



Department of the Environment

TECHNICAL SUPPORT DOCUMENT

FOR

**COMAR 26.11.38 - Control of NO_x Emissions
from Coal-Fired Electric Generating Units**



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NO_x Regulations for Coal EGU's **COMAR 26.11.38**

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I. Introduction

A. Ozone NAAQS and Designations

On March 12, 2008, EPA strengthened the national ambient air quality standard (NAAQS), for ground-level ozone, setting both the primary and secondary standards to a level of 0.075 parts per million (ppm) or 75 parts per billion (ppb) averaged over an 8-hour period. The primary standard serves to protect public health, while the secondary standard serves to protect public welfare such as property, vegetation and ecosystems.

In April and May 2012, EPA designated all areas of the country with respect to the 0.075 ppm ozone standard. Designations include “attainment” which indicates that an area is meeting the standard, or “nonattainment” indicating areas that do not meet it. Three areas of Maryland were designated nonattainment and were then classified with respect to the severity of their ozone problem:

1. Baltimore area – “moderate” nonattainment area
This area includes Anne Arundel County, Baltimore County, Baltimore City, Carroll County, Harford County, and Howard County.
2. Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE – “marginal” nonattainment area
This area includes one jurisdiction in Maryland: Cecil County.
3. Washington, DC-MD-VA – “marginal” nonattainment area
This nonattainment area includes the following Maryland jurisdictions: Calvert County, Charles County, Frederick County, Montgomery County, and Prince George’s County.

Under Clean Air Act (CAA) requirements and subsequent EPA guidance, nonattainment areas of “moderate” or higher classification are required to submit a reasonable further progress (RFP) plan. The RFP plan must show progress by making a 15 percent reduction in emissions over six years toward attainment of the ozone standard.

The Baltimore “moderate” nonattainment area must also submit a state implementation plan (SIP) revision by June 2015 that includes an attainment demonstration. This SIP confirms via modeling and other analyses the success of selected emission reduction strategies in enabling the Baltimore area to attain the standard by 2018.

In 2014, pursuant to Clean Air Act §182, the Maryland Department of the Environment (MDE) is required to review and, as appropriate, revise the nitrogen oxides (NO_x) Reasonably Available Control Technology (RACT) requirements in the Maryland SIP. EPA defines RACT as the lowest emissions limitation that a particular source is capable of meeting via the application of control technology that is reasonably available considering technological and economic feasibility. The emissions limitation may, for example, be measured on a “parts per million” or “pounds per million British thermal units (Btu)” basis. Control technology includes, for example, installation and operation of low-NO_x burners.

Whenever EPA establishes a new ozone standard, states with an ozone nonattainment area of “moderate” or higher classification are required to determine whether existing RACT requirements are stringent enough. The state must consider technological advances, the stringency of the revised ozone standard, and the presence in the nonattainment area of new sources subject to RACT. Maryland's RACT SIP for the new 75 ppb ozone standard must examine major sources of NO_x and their existing controls to determine whether additional controls are economical and technically feasible.

The following table describes the classification and required attainment dates for Maryland’s nonattainment areas.

Table I-1: 8-Hour Ozone Nonattainment Areas in Maryland*

Nonattainment Area	Designation Date	Counties	Classification	Attainment Date
Baltimore	07/20/12	Anne Arundel Baltimore City Baltimore Carroll Harford Howard	Moderate	12/31/18
Philadelphia – Wilmington – Atlantic City	07/20/12	Cecil	Marginal	12/31/15
Washington DC	07/20/12	Calvert Charles Frederick Montgomery Prince George’s	Marginal	12/31/15

*Source: U.S. EPA. NAAQS for ground-level ozone is 0.075 parts per million (ppm) or 75 parts per billion (ppb) averaged over an 8-hour period.

References

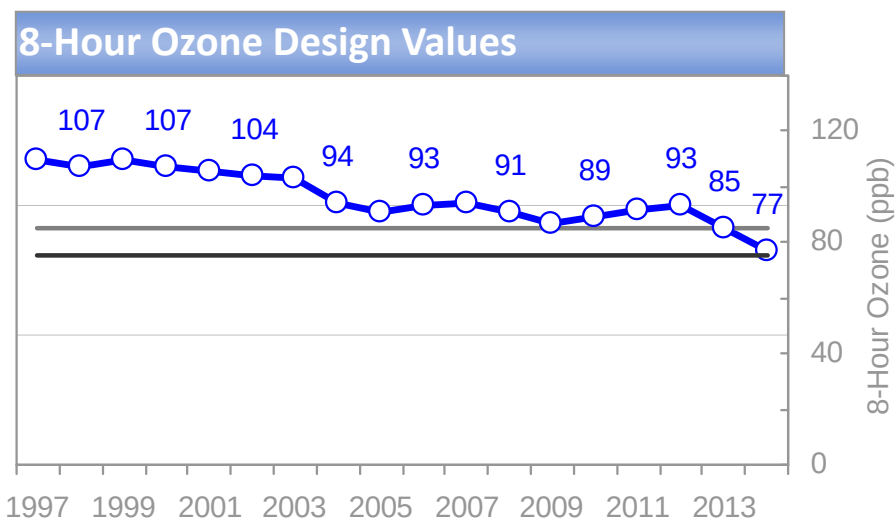
<http://www.epa.gov/airquality/ozonepollution/implement.html>
<http://www.epa.gov/ozonedenignations/2008standards/state.htm>

B. Maryland Historic Design Values

While Maryland’s air quality has improved over recent years, the state continues to struggle to attain the 8-hour 0.075 ppm ozone standard. As shown in Figure 1, Maryland’s design values hover at 76 ppb due to the two very mild summers of 2013 and 2014. During summers with warmer temperatures when the weather is more conducive to ozone formation, Maryland will likely not be able to maintain compliance with the ozone standard. Even though air quality is improving, on November 26, 2014, EPA proposed adoption of a lower ozone standard in the range of 65 to 70 ppb. Stricter controls on local emissions, such as this regulatory action, and federal and regional controls on upwind sources of emissions will be needed to satisfy both

RACT and attainment requirements to reduce ozone levels in Maryland. This regulatory action plays a major role in fulfilling both requirements.

Figure 1: Maryland 8-Hour Ozone Design Values



Source: Maryland Department of the Environment.

Several major regulations are responsible for the most significant reductions in historic ozone levels, such as the EPA NO_x SIP Call and Maryland Healthy Air Act. More recent studies of ozone chemistry have shown that NO_x reductions are the most effective strategy for reducing ozone levels. Ground-level ozone levels dropped nationwide in 2003 due to the NO_x SIP call. The NO_x SIP call resulted in the installation of advanced pollution controls such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and selective alternative catalytic reduction (SACR) technologies at well over 100 electric generating units and significantly reduced the amount of NO_x produced throughout the nation resulting in much less monitored ozone pollution. See Chapter VI for additional historic background.

C. Health and Environmental Impacts

Impacts on Public Health and Welfare

Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies. Reducing ozone concentrations is associated with significant human health benefits, including the avoidance of mortality and respiratory illnesses. NO_x is an ozone precursor, and reducing NO_x emissions would also reduce adverse health effects associated with NO₂ exposure. These health benefits include fewer asthma attacks, hospital and emergency room visits, lost work and school days, and lower premature mortality.

Impacts on the Chesapeake Bay

More than one-third of the pollution entering the Chesapeake Bay comes from the air. Pollutants released into the air (primarily from power plants and vehicle emissions) eventually make their way back down to the earth's surface and are dispersed onto the land and transported into waterways. In addition to other State and federal regulations currently in effect, the standards and

requirements in the proposed regulation reduce the amount of nitrogen entering the Bay each year.

Impacts on Vegetation and Agriculture

Exposure to ozone has been associated with a wide array of adverse impacts on vegetation and ecosystem. These effects include those that damage or impair the intended use of the plant or ecosystem. According to the EPA, new scientific evidence since the last review of the ozone NAAQS continues to document the adverse impact of ozone on the public welfare. This includes reduced growth and/or biomass production in sensitive plant species, including forest trees. High ozone levels reduce crop yields, reduce plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), and cause visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services.

References

<http://www.epa.gov/groundlevelozone/health.html>

<http://www.epa.gov/airquality/ozonepollution/ecosystem.html>

II. Rationale

The Maryland Department of the Environment proposes COMAR 26.11.38 - Control of NO_x Emissions from Coal-Fired Power Plants as a key element in Maryland's current and future State Implementation Plans (SIPs) to achieve statewide compliance with the federal ozone standard. In 2015, the Department is required to submit an ozone attainment SIP that includes emission reduction strategies designed to achieve compliance with the 75 ppb ozone standard by 2017. In addition, Sections 182 and 184 of the Clean Air Act requires the Department to review and revise NO_x RACT requirements in Maryland's SIP as necessary to achieve compliance with new more stringent ambient air quality standards.

Although the Department previously promulgated several regulations applicable to coal-fired power plants, NO_x emissions from this source category continue to comprise a large percentage of ozone season NO_x emissions - in large part due to high electricity demand days.

This proposed regulation, when effective, will result in immediate reductions in ozone season NO_x emissions from these sources, especially on high electricity demand days which are needed to achieve and maintain compliance with the 75 ppb ozone standard.

A. Maryland Coal-fired NO_x Regulations

As stated earlier, Maryland has three nonattainment areas under the 75 ppb ozone standard. One of the requirements for such areas is review of the RACT requirements for each category of major sources to determine whether current RACT limits are adequate in light of the more stringent standard and advancing technologies. The category of coal-fired electric generating units is one of the first categories reviewed.

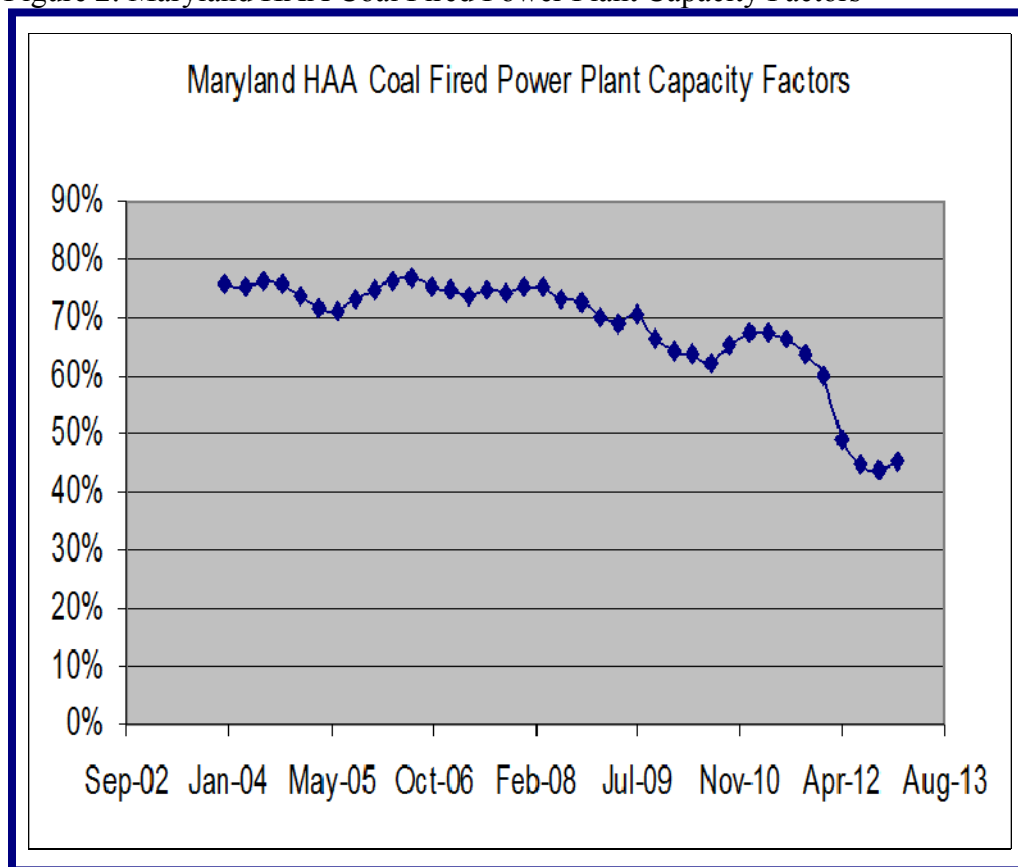
Under the Maryland Healthy Air Act, all active coal-fired electric generating units added NO_x reduction technologies that utilize chemical reductants to lower NO_x outputs. These technologies included selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and selective alternative catalytic reduction (SACR), which are discussed in further detail in Chapter IX. The Healthy Air Act achieved significant reductions in NO_x emissions through the application of mass limitations or caps on the affected coal-fired units. Separate caps were applied to annual and ozone season emissions. The use of caps rather than rates allowed the units flexibility to comply under all modes of operation, but were stringent enough to severely restrict the amount of operating time when the controls were not being optimized. The implementing regulation allowed system-wide compliance with the emission limits by demonstrating that the total tons from the all the units in the system did not exceed the tonnage limit for all units within the system. Systems are defined as all units under the same ownership. At this time, there are two systems: (1) units owned by Raven Power Finance LLC consisting of Brandon Shores Units 1 and 2, H. A. Wagner Units 2 and 3, and C. P. Crane Units 1 and 2 (Raven Power System); and (2) units owned by NRG Energy, Inc. consisting of Morgantown Units 1 and 2, Chalk Point Units 1 and 2, and Dickerson Units 1, 2 and 3 (NRG System). The practice of demonstrating compliance by allowing a system of units to combine to meet the requirement is often referred to as "averaging".

Prior owners of these two systems installed SCR, SNCR and SACR at units subject to the requirements of the Healthy Air Act. The companies made decisions on which of these control systems would be utilized with the concept of averaging emissions from the individual units in mind. “Baseload” units were equipped with SCR while “load following” units were equipped predominantly with SNCR or SACR. Overall, the controls yielded a 75 percent reduction in NO_x emissions from 2002 levels. The mass emission caps driving this reduction were based on historic utilization of the units, at high levels of operation and electricity production.

B. Performance of Existing Coal-fired Electric Generating Units

In recent years the utilization of coal plants has changed dramatically on a national level as well as in Maryland. The sharp decline in natural gas prices, the rising cost of coal, and reduced demand for electricity are all contributing factors to a substantial reduction in how often coal-fired plants are called upon to operate.

Figure 2: Maryland HAA Coal Fired Power Plant Capacity Factors



*Source: Maryland Department of the Environment. See Appendix A - Maryland HAA Notice of Proposed Action March 30, 2007

Today, as a result of these changes in the electricity markets some coal-fired plants only operate during periods of peak electricity demand. This reduction in operation results in lower overall NO_x emissions and units can operate in compliance with the mass emission caps of the Healthy Air Act without having to run the NO_x pollution controls in a manner that optimizes NO_x emission reductions. Emissions are higher over shorter operating time periods. The Department

found through data analysis that existing SCR and SNCR controls at the coal-fired units were not consistently operating to maximize emission reductions. At most units the ozone season NO_x emission rate has increased steadily since 2008¹.

¹An evaluation of performance data related to units equipped with SCR and SNCR can be found in Appendix B and Appendix C.

Through analysis of NO_x emission rate trends, the Department found that coal-fired plants with frequently run units equipped with SCRs, such as Morgantown, were operating the SCRs to achieve peak performance. At peak performance, operation of controls on these units reduced NO_x emissions sufficiently on most operating days to achieve compliance with the HAA and other federal limitations with only sporadic operation of SNCRs or SACR units and units with no controls. Thus, with an increasing amount of electricity generation (load) served by gas-fired units and a decreasing amount of load served by coal-fired units, operation of installed controls was orchestrated to remain within the applicable emission limits, rather than to maximize NO_x reductions.

The Department's analysis also revealed that while units equipped with SNCRs operated less than units equipped with advanced NO_x controls, they often operated on high temperature days when electricity demand is highest ("peak days"). These are the days that also are the most conducive to ozone formation. The operation of these units without the operation of the installed controls often increased the total NO_x emissions of the system by as much as 50% on peak days. The units complied with their regulatory limits, but contributed significantly to high ozone levels locally. The Department developed modeling analyses to evaluate the impact of this lost emission reduction potential. Operation of installed controls is much less expensive than installation of the controls. Optimization of existing controls can produce substantial additional emission reductions very cost-effectively. Effective emission limits in the form of rates can require operation of controls whenever units are called upon to operate.

Most of the existing electricity generating capacity in Maryland is very old. The remaining useful life of a unit is a factor in choosing to equip units with less costly SNCR controls. SNCRs are less efficient at reducing NO_x emissions than SCRs, achieving a 20-40 percent emission reduction depending on the unit. While numerous studies exist evaluating the effectiveness of SCRs at controlling NO_x emissions, substantially less information exists regarding the effectiveness of SNCRs. In a study prepared by Andover Technology Partners and the EPA², high operation units typically achieved rates of 0.07 lbs/MMBtu NO_x when equipped with an SCR. Units equipped with SNCRs typically operate in the 0.2 - 0.3 lbs/MMBtu NO_x range.

The Department did not find clear data regarding exactly when controls on the various units operated for use in identifying unit by unit performance rates. Raven Power and NRG voluntarily agreed to conduct an in-depth study during the summer of 2014 to determine how to achieve optimal performance of installed controls. The agreements of the 2014 Summer Study are attached in Appendix F and the raw data files will be available on MDE's website. This information will be used in developing the plan each company needs to submit under the regulation detailing operational parameters for each individual unit in all modes of operation. Because the weather patterns occurring during the summer of 2014 were not typical of the patterns that form ozone in Maryland, operating hours for a number of units were curtailed and

sufficient data was not available to develop individual unit by unit rates. The study did lay the foundation for more detailed record keeping on the operational parameters of the units during all modes of operation in preparation for development of the plans required under Regulation .03A(1).

²Staudt, James E., Khan, Sikander R., and Manuel J. Oliva. “*Reliability of Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Systems for High Pollutant Removal Efficiencies on Coal Fired Utility Boilers*”. 2004 MEGA Symposium, Paper # 04-A-56-AWMA. Andover Technology Partners. Paper can be found in Appendix D.

C. Proposed NO_x Emissions Control Strategies

The Department weighed emission reductions achieved by establishing generic rates for units controlled with specific equipment (SCR, SNCR and SACR) against establishing a system-wide rate. Through data analysis, the Department found that many of the units with SCR could achieve very stringent rates, exceeding the stringency of the commonly accepted 0.07 lbs/MMBtu NO_x rate. Rates lower than 0.07 lbs/MMBtu NO_x are used to offset higher emission rates from units equipped with SNCR or SACR. The better controlled units operate more often and provide more of the reductions. The proposed regulation includes a not-to-exceed rate of 0.15 lbs/MMBtu NO_x as a system-wide 30-day rolling average. Under this emission limit, operation of units controlled with SCR is not limited as long as the controls operate. Operation of units with SNCR is determined by how well the controls are run and how much overcontrol is provided by the other units in the system. Operation of the SNCR-controlled units may be curtailed in some instances to comply with the 0.15 lbs/MMBtu NO_x emission limit. Curtailment of operation of a unit becomes another method of control. The use of a system-wide rate allows well-controlled units to operate maximally, while limiting operation of less well-controlled units.

While a not-to-exceed ozone season rate of 0.15 lbs/MMBtu NO_x, called a hard rate, provides assurance that emissions remain below a set level averaged over a system, it is evident that during high demand operations with controls optimized, the system is capable of meeting a much lower rate. Coal-fired units operate most efficiently at high utilization, but, as discussed above, current economic conditions force coal-fired units to operate in a number of less efficient ways that require the units to ramp up and down more often. During these times, the operating parameters of the unit do not support the maximum NO_x removal efficiency of the control device. Historically, coal-fired units started up, ramped up to higher load capacity and operated in that manner for quite a long time. While load may have varied by 20 or 30 percent, the units were operating at fairly high capacity. In today’s electricity markets, operations are different. Units may start-up and shut down in the same day. Or they may operate at low capacity, combusting coal and producing electricity at the lowest possible rate. The units can then be ready to ramp up on short notice during peak demand times. Instead of including an exception for low load operation in the regulation as other states have done, the Department requires a plan to minimize NO_x emissions under all modes of operation in Regulation .03A1. The plan will establish alternate rates for each mode of operation, applicable when the unit is operating in that mode. At all times, the controls at each unit will be operating in the most optimal manner possible considering the technical limitations of the control.

The provisions of §A(2) in Regulation .03 require a unit that is operating to optimize the use of all installed control technology to minimize NO_x emissions consistent with the technological

limitations, manufacture's specifications, good engineering and maintenance practices, and good air pollution control practices. The provisions of §A(1) in Regulation .03 requires each unit to develop a plan for operation of the unit that details how the controls will be operated not only at times of peak performance, but also during other modes of operation when operating at low load, ramping up or down, or other off-peak mode. The plan will be reviewed and approved by the Department and by EPA. The table below reproduced from Regulation .05 represents indicator rates of good performance for the named units based on utilization of the installed control technology. See Chapter IV for an expanded discussion of the indicator rates. The rates are calculated in 24-hour blocks to limit the amount of averaging that can take place to offset rates that are higher than the indicator rates. If a unit fails to meet the 24-hour block average indicator rate for a day, the unit operator must submit a report to the Department detailing the operating parameters of the unit for that day. These operating parameters will be compared to the approved plan to evaluate whether the unit followed best practices for the conditions of operation occurring that day. Suggested elements for inclusion in the plan can be found in Chapter IV. Compliance with the 0.15 lbs/MMBtu rate, as well as the indicator rates, will be included in a monthly report. Units that fail to meet the indicator rates will submit supporting operational data for comparison with the unit's emission minimization plan.

Table II-1: Indicator Rates for Coal-Fired Electric Generating Units

Affected Unit	24-Hour Block Average NO _x Emissions in lbs/MMBtu
Brandon Shores	
Unit 1	0.08
Unit 2	
< 650 MWg	0.07
≥ 650 MWg	0.15
C.P. Crane	
Unit 1	0.30
Unit 2	0.28
Chalk Point	
Unit 1 only	0.07
Unit 2 only	0.33
Units 1 and 2 combined	0.20
Dickerson	
Unit 1 only	0.24
Unit 2 only	0.24
Unit 3 only	0.24
Two or more Units combined	0.24

H.A. Wagner	
Unit 2	0.34
Unit 3	0.07
Morgantown	
Unit 1	0.07
Unit 2	0.07

The Department's analysis of data and modeling information during ozone season indicates that exceedances of the ozone standard occur most often on days when the electricity system is operating at peak load. During this time, the less well-controlled high emitting units are called to operate, increasing the daily NO_x emissions by at least 50 percent.

D. The Proposed Regulation – COMAR 26.11.38

Title 26 DEPARTMENT OF THE ENVIRONMENT

Subtitle 11 AIR QUALITY

Chapter 38 Control of NO_x Emissions from Coal-Fired Electric Generating Units

Authority: Environmental Article, § 1-404, 2-103 and 2-301—2-303, Annotated Code of Maryland

ALL NEW MATTER

.01 Definitions.

A. In this chapter, the following terms have the meanings indicated.

B. Terms Defined.

(1) "Affected electric generating unit" means any one of the following coal-fired electric generating units:

- (a) Brandon Shores Units 1 and 2;
- (b) C.P. Crane Units 1 and 2;
- (c) Chalk Point Units 1 and 2;
- (d) Dickerson Units 1, 2, and 3;
- (e) H.A. Wagner Units 2 and 3;
- (f) Morgantown Units 1 and 2; and
- (g) Warrior Run.

(2) "Operating day" means a 24-hour period beginning midnight of one day and ending the following midnight, or an alternative 24-hour period approved by the Department, during which time an installation is operating, consuming fuel, or causing emissions.

(3) "Ozone season" means the period beginning May 1 of any given year and ending September 30 of the same year.

(4) System.

(a) "System" means all affected electric generating units within the State of Maryland subject to this chapter that are owned, operated, or controlled by the same person and are located:

- (i) In the same ozone nonattainment area as specified in 40 CFR Part 81; or
- (ii) Outside any designated ozone nonattainment area as specified in 40 CFR 81.

(b) A system must include at least two affected electric generating units.

(5) "System operating day" means any day in which an electric generating unit in a system operates.

(6) "30-day system-wide rolling average emission rate" means a value in lbs/MMBtu calculated by:

(a) Summing the total pounds of pollutant emitted from the system during the current system operating day and the previous twenty-nine system operating days;

(b) Summing the total heat input to the system in MMBtu during the current system operating day and the previous twenty-nine system operating days; and

(c) Dividing the total number of pounds of pollutant emitted during the thirty system operating days by the total heat input during the thirty system operating days.

(7) "24-hour block average emission rate" means a value in lbs/MMBtu calculated by:

- (a) Summing the total pounds of pollutant emitted from the unit during 24 hours between midnight of one day and ending the following midnight;
- (b) Summing the total heat input to the unit in MMBtu during 24 hours between midnight of one day and ending the following midnight; and
- (c) Dividing the total number of pounds of pollutant emitted during 24 hours between midnight of one day and ending the following midnight by the total heat input during 24 hours between midnight of one day and ending the following midnight.

.02 Applicability.

The provisions of this chapter apply to an affected electric generating unit as that term is defined in §.01B of this chapter.

.03 2015 NO_x Emission Control Requirements.

A. Daily NO_x Reduction Requirements During the Ozone Season.

(1) Not later than 45 days after the effective date of this regulation, the owner or operator of an affected electric generating unit shall submit a plan to the Department and EPA for approval that demonstrates how each affected electric generating unit (the unit) will operate installed pollution control technology and combustion controls to meet the requirements of §A(2) of this regulation. The plan shall summarize the data that will be collected to demonstrate compliance with §A(2) of this regulation. The plan shall cover all modes of operation, including but not limited to normal operations, start-up, shut-down and low load operations.

