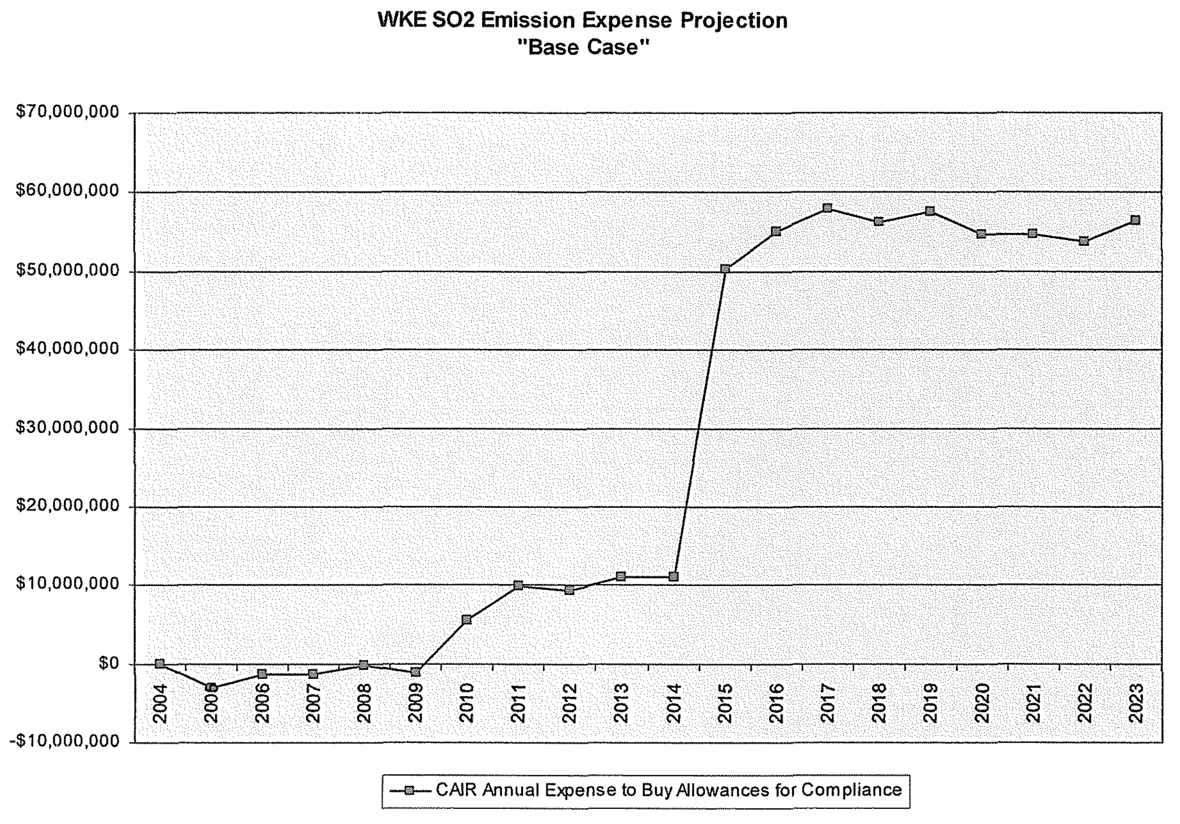


Figure 2A


WKE SO2 Emission Expense Projection
"Base Case"
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$0
-$10,000,000
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
CAIR Annual Expense to Buy Allowances for Compliance

4.4. Impact of Clean Air Mercury Rule (CAMR)

It is unclear as to how the emissions reduction under CAMR will be established and measured.

The "base" year(s) emissions are not "as measured" but "as allocated". This is likely to lead to extreme debate, perhaps lengthy and litigious, with regard to the adequacy and fairness of the allocations of "base" emissions.

With both technical and, to a degree, regulatory uncertainty we sought a relative conservative approach.

We have therefore concentrated on emission reduction or mitigation technologies that, based on European experience, offer the highest levels of removal utilizing the combination of the various pollution control devices already deployed or contemplated by this report.

The main sinks for mercury from the combustion process are usually gypsum and fly ash. Slag and waste water from the FGD plant are negligible sinks of mercury.

Several years ago the behavior of mercury in an SCR plant was investigated by E.ON in Europe. These investigations were commenced after it was discovered that the mercury removal rate in an ESP was significantly lower after the retrofit of an SCR. This degradation was caused by the oxidation of elemental mercury to an ionic form, which cannot be precipitated by an ESP.

Mercury usually leaves the boiler in the vapor phase as atomic species. While the flue gas is cooling down, reactions with halogenides take place and some mercury(II)halogenides are formed. In an SCR plant an additional proportion of the metallic mercury species is oxidized and leaves the SCR as mercury(II)halogenides. Depending on the concentration of unburnt carbon in the fly ash a certain amount of the remaining metallic mercury is precipitated with the fly ash in the ESP's. The oxidized mercury(II)halogenides are not collected in the ESP and are taken into solution and precipitated in the FGD plant. A small amount of mercury leaves the power plant through the stack and the largest proportion of the mercury is found in the gypsum.

While basic elements of a given system's ability to capture mercury are well understood, there are a number of variables that influence the performance. In particular they relate and are very sensitive to:

- The type of coal(s) fired
- The chlorine content of the coal
- The level of unburnt carbon in the flyash (generally higher in North American than European Units)
- The configuration of the gas cleaning train

5. EXISTING PLANTS: CONFIGURATION AND PERFORMANCE

5.1. Coleman Station Units 1, 2 and 3

Coleman Station consists of three units. Unit 1 and 2 are Foster Wheeler natural circulation boilers with front wall firing, rated at 160 MW's gross and Westinghouse turbine/generators. Unit 3 is a Riley stoker natural circulation boiler, rear wall fired rated at 165 MW's gross and General Electric turbine/generator.

The Station is installing an FGD System scheduled to be operational 1st Quarter 2006. The FGD is designed to remove 95% SO_2 with a single absorber equipped to handle all three of the Station's generating units (Table 3).

Table 3

	Unit 1	Unit 2	Unit 3
Commissioning Date	**Nov. 1969**	**Sept. 1970**	**Jan. 1972**
Rating (MW)	**160 MW**	**160 MW**	**165 MW**
***Approximate running hours since commissioning.**	**268189**	**263988**	**253940**
Total number of unit starts since commissioned	**414**	**376**	**360**
Boilers	**Foster Wheeler positive pressure**	**Foster Wheeler positive pressure**	**Riley positive pressure**
Pulverizers	**F/W vertical spindle mills**	**F/W vertical spindle mills**	**Riley ball mills**
Boiler Firing Pattern	**Front Wall**	**Front Wall**	**Rear Wall**
Turbine	**Westinghouse**	**Westinghouse**	**GE**

FGD - SO2 Reduction	**Wheelabrator Air Pollution Control Single absorber, limestone, gypsum 95% removal efficiency**		
NOx Reduction	**B&W Low NOx burners & MOBOTECH Boosted OFA system**	**B&W Low NOx burners & GE / EER OFA system**	**Riley Low NOx burners & F/W OFA system**

B&W "Low NOx" burners were installed on units C-1 & C-2 in 1993 and C-3 in 1997. Advanced Over Fire Air systems have been installed on all three units to futher reduce NOx emissions, C-1 a Mobotec boosted air design in 2002, C-2 a GE/EER close coupled, non boosted design in 2003, and C-3 a Foster Wheeler close coupled, non boosted design in 2004.

All three of the Coleman units are now operating with NOx emissions at or below 0.30 lbs/mmBtu. However, as expected, the carbon in ash has increased and there have been other issues including some furnace slagging.

With all the units firing "low sulfur synfuel" the bottom ash has a low pH. This has led to a number of boiler tube leaks and corrosion problems with the bottom ash systems. Furthermore the ash pond reclaim water pumps have also suffered from aggressive erosion.

This corrosion has caused a number of forced outages. As a result, caustic is now added to the ash pond reclaim water pump suction to increase pH. Additionally, the ash hopper seals are now flushed regularly with river water to increase the pH via dilution. Nevertheless, the bottom ash outlet still has a low pH and corrosion continues to be a problem.

On C-2 the introduction of the OFA system has also led to a number of opacity trigger limit spikes.

The Station has performed some burner line fuel balancing, however flow imbalance is still thought to be less than optimum with C-3 being the most severe due to the end-to-end flow variation of the ball mills and Primary Air duct arrangement.

The original design ESP's on all 3 Coleman units are marginal and even after modifications as described are still somewhat marginal. During the last 2 years they have been modified under the direction of an outside precipitator firm. Rappers sections were shortened with additional rappers installed; also baffle plates were installed to reduce entrainment.

However, the Station has been successful at meeting a particulate limit of 0.27 lbs/mmBtu and 40% opacity. In 2005 the Station began operating under Title V Air Quality Permit, which has placed an opacity trigger limit of approximately 20% on all of the Units. The Station must not exceed the new opacity trigger limits greater than 5% in any quarter year. To date this limit has been met but not without operational challenges.

A "three-into-one" high efficiency wet limestone in-situ forced oxidation FGD system is currently under construction at Coleman and this will have a profound effect on the operating regime of the station.

For example, it will allow the Unit(s) to fire a wide range of high sulfur fuels. These fuels will tend to have a higher Hardgrove Grindability Index and thus be easier to grind. This will improve the milling performance and could possibly recover the ongoing 5 MW derate on Unit 3.

They may also produce ashes with higher pH levels, which will reduce corrosion in the wet bottom ash systems.

After the FGD is commissioned and Performance Guarantees of the FGD system are met, the Station will make a request to the State EPA for a retest of the Title V opacity trigger limits in the new FGD stack. If the EPA is agreeable to retest, then the Stations previous opacity trigger limits of 40% could be restored.

5.2. Henderson Station Units 1 and 2

These two (2) Riley Units are essentially "sister" units of Coleman 3 and thus the same comments regarding burner line imbalance apply.

Both Units have been retrofitted with SCR systems supplied by Alstom with Cormetech catalyst. These SCRs were designed for 90% and typically meet the 90% removal efficiency however design and equipment issues have resulted in lower than expected reliability. The station continues to be challenged to meet NOx control, primarily due to antiquated combustion control systems on both of the Henderson units. The existing Henderson unit controls are late 1960s vintage, not designed for the sophisticated control required to achieve an optimum base line NOx generation.

The Units are equipped with Wheelabrator FGD systems that use thiosorbic lime as the reagent. These systems are not forced oxidized and produced a sulfite sludge. They have also been specifically sized to utilize this highly reactive reagent and are thus very, very small.

They currently achieve SO_2 removal efficiencies of 93 – 94%.

5.3. Green Station Units 1 and 2

Green comprises two (2) opposed wall-fired B & W Units. The burner configuration is unusual in that four (4) MPS mills each have six (6) burner pipes supplying eight (8) burner levels (4 per opposed wall) of three (3) burners each.

This is thought to lead to significant burner line to burner imbalance, including wall to wall. There is a history of high temperature corrosion in the burner zones, indicating localized reducing conditions.

Green has very early vintage "low NOx" burners and was retrofitted with a GE/EER coal re-burn system in 2003/2004. NOx emission levels are now 0.22 lbs/MMBtu. To combat the high temperature corrosion discussed above, alloy weld overlay tubing has been installed in certain areas. The Units are not SCR equipped.

Each Unit has an American Air Filter FGD system that uses thiosorbic lime as the reagent producing a sulfite sludge byproduct. These FGD systems have an SO_2 removal efficiency of approximately 96 – 98%, but, the systems are problematic and expensive to operate.

5.4. Reid Station Unit 1 and CT

This small old non-reheat Riley Unit's current performance has not been fully assessed nor has it been considered for system upgrades and additions.

The consensus is that the Unit be mothballed or retired and its allowances be pooled into the fleet-wide allowances.

If it were deemed that the Unit should run, then this decision would be made on a purely economic basis, inclusive of the purchase or assignment of the necessary emission allowances.

5.5. Common Reagent Pump Preparation & Dewatering Systems

The Regent Preparation System and FGD Sludge Dewatering System were not upgraded nor was their capacity increased when the FGD systems were retrofitted to Henderson 1 and 2. This means that the margins or excess capacity of both these subsystems has been eroded and they are now very sensitive to upset conditions amid peak loads.

Also the current control systems are rather basic and operator skill intensive.

The reagent preparation system comprises eleven (11) lime slakers segregated in three (3) buildings approximately 60 yards apart. They are not overly automated and their operation is relatively labor intensive.

The dewatering system comprises four (4) thickeners and three (3) secondary vacuum drum filters. The resultant sludge, primarily sulfite, is pushed stacked out into mounds on site and the filtrate water is reclaimed and returned to the FGD system.

5.6. Wilson Station Unit 1

Boiler
Foster Wheeler Natural Flow, Superheat / Reheat Design
Rated Pressure 2,950 / 690 psig.
Rated Steam Flow 3,484,000 lbs/hr.
Operating Superheat Outlet 2,620 psig.
Operating Temperatures 1005 /1005

The boiler is of an opposed fired design utilizing 5 MPW Foster Wheeler mills. The mills supply 5 separate burner elevations consisting of 3 burner elevations on the front wall and 2 elevations on the rear wall. Each burner elevation contains 5 first generation low NOx Foster Wheeler burners. The burner compartments utilize a common secondary air duct supplied from both ends. The boiler is a natural flow balanced flow draft design incorporating both primary and secondary air pre heaters.

5.6.1. Electrostatic Precipitator

The ESP is General Electric design utilizing a plate and wire particulate removal technique. The ESP includes 2 separate modules, each module has 2 flow path removal. Fly ash removal is accomplished utilizing a dry fly ash transfer system of an Allen Sermon Hoff design. The ESP has a capacity rating of 110%.

5.6.2. De-NOx System

The unit was retrofit with a Babcock Borsic design Selective Catalyst Removal (SCR) system in 2003. The system is of a delta wing flue gas design incorporating dual reactor modules. The SCR has a design removal efficiency of 90% with an inlet NOx level of 500 ppmv. The SCR reactor modules have the capacity for 4 layers of plate catalyst. The system is currently operating with 2 layers of Hitachi catalyst.

The FGD system is a Pullman-Kellog horizontal gas flow, four (4) module scrubber system utilizing limestone as the primary reagent. Removal enhancement reagents (DBA, emulsified sulfur and sodium bisulfite) are also utilized to achieve design removal efficiencies. The system is successful at achieving an average annual removal efficiency of 91% with an average inlet SO_2 loading of 3,400 ppmv.

The original FGD system design incorporated a Stack Plume Reheat system (SPR). The SPR design used a centrifugal booster fan with ambient inlets utilizing steam coils to preheat the air. The heated air was injected into the FGD outlet duct just prior to the stack inlet breaching. The system was decommissioned by the facilities owner in 1987.

5.6.3. Solid Waste Handling

Sludge material from the FGD system is pumped to a precipitating thickener tank. Sludge materials settling within the thickener are then pumped to the solid waste handling system surge tank. The unit has a Conversion Systems Incorporated (CSI) designed processing system. De-watered sludge solids are mixed with fixation lime and fly ash to form poz-o-tec. The poz-o-tec is then deposited into the station's landfill.

6. ALLOWANCE MARKET AND FORECAST COST

Data provided by WKE, included in Predictive Model.

7. POTENTIAL UPGRADES OR PLANT MODIFICATIONS

7.1. Performance

7.1.1. Coleman

Coleman has the following potential upgrades:

7.1.1.1. NOx

1) Evaluate burner line balancing taking into consideration the wide range of fuels burned at Coleman Station. With HGI ranging from 38 to 55 and BTU contents ranging from 10,800 to 12,000 btu/lb. This evaluation should determine an approximate amount of NOx emission reduction that can be expected. The first step is to ensure the "low NOx" burners and OFA systems are being operated at their optimal level.
2) Evaluate an SNCR to further reduce NOx emissions.
3) Evaluate an in duct SCR to further reduce NOx emissions down from 0.30 lbs/mmBtu. Either on a unit by unit basis or a single reactor serving all three units down stream of the ESP. Low temperature catalyst should be evaluated to eliminate the need for gas reheat.
4) Install a single (serving all 3 Units) low-dust SCR downstream of the FGD. This will require a reheat system depending on the amount of NOx emissions required. With a low dust SCR catalyst should never need replacement.

7.1.1.2. SO_2

1) Maximize the Utilization / Removal Efficiency of the new FGD to 98% or greater.

   All of the hardware is in place to achieve this. Although dibasic acid could be added to marginally improve the SO_2 removal efficiency, it is best employed only if aluminum fluoride blinding becomes a serious impediment to performance. However, environmental constraints must be evaluated and measures put in place before use of dibasic acid is implemented.

7.1.1.3. SO_3

Although not regulated, SO_3 is likely to become a sensitive issue in the next few years, and, quite literally, will become more visible with the commissioning of the FGD system. One possible route to mitigate SO_3 for all three Units at Coleman is reagent injection (e.g. MgO, NH_3, Na_2CO_3 or CaOH) at the furnace, the airheater inlet, the ESP inlet or the FGD inlet as appropriate. With these approaches it is believed that SO_3 levels could be reduced to <5 ppm at the stack (a non-visible plume).

7.1.1.4. Particulate

The Station has been successful at meeting a particulate limit of 0.27 lbs/mmBtu and 40% opacity. In 2005 the Station began operating under Title V Air Quality Permit which has put an opacity trigger limit of approximately 20% on the Units. The Station must not exceed the new opacity trigger limits greater than 5% in any quarter year. To date this limit has been met but not without operational challenges. Work is currently in progress with NEL's to perform modeling required for future design changes of the ESP.

Consideration may be given to installation of a single high temperature vertically upward gas flow SCR complete with a new 500 MW gross ESP upstream of the FGD.

7.1.1.5. Mercury

1) Undertake "baseline" testing to establish a realistic understanding of the current levels of performance.

2) Determine, to what degree, if any, that increasing levels of unburned carbons have on mercury emissions. This investigation should encompass the full range of fuels that are to be fired once the FGD system is in service.

3) As and if necessary, add a specifically designed and sized mercury oxidation catalyst to convert elemental mercury to soluble oxidized mercury. This would have to be on a Unit by Unit basis and should preferably be an "in duct" solution.

   The exact location depends on the development and availability of low temperature oxidizing catalysts currently undergoing trials.

4) Add halogen containing compounds into the fuel or inject them into the boiler.

   Both 3) and 4) above speciate the mercury from elemental into oxidized, ionic or halogen ides species and E.ON is currently investigating their effectiveness and establishing design parameters in partnership with the University of Halle-Wittenberg.

7.1.2. Henderson

Henderson has the following potential upgrades:

7.1.2.1. NOx

The existing SCR systems achieve > 90% removal efficiency (based on 250 – 300ppmv at the inlet); however, the reliability must be improved.

The SCR Units, as reported to us, do not appear to be performing satisfactorily and the following are possible courses of action.

1) Fix, repair or replace the leaking bypass dampers, NEM's system, air heater baskets, seal air fans and expansion joints.

2) The station has utilized the catalyst manufacture (Cormetech) to establish the current condition, activity and chemical analyses of the catalyst. The station has also removed catalyst samples for E.ON to perform a comparison analysis.

   From this establish the remaining Potential and catalyst addition, regeneration or replacement needs.

3) Conduct a MARA (or equivalent) field test to establish the true current operating performance of the system.

7.1.2.2. SO_2

1) Investigate and correct the SO_2 removal efficiency differences between Units 1 and 2. Likely causes are:

   - Gas Flow Distribution
   - Spray Level Sneakage
   - Varying rates of natural oxidation
   - Service hours since last outage

2) Investigate the possibility of replacing the current sump agitator system with an external pumped "suspended bottom solids system". This may allow the system to operate at higher solids concentration and there may be a slight improvement in SO_2 removal. It could possibility improve the dewatering characteristics of the sludge and thus reduce overload on the dewatering system.

3) The ability of the existing thiosorbic lime scrubbers to increase SO_2 removal efficiency is limited due to their aggressively small physical sizing and low Liquid to Gas Ratios.

Therefore, the only long-term viable way of achieving high levels of performance (<95%) is to increase the height of the absorbers and add additional sprays and pumps to raise the Liquid to Gas Ratio. An external "reaction tank" would probably also be required to provide the necessary sump volume. If the removal efficiency is increased, additional equipment and upgrades in the Reagent Preparation System and the FGD Sludge Dewatering System will be necessary. The bleed system and make-up system will also need redesigning before any capacity improvements are made. A conversion to Forced Oxidation should be considered as part of such a major upgrade.

7.1.2.3. SO_3

Please refer to Section 7.1.1.3.

7.1.2.4. Particulate

Due to the marginal precipitator size, particulate is a major concern to the Henderson units. Henderson Unit 2 suffers a 15 to 17 megawatt derate daily due to opacity excursions. Particulate carry over increases the dust loading on the existing FGD. WKE is currently working with the Kentucky Division of Air Quality to certify the use of a wet stack particulate monitor and particulate test method for wet stacks. Even if this project is successful, precipitator upgrades may need to be addressed e.g. wider plate spacing, increased rapper sectionalization, upgraded transformers, etc. This should be undertaken on a high priority basis to recover the derate.

7.1.2.5. Mercury

1) Undertake "baseline" testing to establish a realistic understanding of the current levels of performance.

2) Determine, to what degree, if any, that increasing levels of un-burnt carbon have on mercury emissions.

3) Investigate and measure current mercury removal levels with the SCR in service.

   As and if necessary, add (either to the SCR or in duct) a specifically designed and sized mercury oxidation catalyst to convert elemental mercury to soluble oxidized mercury.

4) Add halogen containing compounds into the fuel or inject them into the boiler.

   Both 2) and 3) above speciate the mercury from elemental into oxidized, ionic or halogenides species and E.ON is currently investigating their effectiveness and establishing design parameters in partnership with the University of Halle-Wittenberg.

   However, as the Henderson FGD systems are not currently forced oxidized, this is unlikely to yield significant increases in the level of mercury removal. If the FGD upgrade includes a forced oxidation conversion, an increase in the mercury removal efficiency is anticipated.

7.1.3. Green

Green has the following potential upgrades:

7.1.3.1. NOx

1) We would recommend that Burner Line Balancing be undertaken across the complete fleet to ensure that “base” conditions are optimized such that all gas cleaning systems can be tuned to maximize their respective removal efficiencies. Add “last-bend” rope breaking orifices local to the burners.

7.1.3.2. SO_2

The existing Green FGD systems consistently achieve very high SO_2 removal efficiencies (97 – 98%). However, O&M cost of the existing FGD system is very high and significant capital improvements will be necessary in the future to maintain current level of performance and reliability. There are a number of things that can be researched to try and improve performance and reliability:

1) Remove the large vertical shaft agitator and replace it with an external pumped "suspended bottom solids system".

   In conjunction with this, close up and acid resistant line the access / maintenance spaces in the sides of the absorber to increase the sump volume. This would greatly improve the solids residence time and allow crystal growth to maximize thus improving clarification, settling and dewatering.

2) If necessary, and if driven by the need to reduce mercury emissions, convert the system to in-situ forced oxidation. In addition to mercury removal this would also lead to an increase in SO_2 removal ($\cong$2%). This would also assist in improving the dewatering characteristics of the sludge.

The four FGD systems are integral to each other and a upset in one will adversely affect the other. Due to this sensitivity, its critical that extensive research and testing be performed before making any changes to either of the FGD systems.

7.1.3.3. SO_3

Please refer to Section 7.1.1.3.

7.1.3.4. Particulate

Not an issue of concern and thus no recommendations or potential upgrades have been assessed.

7.1.3.5. Mercury

1) Undertake "baseline" testing to establish a realistic understanding of the current levels of performance.

2) Determine, to what degree, if any, that increasing levels of un-burnt carbon have on mercury emissions.

3) As and if necessary, add a specifically designed and sized mercury oxidation catalyst to convert elemental mercury to soluble oxidized mercury. Ideally this should be integrated into the new SCR considered in Section 9.2.1.

   The exact location depends on the development and availability of low temperature oxidizing catalysts currently undergoing trials.

4) Add halogen containing compounds into the fuel or inject them into the boiler.

Both 3) and 4) above speciate the mercury from elemental into oxidized, ionic or halogenides species and E.ON is currently investigating their effectiveness and establishing design parameters in partnership with the University of Halle-Wittenberg.

5) Increase the mercury removal efficiency by a conversion to a forced oxidized FGD system, provided an SCR unit is installed upstream of the FGD absorber.

7.1.4. Wilson

Wilson has the following potential upgrades:

7.1.4.1. NOx

1) Install "last-bend" rope-breaking orifices local to burners and undertake Burner Line Balancing. This will require

new test ports and may require a different type of balancing valves.

2) Install limestone addition system to main fuel conveyor(s) to mitigate arsenic poisoning of the catalyst to balance catalyst degradation and extend its life.

3) Tune the SCR regularly (MARA or equivalent) to reliably maintain maximum performance (95%).

7.1.4.2. SO_2

As reported by us elsewhere, the existing FGD cannot, in our view, be enhanced or upgraded economically or viably, either chemically or mechanically, to achieve the 98% SO_2 removal efficiency foreseen as being required under CAIR. There are however certain things that could be done as short-term reliability and performance maximization strategies.

1) It is anticipated that the Burner Line Balancing will show benefits throughout the Unit, including the FGD by reducing gas flow imbalances.

2) The "offset" location of the fourth module and the less than optimum duct layout lead us to believe that significant improvements to flow distribution module to module as well as upstream and downstream of the modules could be achieved. This would lead to improved FGD system performance (both efficiency and reliability) and significant reductions in gas side pressure drop with resultant power savings.

3) Identify if there are any other potential options

Fuel Strategy Changes
Lower sulfur fuels and a cost comparison

Convert the unit to use Powder River Basin fuels

Retrofit the existing FGD system with enhancements through mechanical design changes

Additional chemical reagent additives or enhancements

7.1.4.3. SO_3

Although not regulated, SO_3 is likely to become a sensitive issue in our opinion, and, quite literally, will become more visible with the addition of catalyst layers. The best route to mitigate SO_3 is sorbent injection (e.g. MgO, NH_3, Na_2CO_3 or CaOH) at the furnace, the airheater inlet, the ESP inlet or the FGD inlet as appropriate. With these approaches SO_3 levels could be reduced to <5 ppm at the stack (a non-visible plume).

Wet Electrostatic Precipitator
Wet ESP's have long been proven in large-scale commercial service to remove sub-micron particles and acid mist. These applications have most widely been used in the metallurgical industry and in fact the generic name of such ESP's is "Acid Mist Precipitators".

Wet ESP's have been applied in several special applications in the German Power Industry (non E.ON Units) and are now being deployed and tested on several Utility boilers in the United States. In Canada, one Utility has retrofitted a Wet ESP on top of a Wet FGD system specifically for SO_3 control and is thought to be installing them as original equipment on new Wet FGD systems being retrofitted to three 350 MW Units.

Wet ESP's are the "guaranteed" solution and besides mitigating SO_3 they can also control $PM_{2.5}$. They are very expensive since they are typically fabricated from acid resistant materials. The total cost impact of a Wet ESP can be limited as an integral facet of an FGD scrubber. WESP's can be readily integrated into the scrubber design and offer a number of attractive design features. SO_3 removal efficiencies of greater than 95% can be achieved with commensurate reductions in $PM_{2.5}$.

7.1.4.4. ESP Outlet Particulate

Not an issue of concern and thus no recommendations or potential upgrades have been assessed.

7.1.4.5. Mercury

1) Undertake “baseline” testing to establish a realistic understanding of the current levels of performance.

2) Determine, to what degree, if any, that increasing levels of unburnt carbon have on mercury emissions.

3) As and if necessary, add a specifically designed and sized mercury oxidation catalyst to convert elemental mercury to soluble oxidized mercury. This would probably have to be added into the SCRs.

   The exact location depends on the development and availability of low temperature oxidizing catalysts currently undergoing trials.

4) Add halogen containing compounds into the fuel or inject them into the boiler.

Both 3) and 4) above speciate the mercury from elemental into oxidized, ionic or halogenides species and E.ON is currently investigating their effectiveness and establishing design parameters in partnership with the University of Halle-Wittenberg. However, they will not have any significant effect until Wilson is equipped with a forced oxidation FGD system.

8. NEW / REPLACEMENT ADDITIONS

8.1. Coleman

8.1.1. NOx

1) Add a 95% SCR to a single Unit (on a Unit by Unit basis) above the airheater and ESPs (as earlier proposed for Henderson). On a system basis this may, depending on the overall strategy, lead to surplus NOx allowances being available for sale.

2) Install a single (serving all 3 Units) low-dust SCR between the ESPs and the FGD system. With current catalyst technology this would require a reheat system but catalyst life would be extended due to the light dust loading and the avoidance of catalyst poisons.

8.1.2. Particulate

1) This will only become an issue if the FGD system suffers from aluminium fluoride blinding. If this problem arises it would require the installation of additional ESP capacity on a progressive Unit by Unit basis upstream of the FGD system.

2) Unit 3 is currently operating with a 5 MW derate due to lack of mill capacity on the "hard coals" as fired and opacity spikes. These spikes are thought to be due to the pulveriser performance and the station now diligently monitors and maintains a graded ball change. However, even this level of attention has not been able to restore the derate.

   These mills also suffer from the other well-known attendant issues associated with the use of tube ball mills. We therefore suggest that consideration be given to replacing these mills with vertical spindle pulverisers fitted with rotating classifiers. This would lead to recovery of the derate and overall enhanced operational stability.