(2) Beginning on May 1, 2015, for each operating day during the ozone season, the owner or operator of an affected electric generating unit shall minimize NO_x emissions by operating and optimizing the use of all installed pollution control technology and combustion controls consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 C.F.R. § 60.11(d)) for such equipment and the unit at all times the unit is in operation while burning any coal.

B. Ozone Season NO_x Reduction Requirements.

(1) Except as provided in §B(3) of this regulation, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day system-wide rolling average emission rate of 0.15 lbs/MMBtu during the ozone season.

(2) The owner or operator of an affected electric generating unit subject to the provisions of this regulation shall continue to meet the ozone season NO_x reduction requirements in COMAR 26.11.27.

(3) Ownership of Single Electric Generating Facility.

(a) An affected electric generating unit is not subject to B(1) if the unit is located at an electric generating facility that is the only facility in Maryland directly or indirectly owned, operated or controlled by the owner, operator or controller of the facility.

(b) For the purposes of §B(3) of this regulation, the owner includes parent companies, affiliates and subsidiaries of the owner.

C. Annual NO_x Reduction Requirements. The owner or operator of an affected electric generating unit subject to the provisions of this regulation shall continue to meet the annual NO_x reduction requirements in COMAR 26.11.27.

D. NO_x Emission Requirements for Affected Electric Generating Units Equipped with Fluidized Bed Combustors.

(1) The owner or operator of an affected electric generating unit equipped with a fluidized bed combustor is not subject to the requirements of §§A, B(1), B(2) and C of this regulation.

(2) The owner or operator of an affected electric generating unit equipped with a fluidized bed combustor shall not exceed a NO_x 24-hour block average emission rate of 0.10 lbs/MMBtu.

.04 Compliance Demonstration Requirements.

A. Procedures for demonstrating compliance with §.03(A) of this chapter.

(1) An affected electric generating unit shall demonstrate, to the Department's satisfaction, compliance with §.03(A)(2) of this chapter, using the information collected and maintained in accordance with §.03(A)(1) of this chapter and any additional documentation available to and maintained by the affected electric generating unit.

(2) An affected electric generating unit shall not be required to submit a unit-specific report consistent with §A(3) of this regulation when the unit emits at levels that are at or below the following rates:

Affected Unit	24-Hour Block Average NO _x Emissions in lbs/MMBtu
Brandon Shores	
Unit 1	0.08
Unit 2	
< 650 MWg	0.07
≥ 650 MWg	0.15
C.P. Crane	
Unit 1	0.30
Unit 2	0.28
Chalk Point	
Unit 1 only	0.07
Unit 2 only	0.33
Units 1 and 2 combined	0.20
Dickerson	
Unit 1 only	0.24
Unit 2 only	0.24
Unit 3 only	0.24
Two or more Units combined	0.24
H.A. Wagner	

Unit 2	0.34
Unit 3	0.07
Morgantown	
Unit 1	0.07
Unit 2	0.07

(3) The owner or operator of an affected electric generating unit subject to §.03(A)(2) of this chapter shall submit a unit-specific report for each day the unit exceeds its NOx emission rate of §A(2) of this regulation, which shall include the following information for the entire operating day:

- (a) Hours of operation for the unit;
- (b) Hourly averages of operating temperature of installed pollution control technology;
- (c) Hourly averages of heat input (MMBtu/hr);
- (d) Hourly averages of output (MWh);
- (e) Hourly averages of Ammonia or urea flow rates;
- (f) Hourly averages of NOx emissions data (lbs/MMBtu and tons);
- (g) Malfunction data;
- (h) The technical and operational reason the rate was exceeded, such as:
 - (i) Operator error;
 - (ii) Technical events beyond the control of the owner or operator (e.g. acts of God, malfunctions); or
 - (iii) Dispatch requirements that mandate unplanned operation (e.g. start-ups and shut-downs, idling and operation at low voltage or low load);
- (i) A written narrative describing any actions taken to reduce emission rates; and
- (j) Other information that the Department determines is necessary to evaluate the data or to ensure that compliance is achieved.

(4) An exceedance of the emissions rate of §A(2) of this regulation as a result of factors including but not limited to start-up and shut-down, days when the unit was directed by the electric grid operator to operate at low load or to operate pursuant to any emergency generation operations required by the electric grid operator, including necessary testing for such emergency operations, or to have otherwise occurred during operations which are deemed consistent with the unit's technological limitations, manufacturers' specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions, shall not be considered a violation of §.03A(2) of this chapter provided that the provisions of the approved plan as required in §.03A(1) of this chapter are met.

B. Procedures for demonstrating compliance with NOx emission rates of this chapter.

(1) Compliance with the NOx emission rate limitations in §§.03B(1), .03D(2), and .04A(2) of this chapter shall be demonstrated with a continuous emission monitoring system that is installed, operated, and certified in accordance with 40 CFR Part 75.

(2) For §.03B(1) of this chapter, in order to calculate the 30-day system-wide rolling average emission rates, if twenty-nine system operating days are not available from the current ozone season, system operating days from the previous ozone season shall be used.

.05 Reporting Requirements.

A. Reporting Schedule.

(1) Beginning 30 days after the first month of the ozone season following the effective date of this chapter, each affected electric generating unit subject to the requirements of this chapter shall submit a monthly report to the Department detailing the status of compliance with this chapter during the ozone season.

(2) Each subsequent monthly report shall be submitted to the Department not later than 30 days following the end of the calendar month during the ozone season.

B. Monthly Reports During Ozone Season. Monthly reports during the ozone season shall include:

(1) Daily pass or fail of the NO_x emission rates of §.04A(2) of this chapter.

(2) The reporting information as required under §.04A(3) of this chapter.

(3) The 30-day system-wide rolling average emission rate for each affected electric generating unit to demonstrate compliance with §.03B(1) of this chapter.

END NEW MATTER

III. The Analyses

In preparation for the development of the required SIPs, the Department performed a number of technical analyses regarding the level of emissions over time, the level of controls already installed both in Maryland and surrounding states, and modeling analyses predicting the ozone levels expected from a controlled level of emissions. These analyses suggested strategies for Maryland's attainment SIP and appropriate levels of control for the coal-fired electric generating sector that would also satisfy the RACT requirements for the 2008 ozone standard, and address the new proposed ozone standard. The relevant analyses are presented in this chapter with supporting data included in the Appendices.

A. Peak Day Electricity Generation and High NO_x Emissions

The Department has engaged in extensive analysis of NO_x emissions data from electric generating units to determine how well previously installed controls were operating for Maryland and a number of other states. In many cases, the rate of NO_x emissions indicated the controls were not operating or were not operating optimally. While all of the coal-fired electric generating units (EGUs or units) in Maryland comply with the HAA, the annual and ozone season caps do not require all units to consistently run emission controls each day and meet a specified emissions rate. This is problematic during "peak days" or episodic air quality events when high temperatures trigger high electricity demand and elevated ozone pollution levels.

NO_x emission data analysis indicates that compliance with the HAA annual and ozone season caps through system-wide averaging has not effectively limited daily NO_x emissions during certain peak days. For economic purposes, companies use systems to minimize operating costs. In a system, one or more of the highly utilized units will be over-controlled while less well controlled units operate without using controls. This allows the company to comply with current regulations but results in higher NO_x emissions on days conducive to ozone formation and leads to higher ozone levels. On these days, optimal use of pollution controls on every unit is needed to keep ozone levels below the standard.

The proposed regulations have a new 0.15 lb/MMBTU NO_x rate averaged on a 30-day rolling average will take effect for the Raven Power and NRG systems. At the same time, the requirements to run installed controls at all times and minimize NO_x emissions will begin.

B. 2015 NO_x Emission Control Requirements - Emission Reduction Estimates

Coal-fired electric generating units in Maryland have accounted for more than 80 percent of the State's power plant NO_x emissions. The Department projects that the implementation of the requirements of Regulation .03 will result in an estimated daily NO_x emission reduction of 25 percent, or 9 tons/day from the average level of 36 tons/day, provided ownership of the two existing systems does not change. This projected reduction is based on data from 2011 through 2013³. Additional emission reductions should be realized on peak days as the NO_x emission rate optimization requirements from Regulation .03A(2) will ensure improved performance from units that traditionally have operated only on high electricity demand days and often without controls. Reducing locally produced NO_x on peak days limits ozone production, keeping local ozone levels lower.

³Calculations for the 2015 NO_x Emission Reduction Estimates in the regulation can be found in Appendix G.

As stated earlier, the Baltimore Nonattainment Area is required to prepare a State Implementation Plan that includes the reduction strategies, modeling analyses and other evidence demonstrating that these reduction strategies will achieve compliance with the 0.075 ppm ozone standard in the Baltimore nonattainment area. EPA has selected 2011 as the base year for these analyses and the Department has performed extensive analyses on data from this year. The 2011 ozone season was a fairly typical summer with 29 ozone exceedance days and the highest 8-hour ozone average of 114 ppb. The 2013 and 2014 ozone seasons were very mild with 9 and 5 exceedance days, respectively, and the highest 8-hour ozone average of 81 ppb in 2014. Examples of peak day emissions from Maryland coal-fired units during the summers of 2011 and 2014 are illustrated below.

NO_x emissions on peak days in 2011 ranged from 43-62 tons per day. Ozone exceedances were widespread on each of the illustrated days affecting 12-17 monitors across the state. The maximum 2011 ozone values occurred on June 8 (114 ppb), June 9 (106 ppb), June 10 (98 ppb), July 2 (107 ppb) and July 7 (94 ppb).

NO_x emissions on peak days in 2014 ranged from 34-44 tons per day. Fewer ozone exceedance days occurred in 2014. On each of the 2014 illustrated days only one monitor was affected. The maximum ozone values on June 16, and June 17 were 81 ppb and 80 ppb, respectively.

Figure 3: EGU NO_x Emissions (Peak Day) – Summer 2011

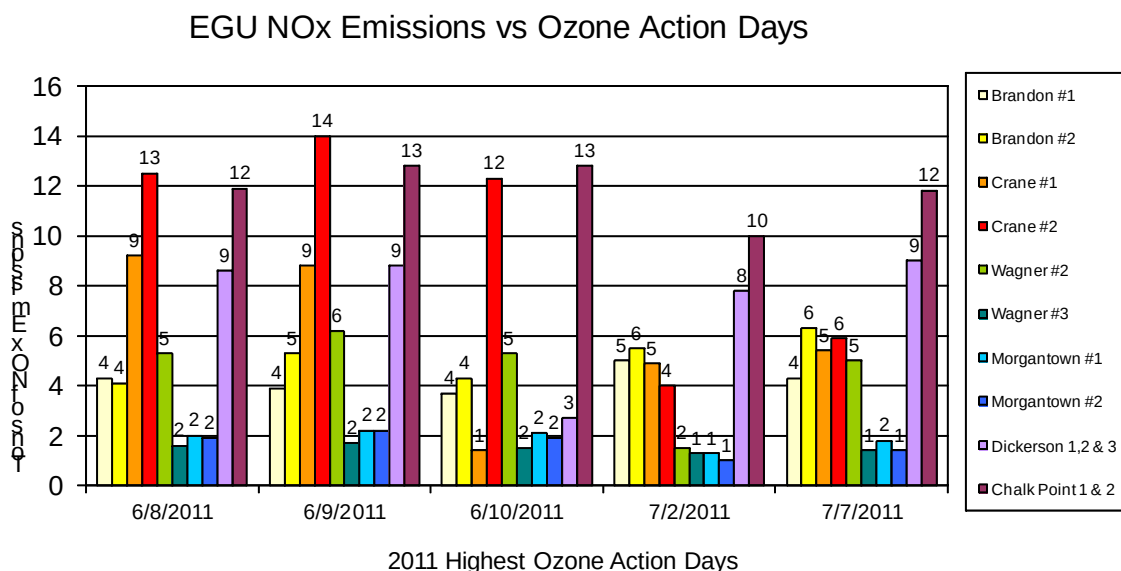
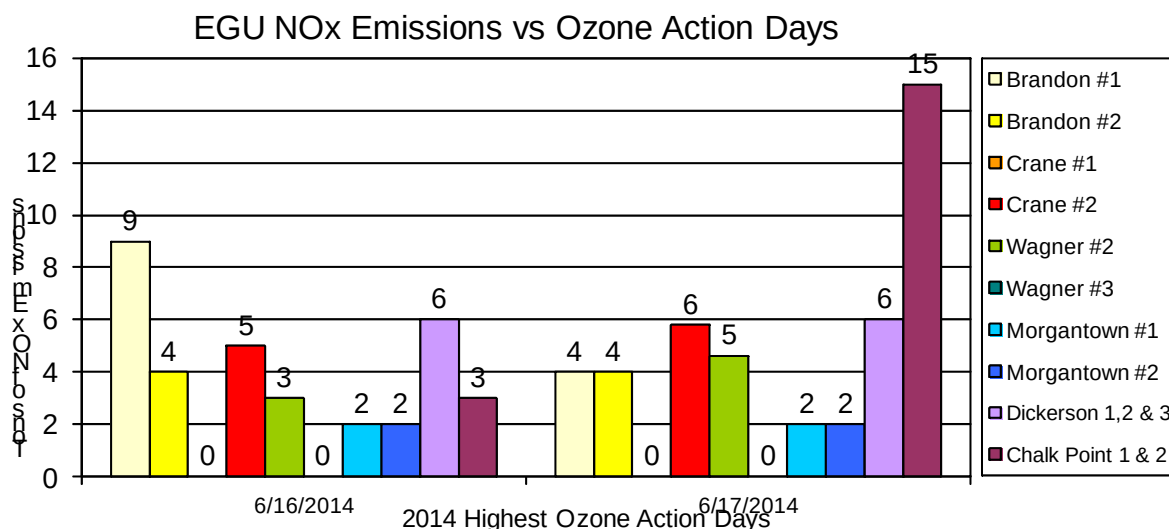


Figure 4: EGU NO_x Emissions (Peak Day) – Summer 2014



Historical performance of 24-hour block (daily) NO_x emission rates have been reviewed by the Department. (See Appendix C – 24 Hour Block Rate) The proposed regulation requires compliance demonstrations for the 24-hour block indicator rates as detailed under Chapter IV of this document.

Comparison of NO_x emissions from example exceedance days from a typical summer, 2011, and a much milder summer, 2014, illustrates the difference in NO_x contributions from units equipped with SCR controls and units equipped with SNCRs. The Brandon Shores units and Morgantown units are all equipped with SCR. Wagner Unit 3 and Chalk Point Unit 1 also have SCR controls. The other units all have SNCR controls. In the 2011 examples, all units are operating to meet higher electricity demand. The units with the highest emissions are almost always the units equipped with SNCR. On average, units equipped with SNCR produce half the total emissions for peak days. Yet these units are smaller and produce only half as much electricity as those equipped with SCR. In the examples from 2014, one Crane unit and one Wagner unit did not run. Emissions from SNCR controlled units still contributed over 40% of the total NO_x emissions. Even though collectively the total NO_x emissions from units with SCRs are similar to the total NO_x emissions from units with SNCRs, the generating capacity of the units with SNCR is only one third the generating capacity of the units with SCR. So on high ozone days, less well-controlled units double local NO_x emissions. During milder episodes, the less well-controlled units contribute about 40% more NO_x emissions.

During both ozone seasons, the ozone season average NO_x rate for the individual units are very close to the indicator rates established for the units in Regulation .05. Peak day NO_x rates can be very different. The NO_x minimization requirements will stabilize the rates and reduce emissions on peak days.

C. Modeling

The Department participates in regional and local modeling efforts to design and evaluate the impacts of various policy and technology options⁴. The Department collaborates with University of Maryland researchers and the Ozone Transport Commission Modeling Committee to prepare

screening scenarios for various NO_x emission reduction strategies that can be employed in the future. Some preliminary modeling analyses have been completed with existing inventories. The final modeling analyses using all the latest inventories and models will be completed and more fully described in the Attainment SIP. Various emission factors have been assumed for electric generating units, including the coal-fired units under this regulation, as well as states upwind of Maryland that contribute to the transport of ozone⁵.

Comprehensive Air Quality Model with Extensions (CAMx) modeling is used to track the contribution of specific sources on ozone formation. Preliminary modeling results using CAMx have shown that local emissions contribute about 30% to the ozone problem in nonattainment areas in Maryland. These preliminary findings support the need for additional substantive NO_x reductions in Maryland.

Community Multi-Scale Air Quality Modeling System (CMAQ) modeling simulates the formation and distribution of ozone over the Eastern U.S. The Department performed preliminary modeling using CMAQ to estimate the impact on air quality of the operation of existing controls. The preliminary modeling results indicated that the disbenefit of EGUs across the eastern U.S., including those in Maryland, running without the installed controls was about 1-2 parts per billion (ppb) ozone. In other words, consistently operating installed controls on coal-fired units could reduce ozone levels by approximately 1-2 ppb.

⁴Appendix E Ozone Transport Commission RACT Statement

⁵Appendix I describes Proposal for a Collaborative Solution to the Ozone Transport Problem

D. The Effectiveness of NO_x Reductions

The following is a White Paper Prepared by the Maryland Department of the Environment & University of Maryland College Park, December 2014

The Effectiveness of NO_x Reductions When it Comes to Reducing Ozone Concentrations

December 2014

This white paper presents observational evidence of the response of ambient ozone (O₃) to nitrogen oxides (NO_x) emissions. In the eastern US, natural biogenic sources usually dominate hydrocarbon reactivity, making NO_x the limiting precursor to ozone. NO_x emissions from the two major categories, point sources (mostly EGUs) and mobile sources (motor vehicles), have decreased dramatically over the past two decades. Surface concentrations of NO_x have decreased correspondingly. Surface ozone concentrations also have decreased, but more irregularly, due the dependence of ozone formation on meteorology as well as to emissions of precursors. From the causal relationships of ambient O₃, NO_x concentrations, and NO_x emissions, we can estimate the increase in ambient ozone concentrations due to not running NO_x controls (i.e., SRCs) during the summer ozone season.

Based on data obtained from the NASA DISCOVER-AQ field campaign over Maryland, it was observed that there was 4 to 8 ppb O₃ produced per ppb NO_x consumed, well within the range of

1-20 for other observations over the continental US (Jacob, 2004). This means that for each 100 tons/d increase in NO_x emissions we can expect ~0.5 to 1.0 ppb increase in ozone [*He et al.*, 2013a; *He et al.*, 2013b]

Figure 1 indicates that observed ambient ozone and NO_x over the Baltimore/Washington area decreased from 1997-2010 (*He et al.*, 2013). Interannual variability responds to a combination of emissions and weather – the greater the number of days with a maximum temperature over 90°F the greater the number of days with an ozone exceedances – but the long-term trend is driven by decreased NO_x (and possibly to some degree VOC) emissions. Using estimates for the three most recent years helps strengthen the statistical significance the long-term decrease in ozone. NO_x concentrations plummeted after 2003, but have shown little decrease since 2010. In conclusion, the observations verify the predictions from chemical transport models – if NO_x emissions revert to levels seen in previous years, ozone concentrations are likely to rise. Other factors held constant, every increase of 100 tons NO_x per day will potentially lead to approximately a 1 ppb ozone increase.

Additional UMD research indicates that from the 1970's thru the early 2000's Maryland's air quality responded to both VOC and NO_x reductions. This has now changed and it can be seen that since the mid-2000's that Maryland has transitioned into a NO_x limited regime, NO_x reductions now provide a greater benefit in reducing ozone levels in Maryland (*Hosley, et al.*, 18 January 2013).

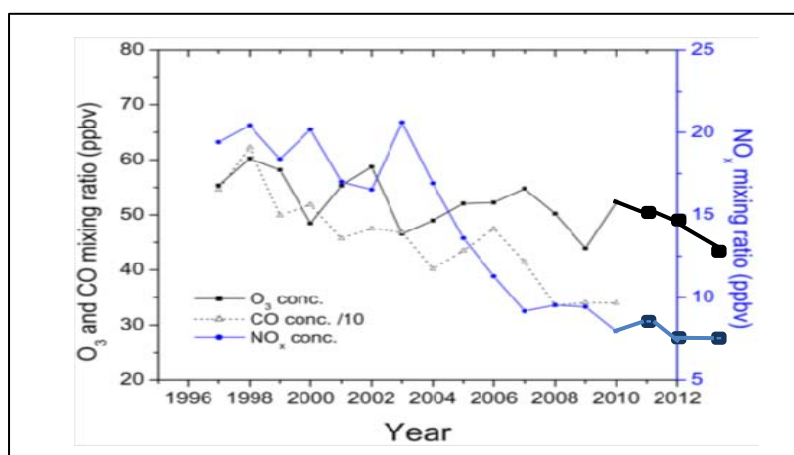


Figure 1, Trends in trace gas concentrations. Taken from *He et al.*, (2013b), these observations show the temporal trends and relationship of O₃, NO_x, and CO. Measurements from 1200-1800 LT in the ozone season are shown. Data for 2011-2013 are estimates added for this report, after the original publication in *ACP*. The inter-annual variability, especially for ozone, is subject to changes in the number of hot days, but ozone and oxides of nitrogen have fallen together over the long run.

Based on the UMD research presented it can clearly be determined that Maryland has reached a point where continued NO_x reductions will result in greater ozone reductions than has been seen in the past.

References

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<http://acmg.seas.harvard.edu/people/faculty/djj/book/>
- He, H., L. Hembeck, K. M. Hosley, T. P. Canty, R. J. Salawitch, and R. R. Dickerson (2013a), High ozone concentrations on hot days: The role of electric power demand and NO_x emissions, *Geophysical Research Letters*, 40(19), 5291-5294.
- He, H., et al. (2013b), Trends in emissions and concentrations of air pollutants in the lower troposphere in the Baltimore/Washington airshed from 1997 to 2011, *Atmospheric Chemistry and Physics*, 13(15), 7859-7874.
- Hosley, K, T. Canty, H. He, R. Salawitch, et al., Surface Ozone and Emission Trends Power Point, 18 January 2013.

IV. Regulation Requirement Details for Operating and Compliance

A. Affected Sources

The proposed regulation applies to the following 14 coal-fired electric generating units currently operating in Maryland, which account for most of the State's power plant NO_x emissions:

- Brandon Shores Generating Station (Units 1 and 2);
- C.P. Crane Generating Station (Units 1 and 2);
- H.A. Wagner Generating Station (Units 2 and 3);
- Chalk Point Generating Station (Units 1 and 2);
- Morgantown Generating Station (Units 1 and 2);
- Dickerson Generating Station (Units 1, 2 and 3); and
- Warrior Run Generating Station.

B. NO_x Reduction Requirements

The proposed regulation is part of an overall strategy to significantly reduce NO_x emissions from coal fired electric generating units (EGUs) in the State by requiring owners and operators of affected EGUs to comply with certain requirements and standards in the regulation by specific dates. These coal-fired electric generating units remain subject to Maryland's Healthy Air Act as implemented in COMAR 26.11.27, as well as all applicable federal regulations.

The requirements specified in the regulation include the following: May 1, 2015 and beyond

- **NO_x Emission Control Technology - Operating Pollution Controls:** For each operating day during the ozone season (beginning May 1, 2015), affected units must minimize NO_x emissions by operating and optimizing the use of all installed pollution control technologies and combustion controls consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 C.F.R. § 60.11(d)) for such equipment and the unit at all times the unit is in operation while burning any coal.

This is a stand-alone requirement that will require the owner or operator of a coal-fired electric generating unit to submit a plan to MDE demonstrating how the unit will operate installed pollution control technology as required in the regulation. The plan is due no later than 45 after the effective date of the regulation⁶.

⁶ See Appendix H – Compliance Plan.

- **System-Wide NO_x Emission Standard:** The regulations will require owners or operators of two or more units to demonstrate compliance by meeting a system-wide ozone season NO_x emission rate of 0.15 lbs/MMBtu as a 30-day rolling average. The rationale for the NO_x emission rate (0.15 lbs/MMBtu) was based upon data derived from the Clean Air Markets Division (CAMD) for coal units operating in 2011 – 2013 and upon the findings that no unit equipped with an SNCR control system in Maryland has demonstrated the ability to achieve a 0.15 lbs/MMBtu NO_x rate. Therefore the 0.15 lbs/MMBtu NO_x emission rate limits the capacity or operation of the SNCR units in the system.

- **Annual and Ozone Season NO_x Reductions:** The regulations will require that owners or operators of coal-fired electric generating units continue to meet the ozone season and annual NO_x reduction requirements set forth in COMAR 26.11.27 (*Emission Limitations for Power Plants*). Units with fluidized bed combustion technology must meet a NO_x emission rate of 0.10 lbs/MMBtu as a 24-hour block average on an annual basis. AES Warrior Run is currently the only unit that utilizes a fluidized bed combustion boiler which operates at lower temperatures compared to other coal-fired boiler technology, suppressing NO_x formation and lowering NO_x emissions. The plant has operated at or below the 0.10 lbs/MMBtu NO_x emission rate since it commenced operations in 2000.
- **Compliance Demonstration – Indicator Rates (24-Hour Block Average NO_x Emission Rate):** Coal-fired electric generating units are required to submit a plan to MDE for approval that demonstrates how the unit will operate the pollution and combustion controls. Coal-fired electric generating units are required to submit a unit-specific report whenever the unit emits at levels above the following unit-specific 24-Hour Block Average NO_x Emission rates:

Table IV-1: Compliance Demonstration - Indicator Rates (24-Hour Block Average NO_x Emission Rate)

Affected Coal-Fired Electric Generating Unit	24-Hour Block Average NO _x Emission Rate in lbs/MMBtu
Brandon Shores	
Unit 1	0.08
Unit 2 < 650 MWg ≥ 650 MWg	0.07 0.15
Rationale For NO _x Emission Rates: Brandon Shores Units 1 and 2 are equipped with SCR control technology. The 0.08 lbs/MMBtu NO _x rate for Brandon Shores Unit 1 was developed with consideration given to the technological limitation that exists with the ESP being upstream of the SCR, making it more challenging for the SCR to reach reaction temperature. Brandon Shores Unit 2 has simulated over fire air technology and side wall burners. The 0.07 lbs/MMBtu NO _x rate was based upon a comprehensive review of literature on SCR installations and represents emission rates associated with state-of-the-art SCR technology at coal units in 2013. Operation of the Brandon Shores Unit 2 boiler above 650 MWg produce NO _x at a higher rate. Considering limitations of the Unit 2 SCR reagent injection system, the NO _x rate for this operating range was increased to 0.15 lbs/MMBtu.	
C.P. Crane	
Unit 1	0.30
Unit 2	0.28
Rationale For NO _x Emission Rates: C.P. Crane Units 1 and 2 are equipped with SNCR control technology.	

The 0.30 and 0.28 lbs/MMBtu NO_x rates were calculated using CEMS data from CAMD (2010, 2011, and 2012) and applying a 35% control efficiency to the 80th percentile of the NO_x rates for the given years. These limits were supported by 2014 Summer Study Data.

Chalk Point	
Unit 1 only	0.07
Unit 2 only	0.33
Units 1 and 2 combined	0.20

Rationale for NO_x Emission Rates: Chalk Point Units 1 and 2 share a common stack. Unit 1 is equipped with an SCR, with the rate set to SCR achievable rate. Unit 2 is equipped with an SACR. The 0.07 lbs/MMBtu NO_x rate for Unit 1 is based upon a comprehensive review of literature on SCR installations and represents emission rates associated with state-of-the-art SCR technology at coal units in 2013. The 0.33 lbs/MMBtu NO_x rate for Unit 2 is based 2014 Summer Study data. The 0.20 lbs/MMBtu NO_x rate for Units 1 and 2 combined was calculated by averaging the NO_x emission rates of units 1 and 2.

Dickerson	
Unit 1 only	0.24
Unit 2 only	0.24
Unit 3 only	0.24
Two or more Units combined	0.24

Rationale for NO_x Emission Rates: Dickerson Units 1, 2, and 3 share a common stack. All three units are equipped with SNCR control technology. The 0.24 lbs/MMBtu NO_x rates were based on 2014 Summer Study data.

H.A. Wagner	
Unit 2	0.34
Unit 3	0.07

Rationale for NO_x Emission Rates: H. A. Wagner Unit 2 is equipped with SNCR control technology. The 0.34 lbs/MMBtu NO_x rate for Unit 2 was based on 2014 Summer Study data. H. A. Wagner Unit 3 is equipped with SCR control technology. The 0.07 lbs/MMBtu NO_x rate for Unit 3 is based upon a comprehensive review of literature on SCR installations and represents emission rates associated with state-of-the-art SCR technology at coal units in 2013.

Morgantown	
Unit 1	0.07

Unit 2	0.07
Rationale for NO _x Emission Rates: The 0.07 lbs/MMBtu NO _x rate for Units 1 and 2 is based upon a comprehensive review of literature on SCR installations and represents emission rates associated with state-of-the-art SCR technology at coal units from 2013.	

- **Unit-Specific Reporting:** The regulations include a requirement for coal-fired electric generating units to submit a report to MDE for each day that exceeds the unit-specific 24-hour block average NO_x emission rates in Table IV-1. Each unit specific report submitted to MDE should include the hours of operation, the operating temperature of the control unit, the heat input, the MW output, reagent (ammonia or urea) flow rates, NO_x emission data, malfunction data, reason for the exceedance, and a description of steps or actions taken to return to compliance. MDE may also request additional information regarding any exceedance of the unit-specific 24-hour block rate that it determines is necessary to evaluate the data or ensure compliance is achieved.
- **Reporting Requirements:** The regulation includes specific monthly reporting requirements for owners and operators of coal-fired electric generating units to demonstrate compliance with the requirements of the regulation.

V. Economic Analysis

A. Summary of Compliance Cost Estimates

A review of factors affecting the cost of compliance is presented in this section. The new regulation provides flexibility for affected sources. An analysis of the 2015 NO_x requirements is discussed below.

2015 NO_x Emission Control Requirements (May 1, 2015).

As a result of prior regulations such as the Healthy Air Act (HAA), all of the coal-fired generating units in the State are equipped with NO_x pollution control technology – such as SCR, SNCR, and SACR. Compliance with the 2015 NO_x emission control requirements will require all coal-fired electric generating units to operate and optimize both NO_x pollution and combustion controls during the ozone season to minimize NO_x emissions. MDE estimates that the annual cost of operating and optimizing NO_x pollution controls ranges from \$430,000 to \$4.3 million (2014 dollars) on a per unit basis.

B. Assumptions.

There are no new control technologies required for this action. Companies must optimize their existing control equipment to meet the 2015 requirements. The annual operating and maintenance cost for a single unit can range from \$430,000 to \$4.3 million. Optimization of the operation of the existing controls may push annual operating and maintenance costs toward the high end of the estimates or even add some additional costs but the exact additional cost if any cannot be determined at this time.

VI. Background Information – Ozone Pollution

A. Background

Ground-level ozone is formed when a mixture of common air pollutants react in heat and strong sunlight. The main ozone-causing pollutants are nitrogen oxides (NO_x) from fuel burning sources like power plants and automobiles and volatile organic compounds (VOCs) from sources such as gasoline, paints, inks and solvents. These two categories of pollutants are also referred to as ozone precursors. The formation of ozone is dependent on weather conditions such as temperature, the amount of sunlight, and wind direction and speed. Because sunlight and high temperatures function as catalysts to form ozone, the problem is seasonal, with the ozone season lasting from May through September in the Baltimore and Washington Region. Typically, ozone levels escalate rapidly around noontime, peak in the afternoon and decline when the sun sets.

B. Effects of Ground Level Ozone

Exposure to ozone has been linked to a number of health effects, including significant decreases in lung function, inflammation of the airways, and increased respiratory symptoms, such as coughing and pain when taking a deep breath. Exposure can also aggravate lung diseases such as asthma, leading to increased medication use and increased hospital admissions and emergency room visits. Active children are the group at highest risk from ozone exposure because they often spend a large part of the summer playing outdoors. Children are also more likely to have asthma, which may be aggravated by ozone exposure. Other at-risk groups include adults who are active outdoors (e.g., some outdoor workers) and individuals with lung diseases such as asthma and chronic obstructive pulmonary disease. In addition, long-term exposure to moderate levels of ozone may cause permanent changes in lung structure, leading to premature aging of the lungs and worsening of chronic lung disease.

Ozone also affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields, reduced growth and survivability of tree seedlings, and increased plant susceptibility to disease, pests, and other environmental stresses (e.g., harsh weather). In long-lived species, these effects may become evident only after several years or even decades of exposure and may result in long-term effects on forest ecosystems. Ground level ozone injury to trees and plants can lead to a decrease in the natural beauty of our national parks and recreation areas.

References

<http://www.epa.gov/airtrends/ozone.html>

VII. Overview of Relevant Federal, Regional and State Standards and Regulations

A. National Ambient Air Quality Standards (NAAQS)

NAAQS are public health and environment-based standards established by the U.S. EPA under the CAA, developed to protect the public health from the impacts associated with various forms of air pollution.

The CAA identifies two types of national ambient air quality standards. Primary standards provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. The Clean Air Act Amendments of 1990 (CAAA) established a process for evaluating air quality in each region and identifying and classifying nonattainment areas according to the severity of their air pollution problem.

In 1997, the U.S. EPA replaced the 1-hour ozone standard with an 8-hour standard of 0.08 ppm*. This revision was developed to take into consideration the long term exposure health effects of ozone versus the acute effects of ozone. The process of determining attainment status under the 8-hour standard was also changed. So an area would be in attainment with the 8-hour standard when the average of the annual 4th-highest daily maximum 8-hour ozone concentration averaged over three years is less than 0.08 ppm. In 2008, the U.S. EPA finalized a revision of the 8-hour ozone standard which set the 8-hour ozone standard at 0.075 ppm and kept the methodology for calculating exceedances of the 2008 ozone standard the same as the 1997 ozone standard.

*The Clean Air Act (CAA) requires the U.S. EPA to review the standards once every five years to determine whether revisions to the standards are appropriate.

Table VII-1: Ozone NAAQS from 1971 to Present

Final Rule/Decision	Primary/Secondary	Indicator	Averaging Time	Level (ppm)	Form
1971 36 FR 8186 Apr 30, 1971	Primary and Secondary	Total photochemical oxidants	1-hour	0.08 ppm	Not to be exceeded more than one hour per year
1979 44 FR 8202 Feb 8, 1979	Primary and Secondary	O ₃	1-hour	0.12 ppm	Attainment is defined when the expected number of days per calendar year, with maximum hourly average concentration greater than 0.12 ppm, is equal to or less than 1
1993 58 FR 13008 Mar 9, 1993	EPA decided that revisions to the standards were not warranted at the time				

1997 62 FR 38856 Jul 18, 1997	Primary and Secondary	O ₃	8-hour	0.08 ppm	Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years
2008 73 FR 16483 Mar 27, 2008	Primary and Secondary	O ₃	8-hour	0.075 ppm	Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years

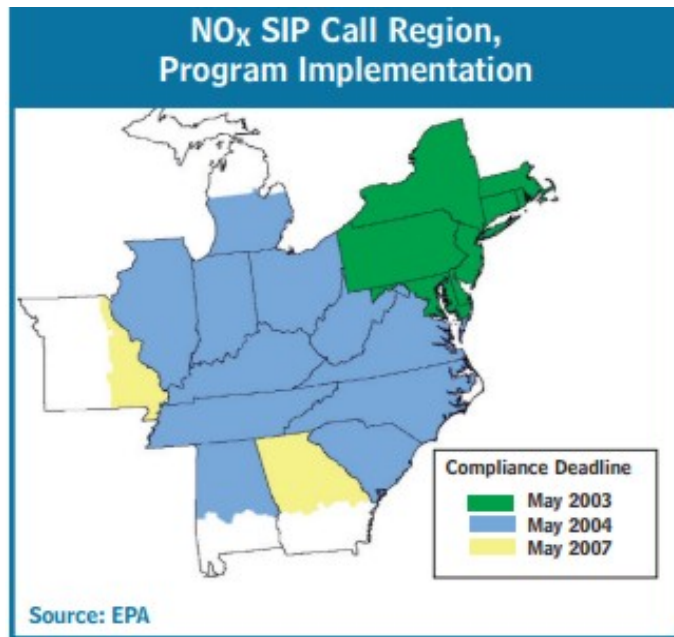
B. NO_x SIP Call

In 1998, the U.S. EPA finalized a federal rule called the NO_x SIP Call to reduce ozone transport in the Eastern United States. The regulation required 22 states and the District of Columbia to submit a state implementation plan (SIP) that addresses the regional transport of ground-level ozone. States that were subject to the regulation (Fig. 1) included Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, Wisconsin, and West Virginia in addition to the District of Columbia.

The regulation was designed to reduce regional NO_x 28 percent from 1996 emissions levels by 2007. States subject to the rule were provided the option of either developing their own SIPs to reduce NO_x (and other precursors) or adopting EPA's model program in the form of a Federal Implementation Plans (FIPs).

Maryland submitted revisions to the SIP to comply with this rule in 2000. The revisions to the SIP required adoption of two new chapters – COMAR 26.11.29 and 26.11.30 — relating to the NO_x Budget and Trading Program for stationary sources and for the State regulators. Maryland's budget program was based on the U.S. EPA's model NO_x Budget program, codified at 40 CFR Part 96. The Maryland NO_x Budget program establishes requirements for electric generating units (EGUs) and non-EGU combustion sources (i.e., industrial boilers greater than 250 MMBtu/hr rated capacity). The initial Maryland program specified ozone season allowance allocations for the years 2003 through 2007 for EGUs; Maryland subsequently revised the SIP to include allocations for 2008 and 2009. Maryland EGUs received allocations of allowances that were far lower than their emissions at that time. Affected sources could control or buy allowances from those sources that over-controlled throughout the region. The U.S. EPA approved Maryland's SIP to comply with Phase I of the NO_x SIP Call and published it in the Federal Register on January 10, 2001. Subsequently, in November 2006, the U.S. EPA approved a revision to the Maryland SIP to include allocations for the year 2008. Allocations for the years 2009 through 2014 were made as a part of the State's plan to comply with the federal CAIR.

Fig. 5: States Covered Under the NO_x SIP Call Region

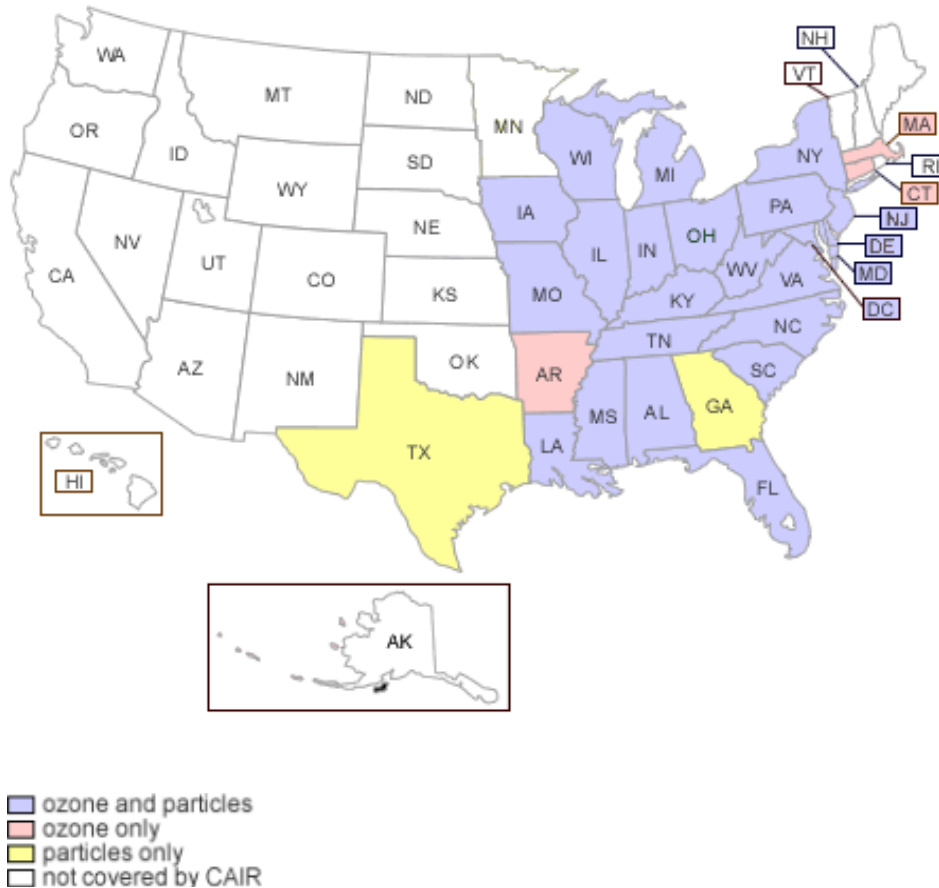


Source: U.S. EPA - <http://www.epa.gov/airmarkt/progsregs/nox/sip.html>

C. Clean Air Interstate Rule (CAIR)

In 2005, the U.S. EPA issued CAIR, which caps emissions of SO₂ and NO_x in the eastern United States. The rule which replaced the NO_x SIP Call, assigns each state an emissions budget and requires states to achieve certain emissions reductions to meet those budgets by using one of two compliance options. The first option is to have the state meet its emissions budget by requiring power plants to participate in an EPA administered interstate cap-and-trade program that caps emissions in two stages. The second option is to have states meet its budget through measures chosen by the states. CAIR sets emissions budgets for 27 eastern states and the District of Columbia. CAIR was later vacated by the U.S. Court of Appeals in 2008. Maryland opted to implement the HAA in addition to CAIR, but the HAA did not allow Maryland sources to meet their emission limitations by purchasing allowances.

Fig. 6: States Covered Under the Clean Air Interstate Rule (CAIR)



Source: US. EPA - <http://www.epa.gov/cair/where.html>

D. Maryland Healthy Air Act (HAA)

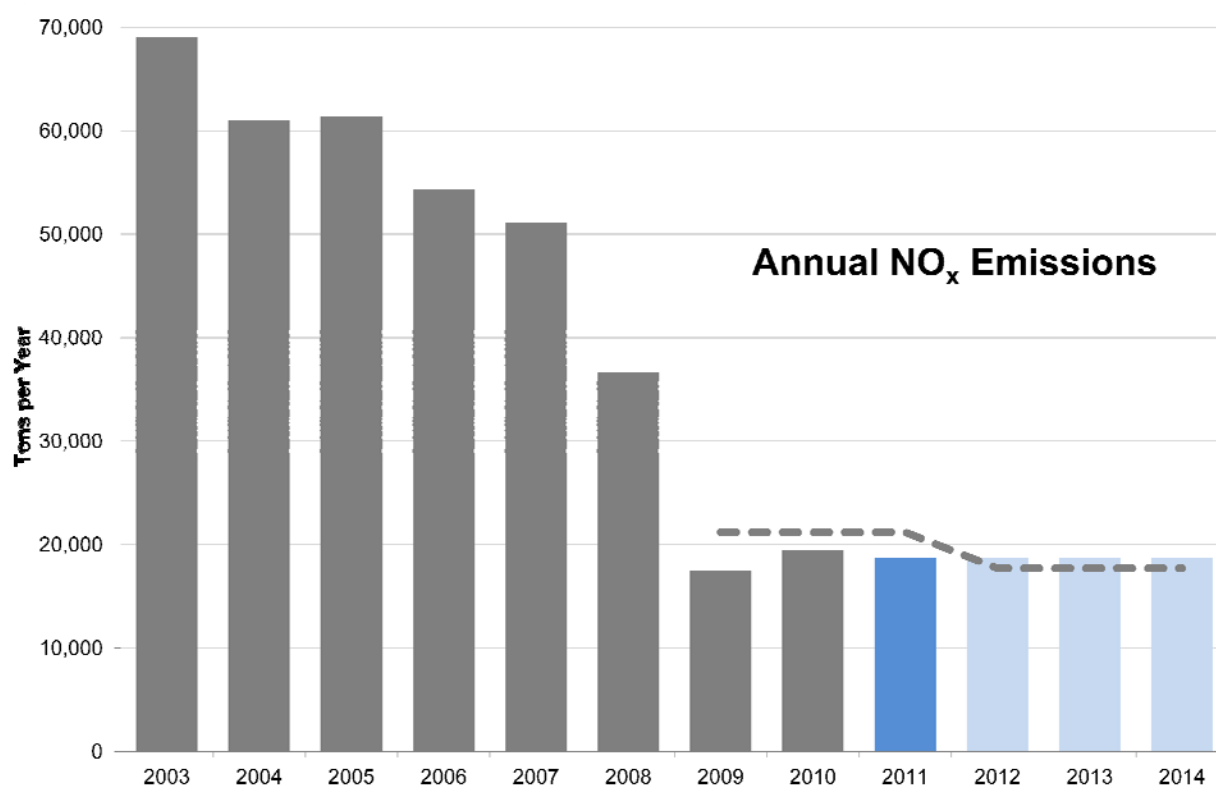
In 2006, the Maryland legislature passed the HAA, which was developed with the purpose of bringing Maryland into attainment with the NAAQS for ozone and fine particulate matter by the federal deadline of 2010. The act, which was widely applauded by the environmental community, was signed into law on April 6, 2006 and established new emission limitations for oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and mercury (Hg) on Maryland's largest coal-fired power plants. The HAA was the most significant control program ever implemented in Maryland.

The HAA was designed to make significant reductions in NO_x emissions through the application of mass limitations or caps on the affected coal-fired units. In addition, the HAA required that Maryland become involved in the Regional Greenhouse Gas Initiative (RGGI) which is aimed at reducing greenhouse gas emissions. The environmental community, electric companies, Maryland Public Service Commission, and the Maryland Department of Natural Resources

(DNR) among others worked with MDE as partners to design and implement the law, which led to almost \$2.6 billion investment for clean air by Maryland power plants. This investment included the installation of pollution controls on coal-fired electric generating units such as flue gas desulfurizers (FGDs), baghouses, hydrated limestone injection systems, SCRS, SNCRs, and powdered activation carbon (PAC) injection systems – within a 2-3 year window.

The requirements of the HAA were adopted as a state regulation on July 7, 2007 and codified as COMAR 26.11.27 – *Emission Limitations for Power Plants* in cooperation with the owners and operators of the State’s largest coal-fired power plants, requiring NO_x reductions by May 2009 (less than 2 years) and SO₂ and Hg reductions by January 2010 (less than 2½ years). The regulation used ozone-season and annual emission caps (Fig. 7) to drive very significant emission reductions of multiple pollutants such as NO_x (by more than 75 percent) - with all regulatory deadlines being met. See Appendix A for 2007 HAA Notice of Proposed Action.

Fig 7: Annual NO_x Emissions for Coal-Fired Units under the Healthy Air Act*



* The grey dotted line represents the cap for the Healthy Air Act - 21,190 tons beginning in 2009 and 17,714 tons beginning in 2012. The cap includes the R. Paul Smith Power Station, which was decommissioned in 2012. Source: Maryland Department of the Environment.

References

National Ambient Air Quality Standards (NAAQS), <http://www.epa.gov/air/criteria.html>
 Clean Air Act, <http://www.epa.gov/air/caa>

U.S EPA Acid Rain Program, <http://www.epa.gov/airmarkets/progsregs/arp/basic.html>
Overview of the Ozone Transport Commission (OTC) NO_x Budget Program,
<http://www.epa.gov/airmarkt/progsregs/nox/otc-overview.html>
NO_x Budget Trading Program/ NO_x SIP Call, 2003-2008,
<http://www.epa.gov/airmarkt/progsregs/nox/sip.html>
Clean Air Interstate Rule (CAIR), <http://www.epa.gov/cleanairinterstaterule>
The Maryland Healthy Air Act,
http://www.mde.md.gov/programs/Air/ProgramsHome/Pages/air/md_haa.aspx

VIII. Maryland Electric Generating Units

A. Coal-Fired Electric Generating Units Located In Maryland

An estimated two-thirds of in-state power is generated by electric generating units that are more than 30 years old and are approaching retirement. These electric generating units are often costlier to maintain, less efficient, and less environmentally friendly. The proposed regulation impacts the following coal-burning electric generating units in Maryland, which account for over 50 percent of the State's power plant NO_x emissions.

Table VIII-1: Coal-Fired Electric Generating Units Located In Maryland

ELECTRIC GENERATING UNIT	LOCATION
Raven Power	
Brandon Shores Generating Station 1 & 2	Anne Arundel County
H.A. Wagner Generating Station 2 & 3	Anne Arundel County
Charles P. Crane Generating Station 1 & 2	Baltimore County
NRG	
Chalk Point Generating Station 1 & 2	Prince George's County
Dickerson Generating Station 1, 2, & 3	Montgomery County
Morgantown Generating Station 1 & 2	Charles County
AES	
Warrior Run Generating Station	Alleghany County

Table VIII-2: Age of Certain Coal-Fired Electric Generating Units

Facility	Commenced Operations (Age of Unit)
H.A. Wagner*	Unit 2: 1959 (55 yrs old) Unit 3: 1966 (48 yrs old)
Charles P. Crane*	Unit 1: 1961 (53 yrs old) Unit 2: 1963 (51 yrs old)
Chalk Point †	Unit 2: 1965 (49 yrs old)
Dickerson†	Unit 1: 1959 (55 yrs old) Unit 2: 1960 (54 yrs old) Unit 3: 1962 (52 yrs old)

* Facilities operated by Raven Power

† Facilities operated by NRG

B. Brandon Shores Generating Station:



Plant profile: The Brandon Shores Generating Station is located in Northern Anne Arundel County, MD on a site adjacent to the Patapsco River. The facility which is operated by Raven Power and part of the Fort Smallwood Complex (which includes the H.A. Wagner Generating Station) is comprised of two 680 MW Babcock & Wilcox wall fired units with circular wall burners: Unit 1 which began operations in 1984 and, Unit 2 which began operations in 1991. Coal is received by barge, which is unloaded and transferred by a mile-long conveyor to onsite coal storage piles. Coal is fed from the coal pile to the plant storage bunkers via conveyor belts, after which the coal is pulverized and blown into the furnace.

Miscellaneous: Both units (Unit 1 and Unit 2) were designed to deliver steam to the turbine at 2400 psi and 1000 EF at a flow of 4,425,000 lbs/hr.

NO_x air pollution controls installed: Selective Catalytic Reduction (SCR) pollution control systems utilizing SmartProcess SCR Optimization Technology were installed on both units (Units 1 and 2) in 2002 at an estimated cost of approximately \$100M. Both Units 1 and 2 are equipped with hot-side electrostatic precipitators (ESPs). The hot-side ESP is upstream of the SCR and has a cooling effect on the flue gas entering the SCR. This results in higher NO_x emission rates at low load, when the cooling effect has a higher impact on the temperature of the gas entering the SCR. The SCR needs to reach a temperature close to 585°F to function efficiently.