8.2. Green

8.2.1. NOx

1) Install an SCR on either one or both Units that is designed for >90% NOx removal from uncontrolled levels without the reburn system in operation.

8.3. Wilson

8.3.1. SO_2

1) Build a new high efficiency (>98%) limestone based in-situ forced oxidation FGD system complete with new external fiberglass stack.

   This system would be built in parallel with the existing system continuing to operate and also overcome the safety concerns associated with the existing outlet ducts and stack linings.

   The following paragraph may have some value, however as related to the meeting of CAIR assumptions this might not the appropriate location. It would appear any additional project enhancements should stand alone.

   In parallel with this system we would also suggest that the Unit proceed with the 50 MWe capacity upgrade of the turbine. While this may involve a NSPS review, it appears that there is unlikely to be a better opportunity to undertake this upgrade. The overall impact of this upgrade on the station services and all aspects of Unit performance, including the condenser, the cooling towers, the boiler and gas cleaning systems can also be evaluated.

If this proves to be a viable case, then we envisage the new FGD system to be built complete with an integral Wet ESP. This will resolve any and all SO_2 and $PM_{2.5}$ issues and will lead to further reductions in mercury emissions. Once this was commissioned, the sorbent injection system for mitigating SO_3 emissions would be shut down.

9. COST: CAPITAL / OPERATING

9.1. Capital

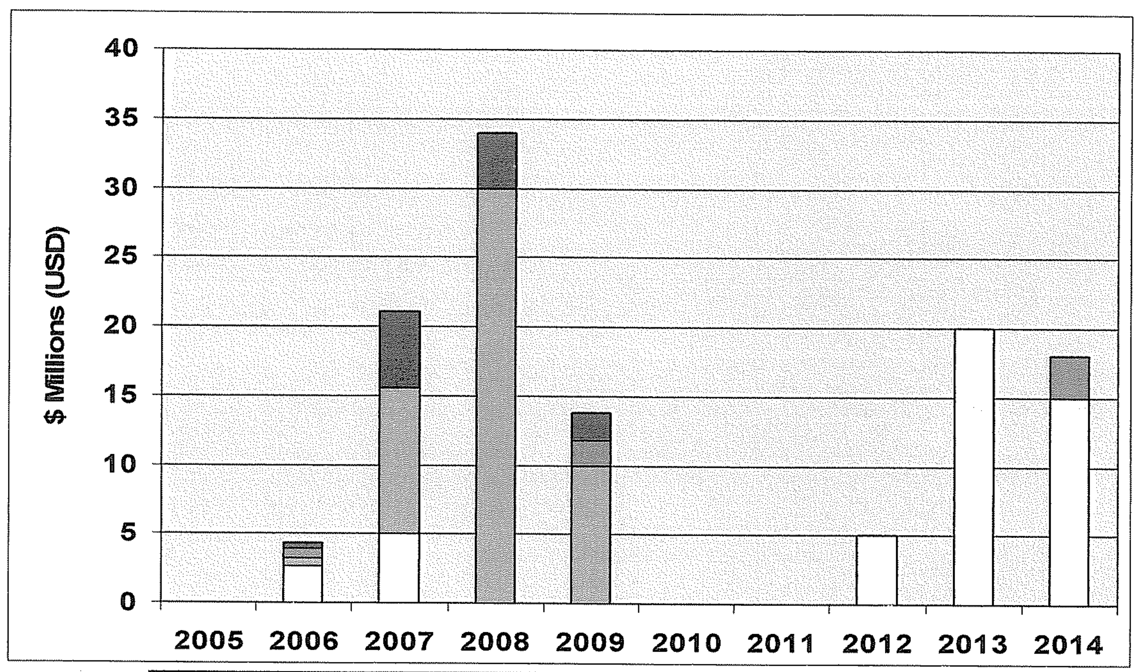
Table 4

Year	Coleman	Henderson	Green	Reagent Prep/ Dewatering	Wilson
2005		• Catalyst testing $0.02		•	•
2006	• BLB (3 Units) $0.45 • Ash pH $1.0 • OFA (Unit 2) $0.3 • Hg Baseline (3 Units) $0.2	• BLB (2 Units) $0.3 • Hg Baseline (2 Units) $0.15 • Suspended Bottom (2 Units) $0.6 • SCR Fix (incl. MARA) $1.0	• BLB (2 Units) $0.3 • Hg Baseline (2 Units) $0.15	•	• $CaCO_3$ Addition $0.2 • Hg Baseline (1 Unit) $0.1 • SO_3 Mitigation $0.3 (Equipment) • BLB (1 Unit) $0.15 • SO_3 Mitigation $0.1 (Tests)
2007	• SO_3 Mitigation (3 Units)-- Tests: $0.2 Equip.: $0.6 • New pulverisers $5.0	• SO_3 Mitigation $0.35	• Suspended Bottom (2 Units) $0.6 • SO_3 Mitigation $0.35 •	•	• New FGD $10.0 • With Wet ESP $4.0 • Station Upgrade $5.0
2008	•			•	• New FGD $30.0 • With Wet ESP $4.0 • Station Upgrade $10.0
2009	• Oxidation catalyst $1.8		•	•	• New FGD $10.0 • With Wet ESP $2.0 • Station Upgrade $15.0
2010	•		•	•	•
2011	•		•	•	•
2012	•		• New SCR (1 Unit) $5.0	•	•

Year	Coleman	Henderson	Green	Reagent Prep/ Dewatering	Wilson
2013	•		• New SCR (1 Unit) $20.0	•	•
2014	•		• New SCR (1 Unit) $15.0 • Forced oxidation $3.0	•	•

Table 4A

WKE Multi-Pollutant Capital Expenditure Plan



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
NOx	0.02	2.7	5.0					5.0	20.0	15.0
SO2		0.6	10.6	30.0	10.0					
Hg		0.6			1.8					3.0
SO3		0.4	5.5	4.0	2.0					
TOTAL:	0.02	4.3	21.1	34.0	13.8	0.0	0.0	5.0	20.0	18.0

9.2. Operating

Table 5

Year	Coleman	Henderson	Green	Reagent Prep/ Dewatering	Wilson
2005				•	• BLB $0.025 (2005-2007) • Catalyst Testing & Management $0.01
2006	• BLB $0.025 (2006-2008) • SO_3 Mitigation Additive $1.2 • MARA $0.04	• Catalyst Testing & Management $0.01	• BLB $0.025 (2006-2008) • SO_3 Mitigation Additive $1.2 • MARA $0.04	•	• $CaCO_3$ Addition $0.2 • SO_3 Mitigation Additive $1.2
2007		• SO_3 Mitigation Additive $1.2 • MARA $0.04 • BLB $0.025 (2007-2009)		•	
2008	• New pulverisers $0.2			•	• BLB $0.25
2009			•	•	• New FGD ($1.0) • With Wet ESP ($1.0)
2010					
2011					
2012					
2013					
2014					
2015			• New SCR $1.0 • Catalyst Testing & Management $0.01		

9.3. Schedule

Assuming a six (6) month "approval lead time" for minor items and a twelve (12) month "approval lead time" for major additions, the lead time and implementation schedule (as shown in 10.1 above) was developed.

10. STRATEGY OPTIONS

10.1. NOx

For the "base case" (Figure 1, Section 4.2), the WKE Predictive Model shows that without further plant upgrades or modifications to the system (in order to achieve lower overall NOx emission levels), the fleet will be NOx allowance deficient (Annual CAIR) from 2009 through to the end of the lease term (2023), except for a small recovery period in 2011 and 2012 following the retirement of Reid Unit 1 in 2010.

Based upon the potential upgrades and modifications discussed in Section 8, a system wide strategy can be applied progressively to achieve the necessary improvements to the NOx emission levels. This will result in a balanced or net positive NOx allowance position over the remainder of the lease term with regard to Annual CAIR.

The following NOx reduction strategies can be considered and should be implemented within timeframes that will allow the system to maintain a balanced or net positive position with regard to NOx allowances.

1) Burner Line Balancing for all Units within the system could be undertaken to optimize the performance of the existing Units. Imbalances within the furnace that lead to NOx formation could be minimized resulting in a commensurate reduction in the NOx emissions levels. Early implementation of Burner Line Balancing would maximize the benefit over the lease term. The following reductions to the NOx emission levels per Unit can be expected from Burner Line Balancing, although the reductions actually achievable cannot be predicted with certainty:

Coleman 1:	5% reduction
Coleman 2:	5% reduction
Coleman 3:	10% reduction

Henderson 1:	2% reduction
Henderson 2:	2% reduction
Green 1:	5% reduction
Green 2:	5% reduction
Wilson 1:	3% reduction

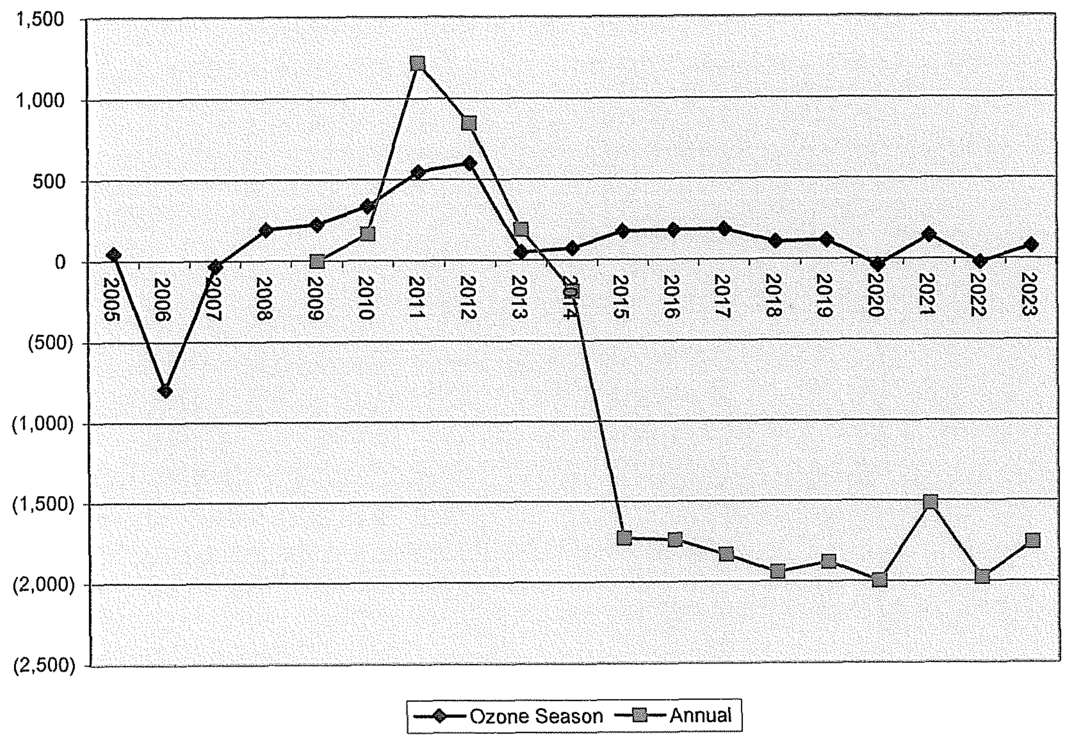
2) Additional NOx reduction can be achieved at Henderson 1 and 2 by fixing the deficiencies in the existing Selective Catalytic Reduction Units, implementing a catalyst management program (see Section 4.2.4), and optimizing performance using MARA at both Henderson and Wilson SCRs, as follows:

Henderson 1:	90% NOx removal (Annual CAIR)
Henderson 2:	90% NOx removal (Annual CAIR)
Wilson:	92% NOx removal (Annual CAIR)

Assuming that Burner Line Balancing is implemented at all Units by the end of 2006, and that the deficiencies are fixed in the SCRs at Henderson and MARA at both Henderson and Wilson is applied in this timeframe; then the WKE Predictive Model shows the impact to the system (Figure 3).

The system wide results indicate a net positive position for Annual CAIR allowances until 2013, after which the system will be deficient in allowances in all succeeding years. Additionally, the cost impact, on the basis of the Predictive Model and the forecast of allowance values, to the WKE system is reduced from $93 million USD in the “base case” to $64 million USD (this value to be adjusted by WKE to a “net present value”).

Figure 3



3) Replacement of the pulverisers at Coleman Unit 3 is estimated to reduce NOx emissions levels by about 2%. However, this will be offset by an increase in the annual NOx emissions due to the increase in flue gas. Although primarily the pulvierisers would be replaced to recover the ~5 MWe derate due to their current configuration and performance, any NOx reduction achieved would be a co-benefit. Due to the time required to purchase, deliver, install and commission the new pulverisers, it is estimated that this upgrade can be implemented by the end of 2007.

Only a marginal improvement may result due to this upgrade

4) After all performance improvements to the system are applied as per Items 1) to 3) inclusive above, the system continues to be deficient after 2013 for NOx allowances. Additional NOx control equipment is necessary to maintain NOx compliance for Annual CAIR after 2013. This can be accomplished by installation of new SCR Unit(s) at one of the stations within the system. Either Coleman or Green are candidates for additional SCR systems (see Section 8). However, considering access and constructability, the retrofit installation of an SCR would be simplest at Green Station Unit 2. Additionally, permits and infrastructure for delivery and storage of ammonia are already in place for this site to support the SCRs currently in operation at Henderson Units 1 and 2.

   Assuming that one (1) SCR Unit (90% NOx removal efficiency) is put into operation at Green Station Unit 2 by the end of 2014, the WKE Predictive Model indicates that the system will be overall compliant for Annual CAIR until 2023, except for small deficiencies in 2014, 2019, 2020 and 2022 (Figure 4). Installing an SCR unit at Green 2 at 92% NOx removal efficiency results in compliance for Annual CAIR until the end of the lease term in 2023 (Figure 5).

Figure 4

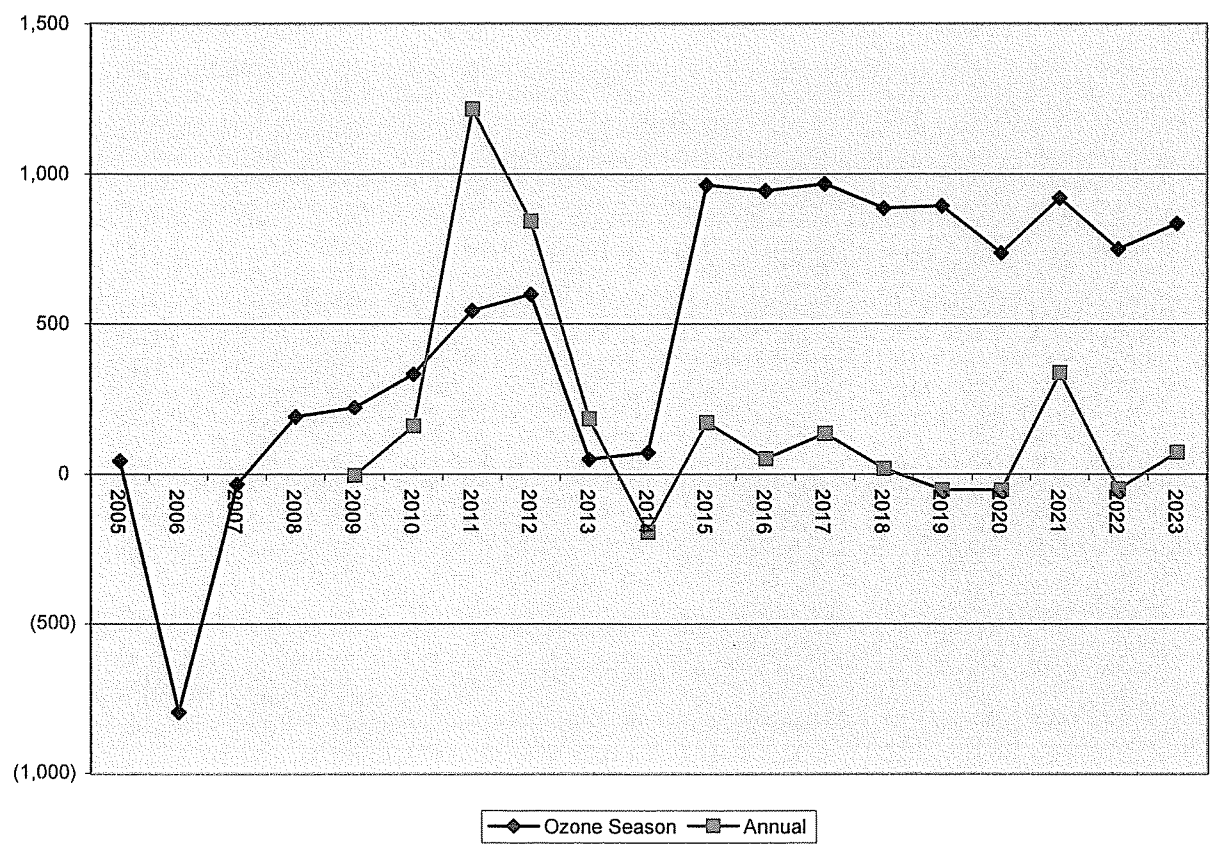
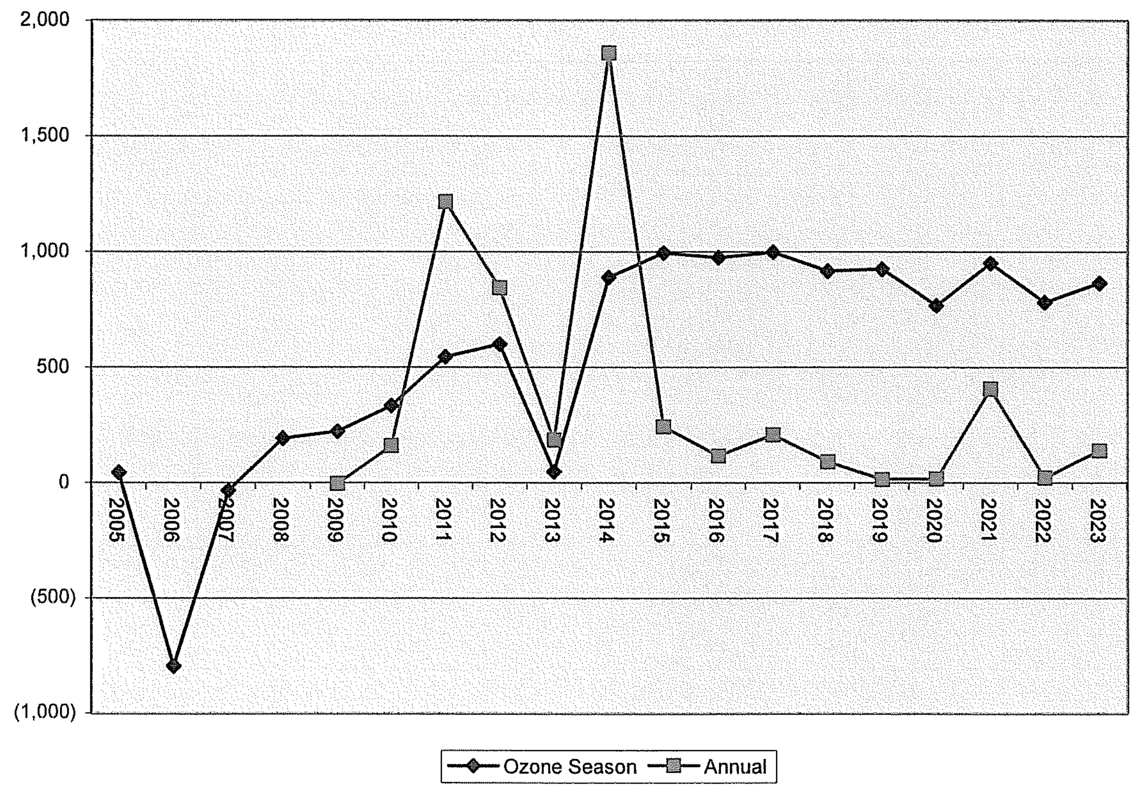

1,500
1,000
500
0
(500)
(1,000)
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Ozone Season
Annual

Figure 5



Furthermore, a second SCR can be considered for Green Unit 1 to be installed within the same time period as Green Unit 2. Using the WKE Predictive Model, the result of two (2) SCR units at Green (90% NOx removal efficiency each), indicates a net positive NOx balance would be achieved for Annual CAIR, which would offer the possibility of selling the banked NOx credits.

5) Based on Items 1) to 4) inclusive above, various options can be considered for Annual CAIR NOx compliance for the system to the end of the lease term in 2023.

   Option A:
   - Item 1) Fully Implement
   - Item 2) Fully Implement
   - Item 4) Implement 1 SCR on Green Unit 2 at 90% NOx removal efficiency, operational January 2015.

   The WKE Model predicts Figure 4, Approximate Balanced NOx Allowances to 2023.

   Option B:
   - Item 1) Fully Implement
   - Item 2) Fully Implement
   - Item 3) Implement 2 SCRs on Green Units 1 and 2 at 90% NOx removal efficiency.

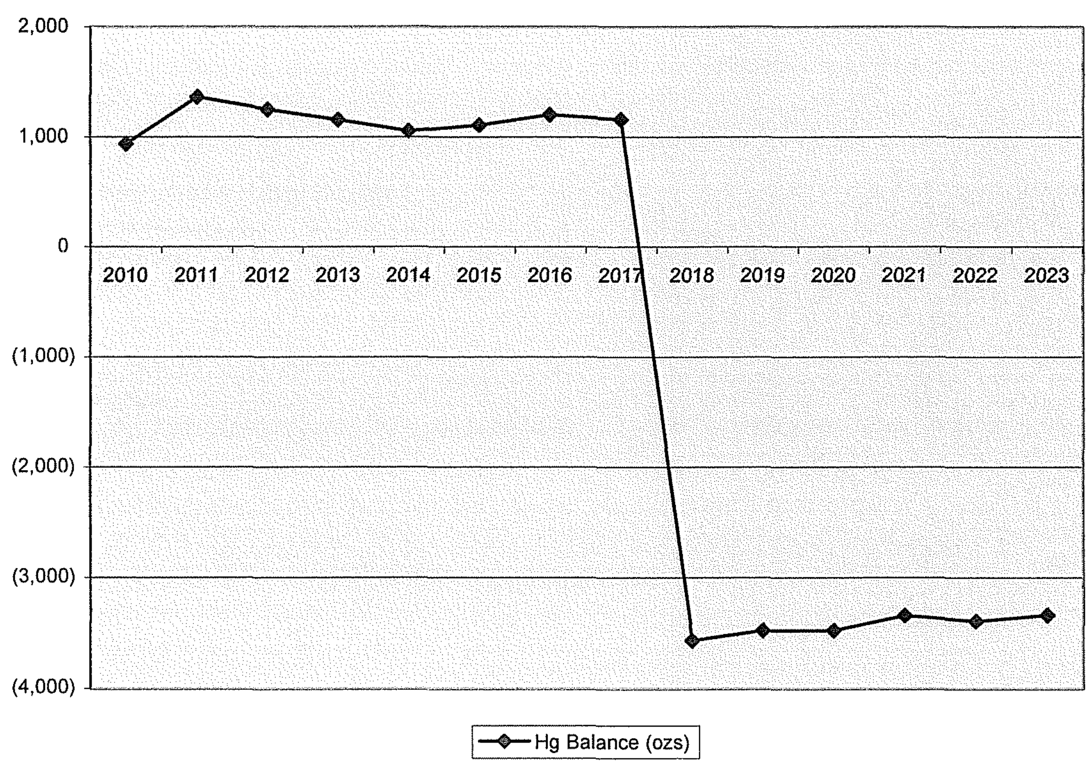
   Option C:
   - Item 1) Fully Implement
   - Item 2) Fully Implement
   - Item 3) Implement 1 SCR on Green Unit 2 at 92% NOx removal efficiency, operational January 2014.

   The WKE Model predicts Figure 5, and that NOx credits will be available to sell.

10.2. Mercury

For the "base case", the WKE Predictive Model (using Hg allotments assumed within the model) shows that with the current 2005 levels of Hg removal (Coleman 25%, Henderson 50%, Green 40%, Wilson 50%), the system will be deficient for Hg allowances (Annual CAMR) starting in 2018 for the remainder of the lease term in 2023 (Figure 6).

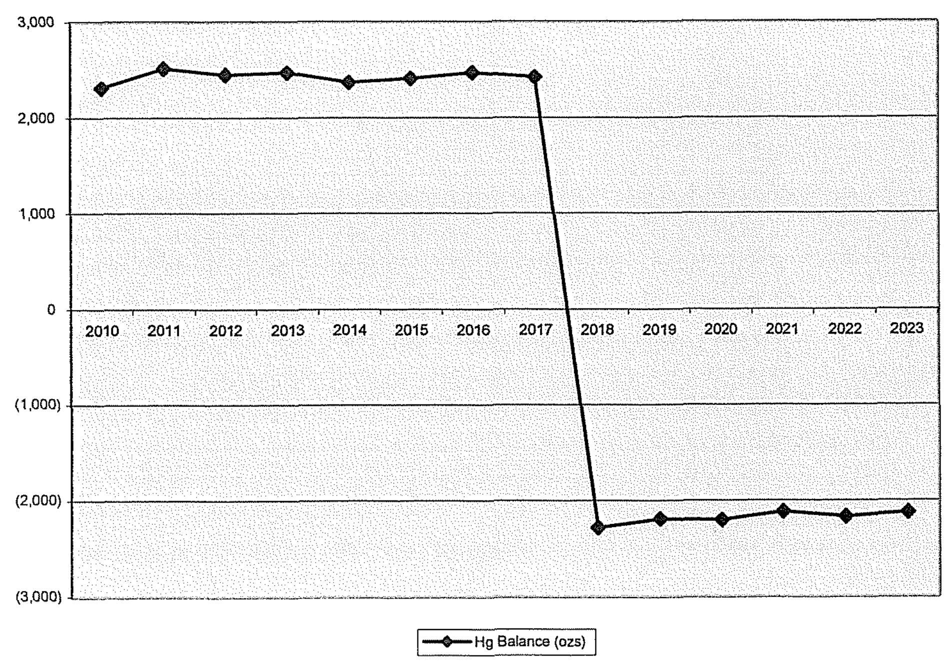
Figure 6



Additional Hg reduction can be achieved through the "co-benefit" approach, where oxidized mercury species (SCR catalyst or oxidizing catalyst) is removed in a forced oxidized FGD system (requiring proper oxidation potential). Prior to 2010 the following "co-benefit" reductions are possible for Hg:

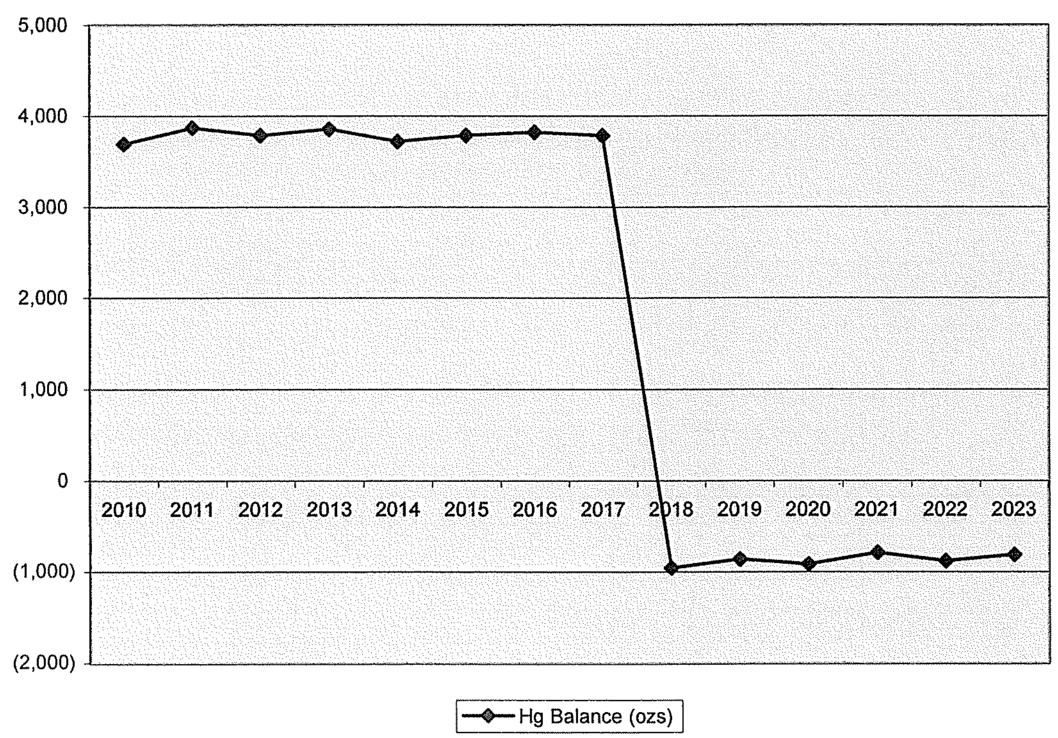
1) With the Coleman FGD system operation beginning in 2006, an oxidizing catalyst can be added upstream to oxidize the Hg and collect it in the FGD system (gypsum/wastewater). This will increase the Hg removal at Coleman from 25% to 80%. The WKE Predictive Model shows the impact to the system of Item 1) (Figure 7). The result is an improvement in the deficit of allowances starting in 2018, which continues to the end of the lease term in 2023.