Total Coal Capacity: 1,360 MW

C. H.A. Wagner Generating Station:



Plant profile: The H.A. Wagner Generating Station is located in Northern Anne Arundel County, MD on a site adjacent to the Patapsco River. The facility which is operated by Raven Power and part of the Fort Smallwood Complex (which includes the Brandon Shores Generating Station) consists of two coal burning Babcock & Wilcox units. Unit 2 is a coal-fired unit, nominally rated at 136 MW, which began operations in 1959. Unit 3 is a coal-fired unit, nominally rated at 359 MW, which began operating in 1966. Coal is received by barge, which is unloaded and transferred by a mile-long conveyor to onsite coal storage piles. Coal is fed from the coal pile to the plant storage bunkers via conveyor belts, after which the coal is pulverized and blown into the furnace.

Miscellaneous: Unit 2 is a Babcock & Wilcox dry bottom wall-fired boiler burning pulverized coal through 16 circular coal burners. The unit was designed to deliver steam to the turbine at 1800 psi and 1000 °F at a flow of 950,000 lbs/hr. Unit 3 is a Babcock & Wilcox supercritical, once through, cell burner boiler firing pulverized coal in 36 cell type coal burners in a three cell design. The unit was designed to deliver steam to the turbine at 3500 psi and 1050°F at a flow of 2,133,000 lbs/hr.

NO_x air pollution controls installed: Low NO_x burners are installed on both units. Unit 3 currently has an SCR (installed in 2003) for the control of NO_x emissions during the ozone season while Unit 2 utilizes a selective non-catalytic reduction system for the same purpose.

Total Coal Capacity: 495 MW

D. Charles P. Crane Generating Station:



Plant profile: The Charles P. Crane Generating Station is located in Bowleys Quarters, MD (Baltimore County) on the Middle River Neck Peninsula. The facility which is operated by Raven Power is comprised of two coal burning Babcock and Wilcox cyclone units: Unit 1, which is rated at 190 MW and began operations in 1961; and Unit 2, which is rated at 209 MW and began operations in 1963. Coal is supplied to the plant via dedicated rail and is stored adjacent to the plant. The coal is prepared for use by four crushers (per boiler) and is gravity-fed into the combustion chamber via mechanical conveyor.

Miscellaneous: Both Units 1 and 2 are fired by four cyclone burners with two cyclones located on the front and two located directly opposite on the rear side of the boiler (opposite fired).

NO_x air pollution controls installed: Both units are equipped with overfire air and selective non-catalytic reduction (SNCR) in the form of urea injection to control NO_x emissions, which was completed in 2009.

Total Coal Capacity: 399 MW

E. Morgantown Generating Station:



Plant profile: The Morgantown Generating Station is located in Newburg, MD (Charles County) on a site adjacent to the Potomac River. The facility which is owned and operated by NRG Energy is comprised of two 640 MW coal-fired T-fired units designed and manufactured by Combustion Engineering Inc. The two coal-fired units (Units 1 and 2) are base-loaded supercritical, combined circulation, tangentially-fired, twin furnace, balanced draft steam generators which went into operation in 1970 and 1971. Coal is currently delivered to Morgantown by CSX Transportation Corporation (CSXT) unit trains.

Miscellaneous: Each boiler has a steam flow rated at 4,250,000 lbs/hr and a pressure of 3500 psig. The rated steam flow has main and reheat steam temperatures of approximately 1000°F. There are five levels of coal burners and igniters at each of the eight corners for a total of forty burners and igniters per unit. In addition to the coal burners, there are four elevations of load-carrying oil burners or thirty two total per unit.

NO_x air pollution controls installed: The coal-fired units were retrofitted in the mid-1990s with low-NO_x burners (Low NO_x Concentric Firing System II in 1994) and an updated distributed control system (DCS). Both units are equipped with SCR pollution control systems to control NO_x emissions.

Total Coal Capacity: 1,280 MW

F. Chalk Point Generating Station:



Plant profile: The Chalk Point Generating Station is located in Eagle Harbor, MD (Prince Georges County) on a site adjacent to the Patuxent River. The facility which is owned and operated by NRG Energy is comprised of Units 1 and 2, which are coal-fired dry-bottom, wall-fired steam generating boilers rated at 364 MW each. The units were put into service in 1964 (Unit 1) and 1965 (Unit 2). Coal is delivered to the Chalk Point generating station by CSX Transportation trains via the Herbert Subdivision, a former Pennsylvania Railroad (PRR) line.

Miscellaneous:

Boiler emissions from Units 1 and 2 exit through a combined single 729-foot stack.

NO_x air pollution controls installed: A SCR control system on was installed on Unit 1 in 2008 and a Selective Auto Catalytic Reduction (SACR) control system was installed on Unit 2 in 2006.

Total Coal Capacity: 728 MW

*On December 2, 2013, PJM received a request to deactivate the coal-fired units by May, 2017.

G. Dickerson Generating Station:



Plant profile: The Dickerson Generating Station is located in Montgomery County, MD (near Dickerson, MD) on a site adjacent to the Potomac River. The facility which is owned and operated by NRG Energy has three coal-fired 190-MW units (Units 1, 2 and 3) that were constructed in 1959, 1960, and 1962. Each boiler is tangentially fired, with a superheater, reheat and economizer. The primary fuel for these boilers is coal with No.2 fuel oil used for ignition warm-up and flame stabilization purposes. All boiler emissions are directed to the common 700-foot stack during normal operations. Coal is delivered to the Dickerson Generating Station by CSX Transportation train.

Miscellaneous: Each boiler has four levels of burners with eight burners on each level for a total of 32 burners per boiler. Gases exiting the pollution control devices are collected in a common duct that exits through a 600 ft high common stack. When the common stack is out of service Units 1 and 2 use a common bypass stack while Unit 3 has its own bypass stack.

NO_x air pollution controls installed: Low-NO_x burners and separated overfire air (SOFA) have been installed on Units 1, 2, and 3 to reduce emissions of nitrogen oxides (NO_x). In addition, SNCR control systems were installed on Units 1, 2, and 3 in 2009.

Total Coal Capacity: 570 MW

*On December 2, 2013, PJM received a request to deactivate the coal-fired units by May, 2017.

H. Warrior Run Generating Station:



Plant profile: Warrior Run Generating Station is an electric cogeneration plant located Alleghany County, MD just south of Cumberland, MD. The facility which is owned by AES Corporation and commenced operations in 2000 is comprised of a 180 MW coal-fired circulating fluidized bed (CFB) boiler manufactured by ABB Combustion Engineering and a 150 ton per day food grade carbon dioxide production plant. The unit uses coal from nearby mines in Maryland and diesel oil as a backup and startup fuel.

NO_x air pollution controls installed: The plant features a type of boiler which is inherently well-controlled and low emitting design of fluidized bed boiler. The injection of ammonia and a selective non-catalytic reduction system are also used to remove nitrogen oxides.

Total Coal Capacity: 180 MW

I. NO_x Emissions Control Equipment on Affected Electric Generating Units

Nitrogen oxides (NO_x) are an acid rain precursor and a contributor to the formation of ground-level ozone, which is a major component of smog. In 2008, power plants accounted for 18 percent of the national NO_x emissions inventory (see Pg. 14 of NESCAUM report cited below). Most of the NO_x formed during the combustion process is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NO_x; and (2) oxidation of nitrogen that is chemically bound in the coal, referred to as fuel NO_x. Controlling NO_x emissions is achieved by controlling the formation of NO_x through combustion controls or by reducing NO_x after it has formed through post-combustion controls. The number of installations of post-combustion NO_x controls such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) systems increased between the periods of 1999 to 2009. This increase was largely driven by federal and state regulations. The following table summarizes the NO_x control equipment installed on coal-fired electric generating units in Maryland:

Table VIII-3: Summary of NO_x Control Equipment Installed on Coal-Fired EGU's in Maryland

Facility	Commenced Operations	Rated Capacity (MW)	Existing NO _x Controls
Raven Power			
Brandon Shores	Unit 1: 1984 Unit 2: 1991	Unit 1: 680 Unit 2: 680	Both units equipped with Selective Catalytic Reduction (SCR) utilizing SmartProcess SCR Optimization Technology.
H.A. Wagner	Unit 2: 1959 Unit 3: 1966	Unit 2: 136 Unit 3: 359	Both units equipped with low NO _x burners installed on both units; Unit 3 equipped with SCR; Unit 2 equipped with Selective Non-Catalytic Reduction (SNCR).
Charles P. Crane	Unit 1: 1961 Unit 2: 1963	Unit 1: 190 Unit 2: 209	Both units equipped with overfire air and SNCR.
NRG			
Chalk Point	Unit 1: 1964 Unit 2: 1965	Unit 1: 364 Unit 2: 364	Unit 1 equipped with SCR; Unit 2 equipped with Selective Auto Catalytic Reduction (SACR) pollution control technology.
Dickerson	Unit 1: 1959 Unit 2: 1960 Unit 3: 1962	Unit 1: 190 Unit 2: 190 Unit 3: 190	All units equipped with low-NO _x burners, separated overfire air (SOFA), and SNCR pollution control technology.
Morgantown	Unit 1: 1970 Unit 2: 1971	Unit 1: 640 Unit 2: 640	Both units equipped with low-NO _x burners and Selective Catalytic Reduction (SCR)
AES			
Warrior Run	2000	180	Unit features state-of-the-art fluidized bed boiler with low emissions; equipped with SNCR.

References

“NO_x SIP Call Rule — Impacts on Maryland and Surrounding States”, January 2009. Maryland Power Plant Research Program.

“Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants”, March 31, 2011. NESCAUM.

IX. Overview of NO_x Control Technologies for Coal-Fired Electric Generating Units

Combustion control is the initial method utilized for reducing NO_x emissions from boilers burning coal, oil, or natural gas. These control systems include low-NO_x burners and dry low-NO_x combustors, with the technology selected for a particular plant dependent on the required NO_x emissions limits and the specific fuel to be fired. To achieve greater NO_x emission reductions from fossil-fueled boilers, post combustion control technologies such as selective catalytic reduction (SCR) systems, selective non-catalytic reduction (SNCR) systems and selective autocatalytic reduction (SACR) systems are installed at coal-fired power plants. The following provides an overview of the various post combustion control technologies.

A. Selective Catalytic Reduction (SCR) Technology

Overview: Selective catalytic reduction (SCR) is a process for controlling emissions of nitrogen oxides from stationary sources. The basic principle behind the technology is the reduction of NO_x to nitrogen (N₂) and water (H₂O) by the reaction of NO_x and a reagent such as ammonia (NH₃) (or urea) within a catalyst reactor or chamber at operating temperatures ranging from 450-800°F. The stoichiometric reaction using either anhydrous or aqueous ammonia for a selective catalytic reduction process is:

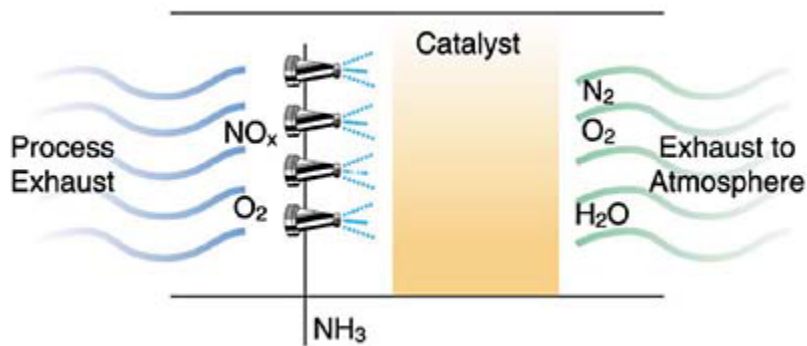
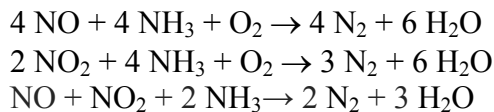
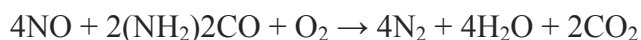


Fig 8: Illustration of the SCR Process

While the stoichiometric reaction for the use of urea instead of either anhydrous or aqueous ammonia is:



The technology, which was developed and patented by Engelhard Corporation in 1959, is used as a post-combustion system on utility and industrial boilers, gas turbines, process heaters, internal

combustion engines, chemical plants, and steel mills worldwide - capable of NO_x removal efficiencies between 75- 90 percent. The largest application of SCR technology is on coal-fired power plants with more than 300 coal-fired power plants having installed the technology over the last 15 years. The U.S. EPA estimates that between 2001 and 2005, the electric generation industry installed more than 96 GW (gigawatts) of SCR systems in response to the NO_x SIP Call. Coal-fired power plant operators installed an additional 20 GW of SCR systems from 2008 through 2010 in response to the Clean Air Interstate Rule (CAIR).

Table IX-1: Summary of Emission Control Technology Retrofit Options in EPA Base Case v4.10

Control Performance Options	Selective Catalytic Reduction (SCR)		Selective Non-Catalytic Reduction (SNCR)
Unit Type	Coal	Oil/Gas	Coal
Percent Removal	90% down to 0.06 lb/MMBtu	80%	Pulverized Coal: 35% Fluidized Bed: 50%
Size Applicability	Units ≥ 25MW	Units ≥ 25MW	Units ≥ 25MW

Source: U.S. EPA IPM Base Case v.4.10 - <http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter5.pdf>

The catalyst reactor or chamber is installed at a point where the temperature is in the range of about 600°F-700°F, normally placing it after the economizer and before the air-preheater of the boiler. Multiple layers of catalysts are generally used to increase the reaction surface and the catalyst is typically replaced every two to three years.

Advantages of Selective Catalytic Reduction (SCR) NO_x Pollution Control Technology:

- Higher NO_x reductions than other post-combustion NO_x pollution control technologies
- Applicable to sources with low NO_x concentrations
- Reactions occur at a lower and broader temperature range than selective non-catalytic reduction (SNCR).
- Does not require modifications to the combustion unit.

Disadvantages of Selective Catalytic Reduction (SCR) NO_x Pollution Control Technology:

- Significantly higher capital and operating costs than post-combustion NO_x pollution control technologies.
- Specific temperatures are required for selective catalytic reduction technology to function efficiently. Because of this, SCR does not operate at all times while electric generating units are in operation.
- Retrofitting certain industrial boilers with SCR may prove to be difficult and costly.
- Large volume of reagent and catalyst required.
- Selective catalytic reduction systems may require downstream equipment cleaning.
- May result in ammonia in the waste gas stream.

B. Selective Non-Catalytic Reduction (SNCR) Technology

Overview: Selective non-catalytic reduction (SNCR) is a chemical process for removing nitrogen oxides (NO_x) from flue gas. The process involves a reagent, typically urea or ammonia, which is injected into the hot flue gas – reacting with the NO_x , converting it to nitrogen gas and water vapor. Unlike selective catalytic reduction, no catalyst is required for this process. Instead, it is driven by the high temperatures, typically ranging from 1400 - 2100°F. SNCR performance depends on factors specific to each source, including flue gas temperature, available residence time for the reagent and flue gas to mix and react, amount of reagent injected, reagent distribution, uncontrolled NO_x level, and CO and O_2 concentrations. Coal-fired electric generating units in Maryland that are equipped with SNCR have experienced NO_x emissions reductions around 30 percent.

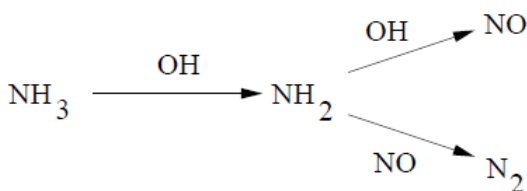


Fig. 9: Reaction Mechanism for the SNCR Process

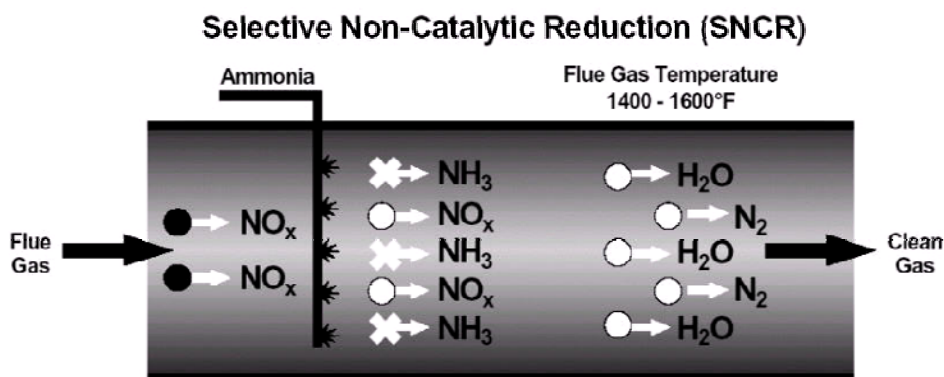


Fig. 10: Illustration of the SNCR Process

Advantages of Selective Non-Catalytic Reduction (SNCR) NO_x Pollution Control Technology:

- Capital and operating costs are among the lowest of all NO_x pollution control methods.
- Retrofitting units for SNCR is relatively simple and requires little downtime for large and medium size units.
- Cost effective for seasonal or variable load applications.
- Can be combined with other post-combustion controls to provide higher NO_x reductions.

Disadvantages of Selective Non-Catalytic Reduction (SNCR) NO_x Pollution Control Technology:

- The waste gas stream must be within a specified temperature range (1400-2100°F).
- Not feasible for units to operate SNCR if the temperature of the waste stream is below the specified temperature range (1400 - 2100°F).
- Not applicable to sources with low NO_x concentrations such as gas turbines.
- Lower NO_x emission reductions than selective catalytic reduction (SCR).
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility.

C. Selective Autocatalytic Reduction (SACR) Technology

Overview: Selective autocatalytic reduction (SACR) is a gas phase NO_x reduction process suitable for installation in a new boiler plant or retrofitting existing equipment. The process can be implemented as stand-alone or in combination with in-furnace NO_x reduction technologies, and is comprised of the autocatalytic reaction zone and injection grid. The NO_x removal efficiencies for units equipped with SACR are comparable to those attained by many SCR systems.

The key feature of the SACR process is the injection of ammonia based reagent and a hydrocarbon (e.g. natural gas, propane, etc) into the flue gas containing NO_x and some O₂. At elevated temperatures the hydrocarbon auto ignites, forming plasma and creating radicals. The radicals catalyze the NO_x reduction reactions – with the resulting flue gas containing reduced amounts of NO_x and a small amount of ammonia slip.

References

U.S. EPA – CICA Fact Sheet, “Air Pollution Control Technology Fact Sheet; Selective Catalytic Reduction (SCR).”

U.S. EPA – CICA Fact Sheet, “Air Pollution Control Technology Fact Sheet; Selective Non-Catalytic Reduction (SNCR).”

NESCAUM, “Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants”, March 31, 2011.

U.S. EPA “Control Technologies Cost and Performance”.

Institute of Clean Air Companies; White Paper - “Selective Non-Catalytic Reduction for Controlling NO_x Emissions”, February 2008.

Institute of Clean Air Companies; White Paper - “Selective Catalytic Reduction Control of NO_x Emissions from Fossil-Fuel Fired Electric Power Plants”, May 2009.

The National Energy Technology Laboratory (NETL) – “Selective Autocatalytic NO_x Reduction (SACR)”

X. APPENDICES

APPENDIX A - HEALTHY AIR ACT NOTICE OF PROPOSED ACTION 2007

APPENDIX B - MARYLAND UNITS WITH SCR AND SNCR RATES AND TONS

APPENDIX C - MARYLAND NO_x RATE 24 HOUR BLOCK

APPENDIX D - NO_x RATES FOR SCR AND SNCR

APPENDIX E - OTC RACT PRINCIPALS STATEMENT

APPENDIX F - SUMMER STUDY

APPENDIX G - EMISSION REDUCTION CALCULATIONS

APPENDIX H - COMPLIANCE PLAN

APPENDIX I - COLLABORATIVE SOLUTION TO THE OZONE TRANSPORT PROBLEM

Appendix A

Maryland Healthy Air Act Notice of Proposed Action (Fact Sheet)

Subtitle 11 AIR QUALITY

26.11.27 Emission Limitations for Power Plants

Authority: Environment Article, §§1-101, 1-404, 2-101 — 2-103, 2-301 — 2-303, 10-102, and 10-103, Annotated Code of Maryland; Ch. 23, Acts of 2006

Notice of Proposed Action

[07-048-P]

The Secretary of the Environment proposes to adopt new Regulations .01 — .06 under a new chapter, **COMAR 26.11.27 Emission Limitations for Power Plants**.

Statement of Purpose

The purpose of this action is to adopt regulations to implement the requirements of the Healthy Air Act (Ch. 23, Acts of 2006), which was signed into law on April 6, 2006 and which establishes emission limitations and related requirements for oxides of nitrogen (NO_x), sulfur dioxide (SO₂), and mercury. These emission limitations will apply to 15 coal-fired electric generating units.

Regulations .01 — .03C, .03E, .05, and .06 related to the reduction NO_x and SO₂ emissions will be submitted to the U.S. EPA as a revision to Maryland's State Implementation Plan. Regulations .03D, .04, .05 and .06 related to the reduction of mercury emissions will be submitted to the U.S. EPA as a revision to Maryland's 111(d) Plan.

Summary of Regulatory Requirements.

These regulations implement the foregoing provisions of The Healthy Air Act (HAA), (Ch. 23, Acts of 2006), which, among other things, establishes Statewide tonnage caps for emissions of NO_x and SO₂ from 15 coal-fired electric generating units in Maryland effective in 2009 and 2012, and 2010 and 2013, respectively. The HAA further requires the same coal-fired units to achieve a mercury emissions removal efficiency of 80 percent in 2010 and 90 percent in 2013. In addition, the HAA establishes monitoring and reporting requirements, authorizes the Department to reduce or waive penalties for noncompliance under certain conditions, and provides for judicial review of decisions by the Department to grant a reduction or waiver of penalties. The HAA specifically vests the Department with regulatory authority to allocate the Statewide NO_x and SO₂ tonnage caps among the affected units, establish procedures for determining the mercury baseline, and generally implement the HAA's provisions through the adoption of regulations by:

(1) Allocating NO_x and SO₂ Statewide tonnage caps among the individual electric generating units that are subject to the HAA;

(2) Establishing procedures for determining the uncontrolled mercury flue gas baseline and options for compliance with the mercury removal efficiency requirements of the law; and

(3) Establishing procedures to govern judicial review of determinations by the Department to grant a reduction or waiver of penalties.

In addition, for ease of reference and completeness, the regulations restate the monitoring and reporting requirements set forth in the law.

Affected Sources.

These regulations affect the following fossil-fuel-fired electric generating units:

Electric Generating Unit Jurisdiction

Constellation Energy Group System
Brandon Shores 1 and 2, Anne Arundel County
H. A. Wagner 2 and 3, Anne Arundel County
C. P. Crane 1 and 2, Baltimore County

Mirant System

Chalk Point 1 and 2, Prince George's County
Dickerson 1, 2, and 3, Montgomery County
Morgantown 1 and 2, Charles County

Allegheny Energy

R. Paul Smith 3 and 4, Washington County

Comparison to Federal Standards

In compliance with Executive Order 01.01.1996.03, this proposed action is more restrictive or stringent than corresponding federal standards as follows:

(1) Regulation citation and manner in which it is more restrictive than the applicable federal standard:

COMAR 26.11.27

Federal CAIR: 70 FR 25162

Federal CAMR: 70 FR 28606

The HAA is more restrictive than corresponding federal standards insofar as it establishes specific NO_x, SO₂, and mercury limitations for the 15 coal-fired electric generating units that are subject to the HAA. Unlike the federal Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), the HAA does not permit compliance through the surrender of allowances.

(2) Benefit to the public health, safety or welfare, or the environment: All of the coal-fired units that are subject to the HAA and these regulations are located in ozone or PM_{2.5} nonattainment areas, in which approximately 90 percent of the Maryland citizens reside.

The HAA, and by necessity these implementing regulations, will require installation of on-site pollution controls at many of the electric generating units subject to the HAA. This will ensure reductions of NO_x and SO₂ emissions from Maryland's coal-fired electric generating units necessary to attain the federal National Ambient Air Quality Standards for ozone and PM_{2.5} by the 2010 attainment deadlines.

Reductions of NO_x emissions will also reduce nitrogen deposition to the Chesapeake Bay and assist with fulfilling Maryland's 2010 nitrogen reduction goal for the Chesapeake Bay.

The HAA requires affected facilities to achieve an 80 percent mercury emission removal efficiency by 2010 and a 90 percent mercury emission removal efficiency by 2013. Reduction of mercury emissions from Maryland coal-fired electric generating units will reduce mercury levels in the environment and in recreational fish species and will contribute to reductions of methyl mercury levels in 14 water bodies currently listed as impaired due to elevated mercury levels in fish.

The HAA, and these implementing regulations, will reduce adverse ozone-related and fine-particulate-matter-related health effects and health care costs as they reduce the quantity of pollutants emitted into Maryland's ambient air.

The U.S. Environmental Protection Agency (EPA) performed an analysis of potential health-based costs and benefits for the CAIR. The HAA, and these implementing regulations, mirror closely the NO_x and SO₂ emission reductions EPA estimated in Maryland from implementation of the CAIR, provided that pollution controls are installed as EPA projects in its CAIR modeling analysis, which is discussed in more detail below. Thus, the HAA, and these implementing regulations, ensure that the benefits to Maryland forecasted by the EPA assessment of implementing the CAIR will actually be achieved.

The HAA, and these implementing regulations, will result in an estimated reduction of more than 300,000 incidents in which Marylanders experience adverse health effects, including hospitalizations, illnesses, restricted activity days, and other effects as defined by EPA, caused by air pollution and save Maryland over \$2,000,000,000 in associated health care costs in 2010.

To conservatively estimate these benefits, the Maryland Department of the Environment (MDE) staff relied on the regulatory impact analysis (RIA) EPA performed for the 28-state CAIR control region in 2010. Based on Maryland's proportional population, the HAA, and these regulations, will annually reduce premature mortality by approximately 400 cases, nonfatal heart attacks by approximately 550 cases, chronic bronchitis by approximately 200 cases, acute bronchitis by approximately 500 cases, and hospital admissions and emergency room visits by approximately 600 cases. EPA also conservatively estimates that nationally, every \$1 spent on power plant controls produces \$10 in annual health benefits.

(3) Analysis of additional burden or cost on the regulated person: The CAIR implements the federal cap-and-trade program for NO_x and SO₂ reductions on the same timetable as the reductions required by the HAA and these regulations, that is, 2009 for NO_x reductions and 2010 for SO₂ reductions. In its analysis accompanying promulgation of the CAIR, EPA projected that to comply with the CAIR, most of the electric generating units subject to these regulations would elect to install selective catalytic reduction (SCR) and flue gas desulfurization (FGD) control technology, rather than acquire and surrender allowances. In this regard, Constellation Energy Group, Inc. has recently announced its intention to install FGD control technology on its two fossil-fuel-fired units at Brandon Shores by 2009. In addition, Mirant Mid-Atlantic, LLC is presently commencing installation of SCR controls on both of its fossil-fuel-fired units at Morgantown.

The capital and operating costs associated with installation of these controls on four of the largest coal-fired electric generating units in Maryland will be incurred, notwithstanding enactment of the HAA and adoption of these regulations. If EPA's projections with respect to installation of controls are similarly accurate for most or all of the remaining units subject to these regulations, a significant portion of the cost to affected sources of installing and operating the pollution control equipment that would otherwise be necessary to comply with the HAA and these regulations will be incurred to achieve compliance with the CAIR, even in the absence of the HAA.

Equipment to reduce SO₂, NO_x, and mercury emissions, primarily through the installation of SCR and FGD controls at most of the affected units, has been estimated to cost between \$1,800,000,000 to \$2,100,000,000. Operating costs for that equipment will be \$150,000,000 to \$200,000,000 annually. Installing on-site controls will either eliminate or

greatly reduce the need for affected units to purchase allowances for NO_x and SO₂ to comply with the CAIR, generating potential annual savings for all affected sources in the range of \$150,000,000 to \$400,000,000. Compliance with the mercury provisions of the HAA and these implementing regulations can be achieved though the cobenefits of both SCR and FGD controls or add-on controls specific for mercury. Capital costs for add-on mercury controls could be another \$150,000,000, with additional operating costs of \$30,000,000 to \$70,000,000. Precise estimates of the costs associated with implementation of the HAA remain difficult because MDE does not have full knowledge of exactly what pollution controls or other strategies owners and operators of the electric generating units subject to the HAA intend to implement to achieve compliance.

(4) Justification for the need for more restrictive standards: State law, the HAA (Ch. 23, Acts of 2006), requires adoption of more restrictive standards.

Estimate of Economic Impact

I. Summary of Economic Impact. The HAA establishes State-wide NO_x and SO₂ emission tonnage caps and mercury emission removal rates in two phases that will require installation of pollution controls on most of the electric generating units subject to the HAA. These implementing regulations merely allocate the State-wide caps among the affected electric generating units and establish procedures for determining the mercury baseline and options for compliance with the applicable mercury removal efficiency. While some portion of the costs to regulated entities may be attributable to the ozone season tonnage caps, the individual tonnage allocations, and the mercury limitation compliance procedures established by these regulations, the capital costs and the majority of the operating costs incurred by the affected facilities are largely attributable to the HAA, which establishes the emissions limitations and the compliance deadlines. Therefore, this economic impact analysis primarily focuses on an estimate of the overall cost to implement the HAA and the broad health and environmental benefits implementation of the HAA will produce. A number of economic analyses have been considered in developing this estimate, including an analysis of an early version of the HAA by the Public Service Commission (PSC), an analysis prepared by the Center for Energy and Economic Development, Inc. (CEED), the EPA's analysis performed to support the Clean Air Interstate Rule (CAIR), and other economic analyses by private consultants. Each of these cost analyses reflects the particular viewpoint of the organization that performed or commissioned that particular analysis.

MDE relied most heavily on the EPA analysis of the costs and benefits associated with implementation of CAIR primarily for two reasons. First, with the NO_x SIP Call cap-and-trade program, a forerunner of CAIR, EPA gained significant experience analyzing the costs and projecting the benefits of a cap and trade air quality control program. Achieving compliance with CAIR will require installation of some of the same pollution control equipment, utilize the same labor force, and generate a similar demand for design and construction resources in a limited time frame as did the NO_x SIP Call. Drawing on its experience with the NO_x SIP Call, the EPA's RIA for CAIR included extensive documentation on availability of the labor force, estimated costs to regulated entities and estimated lead times necessary to complete installation of pollution controls. The CAIR analysis is particularly relevant to analysis of the HAA and its implementing regulations because achieving compliance with the HAA will require installation of the same NO_x and SO₂ pollution controls EPA projects electric generating units in Maryland would install to comply with CAIR in the absence of the HAA. In contrast, the CEED study is a limited analysis based on a hypothetical CAIR Plus regulatory program that is still under development at this time. The PSC study was based on an early version of the HAA as it was introduced in the General Assembly, with the first phase 2010 annual SO₂ cap of approximately 39,000 tons per year, which is significantly lower than the 48,618 ton cap in the bill as enacted.

Second, the CAIR cost analysis was based on the same assumed emission levels as 2010 emission limitations required by the HAA. In assessing the costs and benefits of CAIR, EPA utilized an economic model, the Integrated Planning Model (IPM), which predicts which facilities are likely to install pollution controls to comply with CAIR. The IPM model predicted that nearly all the coal-fired electric generating units in Maryland would install state-of-the-art NO_x and SO₂ pollution controls to comply with CAIR. EPA's photochemical modeling, performed to analyze the air quality benefits of CAIR, projected that with the controls predicted by the IPM model, Maryland would attain the PM_{2.5} standard by the 2010 deadline. Accordingly, the CAIR analysis is directly applicable to implementation of the HAA. Therefore, in light of MDE's limited expertise and resources in the area of economic analysis and the fact that the Phase I SO₂ caps in the HAA are consistent with the SO₂ caps in EPA's attainment scenario, MDE's reliance on EPA's comprehensive analysis for CAIR to develop a cost estimate for implementation of the HAA was both reasonable and prudent. Since the 2013 Phase II SO₂ emission levels are more stringent than the 2010 Phase I levels, this analysis differentiates between the costs for 2009/2010 level controls and the 2012/2013 level controls.

Costs of Installing and Operating NO_x and SO₂ Pollution Controls.

Equipment to reduce NO_x and SO₂ emissions to the 2009 and 2010 emission limitations, primarily through the installation of SCR and FGD controls at most of the affected units, has been conservatively estimated to cost between \$1,800,000,000 to \$2,100,000,000. Annual operating costs for that equipment have been estimated to range from \$150,000,000 to \$200,000,000. These costs will be offset in part by the reduced need to purchase NO_x and SO₂ allowances to comply with CAIR. MDE expects installation and operation of on-site controls to eliminate or greatly reduce the need for affected units to purchase allowances for NO_x and SO₂, generating potential annual savings for all affected sources in the range of \$150,000,000 to \$400,000,000.

MDE concluded that meeting the more stringent Phase II emission limitations is possible by running the controls installed to achieve compliance with the Phase I limitations with greater efficiency. MDE estimates that electric generating units subject to the HAA will incur additional total annual operating costs of between \$150,000,000 and \$200,000,000 to achieve compliance with Phase II limitations.

Mercury Control Costs.

The mercury emission limitations introduce significant variables, given the variation of mercury content in fuels and the flexible control options available. Affected units that have installed SO₂ and NO_x controls may achieve compliance with the HAA Phase I mercury emission removal efficiency requirement and possibly the Phase II requirement entirely through the cobenefits of these controls. Units without SO₂ and NO_x controls will require other means to control mercury. Such reduction measures might include fuel-switching or installation of activated carbon injection (ACI) systems or other add-on control equipment. The capital costs of installing ACI systems FGD or SCR controls units could be approximately \$150,000,000.

Additional operating costs may be incurred to achieve compliance with the HAA mercury standards such as the cost of operation of control equipment and fuel switching (assuming coals with specific sulfur or mercury content are more expensive). Operating costs of ACI systems at units without SCR or FGD would range from \$30,000,000 to \$70,000,000.

Electricity Rate Increases.

Commercial and consumer electricity rates are influenced by many factors. The costs associated with implementation of the HAA may be one factor that influences these rates, but the magnitude of that influence is difficult to quantify when added to other factors that significantly affect electric rates. The current increases in energy prices driven by increases in oil and natural gas prices and factors other than costs associated with meeting environmental obligations are responsible for the recent significant increase in consumer electric rates. In its RIA for CAIR, the EPA projected that

electricity rates would increase in Maryland by 0.17 to 0.26 cents per kilowatt. In contrast, the PSC estimated that rates would increase by 0.63 to 0.83 cents per kilowatt, in part based on the PSC's prediction that implementation of the HAA could result in shutdown of several plants. However, the PSC analysis was based on the HAA as introduced with a 2010 SO₂ emissions cap of approximately 39,000 tons per year, which was significantly more stringent than the 2010 SO₂ emissions cap in the HAA as enacted.

Health Benefits.

MDE estimates that implementation of the HAA will lead to a reduction of over 300,000 incidents of adverse health effects and save Maryland more than \$2,000,000,000 in health costs in 2010. The EPA also conservatively estimates that each \$1 spent nationally on power plant controls results in \$10 worth of annual health benefits. These benefits of implementing the HAA are not in addition to benefits resulting from implementation of CAIR because the Healthy Air Act simply ensures that the reductions projected by EPA for the CAIR will be realized in Maryland.

II. Types of Economic Impacts	Revenue (R+/R-)	
A. On issuing agency:	(E+)	Indeterminate
B. On other State agencies:	(E+)	Indeterminate
C. On local governments:		
Electricity rates	(E+)	Indeterminate
	Benefit (+)	Magnitude
	Cost (-)	
D. On regulated industries or trade groups:		
(1) Capital costs	(-)	\$1,800,000,000 — \$2,100,000,000
(2) Annual operating costs	(-)	\$180,000,000 — \$270,000,000
(3) Annually avoided allowances	(+)	\$150,000,000
E. On other industries or trade groups:		
(1) MD contractors	(+)	Indeterminate
(2) Electricity rates	(-)	Indeterminate
F. Direct and indirect effects on public:		
(1) Health benefits	(+)	\$2,160,000,000 in 2010
(2) Electricity rates	(-)	Indeterminate

III. Assumptions. (Identified by Impact Letter and Number from Section II.)

A, B, C. These controls may result in an increase in commercial or consumer electricity rates, however, the magnitude of any increase that may result is indeterminate. (See electricity rate discussion above.) In general, commodity pricing is the prerogative of the vendor and is influenced by the vendor's assessment of which costs to pass along to the consumer and which costs to absorb. MDE does not possess expertise in energy marketing practices and is unable to predict electricity rates.

D(1). It is difficult to determine the precise costs to regulated entities associated with implementation of these regulations because of a number of site-specific requirements and variables associated with the cost of installation and operation of pollution control equipment necessary to comply with these regulations at specific Maryland plants. Additionally, the regulations do not dictate compliance strategies. MDE has examined a number of cost analyses in developing cost range estimates for the HAA and these implementing regulations. EPA's economic impact analysis for CAIR estimates that the capital costs to control these units will be approximately \$1,300,000,000. Using other cost analyses available, the Department conservatively estimates total capital costs for control of SO₂ and NO_x by 2010 could range from about \$1,800,000,000 to \$2,100,000,000, with variation dependent on many factors, including assumptions regarding equipment cost factors, firms' compli-

ance strategies, fuels used or available during the compliance period, future demand growth, and utilization of units. The estimated capital costs cited here do not include costs associated with installation of NO_x controls to comply with other regulatory requirements.

An important variable in assessing the cost of the proposed rule is whether or not the controls at a particular facility will be installed as a compliance strategy for the CAIR. For example, Constellation Energy Group, Inc. reports that its consultants estimate the installation of FGD technology on two units at one affected plant to cost \$500,000,000. The company has stated that it had planned these controls prior to passage of the HAA as a means of complying with the CAIR. Excluding this equipment from the analysis as a measure not specifically driven by the State regulations would reduce the cost estimate by a third.

The mercury limits introduce significant variables, given the variation in the mercury content in fuels and the flexibility of control strategy choice. Compliance with the 2010 mercury limits in the regulations could be achieved at affected units through the installation of SO₂ and NO_x controls that provide mercury cobenefits. Units without SO₂ and NO_x controls would require other means to control mercury. Such reduction measures might include add-on control equipment or fuel switching. For example, the capital costs of ACI systems to units without FGD or SCR could be approximately \$150,000,000.

D(2). Annual operating costs to comply with the SO₂ and NO_x provisions of the regulations are estimated to range from \$150,000,000 to \$200,000,000 annually. Additional operating costs may be incurred to comply with the mercury standards in the regulations. Such costs might include operation of control equipment and fuel switching (assuming coals with specific sulfur or mercury content are more expensive). Operating costs of ACI systems at units without SCR or FGD would range from \$30,000,000 to \$70,000,000.

D(3). Other considerations in estimating the cost of controls to comply with these regulations include the elimination of the need to purchase allowances and the possibility of using less expensive, higher sulfur coal. In complying with these proposed regulations, affected sources avoid the cost of purchasing allowances for SO₂ and NO_x otherwise needed to comply with federal CAIR budgets. The annual savings in sulfur dioxide allowance costs for all affected sources is estimated to be approximately \$150,000,000 to \$400,000,000 from 2010 through 2014, relative to current emission rates; savings starting in 2015 could be 50 percent higher. NO_x reductions beyond the federal allocation could result in avoided allowance costs of about \$10,000,000. Actual savings would depend on growth rates, actual level of emission reductions, the market price of allowances, and firms' compliance strategies.

E(1). Contractors will construct control systems including supports, housing, storage and mix tanks, piping, and duct work. The percentage of work that will be performed by Maryland contractors is indeterminate because of the specificity of the labor force required for these installations.

E(2), F(2). These controls may result in an increase in commercial or consumer electricity rates, however, the magnitude of any increase that may result is indeterminate. (See electricity rate discussion above.) In general, commodity pricing is the prerogative of the vendor and is influenced by the vendor's assessment of which costs to pass along to the consumer and which costs to absorb. MDE does not possess expertise in energy marketing practices and is unable to predict electricity rates.

F(1). The \$2,160,000,000 dollars is a conservative estimate and based on the benefits estimated by EPA from CAIR for 2010 and proportioned based on Maryland's population as a portion of the CAIR region population. This is a conservative estimate because Maryland's rule is more stringent than CAIR and will reap benefits sooner through requiring on-site controls and prohibiting the surrender of allowances as a means of achieving compliance.

The estimated \$2,160,000,000 total benefit in 2010 accrues from approximate reductions in premature mortality (\$2,000,000,000), chronic bronchitis (\$75,600,000), nonfatal heart attacks (\$42,600,000), minor restricted activity days (\$12,700,000), lost work days (\$5,400,000), and hospital admissions for respiratory

and cardiovascular problems (\$4,000,000). All of the monetary benefits are in constant-year 1999 dollars.

Economic Impact on Small Businesses

The proposed action has minimal or no economic impact on small businesses.

Impact on Individuals with Disabilities

The proposed action has an impact on individuals with disabilities as follows: These regulations will have a positive impact on individuals with disabilities by reducing air pollutants that contribute to numerous respiratory and cardiovascular diseases. The regulations will also reduce mercury emissions that can be harmful to unborn babies and young children through consumption of fish and shellfish.

Opportunity for Public Comment

Comments may be sent to Deborah Rabin, Regulations Coordinator, Air and Radiation Management Administration, Department of the Environment, 1800 Washington Boulevard, Baltimore, MD 21230, or fax to 410-537-4223, or call 410-537-3249, or email to drabin@mde.state.md.us. Comments must be received not later than May 1, 2007, or be submitted at the hearing. For more information, call Deborah Rabin at 410-537-3240. The Department of the Environment will hold a public hearing on the proposed action on May 1, 2007 at 10 a.m. at 1800 Washington Boulevard, 1st Floor Aeris Conference Room, Baltimore, MD 21230. Interested persons are invited to attend and express their views.

Copies of the proposed action and supporting documents are available for review at the following locations: the Air and Radiation Management Administration, regional offices of MDE in Cumberland and Salisbury, all local air quality control offices, and local health departments in those counties not having separate air quality control offices.

Anyone needing special accommodations at the public hearing should contact MDE's Fair Practices Office at (410) 537-3964. TTY users may contact MDE through the Maryland Relay Service at 711.

Editor's Note: The text of this document will not be printed here because it appeared as a Notice of Emergency Action in 34:3 Md. R. 291 — 296 (February 2, 2007), referenced as [07-048-E].

SHARI T. WILSON
Secretary of the Environment

Subtitle 11 AIR QUALITY

26.11.32 Control of Emissions of Volatile Organic Compounds from Consumer Products

Authority: Environment Article, §§1-101, 1-404, 2-101 — 2-103, 2-301 — 2-303, 10-102, and 10-103,
Annotated Code of Maryland

Notice of Proposed Action

[07-072-P-I]

The Secretary of the Environment proposes to:

- (1) Amend Regulations .01 — .04 and .06;
- (2) Adopt new Regulations .08 — .10;
- (3) Amend and recodify existing Regulations .10 — .15 and .18 — .22 to be Regulations .13 — .18 and .21 — .25; and

Appendix B

Maryland Coal-Fired EGUs

Ozone Season Performance Rates Coal-Fired Units
with SCRs and SNCRs, 2007-2013

July 2012 Ozone Season NO_x Reductions at Lowest
OS Rate

Coal-Fired EGU vs Other Fuel EGU

2011 CAMD OS Report

2014 CAMD OS Report

Maryland Coal-Fired EGUs
Ozone Season Performance
NOx Emission Rate

Purpose

The data used in this analysis includes:

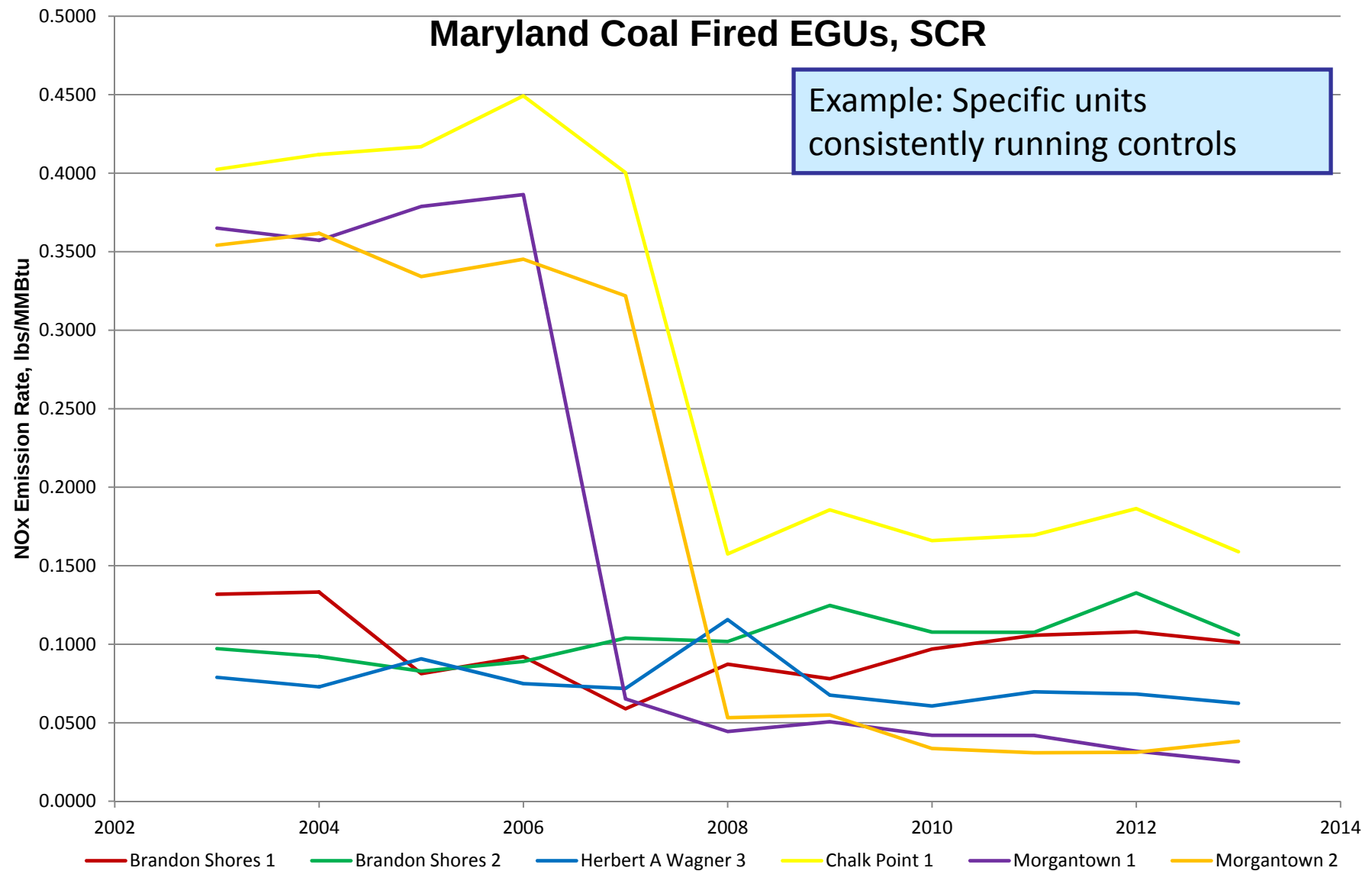
- CEMS data, downloaded from CAMD
- Emissions and projection data from ERTAC

Average ozone season NOx emission rate for operating coal-fired EGUs in Maryland was graphed. A visual evaluation of the data was performed to judge the continuous and effective operation of post combustion controls, specifically SCR and SNCR. In general, it was judged that an increase in the average ozone season NOx emission rate suggests a discontinued, or at a minimum, less effective operation of post combustion controls.

The same data analysis was performed for 10 other States with ozone transport contributions to Maryland. These results are available upon request.

The Maryland graphs are attached.

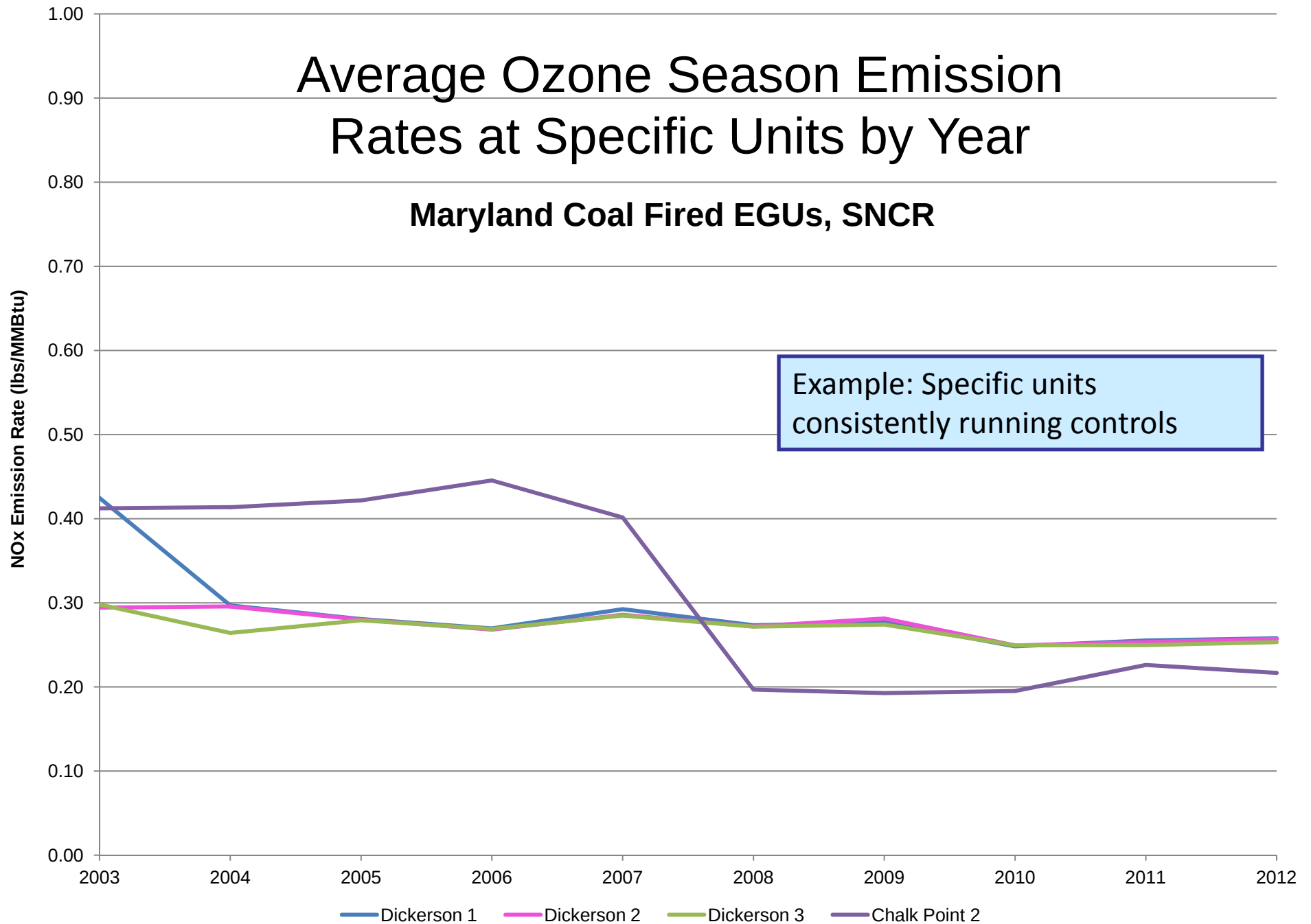
Average Ozone Season Emission Rates at Specific Units by Year



DRAFT – September 18, 2014 – Requesting QA of data. For discussion purposes only.