Figure 7



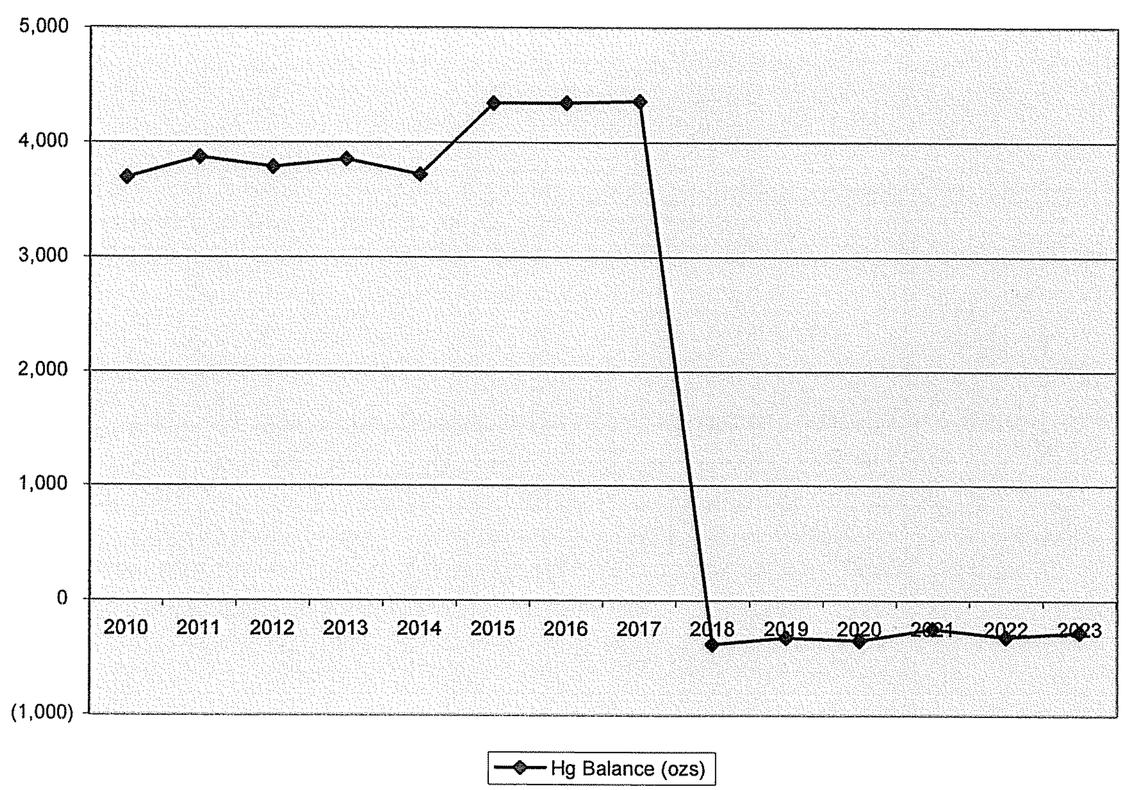
2) Installation of a new forced oxidized FGD scrubber by 2010 at Wilson will increase the removal of the oxidized mercury generated through the SCR catalyst from 50% up to 85%. Further to Item 1) above, this will also improve the deficit of allowances starting in 2018, which will continue to the end of the lease term in 2023. The WKE Predictive Model shows the impact to the system of Items 1) and 2) (Figure 8).

Figure 8



3) Conversion of the existing FGD scrubbers at Green to forced oxidized systems will increase the oxidation potential. Combined with a new SCR at Green Unit 2, additional Hg removal to Items 1) and 2) above can be achieved resulting in further improvement to the allowance deficits after 2018. The WKE Predictive Model shows the impact to the system of Items 1), 2) and 3) (Figure 9).

Figure 9



10.3. SO_2

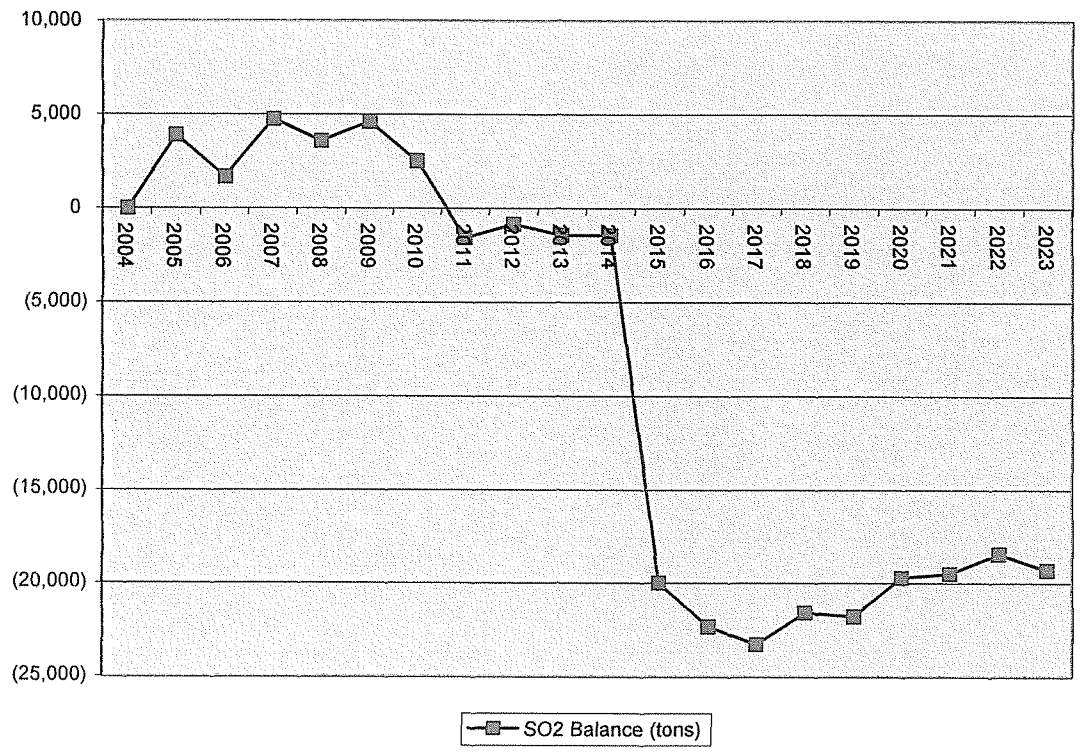
For the “base case”, the WKE Predictive Model shows that without further plant upgrades or modifications to the system (in order to achieve lower overall SO_2 emission levels), the system will be deficient for SO_2 allowances (with CAIR Allotments) after 2009 for the remainder of the lease term in 2023. This includes operation of the new Coleman FGD at 95% SO_2 removal efficiency (Figure 1A).

Based upon the potential upgrades and modifications discussed in Section 8, a system wide strategy can be applied to achieve the necessary improvements in SO_2 emission levels that will result in a balanced or net positive position over the lease term with regard to SO_2 CAIR allowances.

The following SO_2 reduction strategies can be considered and should be implemented within timeframes that will allow the system to maintain a balanced or net positive position with regard to SO_2 allowances for CAIR.

1) The new Coleman scrubber can be operated to achieve up to 98% SO_2 removal efficiency by the end of 2006. This will utilize the existing equipment installed (i.e. switch “on” one extra recirculation pump) and the margin of expected performance that is built-in to the FGD design at Coleman. Compared to the “base case” the WKE Predictive Model shows that this would result in a net positive position for SO_2 CAIR allowances until 2010, after which the system will be deficient in allowances in all succeeding years (Figure 10).

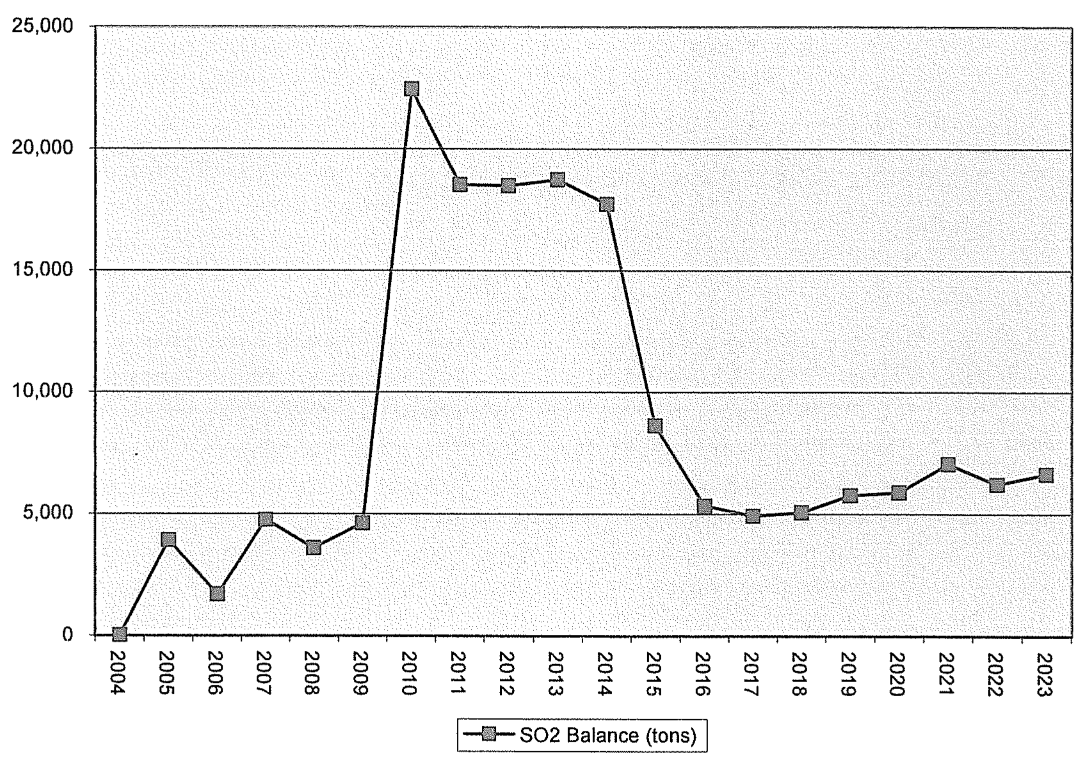
Figure 10



2) From the discussion in Section 8, further significant improvements in SO_2 removal efficiency to existing FGD systems within the WKE fleet are not possible. Minor upgrades would only result in marginal gains in SO_2 removal at best, which would still leave the system deficient regardless of how early such upgrades could be implemented and would result in questionable reliability of operation. Therefore, an additional new FGD system must be considered for the WKE fleet. Based on the current difficulties with reliability of the FGD system at Wilson and the expense (various reagents) to achieve SO_2 removal efficiencies up to 92%, as well as limitations in the design and configuration that do not allow the

FGD system to exceed its current performance reliably, the best candidate for a new FGD system is Wilson Unit 1. In combination with Item 1) above, implementing a new FGD system at Wilson Unit 1 by 2010 capable of achieving 98% SO_2 removal efficiency, similar to Coleman, would result in compliance to the end of the lease term in 2023 and would generate significant SO_2 allowances that could be sold. Figure 11 shows the results using the WKE Predictive Model of installing a new 98% efficient FGD system at Wilson Unit 1, operational in 2010.

Figure 11



Overall, compliance over the lease term for CAIR SO_2, as well as generation of significant SO_2 credits for sale, can be achieved by operating the Coleman FGD system at 98% SO_2 removal efficiency by the end of 2006, and installing a new FGD Scrubber at Wilson Unit 1 operational as early as 2010.

10.4. SO_3

The obvious short-term strategy is to address this issue on a Station by Station basis at the local level until and unless SO_3 becomes a regulated substance.

Therefore, in the near-term, low capital cost but incrementally expensive operating cost sorbent injection systems on a per Unit or per Station basis should be considered.

For Coleman injection of soda ash in the airheater inlets would seem to be the most viable strategy. Alternatively, sorbent addition into the furnace could be considered. However, we would caution that this may adversely affect the performance of the existing ESPs.

If this proves to be the case, the injection of lime at the FGD inlet would seem to be the best approach.

For Henderson (and Green after the installation of the SCR), soda ash injection at the airheater inlet would appear to be the technology of choice.

Equally at Wilson, this solution would also be applicable. However, if the project to achieve the 50 MWe increase in output ever proceeded, then the inclusion of a Wet ESP as an integral element of the new forced oxidation FGD system would be the technology of choice.

In parallel with the above, all the SCRs in the fleet should be progressively equipped with low conversion catalyst as the needs for replacement or additional catalyst arise.

10.5. Particulate (excluding SO_3 aerosols)

With two exceptions, no strategic decisions are required for particulate. The exceptions are Coleman and Henderson particulate emissions resulting in Unit derates.

The new FGD system will dramatically reduce overall levels of particulate emissions. However, if the FGD system suffers from aluminium fluoride blinding and if it is of sufficient severity that it cannot be overcome by the addition of DBA, then installation of a new ESP or additional particulate removal capability, upstream of the FGD, will be required.

11. RECOMMENDATIONS AND SUMMARY

There are two broad categories of recommendations.

Firstly every effort must be made to "sweat the existing assets" to maintain the highest levels of removal efficiency possible. In view of the levels of performance required, a regime of regular and vigorous tuning, balancing and testing will have to be implemented. Thus:

- Undertake periodic Burner Line Balancing (AKOMA or equivalent) verification and tuning after every outage (bi-annually).
- Undertake periodic MARA (or equivalent) SCR optimization and tuning after every outage (bi-annually).
- "Stretch" all existing systems to achieve maximum possible levels of SO_2 removal.
- Acquire, fleet-wide, believable mercury capture and emission data.
- The Henderson SCRs must, as a minimum, be brought up to their design level of performance on a sustainable basis. This level must then be exceeded. This may involve the addition of increased volumes of catalyst.
- The new FGD system at Coleman should be operated between 96.5 to 98% SO_2 removal efficiency with Wilson's new FGD system at 98%.
- SO_3 emissions must be mitigated by the fleet-wide deployment of sorbent technology.
- $CaCO_3$ addition to the coal conveyors should be added to Wilson to enhance and extend catalyst life.

- Wilson's SCR performance should be "stretched" up to 92 - 95% efficiency. This may require additional catalyst volume.
- The performance of the NOx reduction OFA system at Coleman 2 must be improved.
- The 15 MWe derate on Henderson caused by opacity should be recovered.
- The 5 MWe derate on Coleman 3 should be recovered.
- The performance of the Henderson FGD systems should be equalized and operated at maximum efficiency.

Secondly, a capital intensive program of new equipment construction must be implemented to meet the demands of CAIR and CAMR. This involves:

- A new limestone based in-situ forced oxidation FGD system, complete with FRP stack and Wet ESP must be built at Wilson.
- The 50 MWe upgrade at Wilson should be seriously considered and the new FGD/Wet ESP should be sized for these conditions.
- A new SCR should be installed at Green Station Unit 2.
- Oxidizing catalyst, halogen injection and forced oxidation FGD conversions will be required to reduce mercury emissions.

Table 6

Year	Coleman	Henderson	Green	Reagent Prep/ Dewatering	Wilson
2005	•	• Catalyst testing	•	•	•
2006	• BLB #3 (10%) • Fix OFA#2 (20%) • BLB #2 (5%) • BLB#1 (5%) • Ash pH • "Stretch" the FGD (3%) • Hg Baseline (25%)	• Fix SCR #1 (10%) • BLB#1 (2%) • Suspended Bottom (0%) • Fix SCR#2 (6%) • BLB#2 (2%) • Hg Baseline	• BLB#1 (5%) • BLB#2 (5%) • Hg Baseline	• Hg Baseline	• $CaCO_3$ Addition • Trim SCR (2%) • Hg Baseline (50%) • BLB (3% NOx) • SO_3 Fix
2007	• SO_3 Fix #1,2,3 • 5 MWe Derate Recovery #3 (new pulverisers) (2%)	• SO_3 Fix • MARA	• Suspended Bottom (0%) • SO_3 Fix	•	• MARA
2008	•	• MARA		•	• MARA
2009	• Hg catalyst (80%)	• MARA	•	•	• Commission new FGD with wet ESP (6% SO_3, 35% Hg) • Station Output Upgrade 50 MW
2010	•	•	• MARA • Forced oxidation (Hg 40%, SO_2 2%)	•	•
2011	•	•	•	•	•
2012	•	•	•	•	•
2013	•	•	•	•	•
2014	•	•	• Commission SCR Unit #1 (90% NOx, 40% Hg)	•	•

an e·on company

Un-regulated Generation (WKE)
Multi-pollutant Position Report and Proposed Compliance Plan
(SO_2, NO_x, Hg)

DRAFT FINAL

This study does not and is not intended to address the rights or obligations of any parties to the existing lease and other transaction documents between WKEC, Big Rivers and HMP&L, including, without limitation, the rights or obligations with respect to allocation of costs among the parties. Nothing contained in this study shall be construed to waive, diminish, or expand the rights or obligations of any of the parties under the lease or other transaction documents.

Environmental and Technical Services
Version Date – June15, 2007
Last Modified - June 15, 2007

Table of Contents

Un-regulated Generation (WKE)
Multi-pollutant Position Report and Proposed Compliance Plan
(SO_2, NO_x, Hg)

Environmental and Technical Services

June 15, 2007

This report provides a historical as well as forecasted analysis of Western Kentucky Energy's multi-pollutant position. The EPA announced on March 10, 2005 in its CAIR ruling that Phase I NO_x and SO_2 will start in 2009 and 2010, respectively. Although implementation of CAIR does not change WKE's SO_2 allowance allocation, it does change the allowance surrender ratio from the historical one allowance for each ton of SO_2 emitted to a ratio of 2:1 in 2010 and 2.86:1 in 2015. The report includes the current understanding of the Kentucky Division for Air Quality's plan for implementing the requirements of CAIR into KDAQ regulatory requirements and includes assumptions regarding Kentucky's methodology for incorporating new coal fired plants. Current assumptions utilized in the WKE model are included in the Appendix.

Study Basis:

Projections are based on results from the 2006 Production Cost Model runs for WKE as furnished by the Generation Planning Group. These results were incorporated into the budget figures for 2007 – 2011. Additionally, planned operational parameter changes that are incorporated into the current production cost model runs for the 2008 - 2012 budget years have also been included in these projections. There have been significant changes from the original plans included in previous studies in that the latest runs project that Reid Unit 1 will not be run after 2010. This assumption is now included in the "Base Case". Additionally, previous versions included sales and purchases of allowances at levels which would maximize revenues and minimize allowance banking during the time frame immediately prior to the implementation of CAIR requirements. This current version assumes that any such transactions have been reversed and each year will begin with the current allocations remaining intact. Also, the study begins with the year 2008 and includes any 2007 remaining allowances rolled into the 2008 allocation. Finally, the assumption is made that the SO_2 allowance split with the City of Henderson will continue at 70% / 30% throughout the study period and those allowances are added to the bank.

SO_2 Position:

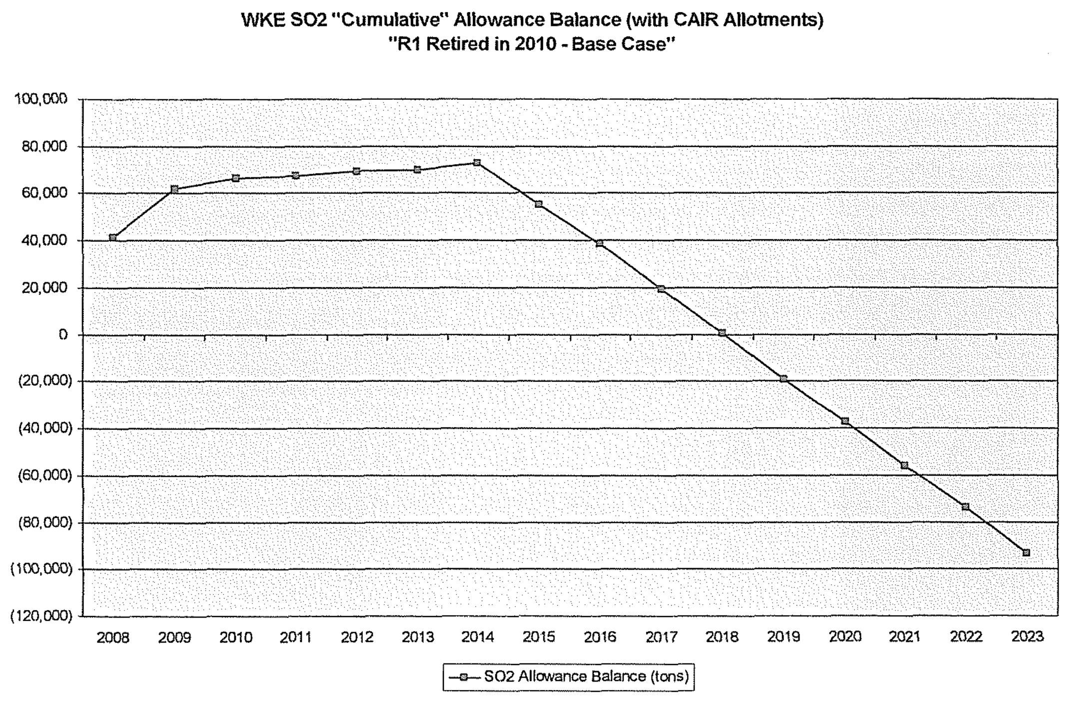
An allowance bank mitigates the need for external allowance purchases. The Big Rivers and City of Henderson, Station Two facilities accumulated an allowance bank early in Phase I of the Acid Rain Program under the Clean Air Act Amendments of 1990. However, beginning with WKE's operation of the facilities at higher utilization rates and with fuel of higher sulfur content, allowances were drawn from the bank. Finally with the beginning of Phase II in 2000, the bank was completely depleted. Since that time WKE was in an allowance purchase position. Economic evaluations showed that the installation of a SO_2 scrubber at the Coleman Plant was the proper decision. Although somewhat delayed from the original target date of the first of 2005, the schedule called for the equipment to be fully functional by early 2006. With the full implementation of the scrubber, Coleman Plant is utilizing fewer allowances than allocated thereby generating a bank for the system. This enabled WKE to be in the position of selling SO_2 allowances through 2009 to help the financial position of the company and has in fact already sold future vintage year allowances. [1]

With the beginning of Phase I of CAIR in 2010, WKE will be in a slightly net positive position on a year-by-year basis, enabling WKE to continue to build upon the bank created during the 2008 and 2009 time period.

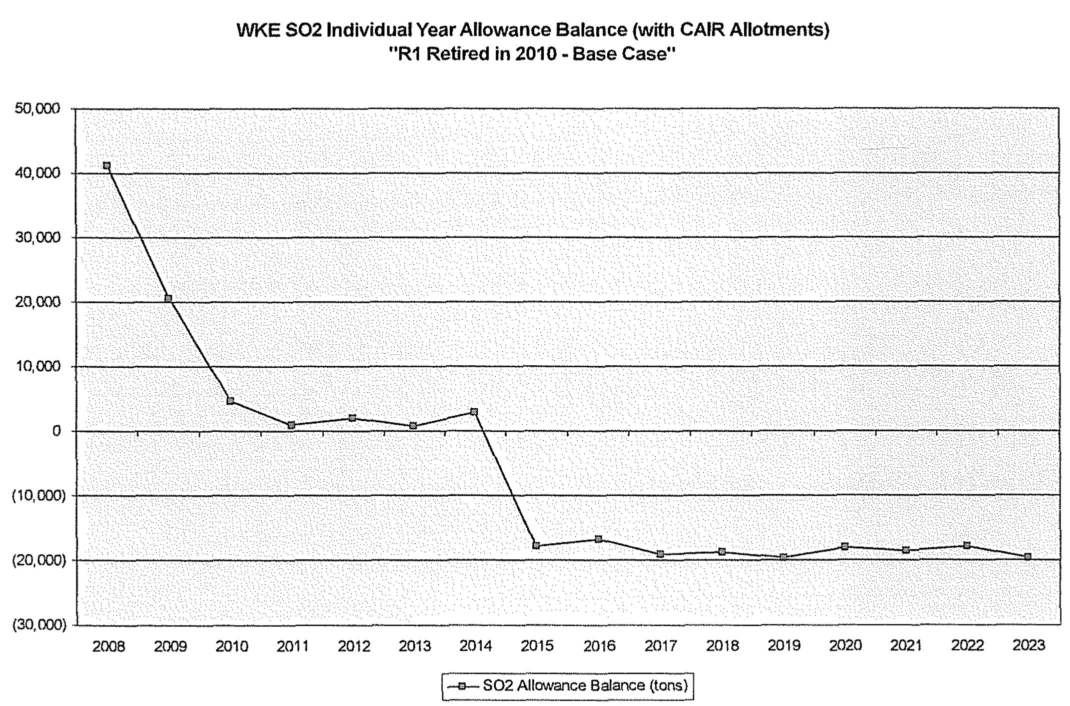
In 2015, as Phase II of CAIR begins, this position will reverse and WKE will be in a deficit position each of the following years. However, the bank that will continue to supply allowances to the system at a rate that will enable compliance out through about 2019 at which time the bank will be depleted, requiring the purchase of substantial allowances for annual compliance.

[1] As noted above this study version assumes reversal of these transactions.

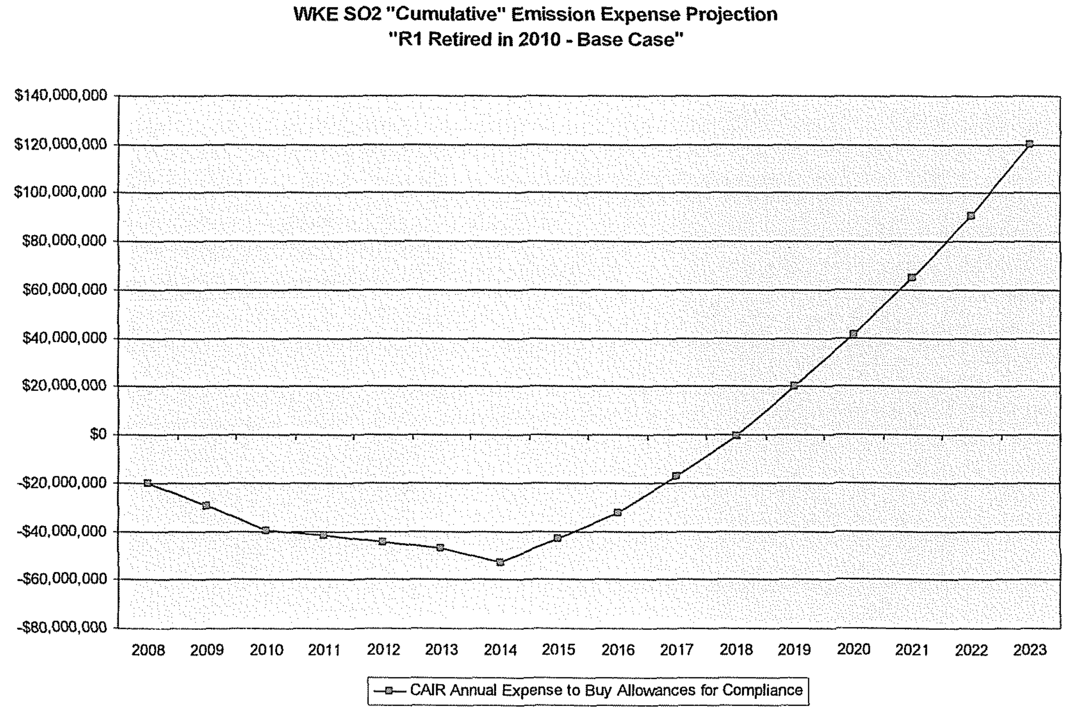
The following graph depicts the forecasted ***cumulative*** SO_2 allowance bank with the implementation of the CAIR with banking of annual surplus allowances.