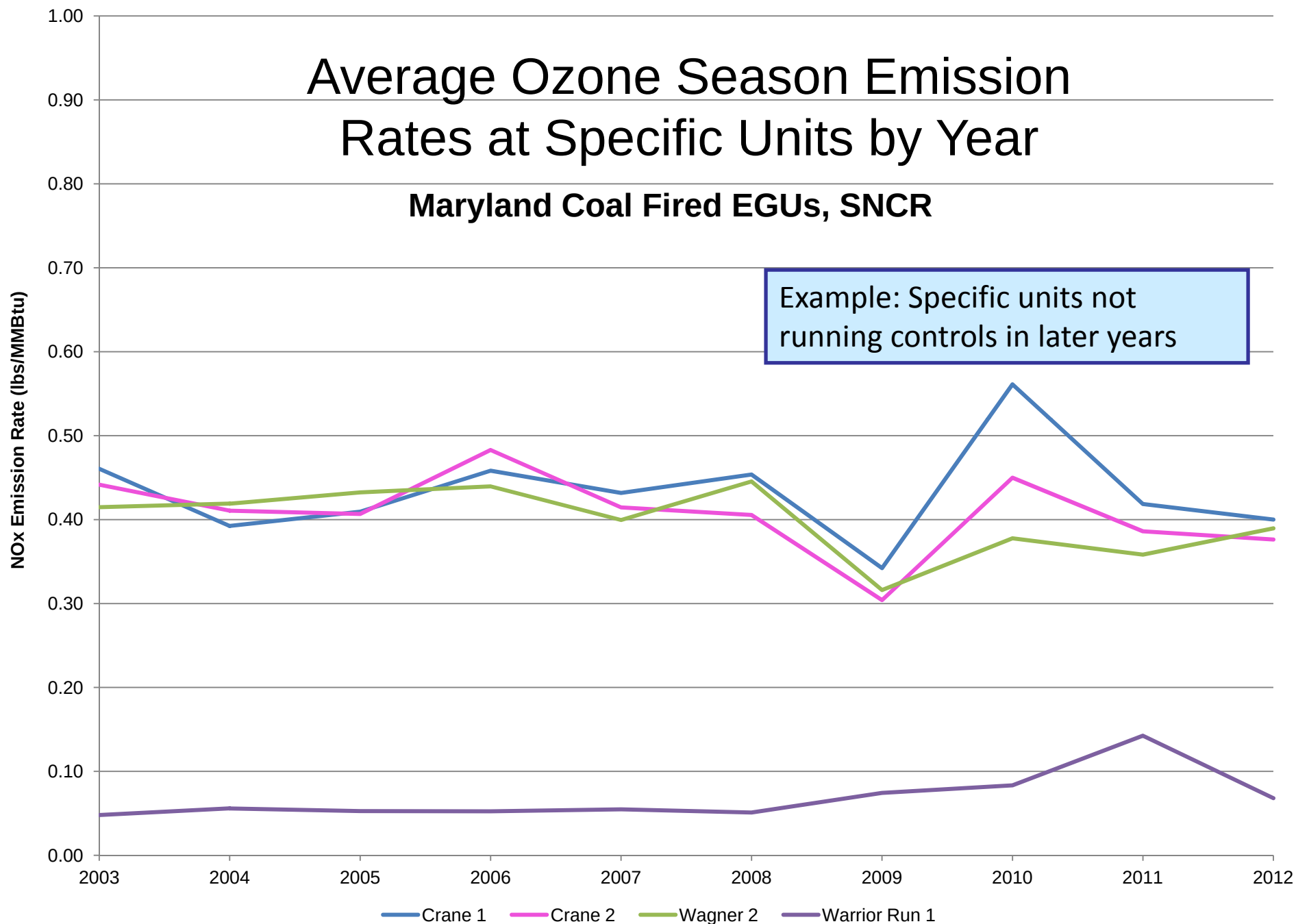
Average Ozone Season Emission Rates at Specific Units by Year

Maryland Coal Fired EGUs, SNCR



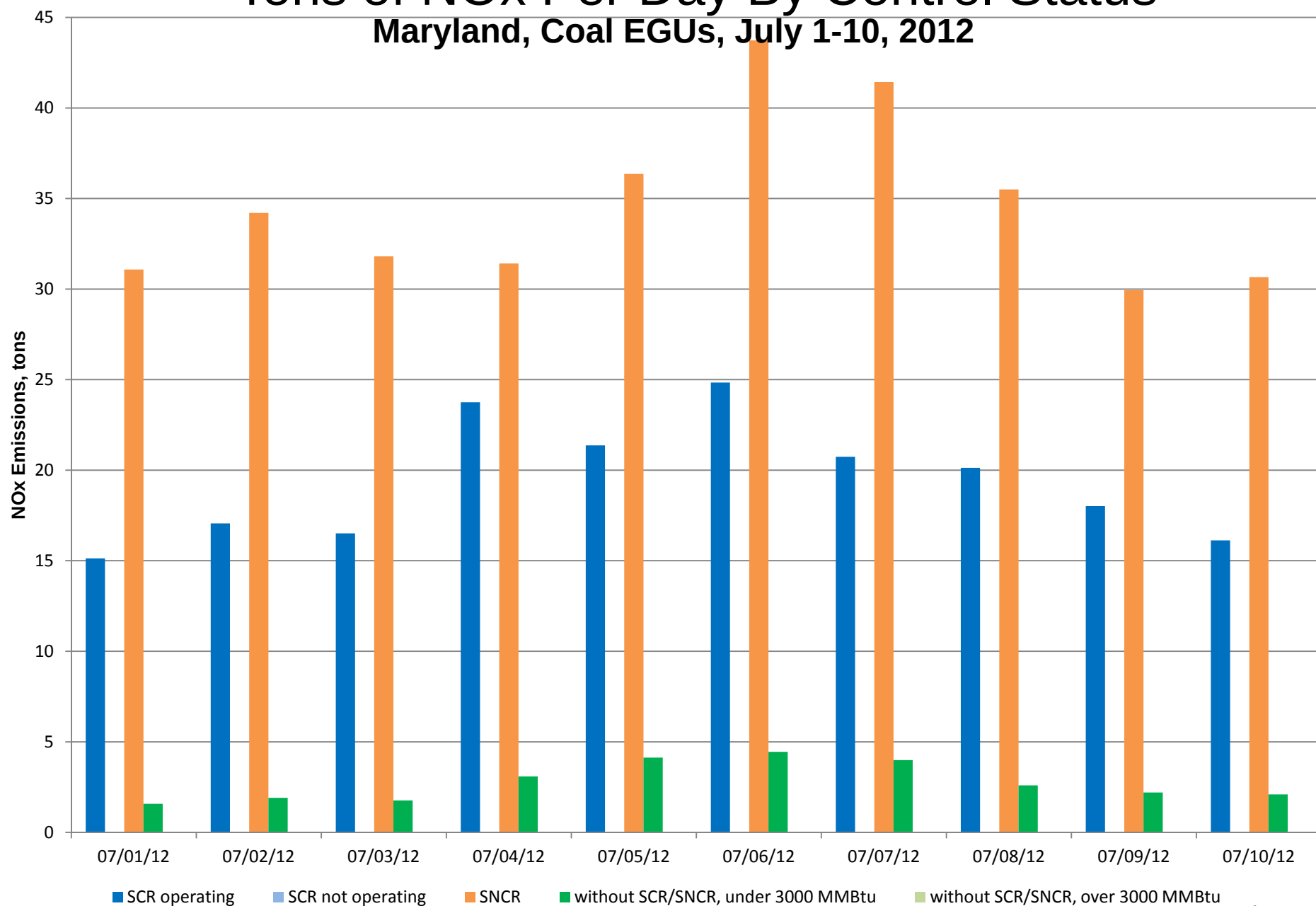
Average Ozone Season Emission Rates at Specific Units by Year

Maryland Coal Fired EGUs, SNCR



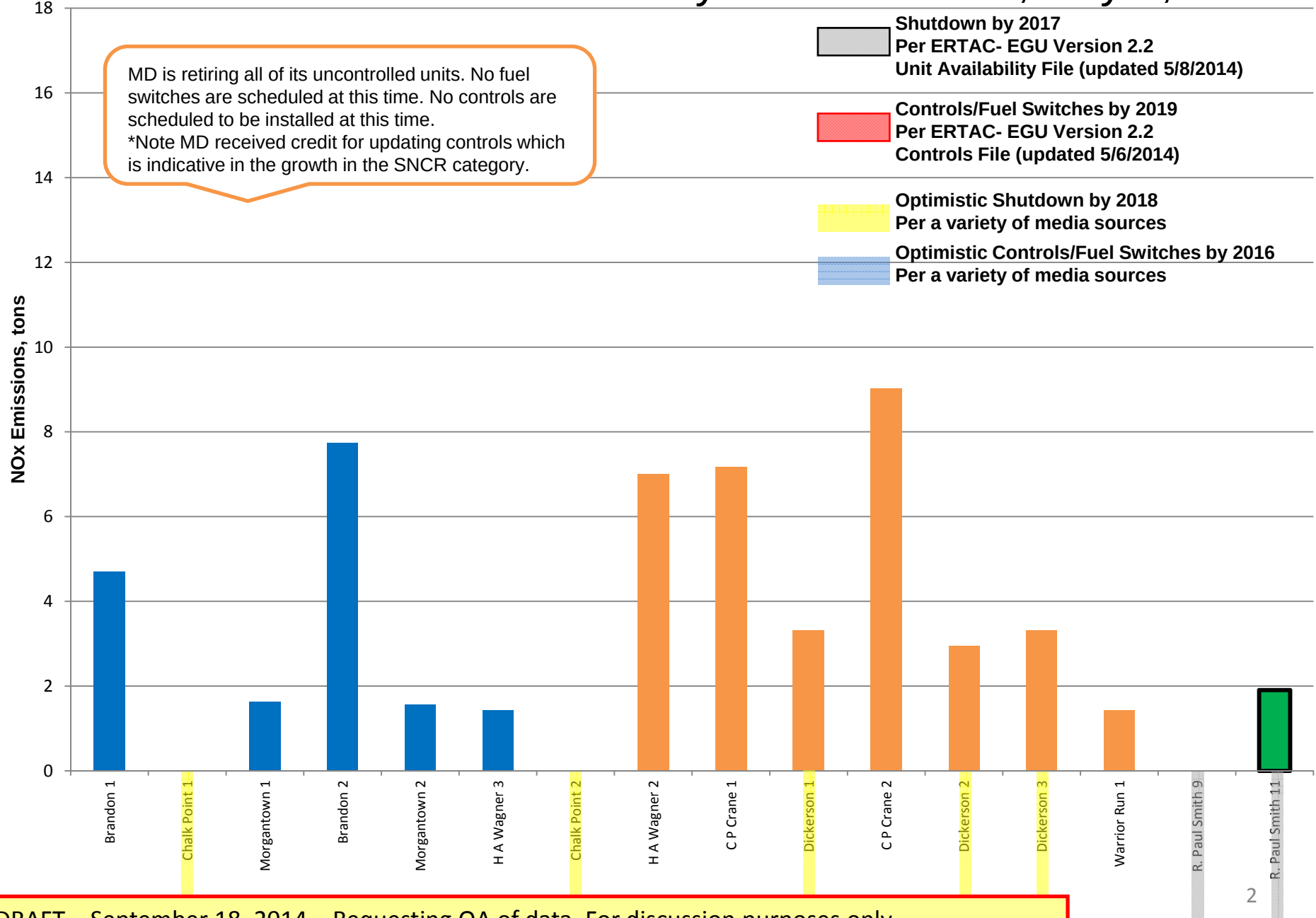
Tons of NOx Per Day By Control Status

Maryland, Coal EGUs, July 1-10, 2012



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MD – Tons of NOx Per Unit By Control Status, July 2, 2012



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MD : Large (> 3000 MMBtu/hr) Coal-Fired EGU NOx Emissions Rate Analysis

	Facility Name	Unit ID	Lowest OS Emission Rate Year	Lowest OS Emission Rate (lbs/MMBtu)	2007 OS Emission Rate (lbs/MMBtu)	Percent Difference Between Lowest OS ER and 2007 OS ER (% Change)	2011 OS Emission Rate (lbs/MMBtu)	Percent Difference Between Lowest OS ER and 2011 OS ER (% Change)	Comments/ ERTAC Closure Date
Controlled with SCR	Brandon Shores	1	2007	0.0589	0.0589	0	0.1057	79	
	Brandon Shores	2	2005	0.0828	0.1039	25	0.1076	30	
	Mirant Chalk Point	1	2008	0.1575	0.4004	154	0.1695	8	Close 2017 (media)
	Mirant Morgantown	1	2012	0.0319	0.0652	104	0.0419	31	
	Mirant Morgantown	2	2011	0.0309	0.3219	942	0.0309	0	
Controlled with SNCR	Mirant Chalk Point	2	2009	0.1927	0.4014	208	0.2261	17	Close 2017 (media)
No Controls or Fuel Switches by 2019	N/A								
Retiring by 2017	N/A								

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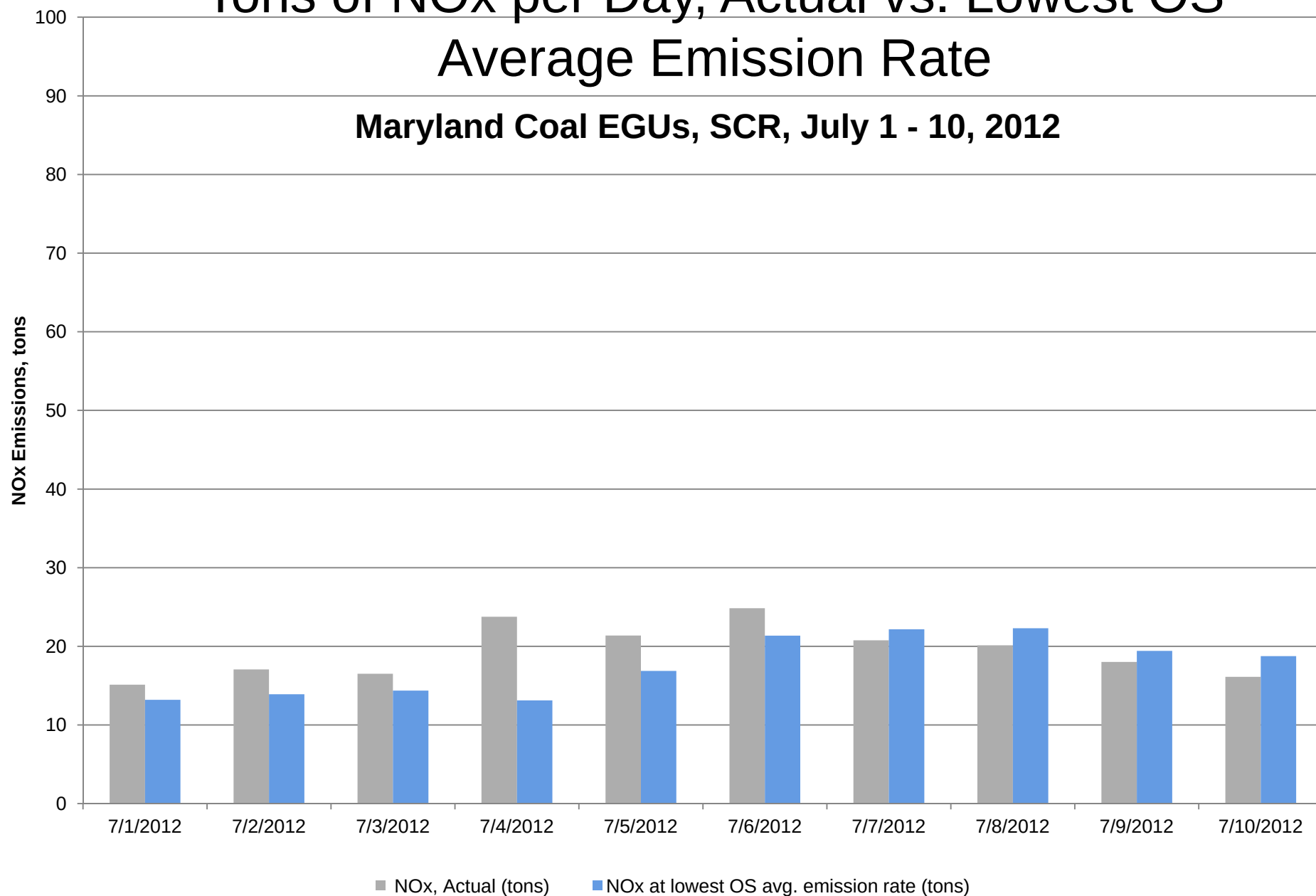
MD: Small (< 3000 MMBtu/hr) Coal-Fired EGU NO_x Emissions Rate Analysis

	Facility Name	Unit ID	Lowest OS Emission Rate Year	Lowest OS Emission Rate (lbs/MMBtu)	2007 OS Emission Rate (lbs/MMBtu)	Percent Difference Between Lowest OS ER and 2007 OS ER (% Change)	2011 OS Emission Rate (lbs/MMBtu)	Percent Difference Between Lowest OS ER and 2011 OS ER (% Change)	Comments/ ERTAC Closure Date
Controlled with SCR	Herbert A Wagner	3	2010	0.0607	0.0718	18	0.0697	15	
Controlled with SNCR	AES Warrior Run	1	2003	0.0479	0.0548	14	0.1426	198	
	C P Crane	1	2009	0.3422	0.4318	26	0.4185	22	
	C P Crane	2	2009	0.3041	0.4145	36	0.386	27	
	Herbert A Wagner	2	2009	0.316	0.3995	26	0.3582	13	
	Mirant Dickerson	1	2010	0.2483	0.2924	18	0.2552	3	Close 2017 (media)
	Mirant Dickerson	2	2010	0.2494	0.2858	15	0.2533	2	Close 2017 (media)
	Mirant Dickerson	3	2010	0.2495	0.2849	14	0.2497	0	Close 2017 (media)
No Controls or Fuel Switches by 2019	N/A								
Retiring by 2017	R. Paul Smith	9	2003	0.3273	0.4216	29	0.3699	13	9/30/2012
	R. Paul Smith	11	2011	0.2607	0.3112	19	0.2607	0	9/30/2012

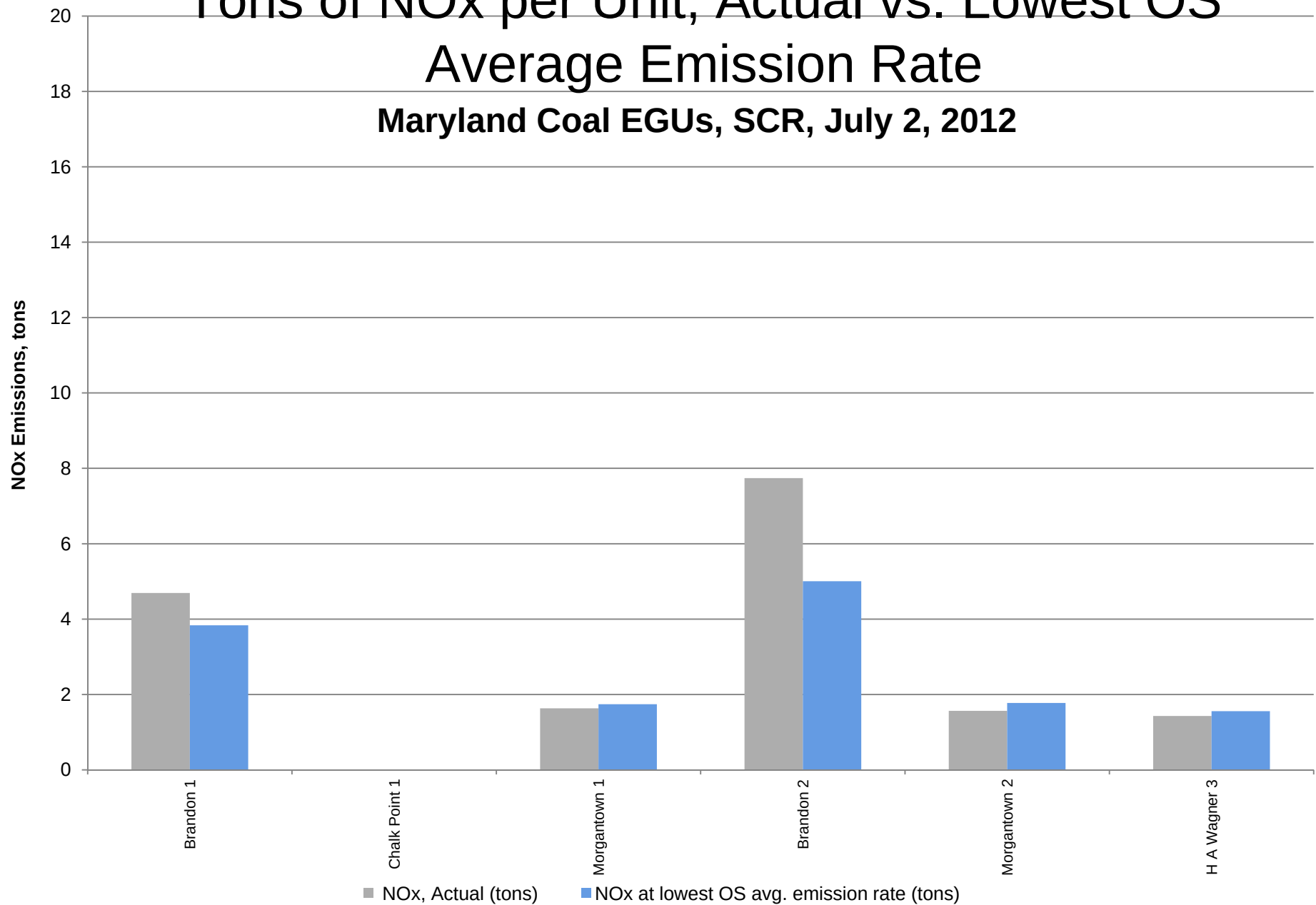
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Tons of NOx per Day, Actual vs. Lowest OS Average Emission Rate

Maryland Coal EGUs, SCR, July 1 - 10, 2012



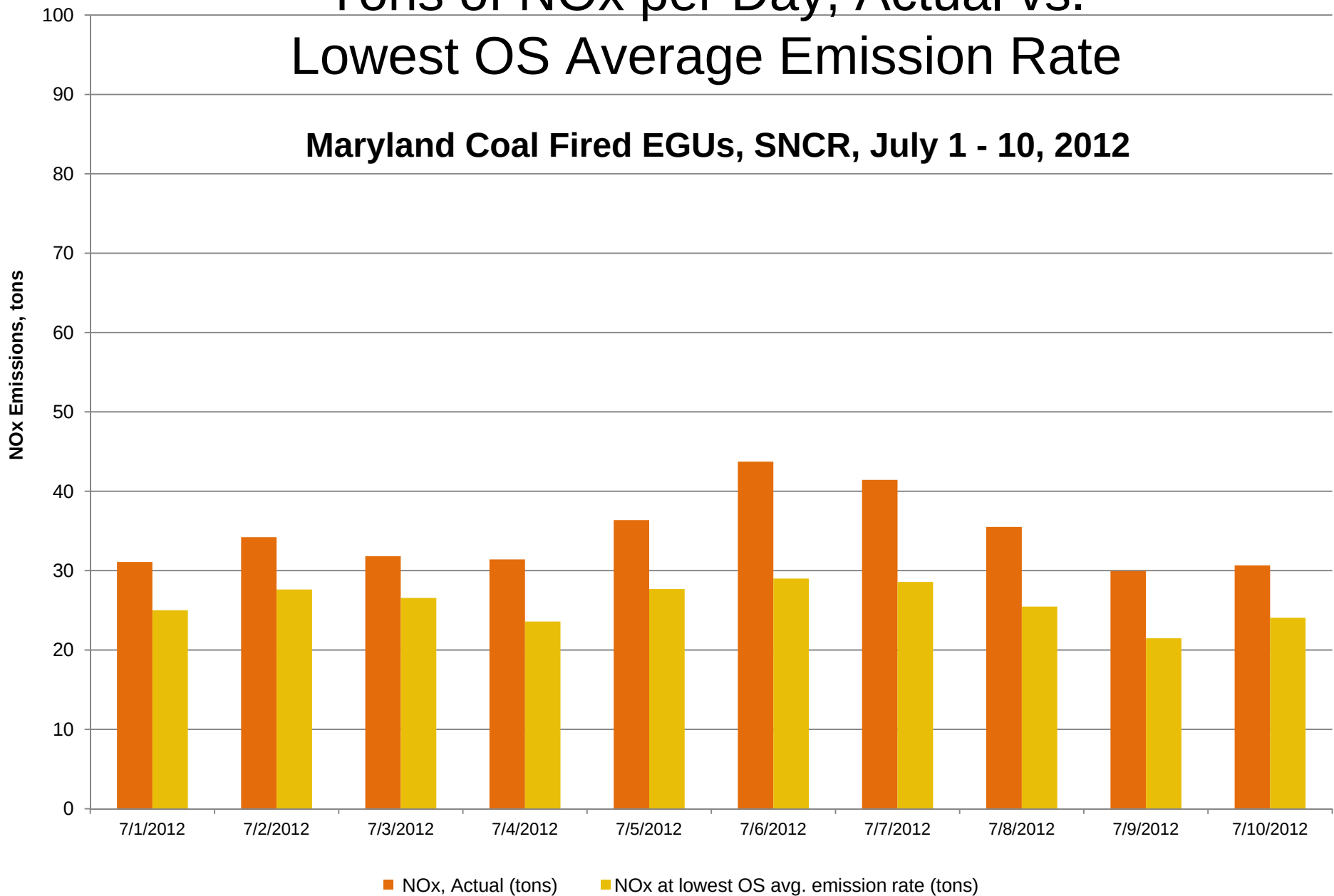
Tons of NOx per Unit, Actual vs. Lowest OS Average Emission Rate Maryland Coal EGUs, SCR, July 2, 2012



DRAFT – September 18, 2014 – Requesting QA of data. For discussion purposes only.