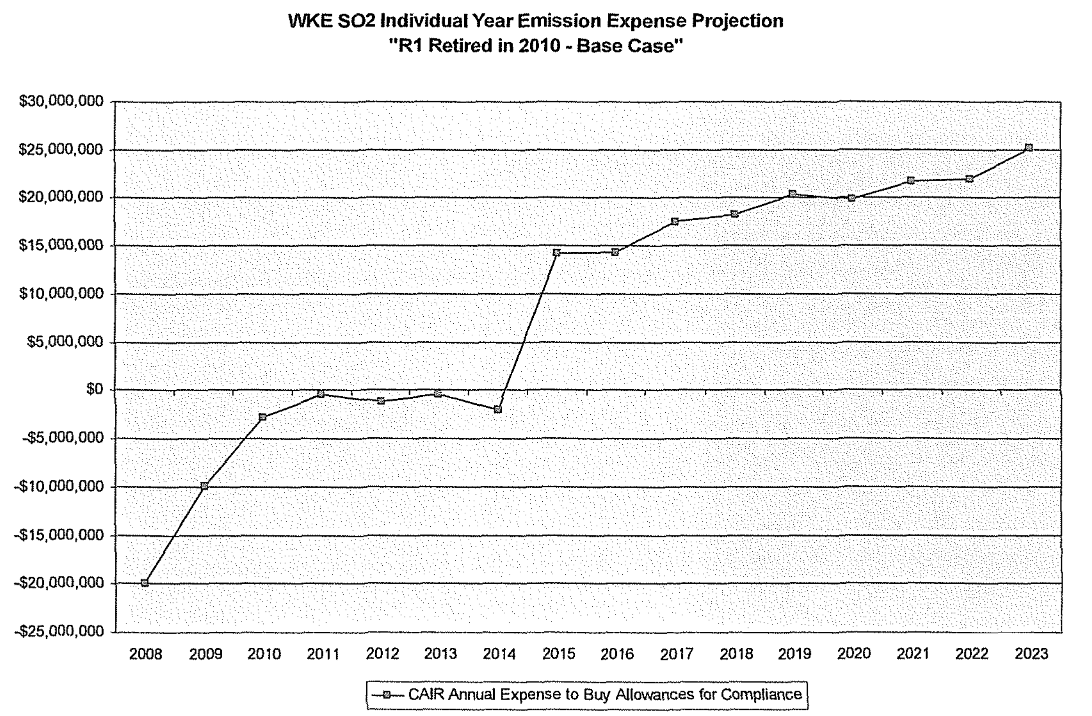
The year by year SO_2 allowance balance with CAIR implemented is shown below



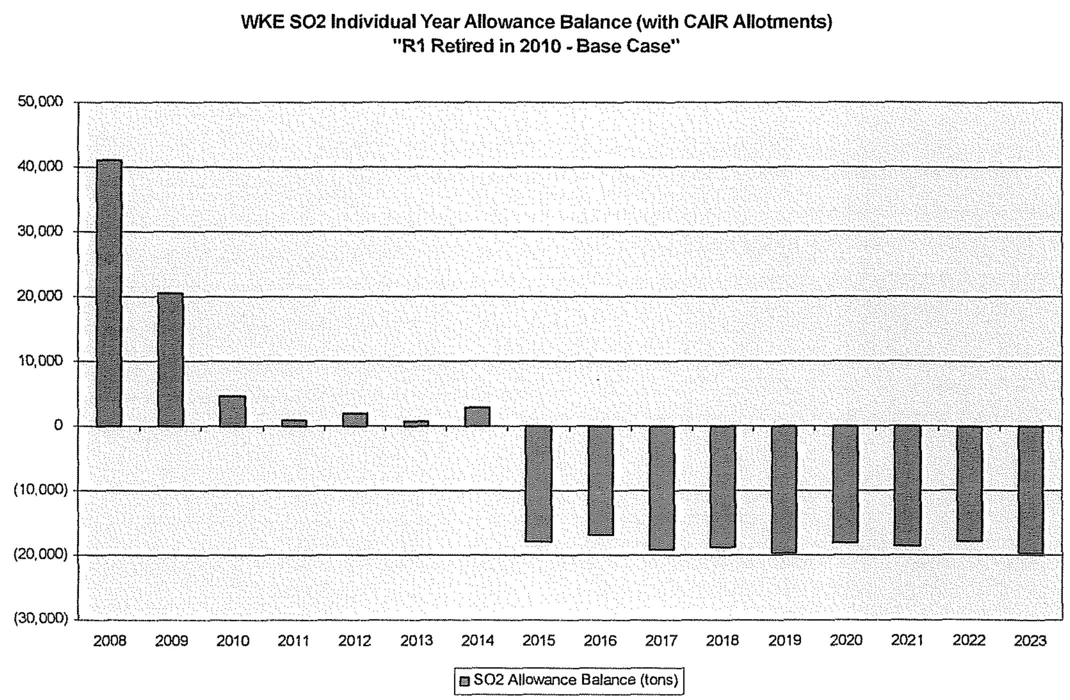
The following SO_2 ***cumulative*** allowance expense graph illustrates the financial impacts over time assuming the budgeted emission allowance price forecast as shown in the Appendix and no further control measures implemented.



The year by year SO_2 Allowance expense is illustrated below



The following graph illustrates the year-by-year SO_2 allowance position for the WKE system through the end of the lease period.



SO_2 Conclusion:

WKE will maintain a net positive SO_2 allowance bank from the present through the initial implementation of CAIR Phase I. Starting in 2015, the first year of CAIR Phase II, the new emissions constraints will begin to deplete any remaining banked allowances. Beginning in about 2019 WKE will either need to begin purchasing allowances on an annual basis or make improvements to the existing scrubbing efficiencies within the system.

NO_x Position:

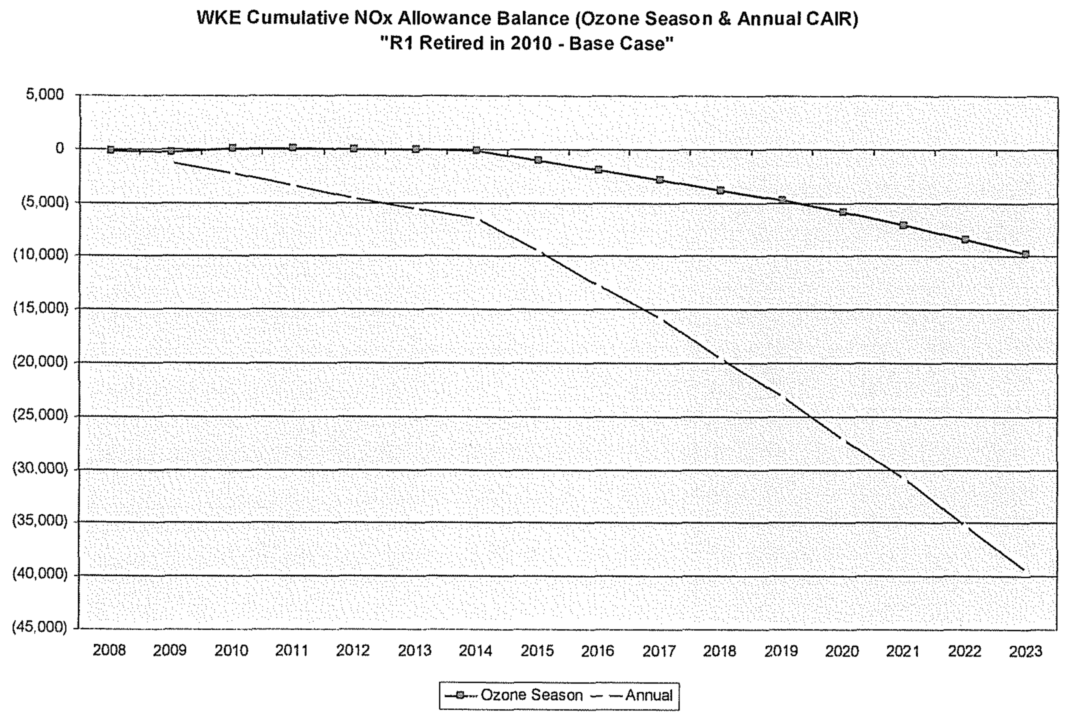
This position report assumes that WKE's NO_x allowance allocation reflects current understanding of regulatory reductions occurring in 2009 and 2015 as well as assumptions regarding Kentucky's methodology for incorporating new coal fired plants. Current assumptions utilized in the WKE model are included in the Appendix.

Similar to SO_2, CAIR will have a corresponding impact to the NO_x allowance allocation process and NO_x compliance will change from being only an ozone season (May through September) requirement to adding an annual allowance program thereby requiring a year round NO_x emission reduction requirement.

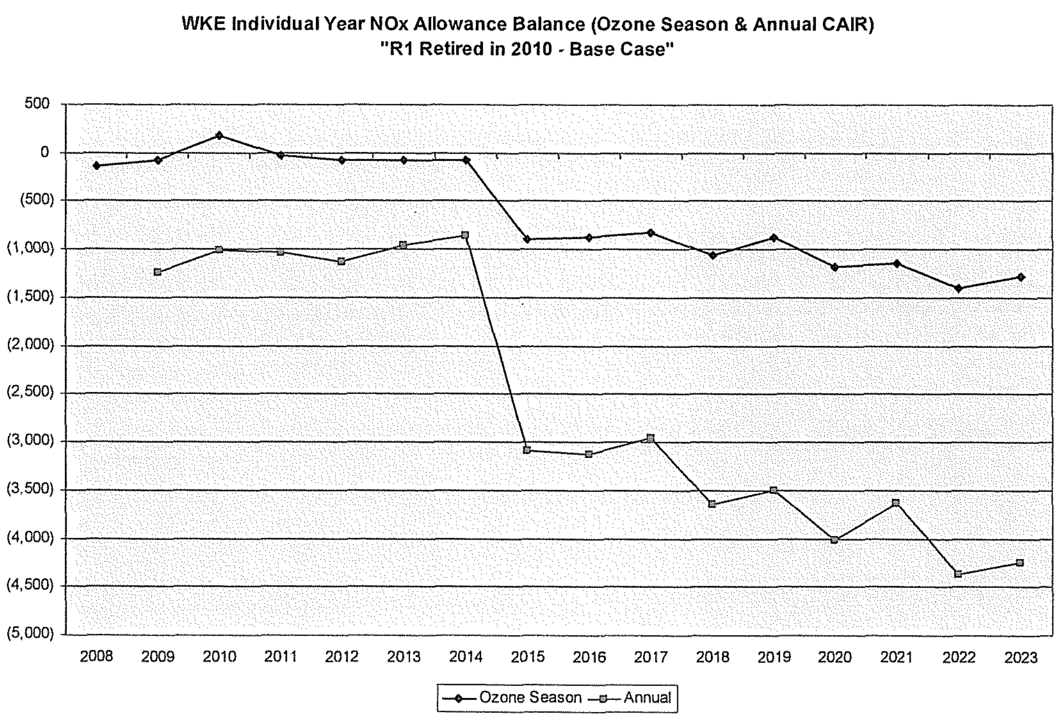
This position report's modeling reflects various situations where the SCRs are removed from service when the unit is operating below the minimum exit gas temperature for which ammonia can be injected. Below these minimums (typically 70-80% of the unit's capacity), the lower exit gas temperature would result in the ammonia plating out on the air heater as ammonia bisulfate and plugging the air heater. This event would require the unit to come off-line for an extended period of time to clean the air heater. These situations include start-ups and shut-downs due to boiler tube leaks, unit operation under wet coal conditions and others.

WKE has a NOx SIP Call Ozone Season allowance bank of 41 allowances as of the end of 2006. Of these 5 are associated with the City of Henderson, Station Two. WKE has completed a cost sharing mechanism with the facility owners which provides for splitting these remaining allowances between the parties. This agreement also provides for furnishing allowances to HMP&L to offset emissions from the Station One units. NOx allowances remaining in the bank are expected to rollover into the CAIR Ozone Season bank. Results from the latest WKE model run indicate that the system will just comply with the CAIR Ozone Season emission requirements through approximately 2015, after which allowances would need to be purchased. Additionally, the CAIR Annual NOx emission allowance allocations are not expected to be sufficient to offset emissions with the first year of the rule. With consideration of currently forecasted unit utilizations (which are higher than those used in previous reports), for most years of Phase I, a relatively small number of allowances (approximately 1,000) will have to be purchased. With the beginning of Phase II WKE will be in a position that will require either the purchase of CAIR Annual NOx allowances or the implementation of additional controls no later than 2015. Additionally, WKE will be deficit in CAIR Ozone Season allowances, which will have to be purchased. Any additional controls installed for the CAIR Annual requirements will impact the CAIR Ozone Season needs.

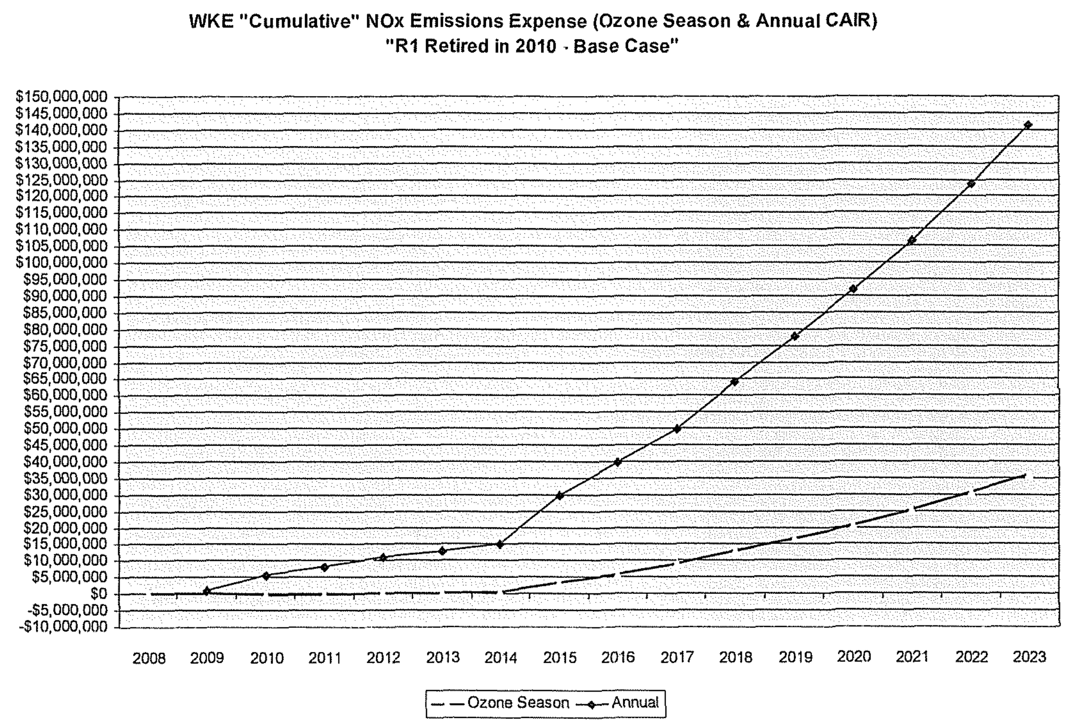
The following graph depicts the forecasted ***cumulative*** NO_x allowance bank for both the CAIR Ozone Season and Annual allowance programs.



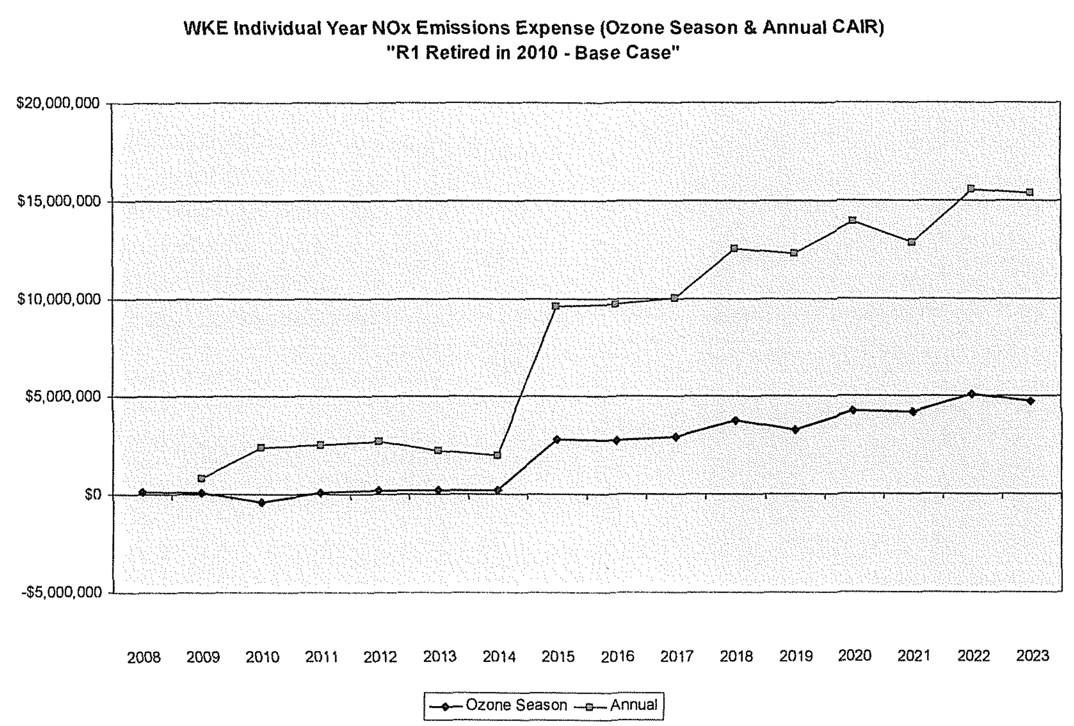
The following graph depicts the forecasted ***annual*** NO_x allowance bank for both the CAIR Ozone Season and Annual allowance programs.



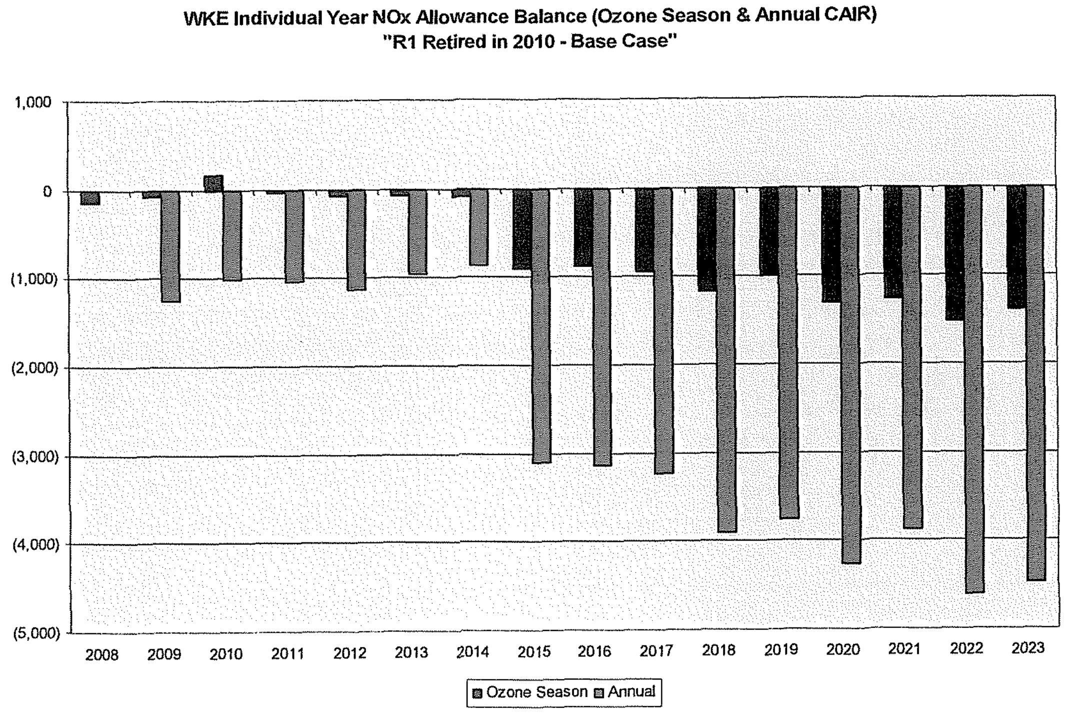
The NO_x ***cumulative*** allowance expense graph below illustrates the financial impacts over time assuming the budgeted NO_x allowance price forecast.



The NO_x ***annual*** allowance expense graph below illustrates the financial impacts over time assuming the budgeted NO_x allowance price forecast.



The following graph illustrates the year-by-year NOx allowance position for both the Ozone Season and Annual CAIR programs for the WKE system through the end of the lease period.



NO$_x$ Conclusion:

WKE is in a somewhat poorer position with regard NOx emissions. The company will be in compliance with the CAIR Ozone Season requirements through about 2015. Beginning with Phase II the system will be deficit each year requiring some allowance purchases into the future.

For CAIR Annual requirements the system will start off in a deficit position requiring allowance purchases during Phase I, with significant allowance purchase requirement in the years after 2015 if there is no construction of additional NOx control equipment on the WKE units.

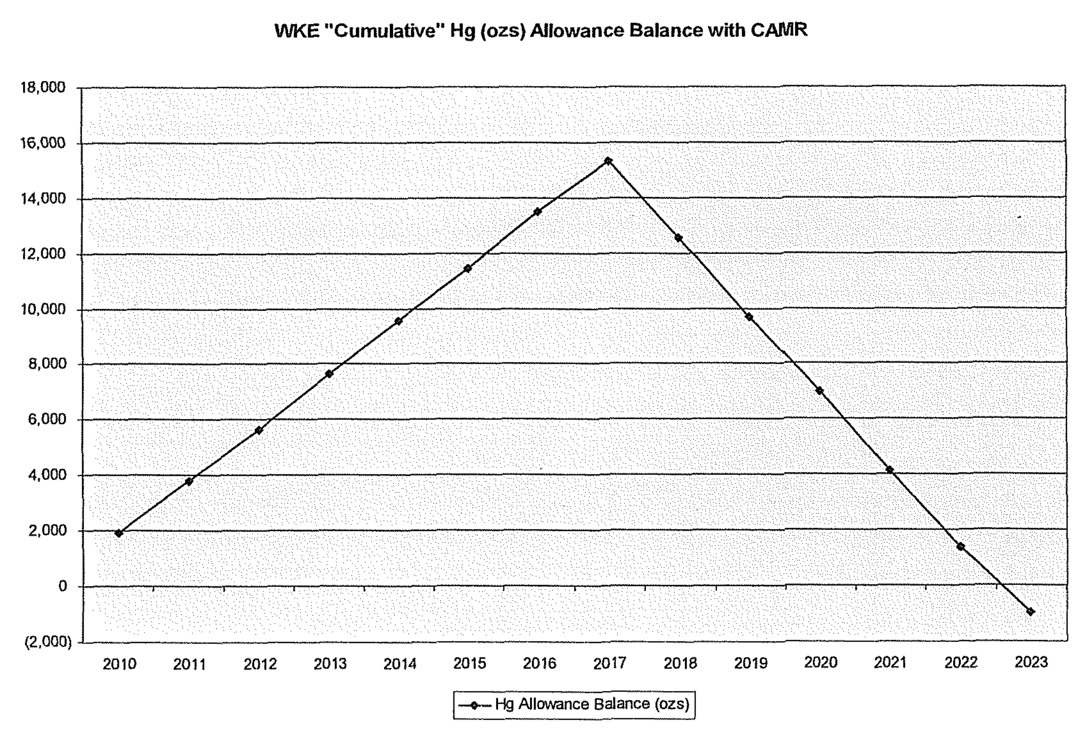
Mercury Position:

On March 15, 2005, the EPA issued "Clean Air Mercury Rule" to permanently cap mercury emissions and will consist of two phases. The Phase I cap will be achieved by "co-benefit" reductions (via SCRs and FGDs) and commence in 2010. Phase II starts in 2018 and will require additional measures be taken to control mercury emissions. Further details on the mercury rule can be found in the Appendix, **"Clean Air Mercury Rule".**

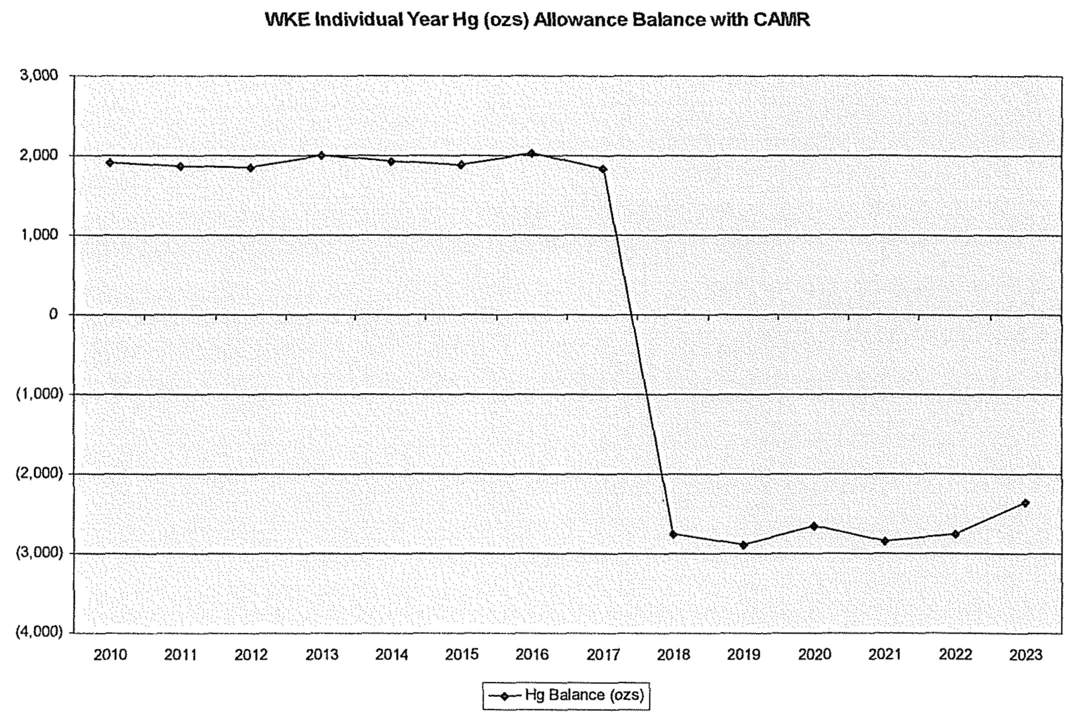
Previous versions of this study discussed the uncertainty of information regarding the co-benefit mercury removal that was currently being achieved, with significant difference between the EPA and EPRI data vs. the experience of other data sources. As a result of this concern a significant mercury testing project was undertaken to better identify the actual levels of mercury emissions from the facilities with the existing control equipment in operation. Using these emission results, estimates can be made regarding the removal efficiencies of the existing equipment.

Using the assumptions outlined in the Appendix and the base removal rates for the existing equipment from mercury testing program, the WKE system is projected to build an allowance bank throughout the Phase I period and will be drawing out of the bank through the end of the lease period.

The following graph depicts the forecasted ***cumulative*** Hg allowance bank on the WKE system using this scenario.



The following graph depicts the forecasted ***annual*** Hg allowance bank on the WKE system using this scenario.



Mercury Conclusion:

Although there remains considerable uncertainty regarding the actual mercury emissions from the WKE units, the testing program has brought some focus to the situation. It appears that the company in a good position with regard mercury through Phase I. Further study and testing is required to better determine the impacts of the Phase II requirements. However, any additional control equipment that is installed to provide enhanced removal of SO_2 and NOx emissions is expected to improve WKE's position on mercury.

The Reid Unit 1 Issue

There are many issues concerning the possible lay-up or permanent shut-down of the Reid Unit 1. This is the oldest unit in the WKE system and currently has minimal particulate controls, no SO_2 control and some minimal NOx reductions as a result of cooling air flow through installed gas burners.

Shutting this unit down starting in 2009 reduces the consumption of NOx allowances in the first year of the CAIR NOx program. Additionally, the earlier shut-down of the Reid Unit will push out the date at which the SO_2 balance goes negative by one year. On the other side, delaying to 2010 adds an additional year of generation for this unit.

There are also political and contractual issues associated with a permanent shut-down of the unit. The best option may be to lay-up the unit starting in 2010. Any potential use of the unit would then be justified on the value of the generation and cost of necessary fuel and allowances needed for operation. The economic differences between a lay-up and a permanent shut-down will also have to be evaluated.

The latest model run results indicate that economic dispatch will not operate Reid Unit 1 starting in 2010. Generation previously assigned to this unit is expected to be picked up by other units within the WKE system.

Proposed WKE System Compliance Plan

CAIR Requirements for NOx

- Operate Reid 1 through 2009 – There will be a need to purchase additional CAIR Annual NOx Allowances for this first year of the program. Shut down Reid 1 beginning in 2010.
  - During this year Reid 1 will generate approximately 113,098 MWH of energy available for sale
  - This will consume approximately 193 Ozone Season Allowances and 389 NOx Annual Allowances.
  - These have a value of approximately $ 600,000.
  - The system will be close to compliant through Phase I for the CAIR Ozone NOx requirements
- Provide additional NOx control inside the WKE system – Additional NOx removal will be required to assure the system will be compliant with the CAIR Annual NOx requirements.

  Option 1

  - It appears that the installation of an SCR system on one of the Green units by 2012 would provide a level of reduction sufficient to maintain system compliance with both the CAIR NOx Season and CAIR Annual requirements through 2014 for a cost of approximately $ 50,000,000
  - With this addition the system will develop a CAIR NOx Season allowance bank during Phase I, but will begin drawing allowances from the bank starting in 2015, depleting it by 2021. However, this addition will only satisfy the CAIR Annual requirements from installation through 2014, after which additional allowances will be required.
  - Some additional NOx control will be required to enable the system to be fully compliant through the end of the lease and beyond. With the uncertainty of future regulation, the required level of reduction is difficult to anticipate.
  - An evaluation should be made to install a companion SCR on the other Green unit at the same time. This would be the least cost time to do the installation and the value of the sale of allowances significant. This would also provide a cushion in event of a failure at another unit. This addition would assure system compliance with CAIR Annual NOx requirements through bank building.

  Option 2

  - There are several cases regarding the installation of the SCR in the 2010 through 2015 time period. These have to be economically evaluated to determine the best combination of early reductions and allowance bank building vs. the option of delaying the capital investment and potentially purchasing allowances during the intervening years.

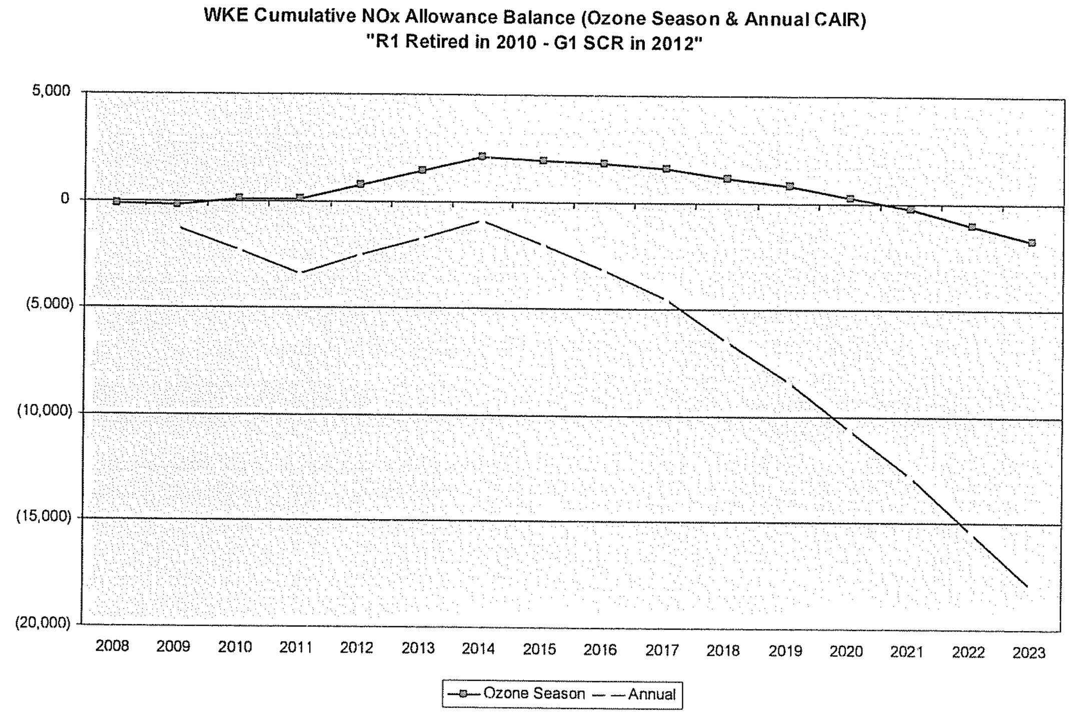
Option 3

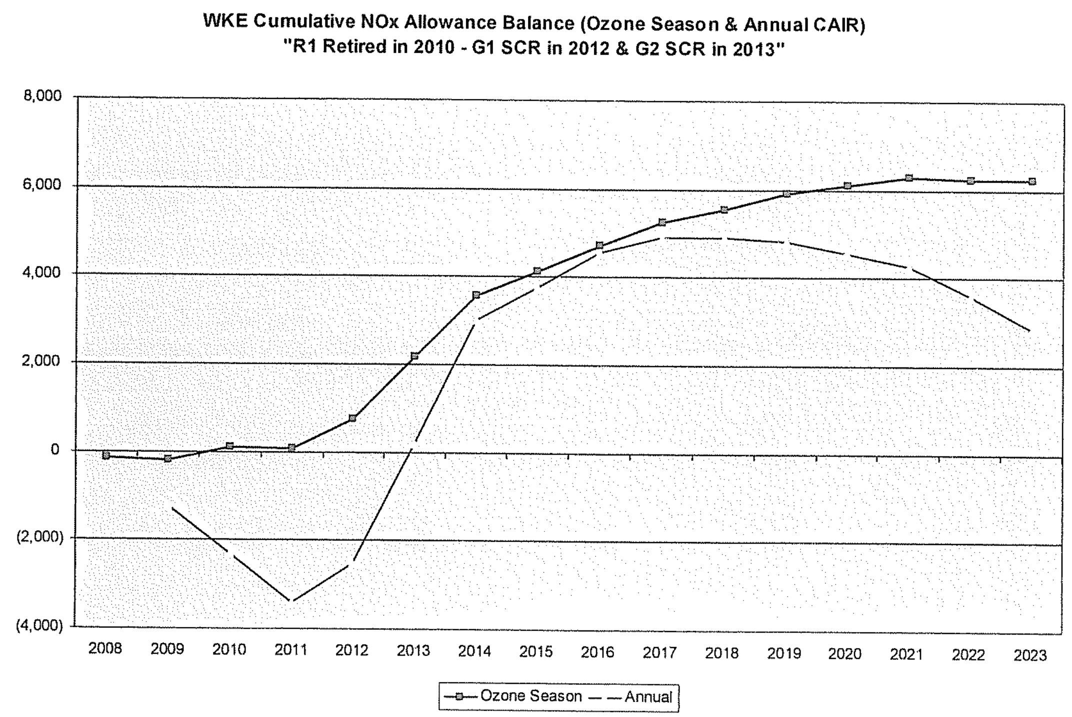
- Consideration must be given to the "do nothing" case in which no additional control equipment is added and both CAIR NOx Season and CAIR Annual allowances are purchased. With the uncertainty inherent in the allowance market and costs associated with control equipment installation, this may be the best economic option for the system[2].

❖ The system is expected to continue to be self-compliant with the CAIR Ozone Season requirements through about 2015 using the base case assumptions. Any additional reductions which occur to offset CAIR Annual requirements, as shown in the above options, will aid in meeting the Ozone Season limits.

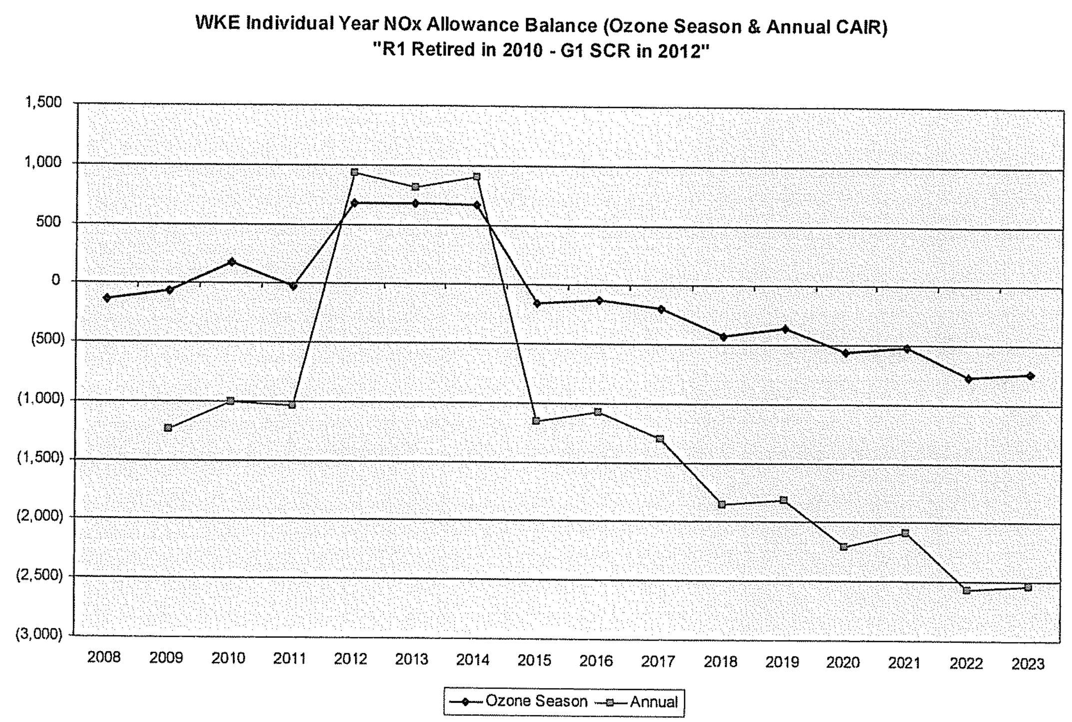
[2] Several rounds of economic studies have been evaluated and the results of these studies indicate that the addition of control equipment is not the best economic decision for the WKE system. Rather, purchase of allowances for the foreseeable future is the current position.

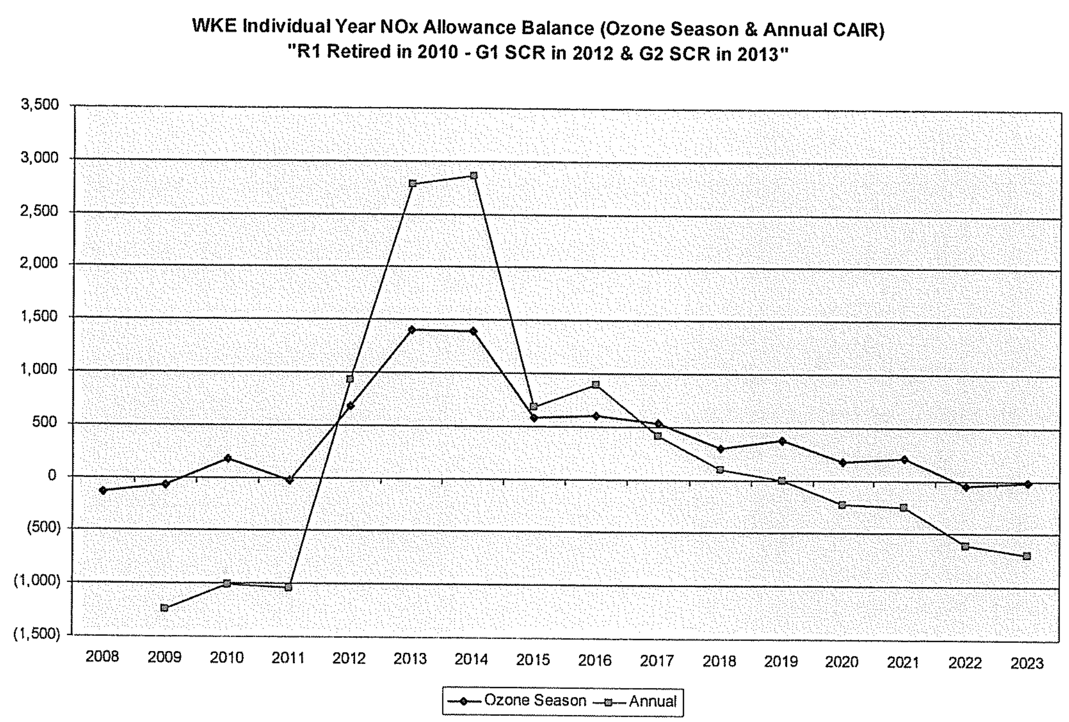
Option 1 – Cumulative Impacts





Option 1 – Annual Impacts


WKE Individual Year NOx Allowance Balance (Ozone Season & Annual CAIR)
"R1 Retired in 2010 - G1 SCR in 2012"
1,500
1,000
500
0
(500)
(1,000)
(1,500)
(2,000)
(2,500)
(3,000)
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Ozone Season
Annual


WKE Individual Year NOx Allowance Balance (Ozone Season & Annual CAIR)
"R1 Retired in 2010 - G1 SCR in 2012 & G2 SCR in 2013"
3,500
3,000
2,500
2,000
1,500
1,000
500
0
(500)
(1,000)
(1,500)
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Ozone Season
Annual

The Wilson scrubber was originally designed to be a horizontal three-module magnesium enhanced lime reagent system. Shortly before the startup of the plant, Big Rivers Electric Corporation (the owner) investigated a switch to limestone reagent. After a review of the process, it was decided to make that change. Upon startup it was discovered that the system could not meet the environmental emission requirements with two modules running and one spare. A fourth module was added in order to reclaim the spare. The system currently just does meet the 90% removal requirements, but only through considerable plant personnel efforts and the use of additional chemical reagents. Currently the scrubber has reached the end of its useful life and with the limited removal efficiency it has a significant negative impact on the ability of the WKE system to meet the new tighter requirements under CAIR. Although it appears that a delay in replacement is possible (see below) just looking at balancing emissions and allowances, this decision will require expenditure of significant capital and maintenance monies just to keep the system operational for the period. An evaluation is currently underway to determine the earliest a replacement scrubber could be installed. The anticipated design would be similar to the Coleman FGD now operating. The nominal removal efficiency would be 95% with capability of 98% using chemical addition. The chemistry would be limestone forced oxidation, making gypsum. Assuming an approximate six months for approvals and three years for design engineering and installation, the scrubber could be expected to be fully functional by the beginning of 2012.

<u>CAIR Requirements for SO_2</u>

- ❖ With Reid 1 in retirement status beginning in 2010, the primary contributor to the annual system non-compliance beginning in 2015 is the Wilson Unit. Coleman and Green Stations are expected to be self-compliant through Phase I. Station Two is expected to be able to provide for its emissions with the current FGD removal efficiency. (See p. 33)

  <u>Option 1</u>
  - Replace the Wilson scrubber reagent with thiosorbic lime by 2010 to enable scrubbing at a continuous 95% removal efficiency with budget fuel requirements.
    - This option would continue to utilize the existing scrubber and is expected to require an expenditure of approximately $ 24M in capital improvements to refurbish the equipment in preparation for the continued operation through the end of the lease and beyond. Additional items not included in this estimate are:
    - Installation of new slakers and control systems is required at a capital expenditure of approximately $2 M.
    - Modification of existing barge and conveying systems including fire protection retrofits at approximately $5.5M
    - Replacements and upgrades in the solid waste handling system for a capital cost of approximately $ 9 M.
  - Although this option does provide for system compliance under current modeling assumptions and regulatory programs, it depends on use of the

banked allowances for compliance and purchase of allowances may be required in future years.

Option 2

- It may be economic to delay construction until Phase I to avoid the "rush to construct" with the anticipated on-line date by the beginning of Phase II in 2015. This option would continue the operation of the existing scrubber at 91% removal causing significant depletion of the allowance bank through Phase I.
- Replace the Wilson scrubber with a single module, limestone based unit capable of continuous 98% removal efficiency with budget fuel requirements. Incorporate higher removal efficiency options with chemical additives. Design for gypsum byproduct.
  - This scrubber installation is expected to require an expenditure of approximately $ 100M and be similar in design to the Coleman Scrubber.
  - This project should begin as soon as possible with full operation scheduled in 2015.
- Based on current assumptions this option will create a modest annual surplus throughout Phase II with the potential for small allowance sales or flexibility in fuel choice.

Option 3

- In order to build further assurance into the plan and provide additional allowances for sale this option is a combination of option 1 and 2. It provides for early increases in scrubber efficiency by converting to thiosorbic lime by 2010 and then constructing a 98% scrubber to be on line by 2015. This option reduces the depletion of the bank during the Phase I time period but increases the overall capital and operating costs.

Option 4

- Consideration must be given to the "do nothing" case in which no additional control equipment is added and the existing equipment is operated and maintained in "as is" condition. This option will require purchase of CAIR SO_2 allowances beginning in 2019 when the bank is exhausted[3]. With the uncertainty inherent in the allowance market and their future value, this may be the best economic option for the system[4].

❖ In order to balance through the end of the lease period and into the future, additional reductions from the base case are required; these may be achieved through increasing the removal efficiency of the Wilson scrubber to 95% by 2015. Assuming this is done through the use of thiosorbic lime as a reagent, there will

---

[3] Based on the generation values and allowance usage from the Production Cost Model

[4] Recent economic evaluations of the installation of a new scrubber vs. the purchase of allowances indicate that the allowance purchase option provides the better economics with the current projected allowance values

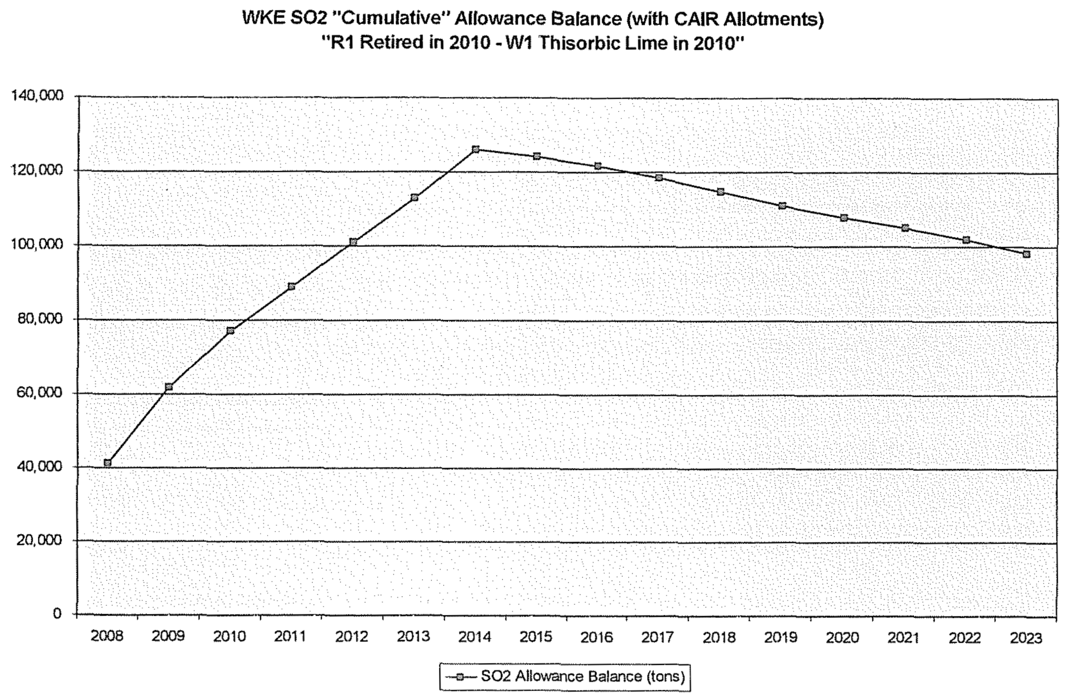
be impacts on the waste handling at the plant as well as in various other systems requiring capital improvements. There will also be increased O&M expense.

- In all of the above options Station Two scrubbers are assumed to operate at the 94% removal efficiency included in the production cost model input values used in the 2007 model run for budget years 2008 thru 2012 and beyond. If additional removal is necessary it may be achieved, however, it is anticipated that an additional thickener (along with associated piping), and at least one additional vacuum filter will be required to treat the additional waste generated from operation at the higher removal efficiencies. There may also need to be upgrades to the existing systems to the handle the higher flow rates. These changes, if required, would need to be finished prior to the beginning of Phase I in 2010. (See also the Station Two stand-alone section)

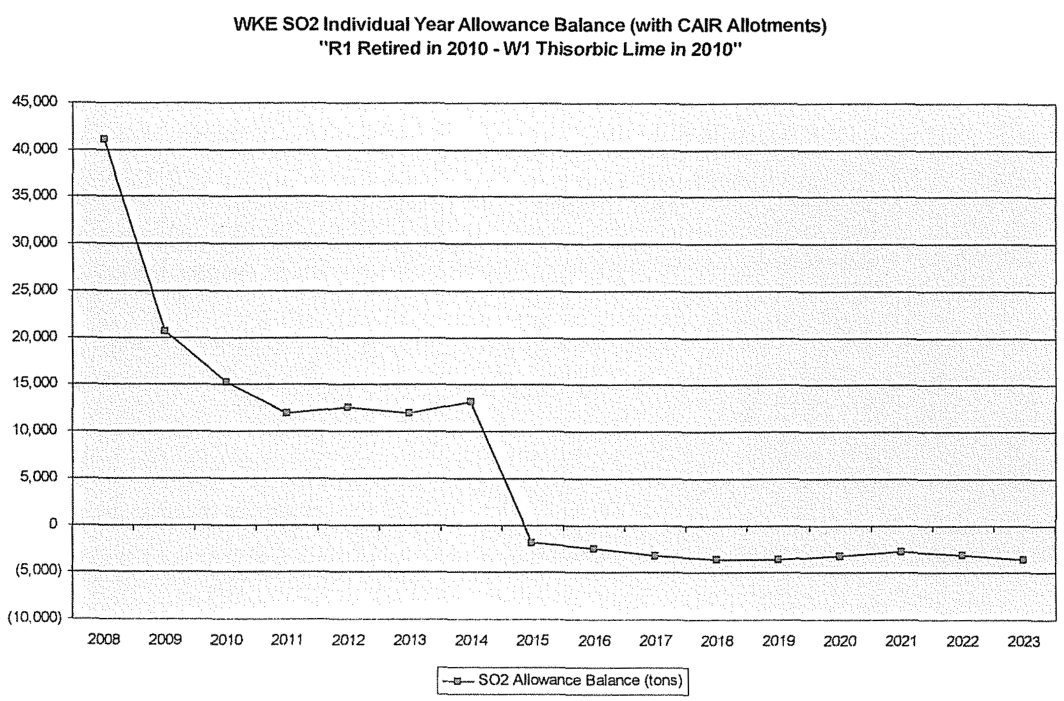
- NOTE: The scrubber addition option assumes the installation of a single-module limestone based scrubber at Wilson – similar in design to the newly installed unit at Coleman Plant. Wilson falls under Subpart Da of the Clean Air Act Amendments of 1990 which requires such units to have a spare scrubber module installed. (This is the issue that forced the addition of the fourth module) We have approached the regulatory agencies to seek relief from this requirement. Such relief may include language in the permit to require unit shut-down on scrubber failure. Certainly much more is known today regarding scrubber operation vs. when the Da requirements were first established (state-of-the-art was 90% removal on limestone systems).

Option 1 (Change to Thiosorbic Lime in 2010)

Cumulative Impact

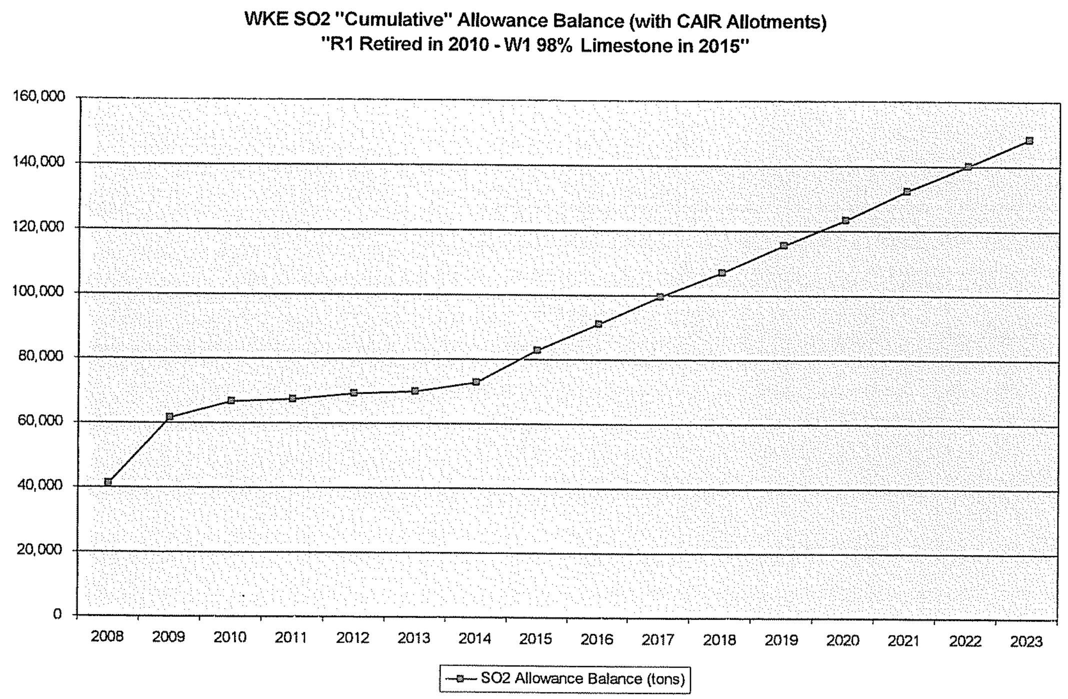


Annual Impact

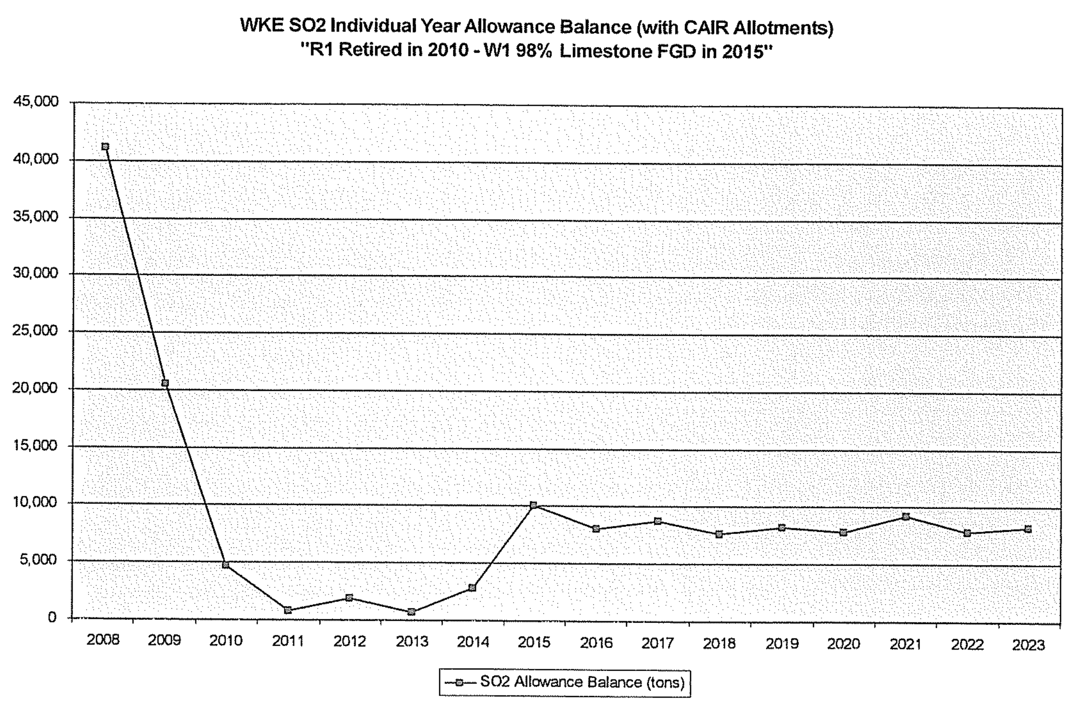


Option 2 (Addition of 98% removal scrubber in 2015)

Cumulative Impact

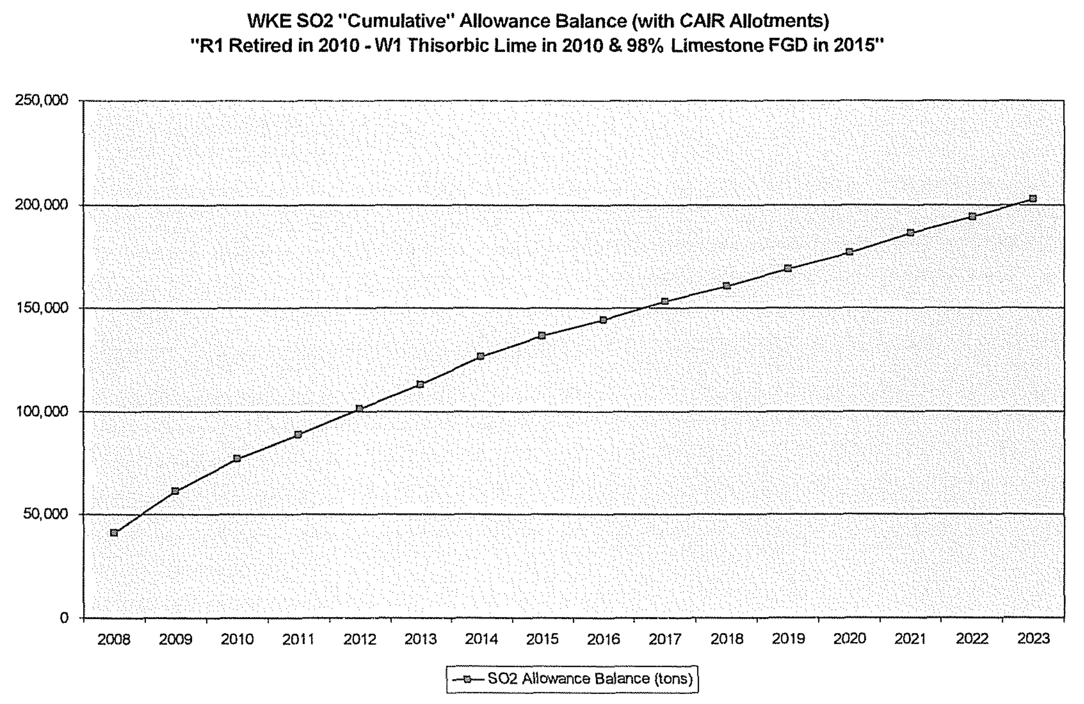


Annual Impact

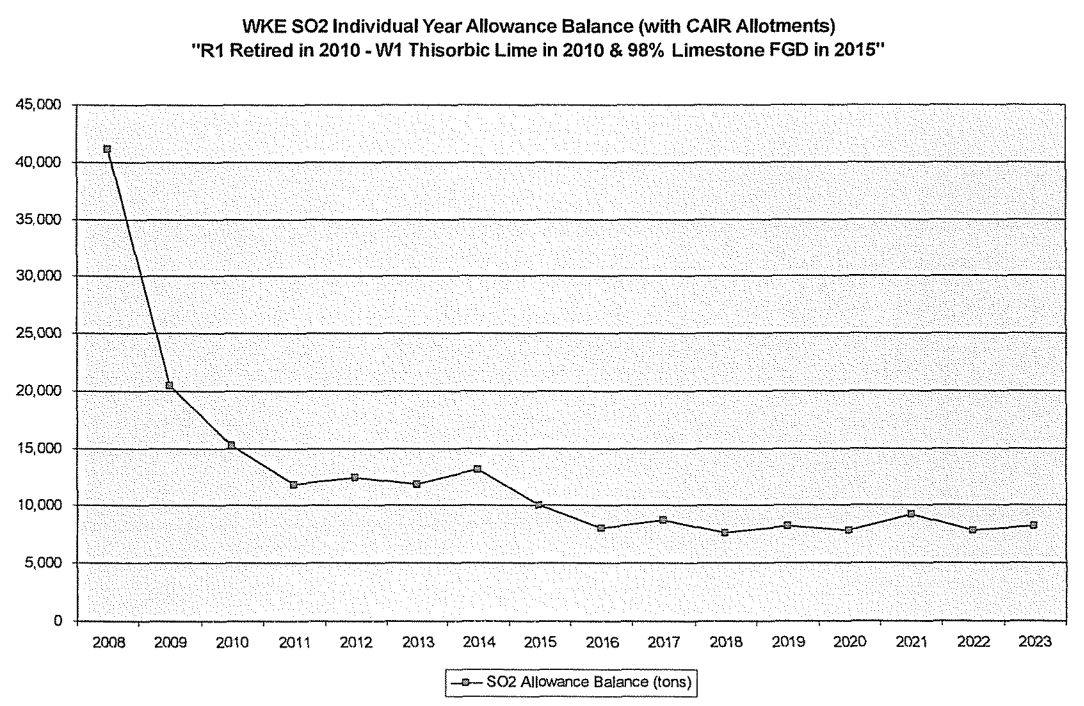


Option 3 (Thiosorbic Lime in 2010, New Scrubber in 2015)

Cumulative Impact



Annual Impact



CAMR Requirements for Mercury

- Based upon what is currently known about the CAMR and the anticipated Hg Allowance program. The State of Kentucky is expected to utilize the model rule and the allocated allowances are expected to be sufficient to balance the mercury emissions at least for Phase I.
- This assumption is based on expected co-benefit mercury removal as a result of operation of existing air pollution control devices (SCR, precipitator, and scrubber).
    - WKE currently still has fairly limited knowledge about the mercury removal capabilities with the existing control equipment.
    - Using data from EPA and EPRI sources, and the mercury testing that was done on all units last year, assumptions can be made that:
        - Coleman achieves about 75% removal with the scrubber only
        - Station Two achieves 90% reduction with the existing SCR and FGD system (non-oxidized)
        - Wilson achieves 75% reduction with the existing SCR and FGD system
        - Green is achieving 76% reduction with the existing FGD system
        - Reid is achieving minimal reduction with the existing precipitator

- New mercury emission monitoring systems[5] will be required for each of the coal fired operating units. These will need to be installed, certified and fully operational by January 2009 in order to collect one year of data prior to the start of the Phase I requirement.
- An additional mercury monitoring system will be required for the Transportable Emission Monitoring System operated by the environmental department as the standard.
- If additional removal of mercury is required (over and above the enhancements indicated above), unlikely for Phase I, possible for Phase II, the required control equipment would need to be installed and operational by 2018. This could occur if co-benefit reductions are not as high as expected, leading to emissions which are greater than currently thought.