Tons of NOx per Day, Actual vs. Lowest OS Average Emission Rate

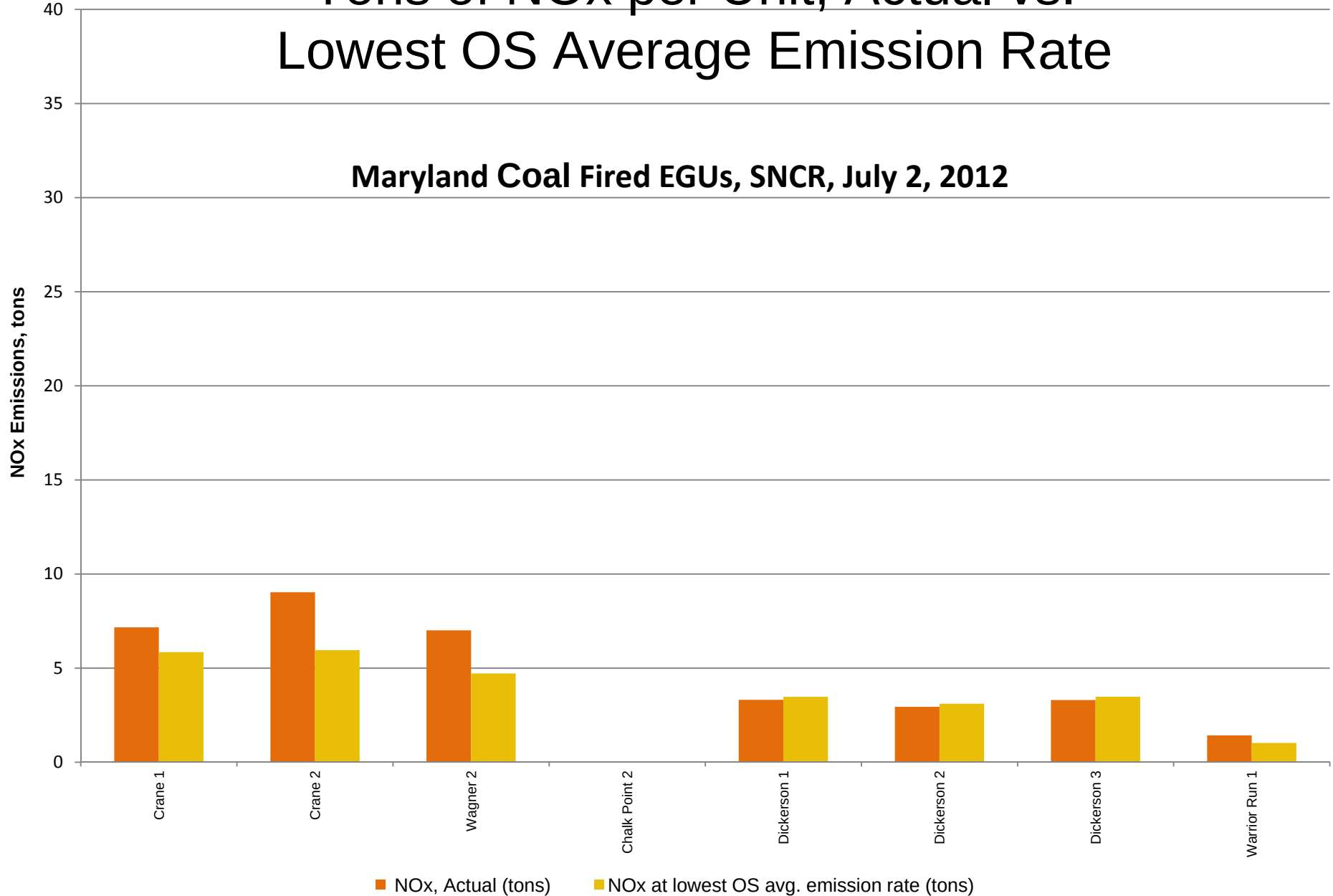
Maryland Coal Fired EGUs, SNCR, July 1 - 10, 2012



DRAFT – September 18, 2014 – Requesting QA of data. For discussion purposes only.

Tons of NOx per Unit, Actual vs. Lowest OS Average Emission Rate

Maryland Coal Fired EGUs, SNCR, July 2, 2012



DRAFT – September 18, 2014 – Requesting QA of data. For discussion purposes only.

	year	Number of units	Gross Load (MW-h)	NOx (tons)	Heat Input (MMBtu)
COAL	2008	16	12,394,695	8,682	118,951,883
	2009	16	10,525,704	6,843	99,302,435
	2010	16	11,758,399	8,138	117,814,269
	2011	16	10,341,743	7,158	105,001,348
	2012	16	8,788,792	5,894	88,160,267
	2013	14	7,601,684	4,591	74,401,348
	2014	14	7,352,403	3,498	74,375,274
ALL FOSSIL FUELS	2008	48	13,350,285	9,395	130,224,098
	2009	48	11,289,002	7,160	107,180,675
	2010	48	13,875,563	9,428	141,086,263
	2011	48	11,927,589	8,201	122,277,216
	2012	48	11,507,048	7,494	118,928,324
	2013	46	9,056,415	5,303	89,279,250
	2014	46	8,086,009	3,934	82,087,413
PERCENT	2008		92.84%	92.41%	91.34%
	2009		93.24%	95.58%	92.65%
	2010		84.74%	86.31%	83.51%
	2011		86.70%	87.28%	85.87%
	2012		76.38%	78.65%	74.13%
	2013		83.94%	86.56%	83.34%
	2014		90.93%	88.92%	90.60%

KW 10-22-14

Calculate the % of Nox emissions from coal-fired EGUS compared to all EGUS

Use CAMD downloads for 48 units (over 25MW) from 2008 - 2014

Ozone season

State	Facility Name	Facility ID		Year	Associate	Program(s)	Operating Time	# of Months Reported	Gross Load (MW-h)	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)	EPA		Source Category	Owner
		(ORISPL)	Unit ID		d Stacks	)									Region	County		
MD	Brandon Shores	602	1	2011		CAIROS	3151	5	1366348	728.249	0.1057	613.82	1495425	1.46E+07	3	Anne Arundel	Electric Utility	Constellation Power Sourc
MD	Brandon Shores	602	2	2011		CAIROS	3627.26	5	1635409	868.51	0.1076	762.214	1621222	1.58E+07	3	Anne Arundel	Electric Utility	Constellation Power Sourc
MD	C P Crane	1552	1	2011		CAIROS	2515.34	5	329215.9	1678.577	0.4185	688.918	343414.5	3274370	3	Baltimore	Electric Utility	Constellation Power Sourc
MD	C P Crane	1552	2	2011		CAIROS	2870.88	5	332467.1	2164.385	0.386	810.969	409147.3	3901106	3	Baltimore	Electric Utility	Constellation Power Sourc
MD	Herbert A Wagner	1554	2	2011		CAIROS	3582.35	5	223820.3	1638.788	0.3582	516.031	284019	2768220	3	Anne Arundel	Electric Utility	Constellation Power Sourc
MD	Herbert A Wagner	1554	3	2011		CAIROS	3084.33	5	670009.8	3384.78	0.0697	204.236	663333.6	6465261	3	Anne Arundel	Electric Utility	Constellation Power Sourc
MD	R. Paul Smith Power St.	1570	9	2011	MS9A, MS	CAIROS	483.01	5	8691.34	86.311	0.3699	27.865	14754.78	143823.2	3	Washington	Electric Utility	Allegheny Energy
MD	R. Paul Smith Power St.	1570	11	2011		CAIROS	868.41	5	50898.01	305.527	0.2607	71.602	53105.69	517595.7	3	Washington	Electric Utility	Allegheny Energy
MD	Chalk Point	1571	1	2011	CSE12, CSE	CAIROS	2431.84	5	665109.4	521.211	0.1695	529.192	649889.5	6335676	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571	2	2011	CSE12, CSE	CAIROS	3141.63	5	911321.1	1356.642	0.2261	988.383	887535.5	8651989	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Dickerson	1572	1	2011	CSDW13, C	CAIROS	2229.21	5	231829.1	164.488	0.2552	273.148	224612.4	2189204	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Dickerson	1572	2	2011	CSDW13, C	CAIROS	2445.43	5	261951.5	181.484	0.2533	312.279	257253	2507343	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Dickerson	1572	3	2011	CSDW13, C	CAIROS	2714	5	291002.2	195.872	0.2497	344.765	286624.5	2793619	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573	1	2011	MSFW1, M	CAIROS	2927.4	5	1175298	2019.031	0.0419	244.741	1301549	1.27E+07	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573	2	2011	MSFW2, M	CAIROS	3488.45	5	1563780	816.005	0.0309	233.309	1549851	1.51E+07	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	AES Warrior Run	10678	1	2011		CAIROS	3660.81	5	624593.3	817.43	0.1426	536.844	746822.7	7284122	3	Allegany	Cogeneration	AES Corporation
MD	Perryman	1556 CT1		2011		CAIROS	106.73	5	4136.14	1.008	0.7612	26.285	5093.457	62773.53	3	Harford	Electric Utility	Constellation Power Sourc
MD	Perryman	1556 CT2		2011		CAIROS	106.7	5	3994.91	1.616	0.6872	23.395	4967.008	61212.91	3	Harford	Electric Utility	Constellation Power Sourc
MD	Perryman	1556 CT3		2011		CAIROS	66.67	5	2356.24	1.003	0.7498	16.602	3083.239	37996.09	3	Harford	Electric Utility	Constellation Power Sourc
MD	Perryman	1556 CT4		2011		CAIROS	46.61	5	1470.27	0.646	1.2	14.68	1985.576	24465.91	3	Harford	Electric Utility	Constellation Power Sourc
MD	Chalk Point	1571 GT2		2011		CAIROS	30.42	5	567.45	2.994	0.868	4.091	697.102	8589.831	3	Prince George's	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573 GT3		2011		CAIROS	50.12	5	1752.26	2.347	0.6603	11.4	2672.516	32938.63	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573 GT4		2011		CAIROS	52.88	5	1995.5	2.376	0.6221	11.004	2705.31	33340.34	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573 GT5		2011		CAIROS	45.9	5	1698.83	2.002	0.6531	9.813	2280.094	28096.97	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573 GT6		2011		CAIROS	44.98	5	1513.36	1.86	0.5179	7.253	2117.871	26101.14	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Herbert A Wagner	1554	1	2011		CAIROS	727.77	5	33584.39	0.132	0.1004	36.934	26220.62	441204.5	3	Anne Arundel	Electric Utility	Constellation Power Sourc
MD	Herbert A Wagner	1554	4	2011		CAIROS	194.23	5	26986.69	105.718	0.2395	49.528	28190.18	348684.1	3	Anne Arundel	Electric Utility	Constellation Power Sourc
MD	Gould Street	1553	3	2011		CAIROS	557.44	5	26874.75	0.093	0.0856	15.589	18499.38	311300.9	3	Baltimore (City)	Electric Utility	Constellation Power Sourc
MD	Perryman	1556 **51		2011		CAIROS	224.04	5	29632.73	0.11	0.0531	8.431	21716.42	365417.9	3	Harford	Electric Utility	Constellation Power Sourc
MD	Riverside	1559	4	2011		CAIROS	482.8	5	17898.33	0.067	0.2141	25.589	13289.41	223627.1	3	Baltimore	Electric Utility	Constellation Power Sourc
MD	Riverside	1559 CT6		2011		CAIROS	21.28	5	688.71	0.004	0.216	1.365	750.874	12637.11	3	Baltimore	Electric Utility	Constellation Power Sourc
MD	Westport	1560 CT5		2011		CAIROS	8.63	5	300.19	0.002	0.216	0.745	410.185	6901.316	3	Baltimore (City)	Electric Utility	Constellation Energy Comr
MD	Chalk Point	1571 **GT3		2011		CAIROS	159.03	5	10893.78	1.613	0.0873	6.472	9225.668	147354.7	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571 **GT4		2011		CAIROS	115.19	5	7571.02	0.126	0.0711	3.622	6164.644	103259.2	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571 **GT5		2011		CAIROS	160.4	5	12962.27	2.672	0.0876	7.622	9475.441	146237.6	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571 **GT6		2011		CAIROS	181.74	5	14774.97	1.631	0.0632	6.01	11466.65	185031.5	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571 SMECO		2011		CAIROS	99	5	6251	2.291	0.7607	35.599	5817.7	95240.7	3	Prince George's	Electric Utility	South Maryland Electric Co
MD	Dickerson	1572 GT2		2011		CAIROS	117.34	5	12539.01	0.141	0.1017	5.275	6205.247	104323.8	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Dickerson	1572 GT3		2011		CAIROS	124.18	5	12110.28	0.034	0.1144	6.452	6642.288	111765.8	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Rock Springs Generatin	7835	1	2011		CAIROS	357.72	5	54520.68	0.171	0.0355	7.781	33809.1	568895.5	3	Cecil	Electric Utility	Old Dominion Electric Coop
MD	Rock Springs Generatin	7835	2	2011		CAIROS	364.73	5	55755.87	0.173	0.0417	9.141	34341.05	577843.4	3	Cecil	Electric Utility	Old Dominion Electric Coop
MD	Rock Springs Generatin	7835	3	2011		CAIROS	503.13	5	76567.01	0.241	0.0432	13.729	47742.46	803366.2	3	Cecil	Electric Utility	North American Energy All
MD	Rock Springs Generatin	7835	4	2011		CAIROS	489.44	5	74577.91	0.236	0.0422	13.344	46838.36	788135.7	3	Cecil	Electric Utility	North American Energy All
MD	Brandywine Power Fac	54832	1	2011		CAIROS	1746.66	5	183109.5	0.433	0.0351	21.119	85718.25	1442378	3	Prince George's	Cogeneration	Panda Brandywine, LP
MD	Brandywine Power Fac	54832	2	2011		CAIROS	1714.7	5	178705.6	0.414	0.0327	18.585	82070.76	1380996	3	Prince George's	Cogeneration	Panda Brandywine, LP
MD	Vienna	1564	8	2011		CAIROS	293	5	16093	158.783	0.31	34.547	17346.25	213766.9	3	Dorchester	Electric Utility	Vienna Power, LLC
MD	Chalk Point	1571	3	2011		CAIROS	818.77	5	345136.7	38.69	0.11	263.932	226093.5	3784164	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571	4	2011		CAIROS	942.15	5	368826.3	41.714	0.1041	327.161	286330.7	4797821	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
48									11927589			8201.411		1.22E+08				

Facility Name	Representative		SO2 Phase	NOx Phase	Operating Status	Unit Type	Fuel Type (Primary)	Fuel Type (Secondary)	SO2 Control(s)	NOx Control(s)	PM Control(s)
	(Primary)	(Secondary)									
Brandon Shores	ARP : Morrison, Q	ARP : Trace	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boiler	Coal		Wet Lime FGD	Low NOx Burner Technology w/ Overfire Air Sel Cyclone Baghouse	
Brandon Shores	TRNOX : Haught, L	TRNOX : M	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boiler	Coal		Wet Limestone	Low NOx Burner Technology w/ Overfire Air Sel Cyclone Baghouse	
C P Crane	TRNOXOS : Butler,	TRNOXOS : Table 1		Group 2	Operating	Cyclone boiler	Coal			Overfire Air Combustion Modification/Fuel Reb	Baghouse
C P Crane	CAIRNOX : Butler,	CAIRNOX : Table 1		Group 2	Operating	Cyclone boiler	Coal			Overfire Air Combustion Modification/Fuel Reb	Baghouse
Herbert A Wagner	ARP : Morrison, Q	ARP : Trace	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boiler	Coal			Low NOx Burner Technology (Dry Bottom only) Electrostatic Precipitator	
Herbert A Wagner	CAIROS : Morrisor	CAIROS : Tr	Phase 2	Phase 2	Operating	Dry bottom wall-fired boiler	Coal			Low NOx Burner Technology w/ Overfire Air Sel Electrostatic Precipitator	
R. Paul Smith Power Station	ARP : Cannon, David	ARP : Cain, Phase 2		Phase 1 Gr	Operating	Dry bottom wall-fired boiler	Coal			Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitator
R. Paul Smith Power Station	ARP : Cannon, David	ARP : Cain, Phase 2		Phase 1 Gr	Operating	Tangentially-fired	Coal			Low NOx Burner Technology w/ Closed-coupled/Seq	Electrostatic Precipitator Electrostatic Precipitator
Chalk Point	RGGI : Garlick, Jan	RGGI : Gaud	Table 1	Phase 1 Gr	Operating	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas	Wet Limestone	Low NOx Burner Technology (Dry Bottom only) Electrostatic Precipitator	
Chalk Point	ARP : Garlick, James	ARP : Gaud	Table 1	Phase 1 Gr	Operating	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas	Wet Limestone	Low NOx Burner Technology (Dry Bottom only) Electrostatic Precipitator	
Dickerson	TRSO2G1 : Gouveia	TRSO2G1 : Phase 2		Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Separated OFA Baghouse Electrostatic	
Dickerson	TRNOXOS : Gouveia	TRNOXOS : Phase 2		Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Separated OFA Baghouse Electrostatic	
Dickerson	TRNOXOS : Gouveia	TRNOXOS : Phase 2		Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Separated OFA Baghouse Electrostatic	
Morgantown	ARP : Garlick, James	ARP : Gaud	Table 1	Phase 1 Gr	Operating	Tangentially-fired	Coal	Residual Oil	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Seq	Electrostatic Precipitator
Morgantown	ARP : Garlick, James	ARP : Gaud	Table 1	Phase 1 Gr	Operating	Tangentially-fired	Coal	Residual Oil	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Seq	Electrostatic Precipitator
AES Warrior Run	RGGI : Leaf, Jeff	(RGGI : Braun, Wilma L (3185),	CAIR	Operating		Circulating fluidized bed boiler	Coal	Diesel Oil	Fluidized Bed Limestone	Ammonia Injection Selective Non-catalytic Reduction	Baghouse
Perryman	ARP : Blair, Scott	ARP : Tracey, Edward F (2683)	(En	Operating		Combustion turbine	Diesel Oil				
Perryman	ARP : Blair, Scott	ARP : Tracey, Edward F (2683)	(En	Operating		Combustion turbine	Diesel Oil				
Perryman	CAIRNOX : Blair, Scott	CAIRNOX : Tracey, Edward F (2683)	Operating			Combustion turbine	Diesel Oil				
Perryman	ARP : Blair, Scott	ARP : Tracey, Edward F (2683)	(En	Operating		Combustion turbine	Diesel Oil				
Chalk Point	CAIROS : Garlick, James	CAIROS : Gaudette, Robert (605481)	Operating			Combustion turbine	Diesel Oil				
Morgantown	ARP : Garlick, James	ARP : Gaudette, Robert (605481)	Operating			Combustion turbine	Diesel Oil				
Morgantown	ARP : Garlick, James	ARP : Gaudette, Robert (605481)	Operating			Combustion turbine	Diesel Oil				
Morgantown	ARP : Garlick, James	ARP : Gaudette, Robert (605481)	Operating			Combustion turbine	Diesel Oil				
Herbert A Wagner	TRNOX : Haught, L	TRNOX : M	Phase 2		Operating	Dry bottom wall-fired boiler	Other Oil	Pipeline Natural Gas			Electrostatic Precipitator
Herbert A Wagner	RGGI : Morrison, C	RGGI : Trace	Phase 2		Operating	Dry bottom wall-fired boiler	Other Oil	Pipeline Natural Gas			Electrostatic Precipitator
Gould Street	ARP : Blair, Scott	ARP : Trace	Phase 2		Operating	Dry bottom wall-fired boiler	Pipeline Natural Gas				
Perryman	ARP : Blair, Scott	ARP : Trace	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Riverside	ARP : Blair, Scott	ARP : Trace	Phase 2		Operating	Dry bottom wall-fired boiler	Pipeline Natural Gas				
Riverside	ARP : Blair, Scott	ARP : Tracey, Edward F (2683)	(En	Operating		Combustion turbine	Pipeline Natural Gas	Diesel Oil			
Westport	CAIROS : Blair, Scott	CAIROS : Tracey, Edward F (2683)	Operating			Combustion turbine	Pipeline Natural Gas				
Chalk Point	CAIRNOX : Garlick, James	CAIRNOX : Phase 2			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	ARP : Garlick, James	ARP : Gaud	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	ARP : Garlick, James	ARP : Gaud	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	ARP : Garlick, James	ARP : Gaud	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	ARP : Garlick, James	ARP : Gaudette, Robert (605481)	Operating			Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Dickerson	CAIRNOX : Garlick, James	CAIRNOX : Phase 2			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Dickerson	CAIRSO2 : Garlick, James	CAIRSO2 : Phase 2			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Rock Springs Generating Station	ARP : Peach, James	ARP : Doug	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generating Station	ARP : Peach, James	ARP : Doug	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generating Station	ARP : Peach, James	ARP : Doug	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generating Station	ARP : Peach, James	ARP : Doug	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Brandywine Power Facility	ARP : Martin, John	ARP : Brigg	Phase 2		Operating	Combined cycle	Pipeline Natural Gas	Diesel Oil		Water Injection Other	
Brandywine Power Facility	ARP : Martin, John	ARP : Brigg	Phase 2		Operating	Combined cycle	Pipeline Natural Gas	Diesel Oil		Water Injection Other	
Vienna	ARP : Grant, Jack	ARP : Sullivan	Phase 2		Operating	Tangentially-fired	Residual Oil				
Chalk Point	ARP : Garlick, James	ARP : Gaud	Phase 2		Operating	Tangentially-fired	Residual Oil	Pipeline Natural Gas		Overfire Air	
Chalk Point	CAIRSO2 : Garlick, James	CAIRSO2 : Phase 2			Operating	Tangentially-fired	Residual Oil	Pipeline Natural Gas		Overfire Air	