[5] Currently the state of the art in continuous monitors is questionable. WKE is expecting to utilize sorbent tube monitoring systems for a least a period of time to allow continuous monitoring technology to catch up.

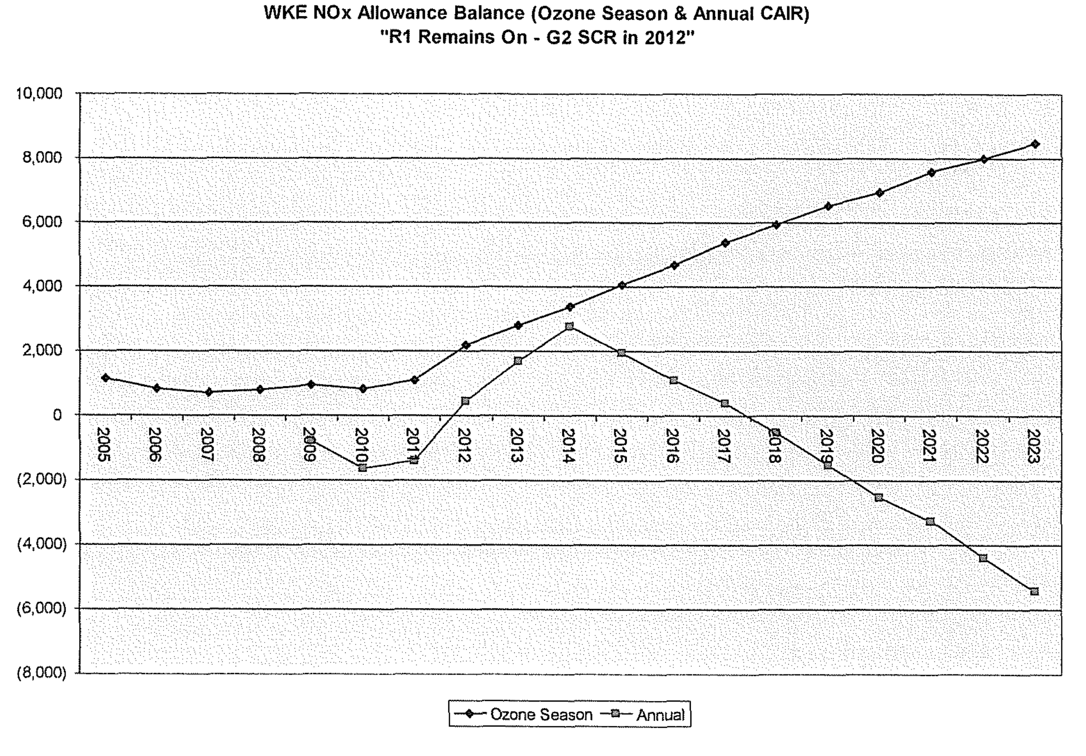
Addendum 1

Continued Operation of Reid Unit 1

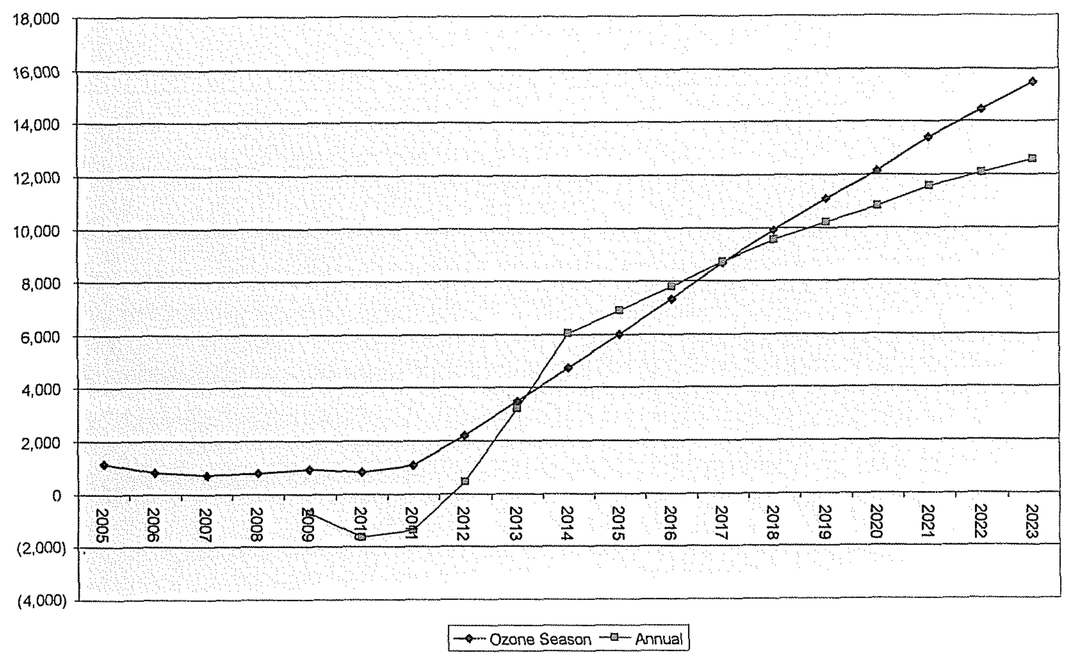
Authors Note: This section was included in previous versions of this position report and is included here for consistency using the original model run results. As is noted earlier in the report, the latest Production Cost Model run results show that the Reid Unit does not meet the economic threshold to justify continued operation past 2009. However, the system impact is useful to understand. Since the current model runs do not include the Reid Unit, the graphs below use data from the previous runs – it must be noted these previous runs show unit utilizations lower than those indicated by the most current information.

Recently there has been consideration given to reviewing the decision to either shut-down or lay-up the Reid Unit. Forward price curves indicate that it may well be economic to continue to operate that unit for the foreseeable future. Using the same approach as illustrated starting on page 15, except for continuing to operate Reid Unit 1, the following series of curves indicate the impact of this decision on the NOx and SO_2 allowances.

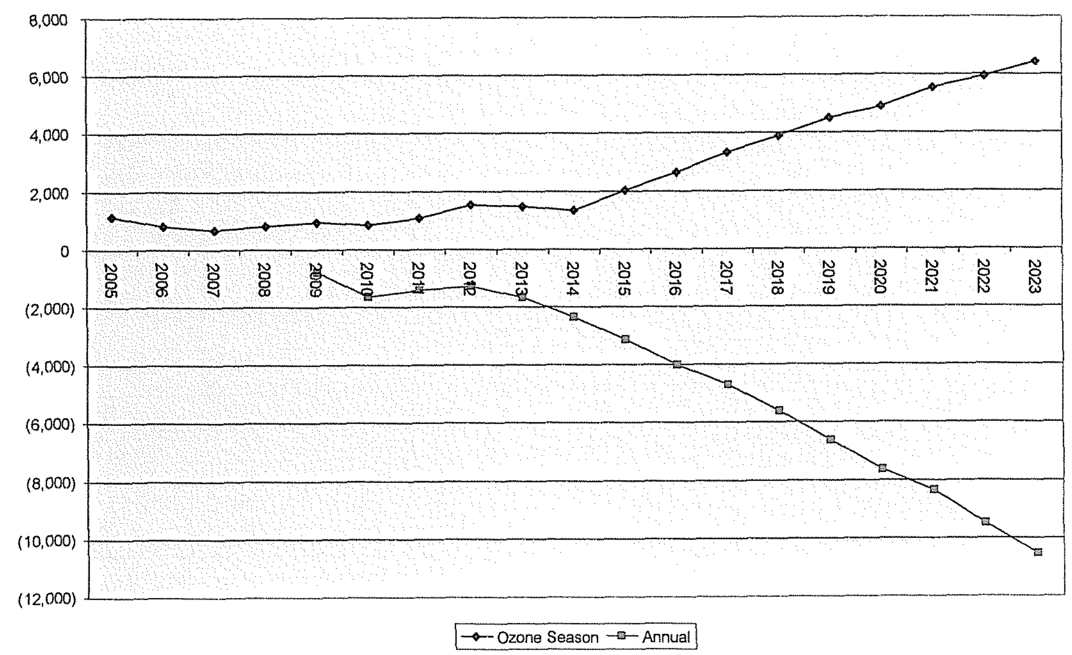
For CAIR NOx Requirements



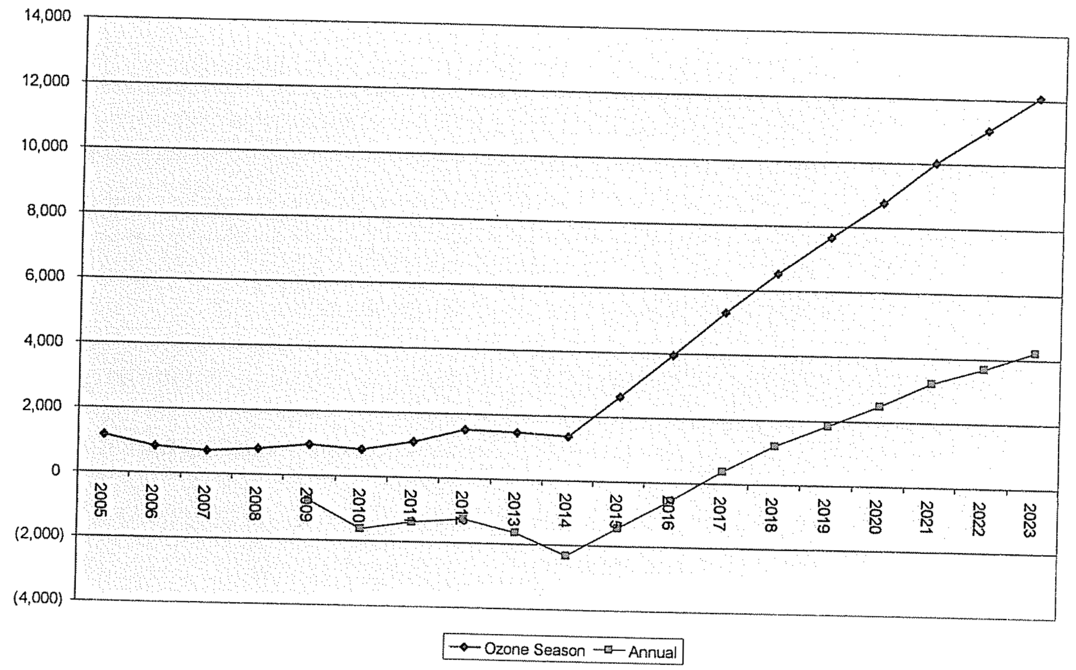
WKE NOx Allowance Balance (Ozone Season & Annual CAIR)
"R1 Remains On - G2 SCR in 2012 - G1 SCR In 2013"



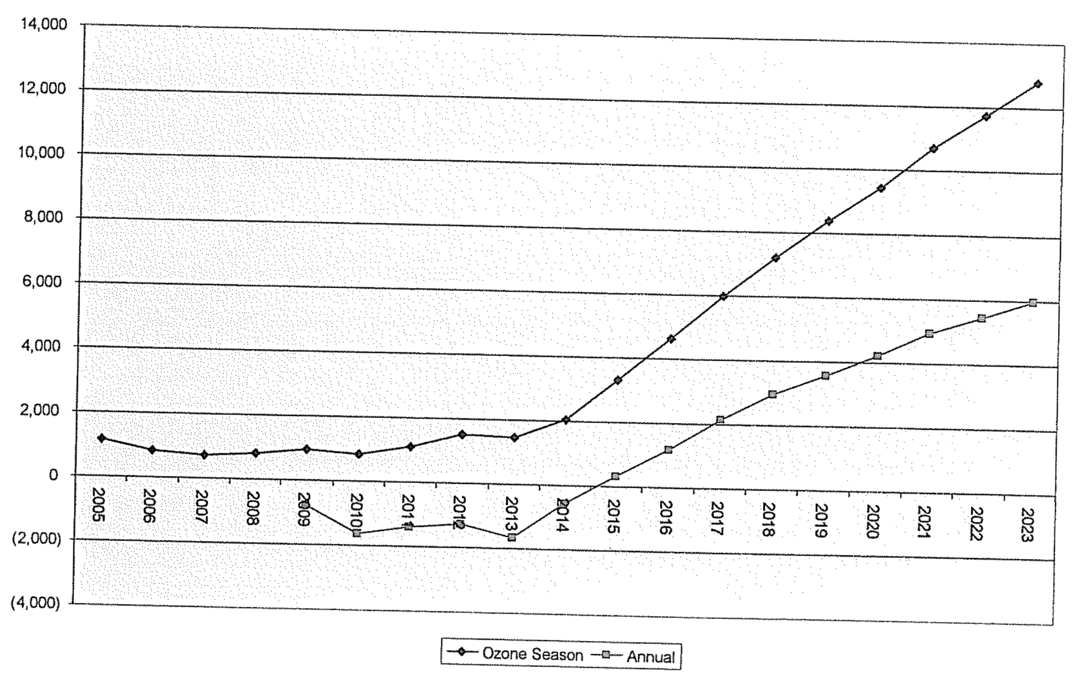
WKE NOx Allowance Balance (Ozone Season & Annual CAIR)
"R1 Remains On - G2 SCR in 2015"



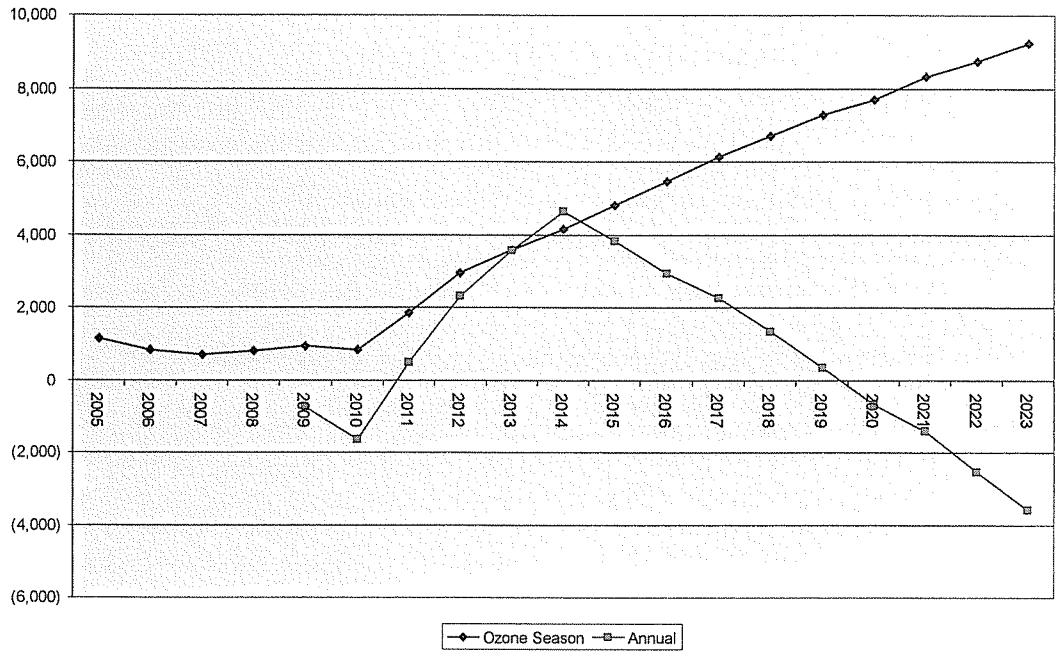
WKE NOx Allowance Balance (Ozone Season & Annual CAIR)
"R1 Remains On - G1 SCR in 2015 & G2 SCR in 2015"



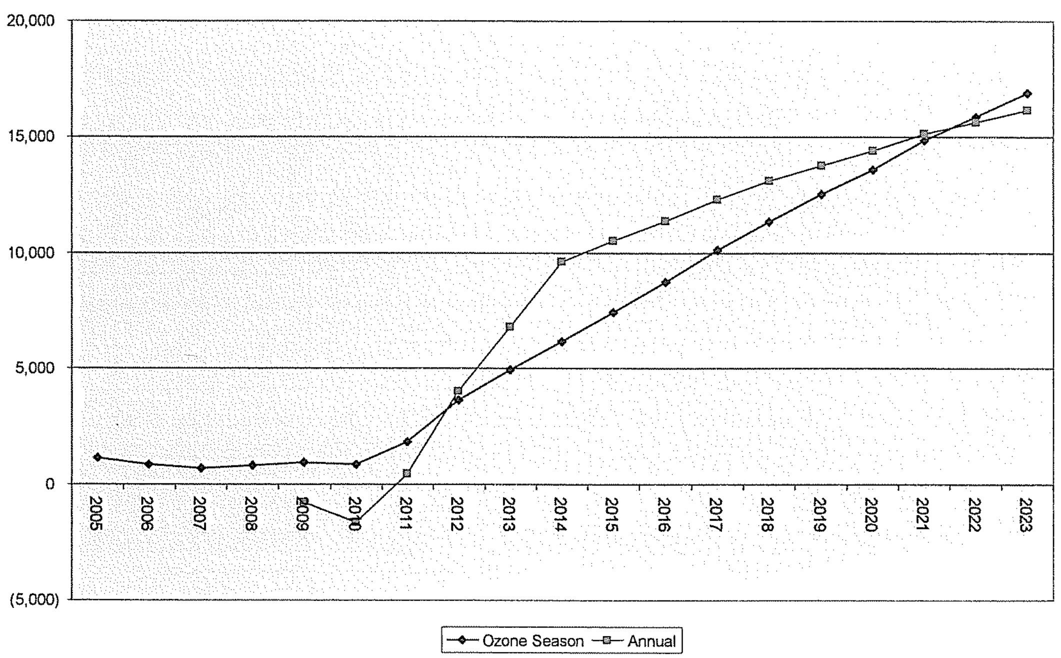
WKE NOx Allowance Balance (Ozone Season & Annual CAIR)
"R1 Remains On - G2 SCR in 2014 & G1 SCR in 2015"



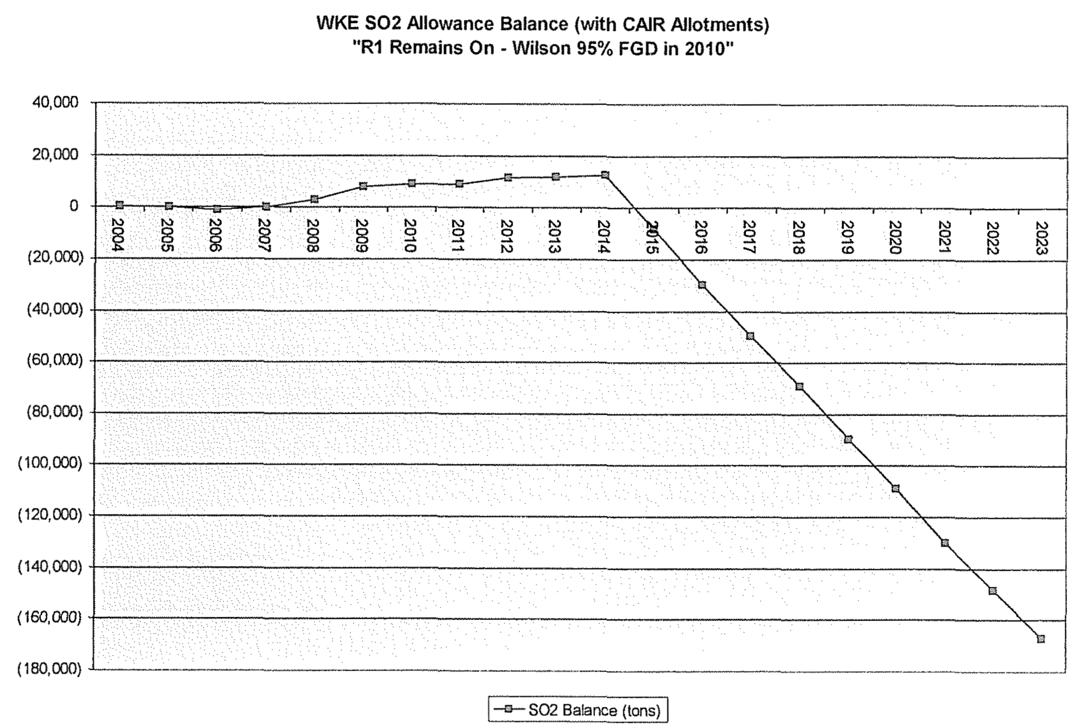
WKE NOx Allowance Balance (Ozone Season & Annual CAIR)
"R1 Remains On - G2 SCR in 2011"

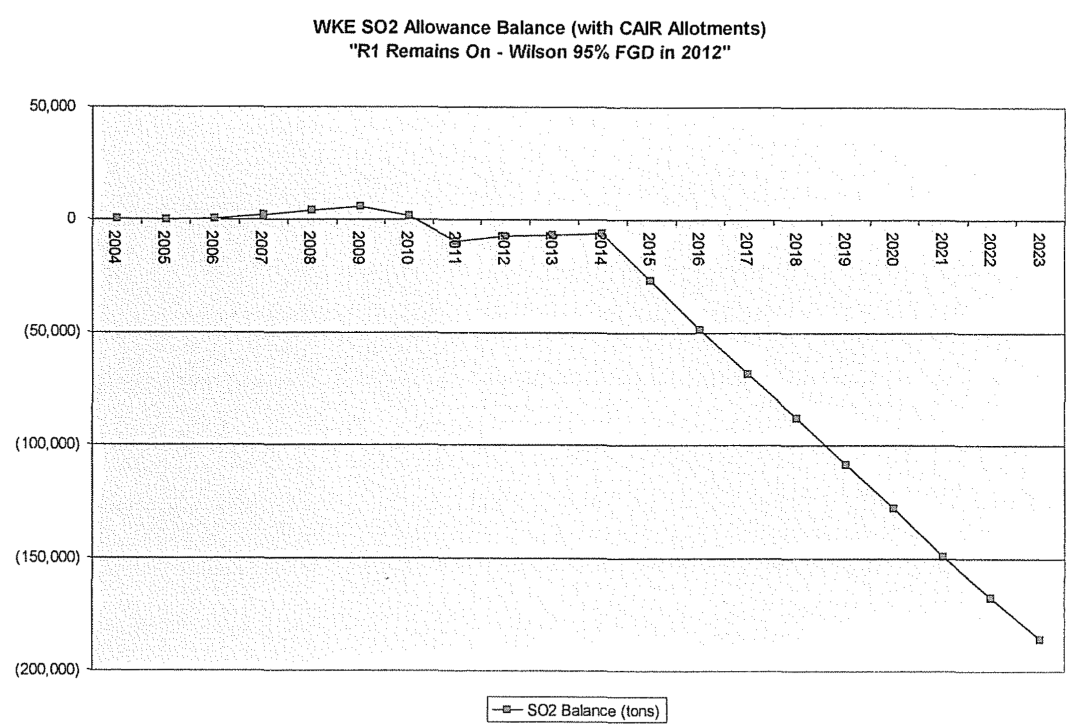


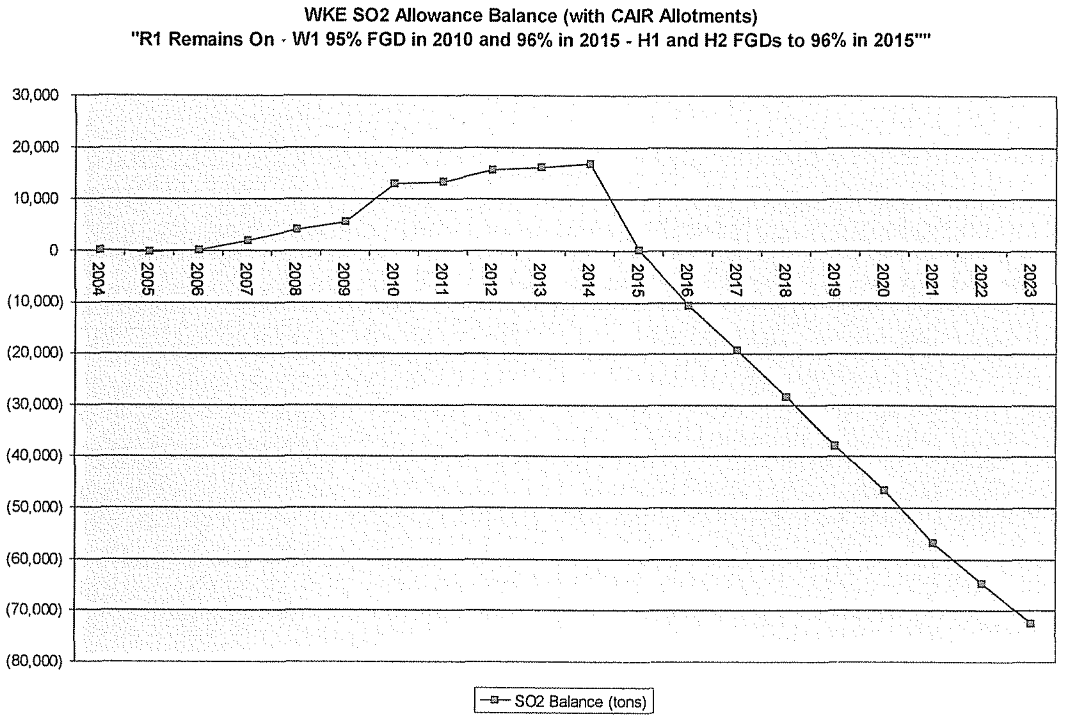
WKE NOx Allowance Balance (Ozone Season & Annual CAIR)
"R1 Remains On - G2 SCR in 2011 - G1 SCR in 2012"



CAIR Requirements for SO_2







Summary

For NOx, the options of installing an SCR on Green Unit 2 in 2012 and Green Unit 1 in 2013 will still work for longer term system compliance but at the expense of considerable allowance purchases in the first three years of Phase I. Delaying installation until 2015 is no longer a viable option. The best option appears to be the addition of an SCR to a Green Unit a year earlier than originally thought, ie. in 2011. A careful economic analysis should be performed to follow-up on the timing.

For SO_2, these charts illustrate that of the various scenarios investigated there is not a combination that assures system compliance with the Phase II SO_2 requirements as long as Reid Unit 1 continues to burn coal unscrubbed.

As an alternate, the compliance plan might proceed as originally thought with no provision for incorporating Reid Unit 1 into the system; but instead operate the unit on a "cost-plus" basis by providing necessary allowances as a part of the power cost.

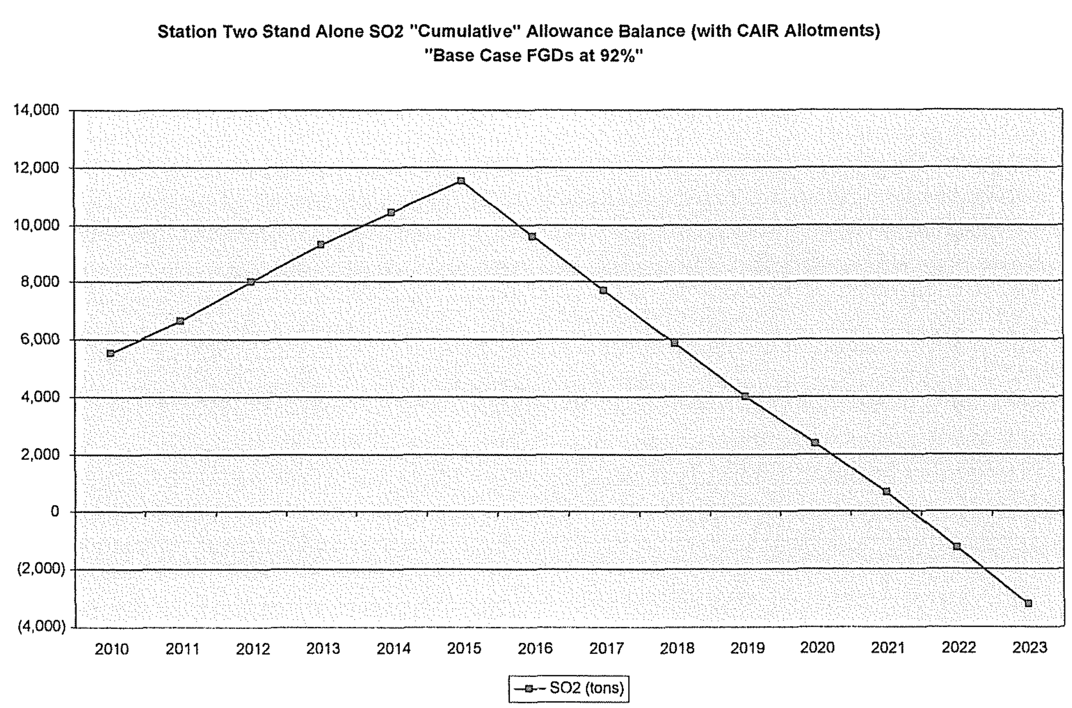
Addendum 2

Operation of the City of Henderson, Station Two in a "Stand-Alone" Mode

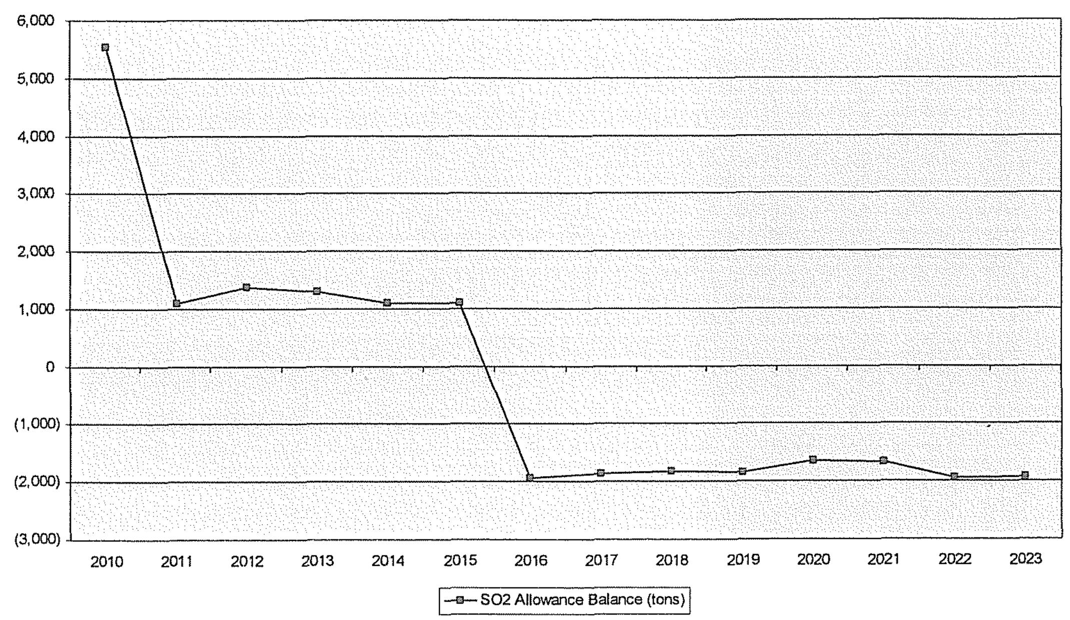
The Clean Air Act Amendments, Acid Rain Requirements, allocate SO_2 allowances specifically to unit accounts. For the City of Henderson, Station Two, the allocated allowances are directly allocated into the Unit 1 and Unit 2 accounts and are under control of the City through its Designated Representative. For these allowances there has been a long standing arrangement from the original implementation of the Acid Rain Rule, that the allowances which are allocated to the Station Two units will first be utilized to balance the emissions from those units – with the remainder split between the parties in accordance with the power supply split for that particular year. If in a particular year there happened to be a deficit of allowances in the accounts, then each party would need to provide their portion of the required allowances in accordance with the power supply split for that year. (To date this has never happened) This means essentially these units operate on a stand alone basis already.

With the new requirements of CAIR it is prudent to evaluate the compliance capability of these units on this stand alone basis, starting in 2010, to determine if the units can self comply with the Phase I and Phase II reductions or if additional SO_2 control (or purchase of allowances) appear to be necessary.

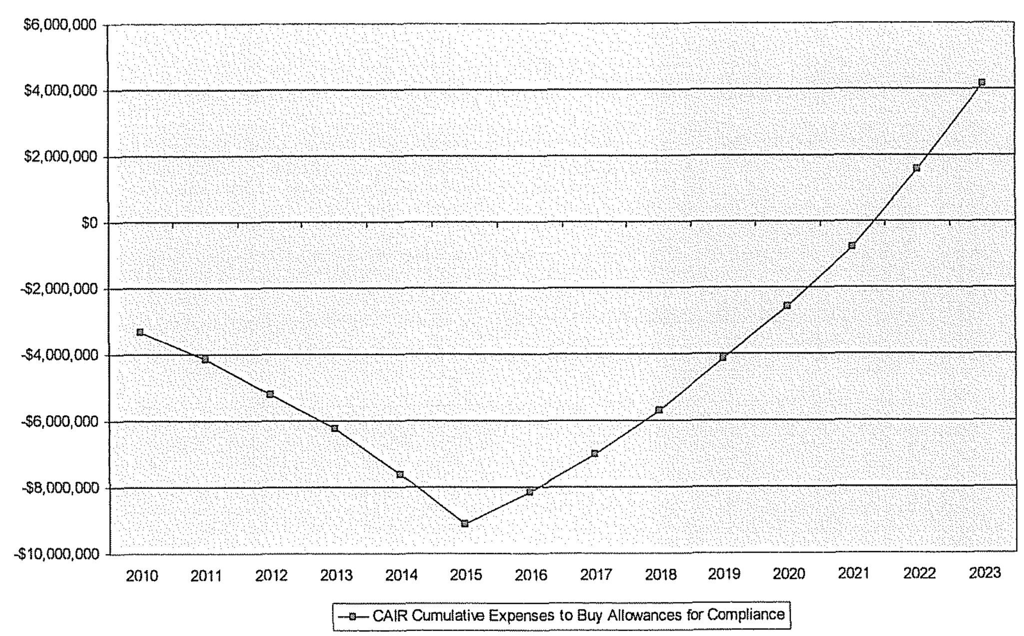
Option 1



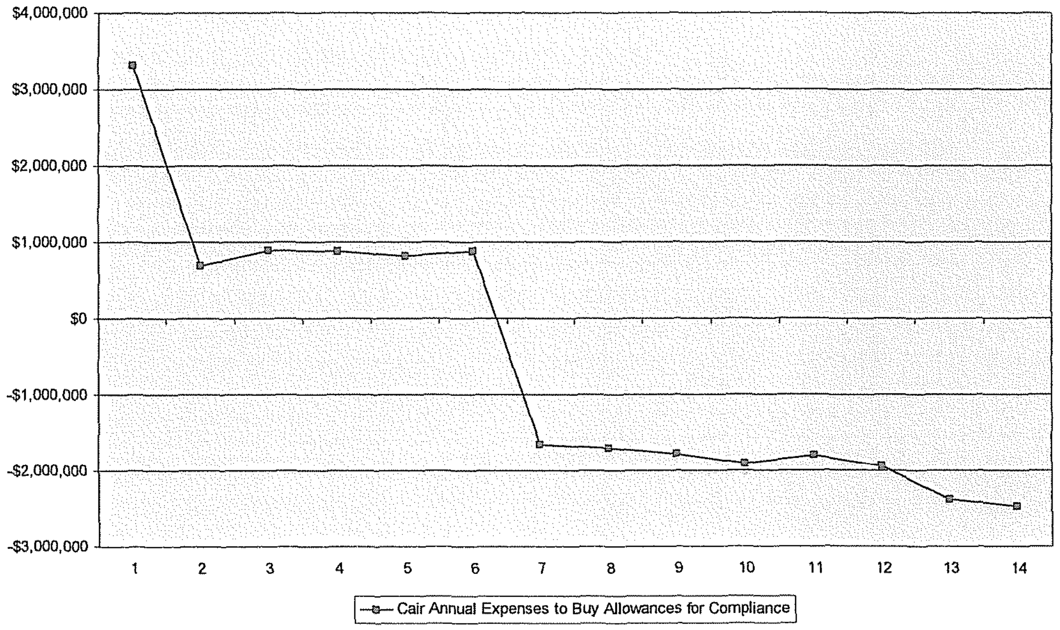
Station Two Stand Alone SO2 "Individual Year" Allowance Balance (with CAIR Allotments)
"Base Case FGDs at 92%"



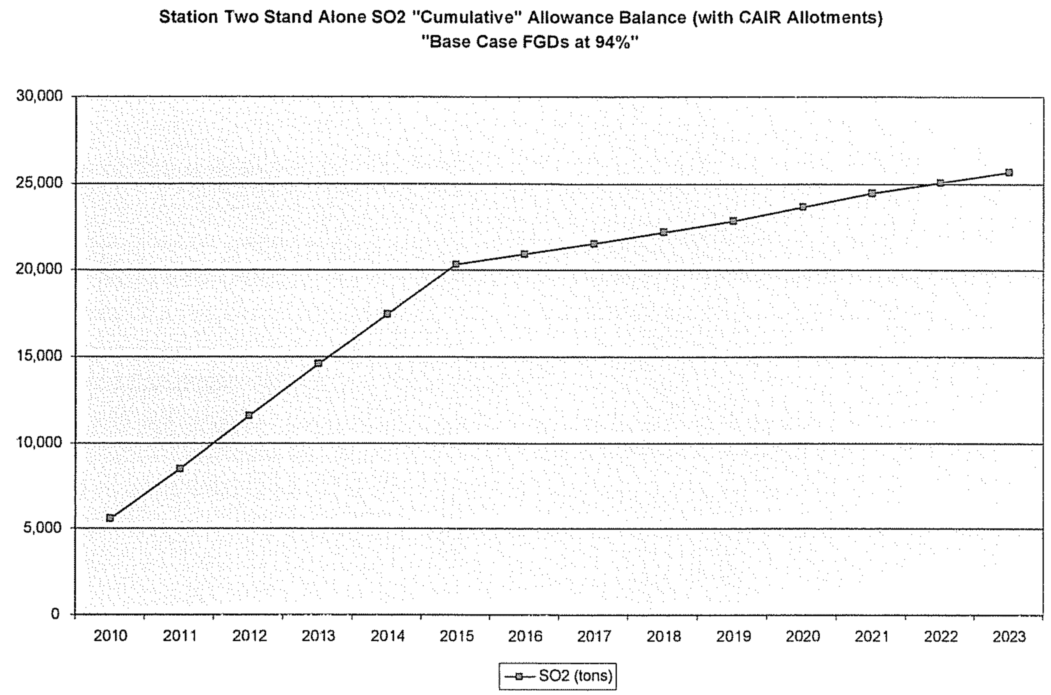
Station Two Stand Alone SO2 "Cumulative" Emission Expense Projection
"Base Case FGDs at 92%"



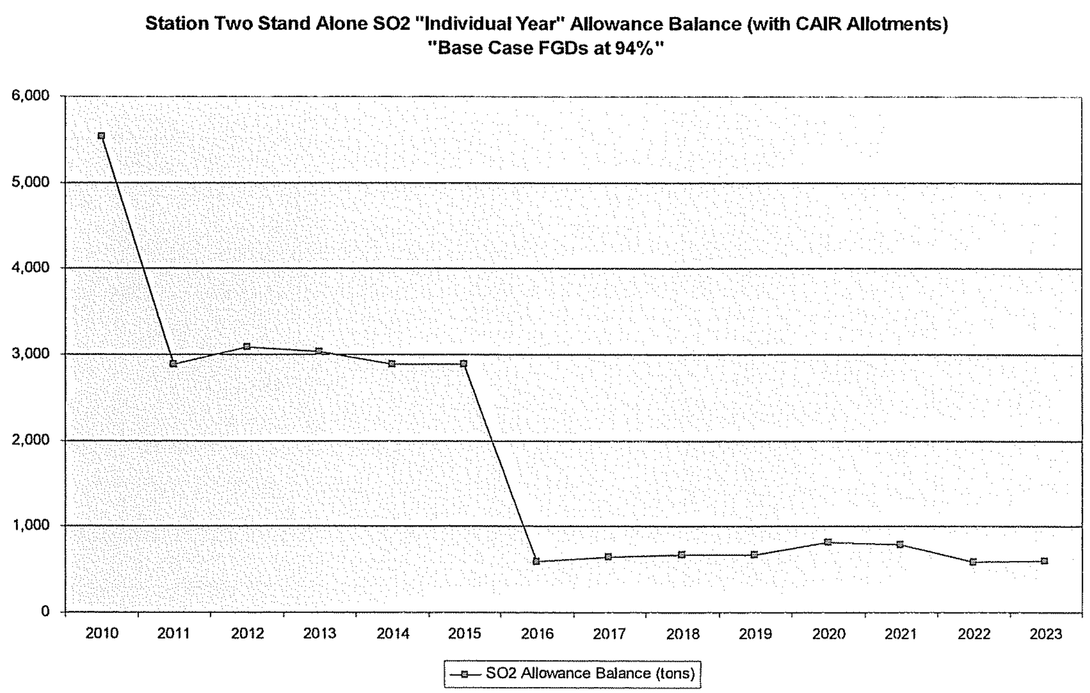
Station Two Stand Alone SO2 "Individual Year" Emission Expense Projection
"Base Case FGDs at 92%"



Option 2



Station Two Stand Alone SO2 "Cumulative" Allowance Balance (with CAIR Allotments)
"Base Case FGDs at 94%"
30,000
25,000
20,000
15,000
10,000
5,000
0
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
SO2 (tons)



Station Two Stand Alone SO2 "Individual Year" Allowance Balance (with CAIR Allotments)
"Base Case FGDs at 94%"
6,000
5,000
4,000
3,000
2,000
1,000
0
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
SO2 Allowance Balance (tons)

SO_2 Position
Using the 92% removal efficiency that was in previous studies (Option 1 above), the first series of charts indicate that beginning in 2015, the first year of CAIR Phase II, the Station Two units will not have sufficient allowances to cover their emissions with the new requirements in place. It should be noted that in this stand alone case the bank of allowances that is created during the first phase is expected to continue to operate and provide allowances to balance the system until about 2022, assuming no allowance sales. However, it appears that if the current removal efficiency of 94% is modeled (Option 2), there are sufficient allowances balance the emissions through the end of the lease period and into the future, including some bank building for potential sales.

Other system-wide modeling shown earlier includes a change in removal efficiency for the Station Two units from the current 94% to 97% in 2010. Such an increase in scrubber removal efficiency is possible; however, as has been discussed elsewhere, this increase in removal efficiency will have an impact on the waste handling and treatment facilities which will likely need significant upgrading to handle the increased volume of material.

Additionally, if significant physical changes are to be made to the scrubber modules, it would likely be worthwhile to achieve the maximums available to provide additional offset capability for the remainder of the WKE system. These changes will require economic evaluations to determine the best cost alternative.

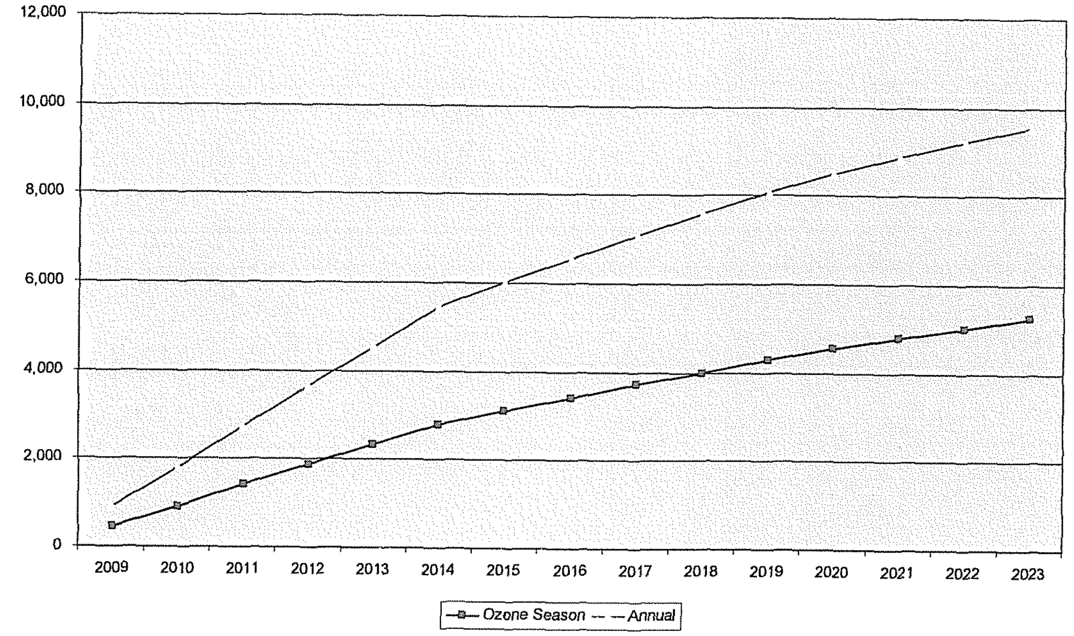
A review of previous studies shows that these earlier models project Station Two to be deficit in allowances much earlier (ie. beginning in 2010). This earlier date is primarily due to a much higher fuel sulfur value and unit generation.

NOx Position
With regard to the emissions of NOx contributing to the NOx SIP Call Ozone Season and the new requirements under CAIR, Station Two on a stand alone basis easily complies and builds allowance banks for both of these programs.

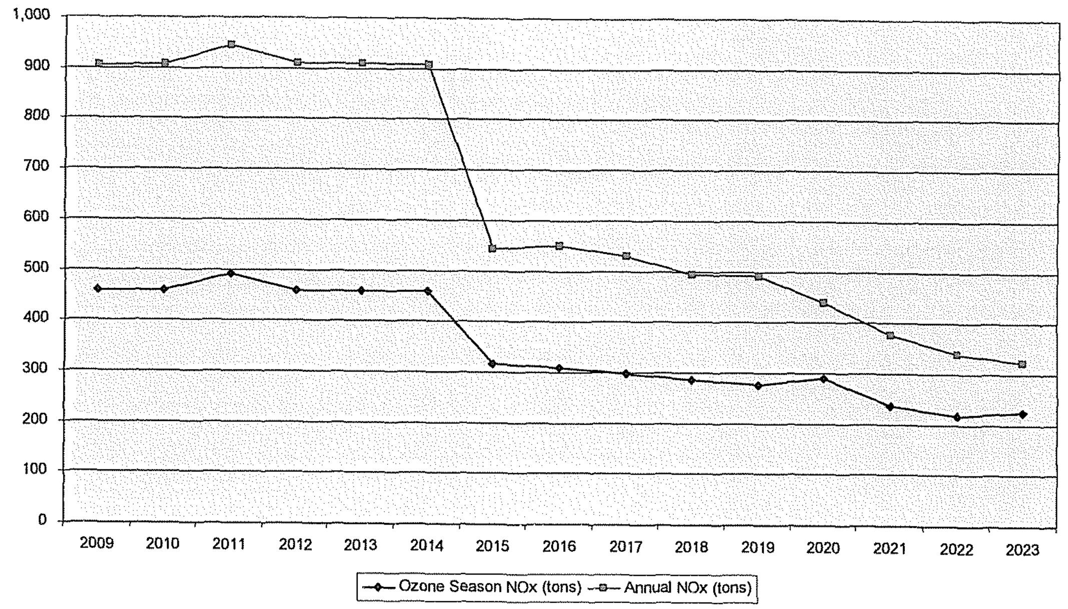
Since WKE was a partner with the City of Henderson in the installation of the SCR controls on these units up to the removal efficiency requirements for the City and additionally funded the additional equipment necessary for the units to achieve 90% removal. This extra removal efficiency conserves allowance consumption and results in a bank of allowances which WKE utilizes to help balance emissions throughout the remainder of the WKE fleet.

As a result of this arrangement, WKE gains title to a percentage of the banked allowances from these units. This split is dependent on the current power split for the units and capacity factor the City has had on its reserved power. Therefore, it is expected that the number of allowances that WKE receives will change from year to year. It is expected that additional negotiations will be required to address this change in operation as a result of a new regulatory requirement.

Station Two Stand Alone "Cumulative" NOx Allowance Balance
(Ozone Season & Annual CAIR)
"Base Case"



Station Two Stand Alone "Individual Year" NOx Allowance Balance
(Ozone Season & Annual CAIR)
"Base Case"



Appendix

Base Case Assumptions

Unit Operation:

1. Reid Unit 1 is not expected to operate routinely after 2009. Unit operation will be dependent upon economic constraints.
2. Unit operation is based on results from the 2006 Production Cost Model runs for Budget years 2007 thru 2011.

SCR Operation:

1. Currently installed SCRs are expected to operate at 90% average removal efficiency while on line. Full season removal efficiencies, which are calculated based on expected "unit events", are used to determine allowance use. These include unplanned unit outages and associated startup situations including SCR warm-ups.
2. SCR removed when load level is below ammonia cutoff point
3. No restriction on ramp rates beyond original design limits

Scrubber Operation

1. Coleman will operate at a 96% removal rate thru 2009, after-which it will increase to 97% removal.
2. Green Station will operate at a 96% removal rate thru the plan period.
3. Station Two will operate at a 94% removal rate thru the plan period.
4. Wilson will operate at a 91% removal rate thru the plan period.

Allowance Prices (Nominal $/ton):

2007 Plan ($/Ton Emissions)			
Year	SO_2	NO_x (ozone season)	NO_x (annual)
2008	485	850	850
2009	480	645	645
2010	599	2,366	2,366
2011	624	2,369	2,369
2012	649	2,372	2,372
2013	673	2,274	2,274
2014	733	2,250	2,250
2015	794	3,098	3,098
2016	855	3,092	3,092
2017	916	3,086	3,086
2018	977	3,197	3,197
2019	1,038	3,255	3,255
2020	1,099	3,261	3,261
2021	1,160	3,314	3,314
2022	1,221	3,368	3,368
2023	1,282	3,423	3,423

Final "Clean Air Interstate Rule (CAIR)" Regulations

Glenn Gibian
March 18, 2005[6]

On March 10, 2005, USEPA finalized CAIR regulations requiring significant SO_2 and/or NO_x reductions in 28 eastern states. The rules are intended to further reduce ozone (by requiring further reductions in NO_x during the summer) and to reduce fine particulates or PM-2.5 (by reducing SO_2 and NO_x on an annual basis).

It requires the following reductions from electric utilities compared to their 2003 levels*:

	Applies during:	28-states	Kentucky
Annual NO_x	2009-2014	53%	42%
Annual NO_x	2015 and beyond	61%	58%
Annual SO_2	2010-2014	45%	36%
Annual SO_2	2015 and beyond	57%	49%

*(assumes all reductions are achieved at electric utilities, as EPA envisions)

Ozone Season NO_x: It replaces the current NO_x SIP Call (which caps NO_x emissions during May-September) with CAIR NO_x caps, also during May-September. For Kentucky, the new cap is identical to the NO_x SIP Call for 2009-2014 and is reduced by about 15% for 2015 and beyond.

LG&E anticipated these types of requirements (based on a similar proposed regulation) and:
• is installing additional scrubbers on six units to reduce SO_2,
• is planning to install additional SCRs and to operating existing SCRs year-round to reduce NO_x.

The rule requires states to submit a plan to USEPA on how it will achieve the reductions, either by participating in a regional "cap-and-trade program" (similar to the Acid Rain and NO_x SIP Call programs) or by an alternative of the states choosing. States must submit their plans for achieving the reductions within 18 months, around September 2006.

It is likely that Kentucky and most states will choose the cap-and-trade approach. Under a cap-and-trade program, each combustion unit is awarded a set number of "allowances." Historically, the unit would surrender allowances in an amount equal to its emissions to be in compliance; this rule modifies the surrender ratio for SO_2, explained later. Each allowance has an associated vintage year and cannot be used for compliance before its vintage. Allowances can be traded between units, plants, companies, and so on (subject to PSC conditions).

[6] This summary was based on initial readings of the EPA model rule and estimates of allowance distributions. The final codified Kentucky Division For Air Quality regulations implementing CAIR Annual NOx , CAIR Ozone Season NOx ,and CAIR SO_2 requirements are included following this section

The allowance programs will be complicated since different states are subject to different combinations of the Acid Rain program, the NO_x SIP Call, CAIR ozone-season reductions, and CAIR SO_2/ NO_x reductions.

The following is a simplified summary, based on EPA's model rule:

Sulfur Dioxide

Existing Acid Rain allowances would be used. Allowances with vintage 2009 and earlier would be surrendered on a "one-for-one" basis throughout the CAIR program. Vintages 2010 through 2014 would be surrendered on a "two-for-one" basis (surrender two allowances for each ton of emissions) and vintages 2015 and beyond would be surrendered on a "2.86-for-one" basis. This increases incentive to reduce emissions and bank SO_2 allowances before 2010.

NO_x

LG&E's allocation will not be known until the state develops an in-state allocation process. A range of estimates will be provided below.

EPA will allocate predetermined numbers of NO_x allowances to each state and the individual states determine how to allocate these to individual units, similar to the current process under the NO_x SIP Call. Because Kentucky is required to reduce NO_x for both ozone and PM-2.5, there will ozone season allowances and annual allowances.

For ozone-season control, Kentucky's allocation is same as under the NO_x SIP Call for 2009-2014. For 2015 and beyond, Kentucky's ozone season cap is about 15% lower (nominally based on 0.125 lb/mmBtu vs 0,15 lb/mmBtu).

For PM-2.5 control, Kentucky's annual NO_x allocation is 83,205 tons during 2009-2014 and 69,337 tons for 2015 and beyond. These are about 7% higher than in the proposed regulations, largely because EPA applied a weighting factor that allocates more allowances to coal-fired generation than to oil and gas; thus, Kentucky's allocation increased because of its high percentage of coal-fired generation. A ballpark estimate of LG&E's possible allocation is provided below. However, Kentucky may choose to set some allowances aside for new sources or to withhold some and auction them. For example, under the NO_x SIP Call, Kentucky withheld 5% of the 2004-2007 allocation and auctioned them, with proceeds going to the Kentucky General Fund.

Ballpark estimate of Annual NO_x Allowances assuming no withholding

	2009-2014	2015 and beyond
KU	16,300	13,400
LG&E (75% TC)	12,600	10,500
WKE	10,500	8,700

The final regulations include a new Compliance Supplement Pool of 200,000 NO_x allowances for utilities that achieve early reductions or demonstrate need. Kentucky would receive 15,000 tons of these. Under the NO_x SIP Call, Kentucky made these all available for Early Reductions. It is unknown how Kentucky will determine what constitutes early reductions and how these will be awarded.

EPA estimated benefits in Kentucky

EPA's revised modeling indicates that the reductions not quite bring Jefferson County into attainment with the PM-2.5 standard (whereas its previous modeling indicated it would). EPA predicts the reductions will reduce Jefferson County's concentration from a Base Case of 16.61 to 15.13 (compared to the standard of 15 ug/m3). Otherwise, EPA estimates the reductions will bring all other areas of Kentucky into attainment for both ozone and PM-2.5.

States Covered by the Interstate Air Quality Rule (from EPA Fact Sheet)
(States listed are controlling for both particle pollution and ozone unless otherwise noted.)

Alabama
Arkansas
Connecticut (ozone only)
Delaware
Florida (particle pollution only)
Georgia
Illinois
Indiana
Iowa
Kansas (particle pollution only)
Kentucky
Louisiana
Maryland
Massachusetts
Michigan
Minnesota (particle pollution only)
Mississippi
Missouri
New Jersey
New York
North Carolina
Ohio
Pennsylvania
South Carolina
Tennessee
Texas (particle pollution only)

Virginia
West Virginia
Wisconsin
District of Columbia

KENTUCKY ENVIRONMENT CODIFIED REGULATIONS
TITLE 401 ENVIRONMENTAL AND PUBLIC PROTECTION CABINET
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY
CHAPTER 51 ATTAINMENT AND MAINTENANCE OF THE NATIONAL AMBIENT AIR QUALITY STANDARDS
401 KAR 51:210. CAIR NOX ANNUAL TRADING PROGRAM.

401 KAR 51:210. CAIR NOx annual trading program.

[33 KY R 1798, 03/01/2007]

Section 1. Applicability.

This administrative regulation shall apply to CAIR NOx units in Kentucky that are subject to 40 C.F.R. 96.104.

Section 2. Compliance Requirements.

CAIR NOx units shall comply with the following requirements:

(1) 40 C.F.R. 96.101 to 96.108 (Subpart AA), "CAIR NOx Annual Trading Program General Provisions";

(2) 40 C.F.R. 96.110 to 96.115 (Subpart BB), "CAIR Designated Representative for CAIR NOx Sources";

(3) 40 C.F.R. 96.120 to 96.124 (Subpart CC), "Permits";

(4) 40 C.F.R. 96.150 to 96.157 (Subpart FF), "CAIR NOx Allowance Tracking System";

(5) 40 C.F.R. 96.160 to 96.162 (Subpart GG), "CAIR NOx Allowance Transfers";

(6) 40 C.F.R. 96.170 to 96.175 (Subpart HH), "Monitoring and Reporting"; and

(7) 40 C.F.R. 96.180 to 96.188 (Subpart II), "Cair Nox Opt-in Units'.

Section 3. Methodology for the Allocation and Sale of CAIR NOx Annual Allowances.

The number of CAIR NOx allowances to be allocated to each CAIR NOx unit by the cabinet and to be sold by the Commonwealth of Kentucky shall be determined pursuant to this section.

(1) The total number of CAIR NOx allowances shall be;

(a) For the 2009 through 2014 control periods. 83,205 tons, as specified in 40 C.F.R. 96.140; and

(b) For the 2015 control periods and thereafter. 69.337 tons, as specified in 40 C.F.R. 96.140.

(2) The total number of CAIR NOx allowances assigned to Kentucky shall be divided into separate pools as follows:

(a) Ninety-eight (98) percent of this amount allocated for each control period to units that commence commercial operation before:

1. January 1, 2006, for the control periods 2009, 2010, 2011, 2012, 2013, and 2014;

2. January 1, 2009, for the control period 2015; and

3. Thereafter, January 1 of the year that is six (6) years before the first year of the next control period; and

(b) Two (2) percent of this amount for each control period sold by the Commonwealth of Kentucky with the proceeds deposited into Kentucky's general fund.

(3) For each CAIR NOx unit, the baseline heat input or adjusted control period heat input in mmBtu shall be determined and shall be used to determine CAIR NOx allowances for the pool specified in subsection (2)(a) of this section as follows:

(a) For CAIR NOx units commencing operation before January 1, 2001, and

1. Operating each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for 2001 through 2005; or

2. For units not having operated each calendar year for a period of five (5) or more consecutive years, the baseline heat input shall be established during the next allocation period when the unit has five (5) consecutive years of operation, using the average of the three (3) highest amounts of the unit's adjusted control period heat input for the most recent five (5) consecutive years of operation; []

(b) For units commencing operation on or after January 1, 2001, and operating each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for the most recent five (5) consecutive years of operation; or

(c) For units that have not operated each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall not be established. For purposes of allocations, the heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for the previous five (5) years of operation, the:

1. Adjusted control period heat input for a control period of not operating shall equal zero; and

2. Cabinet shall allocate CAIR NOx allowances for the unit.

(4) The adjusted control period heat input for each year shall be calculated as follows:

(a) If the unit is coal-fired during the year, the unit's control period heat input for that year shall be multiplied by 100 percent;

(b) If the unit is oil-fired during the year, the unit's control period heat input for that year shall be multiplied by sixty (60) percent; and

(c) If the unit is not subject to paragraphs (a) or (b) of this subsection, the unit's control period heat input for that year shall be multiplied by forty (40) percent.

(5) For a calendar year, the unit's control period heat input and the unit's status as coal-fired or oil-fired shall be determined:

(a) In accordance with 40 C.F.R. Part 75, if the unit is subject to 40 C.F.R. Part 75;

(b) By the best available data reported to the cabinet for the unit if the unit is not otherwise subject to 40 C.F.R. Part 75; or

(c) By the best available data obtained by the cabinet.

(6) For CAIR NOx units included in the pool specified in subsection (2)(a) of this section, the cabinet shall allocate CAIR NOx allowances to each CAIR NOx unit in an amount equal to the result obtained by:

(a) Multiplying the total amount of CAIR NOx allowances specified in subsection (2)(a) of this section by the baseline heat input for each unit or the heat input established under subsection (3)(c) of this section;

(b) **Dividing** by the total amount of baseline heat input and the heat input established under subsection (3)(c) of this section for all applicable CAIR NOx units; and

(c) Rounding to the nearest whole CAIR NOx allowance, as appropriate.

(7) The cabinet shall submit to the U.S. EPA and CAIR NOx sources the CAIR NOx allowances to be allocated and sold from the pools specified in subsection (2) of this section in a format prescribed by the U.S. EPA by:

(a) October 31, 2006, for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014;

(b) October 31,2009, for control period 2015; and

(c) October 31 of each year thereafter, for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

Section 4. Compliance Supplement Pool.

The CAIR designated representative may request early reduction credits and the allocation of CAIR NOx allowances from the compliance supplement pool established under 40 C.F.R. 96.143(a) for any CAIR NOx unit in the Commonwealth that achieves emission reductions in 2007 or 2008 or in both years when compared to the unit's NOx emission rate during the 2005 control period. Only emission reductions achieved in 2007 or 2008 or in both years that are not necessary to comply with any state or federal emissions limitation applicable during 2007 and 2008 may be used to request early reduction credits as specified in this section.

(1) The owners and operators of the CAIR NOx unit shall monitor and report the NOx emissions rate and the heat input of the unit in accordance with 40 C.F.R. 96.170 to 96.175 in each control period for which the early reduction is requested and for the 2005 control period. The difference resulting from subtracting the applicable 2007 or 2008 control period NOx emission rate from the 2005 control period NOx emission rate multiplied by the applicable 2007 or 2008 control period heat input divided by 2000, shall provide the amount in tons of the early reduction credit request.

(2) The CAIR designated representative shall submit to the cabinet by July 1, 2009, a request for allocation of an amount of CAIR NOx allowances from the compliance supplement pool:

(a) Not exceeding the sum of the amounts, in tons, of the unit's NOx emission reductions in 2007 and 2008 that are not necessary to comply with any state or federal emissions limitation applicable during the years, determined in accordance with 40 C.F.R. 96.170 to 96.175 ; or

(b) Not exceeding the minimum amount of CAIR NOx allowances necessary to remove undue risk to the reliability of electricity supply.

(3) To request allocations pursuant to subsection (2)(b) of this section, the CAIR designated representative shall demonstrate that, in the absence of allocation of an amount of CAIR NOx allowances requested, the unit's compliance with CAIR NOx emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during the control period. This demonstration shall include a showing that the owners and operators cannot feasibly obtain a sufficient amount of:

(a) Electricity from other electricity generating facilities during the installation of control technology at the unit for compliance with the CAIR NOx emissions limitation to prevent undue risk; or

(b) CAIR NOx allowances in accordance with this section, or otherwise, to prevent undue risk.

(4) Early reduction credits shall be rounded to the nearest whole number and distributed in the form of one (1) NOx allowance for one (1) ton of NOx emission reduction.

(5) The cabinet shall distribute the early reduction credits on a proportional basis.

(a) The total amount of early reduction credit available to a CAIR NOx unit shall be determined by the following calculation:

1. The unit's baseline heat input determined in Section 3(3)(a)1 of this administrative regulation;

2. Divided by the total amount baseline heat input **from all sources** pursuant to Section 3(3)(a)1 of this administrative regulation ; and

3. Multiplied by the early reduction credits available pursuant to 40 C.F.R. 96.143(a).

(b) The unused early reduction credits shall be combined together and distributed pro rata to those CAIR NOx units with early reduction credits that exceeded the amount of credits made available by the cabinet pursuant to paragraph (a) of this subsection by the following calculation:

1. The applicable unit's emission reductions that exceeded the credits made available pursuant to paragraph (a) of this subsection;

2. Divided by the total NOx emission reductions that exceeded the credits provided under paragraph (a) of this subsection from all applicable units;

3. Multiplied by the total number of unused early reduction credits.

(c) Early reduction credits provided under paragraph (b) of this subsection shall not cause the early reduction credits allocated to the source to exceed the number of early reduction credits requested.

(6) By November 30, 2009, the cabinet shall determine and submit to the U.S. EPA the allocations under this section.

(7) By January 1, 2010, the U.S. EPA shall record the allocations submitted under subsection (6) of this section.

Section 5. Sale of CAIR NOx Allowances by the Commonwealth of Kentucky.

(1) The Commonwealth of Kentucky shall establish an account pursuant to 40 C.F.R. 96.151(b) for the purpose of selling the CAIR NOx allowances in the pool specified in Section 3(2)(b) of this administrative regulation.

(2) The proceeds from the sale of the CAIR NOx allowances shall be deposited in the general fund of the Commonwealth of Kentucky.

KENTUCKY ENVIRONMENT CODIFIED REGULATIONS
TITLE 401 ENVIRONMENTAL AND PUBLIC PROTECTION CABINET
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
DIVISION OF AIR QUALITY
CHAPTER 51 ATTAINMENT AND MAINTENANCE OF THE NATIONAL AMBIENT AIR QUALITY STANDARDS
401 KAR 51:220. CAIR NOX OZONE SEASON TRADING PROGRAM.

401 KAR 51:220. CAIR NOx ozone season trading program.

[33 KY R 1799, 03/01/2007]

Section 1. Applicability.

This administrative regulation shall apply to:

(1) CAIR NOx Ozone Season units in Kentucky that are subject to 40 C.F.R. 96.304; or

(2) An industrial boiler or turbine as defined in 401 KAR 51:001 that was previously allocated NOx allowances pursuant to 401 KAR 51:160; or

(3) A unit that qualifies as a cogeneration unit pursuant to 40 C.F.R. 96.304(b)(1)(i) and that was previously allocated NOx allowances [pursuant to 401 KAR 51:160,]

Section 2.

CAIRO Ox Ozone Season units shall comply with the following requirements:

(1) 40 C.F.R. 96.301 to 96.308 (Subpart AAAA), "CAIR NOx Ozone Season Trading Program General Provisions";

(2) 40 C.F.R. 96.310 to 96.315 (Subpart BBBB), "CAIR Designated Representative for CAIR NOx Ozone Sources";

(3) 40 C.F.R. 96.320 to 96.324 (Subpart CCCC), "Permits';

(4) 40 C.F.R. 96.350 to 96.357 (Subpart FFFF), "CAIR NOx Ozone Season Allowance Tracking System";

(5) 40 C.F.R. 96.360 to 96.362 (Subpart GGGG), "CAIR NOx Ozone Season Allowance Transfers";

(6) 40 C.F.R. 96.370 to 96.375 (Subpart HHHH), "Monitoring and Reporting"; and

(7) 40 C.F.R. 96.380 to 96.388 (Subpart IIII, "CAIR NOx Ozone Season Opt-in Units".

Section 3. Methodology for the Allocation of CAIR NOx Ozone Season Allowances.

The number of CAIR NOx Ozone Season allowances to be allocated to each CAIR NOx Ozone Season unit by the cabinet and to be sold by the Commonwealth of Kentucky shall be determined pursuant to this section.

(1) The total number of CAIR NOx Ozone Season allowances shall be;

(a) For the 2009 through 2014 control periods. 36.109 tons, which includes 36.045 tons as specified in 40 C.F.R. 96.340, and sixty-four (64) allowances previously allocated under 401 KAR 51:160 for units specified in Section 1(2) of this administrative regulation: and

(b) For the 2015 control periods and thereafter, 30.651 tons, which includes 30.587 tons as specified in 40 C.F.R. 96.340. and sixty-four (64) allowances previously allocated under 401 KAR 51:160 for units specified in Section 1(2) of this administrative regulation.

(2) The total number of CAIR NOx Ozone Season allowances assigned to Kentucky shall be divided into separate pools as **follows** :

(a) Ninety-eight (98) percent of **the total number of allowances shall be** allocated for each control period to units that commence operation or commence commercial operation before:

1. January 1, 2006, for the control periods 2009, 2010, 2011, 2012, 2013, and 2014;

2. January 1, 2009, for the 2015 control period; and

3. Thereafter, before January 1 of the year that is six (6) years before the next control period; and

(b) Two (2) percent of **the total number of allowances** [for each control period **shall be** sold by the Commonwealth of Kentucky **In accordance with Section 4 of this administrative regulation**.

(3) For each CAIR NOx Ozone Season unit, the baseline heat input or adjusted control period heat input in mmBtu shall be determined and shall be used to determine CAIR NOx Ozone Season allowances for the pool specified in subsection (2) of this section as follows:

(a) For CAIR NOx Ozone Season units commencing operation or commencing commercial operation before January 1, 2001, and:

1. Operating each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall be the average of the three (3) highest amounts of the unit's adjusted control period heat input for 2001 through 2005; or

2. For units not having operated each calendar year for a period of five (5) or more consecutive years, the baseline heat input shall be established during the next allocation period when the unit has five (5) consecutive years of operation, using the average of the three (3) highest amounts of the unit's adjusted control period heat input for the most recent five (5) consecutive years of operation; or

(b) For CAIR NOx Ozone Season units commencing operation or commencing commercial operation on or after January 1, 2001, and operating each calendar year during a period of five (5) or more consecutive years, the baseline heat input shall be the average of the three highest amounts of the units adjusted control period heat input over the most recent consecutive five (5) years of operation; or

(c) For CAIR NOx Ozone Season units that have not operated each calendar year during a period of five (5) or more consecutive years, the average of the three **(3)** highest amounts of the unit's adjusted control period heat input for the previous five (5) years of operation, where the:

1. Unit shall not establish a baseline heat input;

2. Adjusted control period heat input for a control period of not operating shall equal zero;

3. Cabinet shall allocate CAIR NOx Ozone Season allowances for the unit.

(4) The adjusted control period heat input for each ozone season shall be calculated as follows for CAIR NOx Ozone Season units specified in subsection (2)(a) of this section:

(a) If the unit is coal-fired during the year, the unit's control period heat input for that year shall be multiplied by 100 percent;

(b) If the unit is oil-fired during the year, the units control period heat input for that year shall be multiplied by sixty (60) percent; and

(c) If the unit is not subject to paragraphs (a) or (b) of this subsection, the unit's control period heat input for that year shall be multiplied by forty (40) percent; and

(5) The adjusted control **period** heat input for CAIR NOx Ozone Season units specified in subsection (2)(b) of this section shall equal the unit's control period heat input multiplied by 100 percent.

(6) For an ozone season, the unit's control period heat input and the unit's status as coal-fired or oil-fired shall be determined:

(a) In accordance with 40 C.F.R. Part 75, if the unit is subject to 40 C.F.R. Part 75;

(b) By the best available data reported to the cabinet for the unit if the unit is not otherwise subject to 40 C.F.R. Part 75; or

(c) By the best available data obtained by the cabinet.

(7) For CAIR NOx Ozone Season units included in the pool specified in subsection (2)(a) of this section, the cabinet shall allocate CAIR NOx Ozone Season allowances to each CAIR NOx Ozone Season unit in an amount equal to the result obtained by:

(a) Multiplying the total amount of CAIR NOx Ozone Season allowances specified in subsection (2)(a) of this section by the baseline heat input for each unit or the heat input established under subsection (3)(c) of this section;

(b) Dividing by the total amount of baseline heat input and the heat input established under subsection (3)(c) of this section for all applicable CAIR NOx Ozone Season units; and

(c) Rounding to the nearest whole CAIR NOx Ozone Season allowance, as appropriate.

(8) The cabinet shall submit to the U.S. EPA the CAIR NOx Ozone Season allowances to be allocated and sold from the pools specified in subsection (2) of this section in a format prescribed by the U.S. EPA by:

(a) October 31, 2006, for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014; and

(b) October 31, 2009, for control period 2015; and

(c) October 31 of each year thereafter, for the control period in the sixth year after the year of the applicable deadline for submission.

Section 4. Sale of CAIR NOx Allowances by the Commonwealth of Kentucky.

(1) The Commonwealth of Kentucky shall establish an account pursuant to 40 C.F.R. 96.351(b) for the purpose of selling the CAIR NOx Ozone Season allowances in the pool specified in Section 3(2)(b) of this administrative regulation.

(2) The proceeds from the sale of the CAIR NOx Ozone Season allowances shall be deposited in the general fund of the Commonwealth of Kentucky.

401 KAR 51:230. CAIR SO_2 trading program.

[33 KY R 1617, 03/01/2007]

Section 1. Applicability.

This administrative regulation shall apply to CAIR SO_2 sources and CAIR SO_2 units under the CAIR SO_2 Trading Program located in Kentucky that are subject to 40 C.F.R. 96.204.

Section 2. Compliance requirements.

CAIR SO_2 sources and CAIR SO_2 units shall comply with the following requirements:

(1) 40 C.F.R. 96.201 to 96.208 (Subpart AAA), "CAIR SO_2 Trading Program General Provisions";

(2) 40 C.F.R. 96.210 to **96.215** (Subpart BBB), "CAIR Designated Representative for CAIR SO_2 Sources";

(3) 40 C.F.R. 96.220 to 96.224 (Subpart CCC), "Permits";

(4) 40 C.F.R. 96.250 to 96.257 (Subpart FFF), "CAIR SO_2 Allowance Tracking System";

(5) 40 C.F.R. 96.260 to 96.262 (Subpart GGG), "CAIR SO_2 Allowance Transfers";

(6) 40 C.F.R. 96.270 to **96.275** (Subpart HHH), "Monitoring and Reporting"; and

(7) 40 C.F.R. 96.280 to 96.288 (Subpart III), 'CAIR SO_2 Opt-in Units".

Clean Air Mercury Rule

Jason Wilkerson
March 18, 2005

Currently, an estimated 48 tons of mercury are emitted into the atmosphere each year from coal-burning power plants in the U.S. On January 30, 2004, the United States Environmental Agency (EPA) proposed the "National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units," known as the Clean Air Mercury Rule. This rule would permanently cap and reduce mercury emissions from coal-fired power plants. The rule was finalized on March 15, 2005.[7]

It is a Cap and Trade Program!
The rule sets a mandatory two-phased declining cap on the total amount of mercury emissions and establishes a market-based mercury trading program under Section 111 (State-run program) of the Clean Air Act that will apply to all 50 States (plus two Tribal lands). It requires emission reductions from all existing coal-fired electric generating units in two distinct phases. In the first phase, due by 2010, mercury emissions will be reduced by taking advantage of "co-benefit" controls (a 38 ton national cap instead of 34 ton cap in the 2004 proposal) – that is, mercury reductions achieved by reducing SO_2 and NO_X emissions through the installation of flue gas desulphurization equipment (FGD) and selective catalytic reduction devices (SCR) under the existing Acid Rain Program, the NO_X SIP Call and the new Clean Air Interstate Rule (issued March 10, 2005). When fully implemented in 2018, mercury emissions will be reduced to 15 tons (69% reduction).

Under this cap-and-trade approach, EPA will allocate to each state specified amounts of emission "allowances" for mercury. EPA has offered a model cap-and-trade rule that allows allowances to be allocated to affected utility units based on the proportionate share of their baseline heat input to the total heat input of all affected units. For purposes of allocating the allowances, each unit's baseline heat input is adjusted to reflect the ranks of coal combusted by the unit during the baseline period. The rule is allowing 2000-2004 to be the choice of baseline years for allowance determination. The sum of the individual utility unit emission allowances in a State would be considered the State's emissions budget. EPA's allocations to Kentucky are listed in the table below. For comparison the numbers in parenthesis are what were designated in the 2004 proposed rule. Additionally, based on 2003 heat inputs, potential allocations for LG&E/KU are predicted. This does not take into account any possible new source set-aside pool.

---

[7] This summary was based on initial readings of the EPA model rule and estimates of allowance distributions. The final amended after comment Kentucky Division For Air Quality regulations implementing the CAMR Mercury Budget Trading Program requirements is included following this section.

Allocations given (tons)	For 2010	For 2018
Kentucky	1.525 tons (1.371)	0.602 tons (0.605)
Potential Allocations from Kentucky for LG&E/KU	0.549	0.217

The states have until October 31, 2006 to turn in their initial unit-specific allocation decisions to EPA. EPA has to approve that plan.

Compliance will be determined through continuous (or semi-continuous) mercury emission monitoring systems based on a rolling 12-month average. Utility units would demonstrate compliance with the standard by surrendering one "allowance" for each ounce of mercury emitted in any given year. The penalty for not having enough allowances is to (1) surrender allowances sufficient to offset the excess emissions and (2) surrender allowances from the next control period equal to three times the excess emissions.

Continuous mercury emission monitoring (or semi-continuous via sorbent trap method) will be required to track emission levels. For units built before July 1, 2008, the system must be installed and certified before January 1, 2009. However, for low mercury emitters (equal to or less than 29 pounds per year), there is the option to use periodic testing to quantify mercury emissions. If the unit emits 9 lb/yr or less, they can perform annual testing. If the unit emits greater than 9 lbs/year but less than or equal to 29 lbs/yr, semi-annual testing would be required. Reports of mercury emissions data will be submitted quarterly.

Under a Section 111 State-run program, trading would be allowed on a nationwide basis (allowances would be transferable among all regulated facilities), but since the mercury reduction program will be implemented by the states (like the NOx SIP Call), the states are free to impose stricter mercury control requirements or restrictions on mercury trading. On the positive side, the rule allows for unlimited banking of allowances. Therefore, those who can reduce emissions earlier can hold onto emission allowances longer.

New sources (construction starting on or after January 30, 2004) will comply with New Source Performance Standards (NSPS) for mercury. The proposed rule establishes very stringent performance standards for mercury emissions from new sources---these standards are also subcategorized by coal type:

Emission Limits for Mercury (based on gross energy output)			
	2004 - Proposed	2005 - Final	
Bituminous units	0.006 lb/GWh	$21x10^{-6}$ lb/MWh (0.021 lb/GWh)	
Sub-bituminous units	0.020 lb/GWh	$42x10^{-6}$ lb/MWh (0.042 lb/GWh)	with WFGD
		$78x10^{-6}$ lb/MWh (0.078 lb/GWh)	with DFGD
Lignite units	0.062 lb/GWh	$145x10^{-6}$ lb/MWh (0.145 lb/GWh)	
Waste coal units	0.0011 lb/GWh	$1.4x10^{-6}$ lb/MWh (0.0014lb/GWh)	
IGCC units	0.020 lb/GWh	$20x10^{-6}$ lb/MWh (0.020lb/GWh)	

WFGD = Wet flue gas desulphurization equipment
DFGD = Dry flue gas desulphurization equipment

In addition, new sources might **not** be allocated allowances under the mercury cap and trading program, but would be required to surrender allowances equivalent to their NSPS emission rate limit times their baseline heat input. New sources would only received allowances if the State includes a new source set-aside in its allowance allocation methodology.

For those new units that burn a blend of coal ranks, a unit-specific emission limit will be developed. That limit will be used for the portion of the compliance period in which the unit burned the blend of fuels. The limit will be a computed weighted mercury emission limit based on the proportion of energy output (BTU or MWh) contributed by each coal rank burned during the compliance period and its applicable mercury emission limit

Nickel emissions from oil-fired boilers are no longer addressed by this or any other rule.

ENVIRONMENTAL AND PUBLIC PROTECTION CABINET

Department For Environmental Protection

Division for Air Quality

(Amended After Comments)

401 KAR 60:020. Mercury Budget Trading Program.

RELATES TO: KRS 224.10-100, 224.20-100, 224.20-110, 224.20-120, 40 C.F.R. Parts 60, 72 and 75, 42 U.S.C. 7410, 7411

STATUTORY AUTHORITY: KRS 224.10-100(5), 42 U.S.C. 7410, 7411

NECESSITY, FUNCTION, AND CONFORMITY: KRS 224.10-100(5) requires the Environmental and Public Protection Cabinet to promulgate administrative regulations for the prevention, abatement, and control of air pollution. This administrative regulation establishes requirements for the control of mercury emissions from coal-fired electric generating units, pursuant to the federal mandate published under the "Clean Air Mercury Rule (CAMR)", 40 C.F.R. 60.4101 to 60.4176. This administrative regulation is not more stringent than the provisions allowed under the federal mandate.

Section 1. Applicability. This administrative regulation shall apply to Hg Budget sources and all Hg Budget units at those sources in Kentucky that are subject to 40 C.F.R. 60.4104.

Section 2. Hg Budget sources and all Hg Budget units at those sources shall comply with the following requirements:

(1) 40 C.F.R. 60.4101 **through**[~~to~~] 60.4108, "Hg Budget Trading Program General Provisions", except for 40 C.F.R. 60.4105, subparagraph (b)(2);

(2) 40 C.F.R. 60.4110 **through**[~~to~~] 60.4114, "Hg Designated Representative for Hg Budget Sources";

(3) 40 C.F.R. 60.4120 **through**[~~to~~] 60.4124, "Permits";

(4) 40 C.F.R. 60.4151 **through**[~~to~~] 60.4157, "Hg Allowance Tracking System";

(5) 40 C.F.R. 60.4160 **through**[~~to~~] 60.4162, "Hg Allowance Transfers"; and

(6) 40 C.F.R. 60.4170 **through**[~~to~~] 60.4176, "Monitoring and Reporting".

Section 3. Hg Allowance Allocations. The number of Hg allowances to be allocated to each Hg Budget unit by the cabinet and to be sold by the Commonwealth of Kentucky shall be determined pursuant to this section.

(1) The total number of Hg allowances shall equal the total number of **ounces** [~~tons~~] in the Kentucky annual trading budget, which for the control periods in 2010 through 2017 is **48,800 ounces (1.525 tons)**[~~1.525 tons~~] and in 2018 and thereafter is **19,264 ounces (0.602 tons)**[~~0.602 tons~~].

(2) The total number of Hg allowances as determined in Section 3 (1) shall be divided into two (2) separate pools as follows:

(a) Ninety-eight (98) percent of this amount allocated for each control period; and

(b) Two (2) percent of this amount for each control period, to be sold by the Commonwealth of Kentucky with the proceeds deposited in Kentucky's general fund.

(3) For each Hg Budget unit, the baseline heat input in MMBtu shall be determined and shall be used to determine Hg allowance allocations**.**[~~as follows:~~]

(a) For units commencing operation before January 1, 2001, the baseline heat input shall be the average of the three highest amounts of the unit's control period heat input for 2001 through 2005 **and shall be:** [~~.~~]

1. [~~a.~~] Determined in accordance with 40 C.F.R. part 75 to the extent the unit was otherwise subject to the requirements of 40 C. F.R. Part 75 for the year; or

2. [~~b.~~] Based on the best available data reported to the cabinet for the unit, to the extent the unit was not otherwise subject to the requirements of 40 C.F.R. Part 75 for the year.

[~~1. A unit's control period heat input for a calendar year under paragraph (3) (a) of this section shall be:~~

~~2. The unit's types and amounts of fuel combusted, under paragraph (3) (a) of this section, shall be based on the best available data reported to the cabinet for the unit.~~]

(b) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 (five) or more consecutive calendar years, the baseline heat input shall be the average of the 3 (three) highest amounts of the unit's total converted control period heat input over the first 5 (five) consecutive year period. The unit's converted control period heat input for a calendar year shall equal:

1. Except as provided in subparagraph (3) (b) 2 or 3 of this section, the control period gross electrical output of the generator or generators served by the unit;

a. Multiplied by 7,900 Btu/kWh;

b. Divided by 1,000,000 Btu/MMBtu; and

c. Provided that if a generator is served by 2 (two) or more units, then the gross electrical output of the generator shall be attributed to each unit in proportion to the unit's share of the total control period heat input of each unit for the year;

2. The total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/MMBtu for a unit that:

a. Is a boiler; and

b. Has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; or

3. The control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/MMBtu for a unit that;

a. Is a combustion turbine; and

b. Has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy.

(4) For each control period in 2010 and thereafter, the cabinet shall allocate:

(a) To all Hg Budget units that have a baseline heat input, as determined under subsection (3) of this section, a total amount of Hg allowances equal to the amount of Hg allowances in the pool established under paragraph (2) (a) of this section;

(b) Hg allowances to each Hg Budget unit that has a baseline heat input, as determined under subsection (3) of this section, in an amount determined by multiplying the total amount of Hg allowances allocated under paragraph (a) of this subsection by the ratio of the baseline heat input of the Hg Budget unit to the total amount of baseline heat input of all Hg Budget units in Kentucky that have a baseline heat input, and rounding to the nearest whole allowance as appropriate.

(5) The cabinet shall submit to the U.S. EPA, in a format prescribed by the U.S. EPA, the Hg allowance allocations determined in accordance with this section by the following deadlines:

(a) November 17, 2006, for the control periods 2010, 2011, 2012, 2013, and 2014; and

(b) October 31, **2009**[~~2008~~] and October 31 of each year thereafter, for the control period in the sixth year after the year of the applicable deadline.

MODEL ASSUMPTIONS

General
These are ballpark estimates, based on the assumptions below, which include the Kentucky Division for Air Quality's initial allocation of the state-wide allowance pool (which should not change), the amount of new generation in the state, and other unknowns.

Initial allocations are based on Btu consumption, average of highest two years selected from 2001-2005.

Ozone Season NOx
NOx SIP Call:
2004-2006 actual allocations
2007-2009 latest proposed from KYDAQ (which includes a 2% set-aside)

CAIR SO2:
Assumes that a surrender ratio (e.g. surrendering 2 for 1) equates to receiving that fraction (e.g. half) of Acid Rain allowances; technically, we will still receive the same number of allowances but will have to surrender multiple allowances for each ton of emissions.
2010-2014: assume surrender of 2.0 for 1
2015+: assume surrender of 2.86 for 1

Mercury:
2010-2017: 5% withheld / 2018+: 10% withheld