State	Facility Name	Facility ID		Year	Associate	Program(s)	Operating Time	# of Months Reported	Gross Load (MW-h)	SO2 (tons)	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	CO2 (short tons)	Heat Input (MMBtu)	EPA Region	County	Source Category	Owner
		(ORISPL)	Unit ID															
MD	Brandon Shores	602	1	2014		CAIROS	2694.56	5	1118773	714.035	0.0923	481.504	1185612	1.16E+07	3	Anne Arundel	Electric Utility	Raven Power Fort Smallv
MD	Brandon Shores	602	2	2014		CAIROS	2915.68	5	1185928	721.138	0.0823	520.367	1350937	1.32E+07	3	Anne Arundel	Electric Utility	Raven Power Fort Smallv
MD	C P Crane	1552	1	2014		CAIROS	116.15	5	6127.12	15.283	0.3478	14.004	6958.253	66345.82	3	Baltimore	Electric Utility	C.P. Crane LLC
MD	C P Crane	1552	2	2014		CAIROS	1354.74	5	128047.3	395.237	0.2584	232.107	178263.2	1699679	3	Baltimore	Electric Utility	C.P. Crane LLC
MD	Herbert A Wagner	1554	2	2014		CAIROS	1064.15	5	64494.9	619.378	0.2702	123.189	82900.89	808015.2	3	Anne Arundel	Electric Utility	Raven Power Fort Smallv
MD	Herbert A Wagner	1554	3	2014		CAIROS	1217.45	5	243107.3	1939.889	0.0744	77.046	247198.4	2356974	3	Anne Arundel	Electric Utility	Raven Power Fort Smallv
MD	Chalk Point	1571	1	2014	CSE12, CSE	CAIROS	2701.03	5	663037	674.04	0.104	336.469	694170.6	6771596	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571	2	2014	CSE12, CSE	CAIROS	1881.16	5	444415.3	475.359	0.2758	643.567	458810.7	4476799	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Dickerson	1572	1	2014	CSDW13, (	CAIROS	1516.53	5	153946.7	88.577	0.2353	168.696	146402	1426936	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Dickerson	1572	2	2014	CSDW13, (	CAIROS	1362.51	5	135311.6	75.303	0.2368	151.326	130102	1268059	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Dickerson	1572	3	2014	CSDW13, (	CAIROS	1258.92	5	122786.5	78.383	0.2353	135.847	118103.6	1151128	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573	1	2014	MSFW1, M	CAIROS	3374.05	5	1281962	582.357	0.0343	197.265	1200504	1.17E+07	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573	2	2014	MSFW2, M	CAIROS	3143.93	5	1322639	610.815	0.0379	230.094	1266327	1.23E+07	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	AES Warrior Run	10678	1	2014		CAIROS	3118.22	5	481828.2	443.273	0.0676	186.291	572658.7	5583672	3	Allegany	Cogeneration	AES Corporation
MD	Perryman	1556 CT1		2014		CAIROS	27.01	2	1108.46	0.083	0.7706	6.905	1291.478	15916.41	3	Harford	Electric Utility	Constellation Power Sour
MD	Perryman	1556 CT2		2014		CAIROS	7.51	2	213.39	0.019	0.6071	1.293	302.296	3724.498	3	Harford	Electric Utility	Constellation Power Sour
MD	Perryman	1556 CT3		2014		CAIROS	9.56	2	235.62	0.112	0.592	1.515	351.285	4328.383	3	Harford	Electric Utility	Constellation Power Sour
MD	Perryman	1556 CT4		2014		CAIROS	16.05	2	553.3	0.045	1.2	5.154	696.948	8590.53	3	Harford	Electric Utility	Constellation Power Sour
MD	Chalk Point	1571 GT2		2014		CAIROS	5.5	5	98.9	0.369	1.2007	1.462	197.6	2435.9	3	Prince George's	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573 GT3		2014		CAIROS	7.83	5	198.17	0.545	0.5935	1.045	291.3	3596.1	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573 GT4		2014		CAIROS	10.18	5	368	0.808	0.5725	1.519	432.2	5335.8	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573 GT5		2014		CAIROS	8.7	5	299.39	0.685	0.5582	1.264	366.4	4523.9	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Morgantown	1573 GT6		2014		CAIROS	5.86	5	194.26	0.437	0.5782	0.831	233.4	2882.1	3	Charles	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Herbert A Wagner	1554	1	2014		CAIROS	583.61	5	10635.97	0.053	0.051	11.759	10439.08	175654.8	3	Anne Arundel	Electric Utility	Raven Power Fort Smallv
MD	Herbert A Wagner	1554	4	2014		CAIROS	17.67	5	1916	10.085	0.1336	2.958	2764.859	34076.12	3	Anne Arundel	Electric Utility	Raven Power Fort Smallv
MD	Gould Street	1553	3	2014		CAIROS	150.62	2	5235.64	0.019	0.0951	5.192	3672.144	61784.47	3	Baltimore (City)	Electric Utility	Constellation Power Sour
MD	Perryman	1556 **51		2014		CAIROS	136.73	2	18877.62	0.068	0.0819	7.974	13468.51	226628.5	3	Harford	Electric Utility	Constellation Power Sour
MD	Riverside	1559	4	2014		CAIROS	188.36	2	6750.58	0.025	0.1587	7.871	4866.306	81874.57	3	Baltimore	Electric Utility	Constellation Power Sour
MD	Riverside	1559 CT6		2014		CAIROS	0	2							3	Baltimore	Electric Utility	Constellation Power Sour
MD	Westport	1560 CT5		2014		CAIROS	15.88	2	1760.56	0.008	0.216	2.966	1631.787	27461.05	3	Baltimore (City)	Electric Utility	Constellation Energy Con
MD	Chalk Point	1571 **GT3		2014		CAIROS	5.35	5	316.67	0.266	0.1015	0.251	334.2	4682.1	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571 **GT4		2014		CAIROS	44.23	5	2856.99	0.315	0.0837	1.525	2298.3	37823.4	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571 **GT5		2014		CAIROS	9.34	5	760.02	0.003	0.0755	0.344	533.7	9042.1	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571 **GT6		2014		CAIROS	17.77	5	1462.07	0.005	0.0761	0.648	1005.8	17044.9	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571 SMECO		2014		CAIROS	22	5	1315	0.005	0.1219	1.01	977.4	16565.3	3	Prince George's	Electric Utility	South Maryland Electric (
MD	Dickerson	1572 GT2		2014		CAIROS	36.03	5	4457.72	0.016	0.1151	3.071	3151.6	53409.1	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Dickerson	1572 GT3		2014		CAIROS	268.18	5	35533.37	0.126	0.126	26.724	25027.2	424246	3	Montgomery	Electric Utility	GenOn Mid-Atlantic, LLC
MD	Rock Springs Generati	7835	1	2014		CAIROS	49.62	2	7880.39	0.024	0.0428	1.286	4845.472	81535.67	3	Cecil	Electric Utility	Old Dominion Electric Co
MD	Rock Springs Generati	7835	2	2014		CAIROS	50.99	2	7928.24	0.024	0.0529	1.743	4842.781	81488.43	3	Cecil	Electric Utility	Old Dominion Electric Co
MD	Rock Springs Generati	7835	3	2014		CAIROS	151.29	2	23886.2	0.074	0.0402	3.802	14643.02	246397.8	3	Cecil	Electric Utility	EP Rock Springs, LLC
MD	Rock Springs Generati	7835	4	2014		CAIROS	136.27	2	21930.9	0.067	0.0383	3.762	13370.36	224983.3	3	Cecil	Electric Utility	EP Rock Springs, LLC
MD	Brandywine Power Fa	54832	1	2014		CAIROS	650.56	2	67241.48	0.159	0.0361	7.477	31434.3	528935.9	3	Prince George's	Cogeneration	Panda Brandywine, LP
MD	Brandywine Power Fa	54832	2	2014		CAIROS	579.95	2	58351.43	0.132	0.0337	5.798	26168.12	440325.9	3	Prince George's	Cogeneration	Panda Brandywine, LP
MD	Vienna	1564	8	2014		CAIROS	52.77	5	1476.84	16.926	0.1747	4.31	2491.453	30702.41	3	Dorchester	Electric Utility	Vienna Power, LLC
MD	Chalk Point	1571	3	2014		CAIROS	651.39	5	248428.9	8.395	0.0977	172.288	152326.4	2569483	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
MD	Chalk Point	1571	4	2014		CAIROS	568.85	5	201333.7	2.75	0.09	142.261	135556.3	2286660	3	Prince George's	Electric Utility	GenOn Chalk Point, LLC
									8086009			3933.78		82087413				

Facility Name	SO2 Phase	NOx Phase	Operating Status	Unit Type	Fuel Type (Primary)	Fuel Type (Secondary)	SO2 Control(s)	NOx Control(s)	PM Control(s)
Brandon Shores	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boiler	Coal		Wet Lime FGD	Low NOx Burner Technology w/ O\ Cyclone	Baghouse
Brandon Shores	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boiler	Coal		Wet Limestone	Low NOx Burner Technology w/ O\ Cyclone	Baghouse
C P Crane	Table 1	Group 2	Operating	Cyclone boiler	Coal			Overfire Air	Combustion Modifiers Baghouse
C P Crane	Table 1	Group 2	Operating	Cyclone boiler	Coal			Overfire Air	Combustion Modifiers Baghouse
Herbert A Wagner	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boiler	Coal			Low NOx Burner Technology (Dry F	Electrostatic Precipitator
Herbert A Wagner	Phase 2	Phase 2	Operating	Dry bottom wall-fired boiler	Coal			Low NOx Burner Technology w/ O\	Electrostatic Precipitator
Chalk Point	Table 1	Phase 1 Gr	Operating	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas	Wet Limestone	Low NOx Burner Technology (Dry F	Electrostatic Precipitator
Chalk Point	Table 1	Phase 1 Gr	Operating	Dry bottom wall-fired boiler	Coal	Pipeline Natural Gas	Wet Limestone	Low NOx Burner Technology (Dry F	Electrostatic Precipitator
Dickerson	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Se	Baghouse
Dickerson	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Se	Baghouse
Dickerson	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Se	Baghouse
Morgantown	Table 1	Phase 1 Gr	Operating	Tangentially-fired	Coal	Residual Oil	Wet Limestone	Low NOx Burner Technology w/ Cl	Electrostatic Precipitator
Morgantown	Table 1	Phase 1 Gr	Operating	Tangentially-fired	Coal	Residual Oil	Wet Limestone	Low NOx Burner Technology w/ Cl	Electrostatic Precipitator
AES Warrior Run			Operating	Circulating fluidized bed boiler	Coal	Diesel Oil		Fluidized Bed Limestone	Ammonia Injection
Perryman	Perryman Energy Generation Inc.		Operating	Combustion turbine	Diesel Oil				
Perryman			Operating	Combustion turbine	Diesel Oil				
Perryman			Operating	Combustion turbine	Diesel Oil				
Perryman			Operating	Combustion turbine	Diesel Oil				
Chalk Point			Operating	Combustion turbine	Diesel Oil				
Morgantown			Operating	Combustion turbine	Diesel Oil				
Morgantown			Operating	Combustion turbine	Diesel Oil				
Herbert A Wagner	Phase 2		Operating	Dry bottom wall-fired boiler	Other Oil	Pipeline Natural Gas			Electrostatic Precipitator
Herbert A Wagner	Phase 2		Operating	Dry bottom wall-fired boiler	Other Oil	Pipeline Natural Gas			Electrostatic Precipitator
Gould Street	Phase 2		Operating	Dry bottom wall-fired boiler	Pipeline Natural Gas				
Perryman	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Riverside	Phase 2		Operating	Dry bottom wall-fired boiler	Pipeline Natural Gas				
Riverside	Perryman Energy Generation Inc.		Operating (Retired)	Combustion turbine	Pipeline Natural Gas	Diesel Oil			
Westport			Operating	Combustion turbine	Pipeline Natural Gas				
Chalk Point			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Dickerson	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Dickerson	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Rock Springs Generating Station	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generating Station	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generating Station	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generating Station	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Brandywine Power Facility	Phase 2		Operating	Combined cycle	Pipeline Natural Gas	Diesel Oil, Liquified Petroleum Gas	Water Injection	Other	
Brandywine Power Facility	Phase 2		Operating	Combined cycle	Pipeline Natural Gas	Diesel Oil, Liquified Petroleum Gas	Water Injection	Other	
Vienna	Phase 2		Operating	Tangentially-fired	Residual Oil				
Chalk Point	Phase 2		Operating	Tangentially-fired	Residual Oil	Pipeline Natural Gas		Overfire Air	
Chalk Point	Phase 2		Operating	Tangentially-fired	Residual Oil	Pipeline Natural Gas		Overfire Air	

Appendix C

Maryland Coal-Fired EGUs 24 Hour Block Data Analysis

Daily ozone season data for the period of 2007 through 2013 was downloaded from Air Markets Program Data (AMPD), which is maintained by the U.S. EPA (<http://ampd.epa.gov/ampd/QueryToolie.html>).

This data included, but was not limited to: daily NO_x emission rate (lbs/MMBtu), NO_x emissions per day (tons), operating time (hours), daily heat input (MMBtu), and load (MWh).

For each parameter, there are a maximum 153 data points for each ozone season:

May	31 days
June	30
July	31
August	31
September	30
TOTAL	153 days

For each ozone season, the data was sorted from the minimum to the maximum daily NO_x emission rate; days which had no operation were not included. Thus, if the unit operated for 100 days, there would be 100 data points with values, and 53 with no values. This accounts for why some ozone seasons extend all the way to the right on the graph (153 data points), and others not. These sorted daily NO_x emission rates were plotted along the x-axis, with the corresponding daily NO_x emission rate on the y-axis. This was done for all coal fired units in Maryland. Currently, all coal fired units in Maryland have either SCR or SNCR post combustion controls.

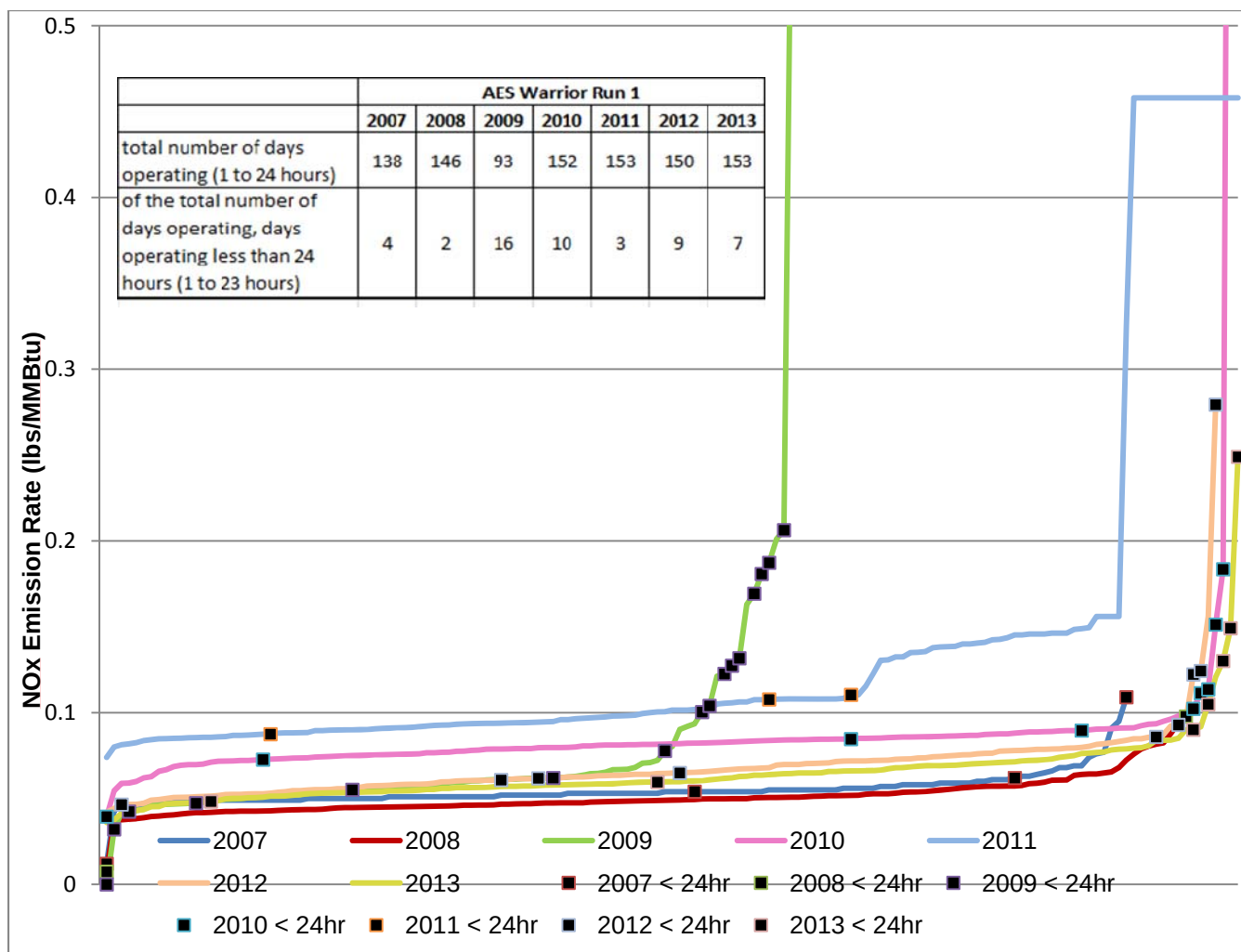
For each ozone season, any daily operation of less than 24 hours was identified by a black box. This was done to determine if start up or shut down (or, operation less than 24 hours per day), contributes to excessive, or, at a minimum, above average daily NO_x emission rates, which has been reported by certain operators. Based on a visual examination of the distribution of the black boxes, there is a slight increase in frequency of operating less than 24 hours per day in periods of either above or below average NO_x emission rates. However, these periods of operating less than 24 hours (black boxes) also occur during periods reporting average NO_x emission rates. Therefore, start up and shut downs are not solely responsible for excessive, or, at a minimum, above average NO_x emission rates.

On each graph, there is a table reporting the total number of days the unit operated during each ozone season (maximum of 153), along with the number of days operating less than 24 hours; this number corresponds to the number of black boxes for that ozone season. The purpose for this was to first look at operating frequency in general: was the unit operating all 153 days or less, and any recent changes, specifically a reduction, in operating frequency; and secondly to see the number of times the unit was started and shut down during each ozone season, or the number of times the unit was 'cycled'. Certain operators have reported that they are being both called on less, and 'cycled' more in recent years, which has contributed to the above normal average ozone season NO_x emission rate during recent years. This is not supported by the data.

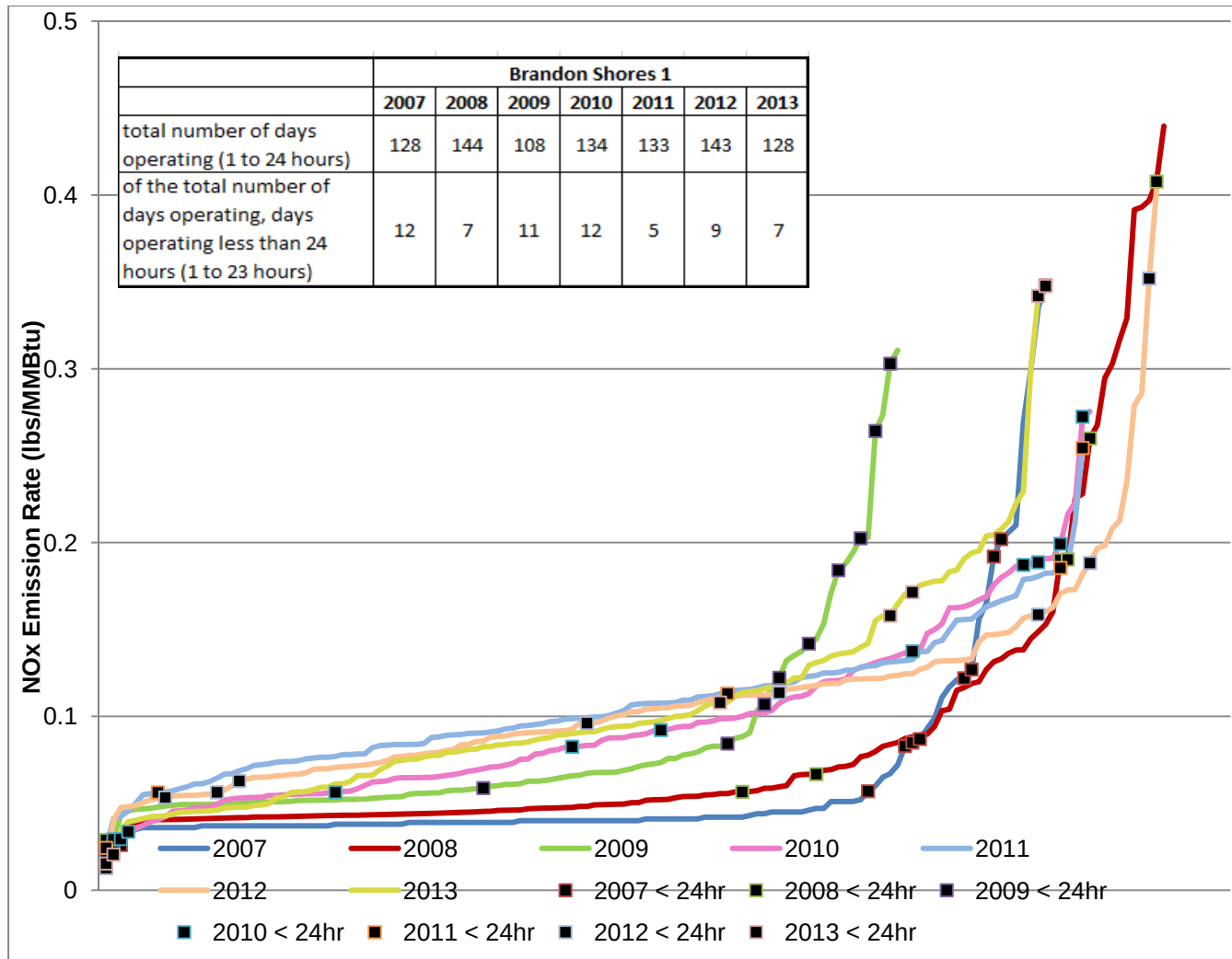
MDE Regulations Development Division 8/15/14

Facility Name	Unit #	Fuel	Control	Average OS NOx Emission Rate, lbs/MMBtu (based on visual inspection)					Capacity (based on visual inspection)				
				min	year	max	year	2013	min	year	max	year	2013
AES Warrior Run	1	coal	SNCR	0.04	2008	0.1	2011	0.07	60%	2009	99%	2013	99%
Brandon Shores	1	coal	SCR	0.04	2007	0.1	2011	0.09	70%	2009	92%	2012	82%
	2	coal	SCR	0.06	2008	0.12	2012	0.11	85%	2013	99%	2011	85%
Chalk Point	1	coal	SCR	0.17	2008	0.41	2007	0.08	62%	2013	92%	2009	62%
	2	coal	SNCR	0.17	2010	0.41	2007	0.2	48%	2012	98%	2010	68%
Crane	1	coal	SNCR	0.3	2009	0.4	2010	0.4	27%	2010	67%	2012	45%
	2	coal	SNCR	0.3	2009	0.4	2013	0.4	33%	2013	80%	2007	33%
Dickerson	1	coal	SNCR	0.24	2010	0.28	2007	0.27	50%	2013	93%	2010	50%
	2	coal	SNCR	0.25	2010	0.28	2013	0.28	50%	2013	95%	2007	50%
	3	coal	SNCR	0.24	2010	0.28	2013	0.28	52%	2013	98%	2008	52%
Morgantown	1	coal	SCR	0.03	2013	0.06	2007	0.03	65%	2007	90%	2008	80%
	2	coal	SCR	0.03	2012	0.3	2007	0.03	74%	2013	98%	2007	74%
Wagner	2	coal	SNCR	0.31	2009	0.43	2008	0.4	47%	2013	98%	2011	47%
	3	coal	SCR	0.04	2009	0.1	2008	0.04	73%	2012	95%	2007	80%

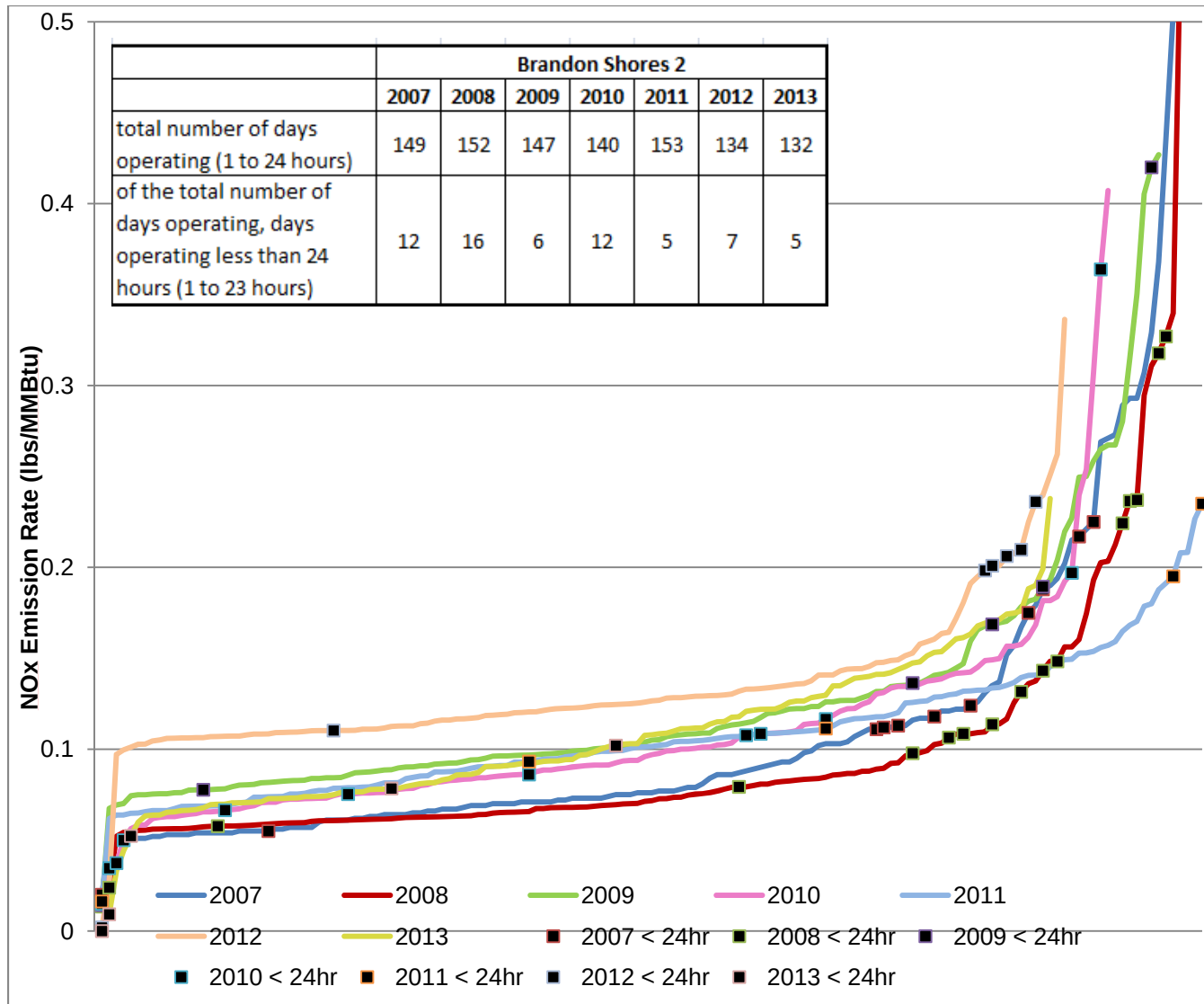
AES Warrior Run (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



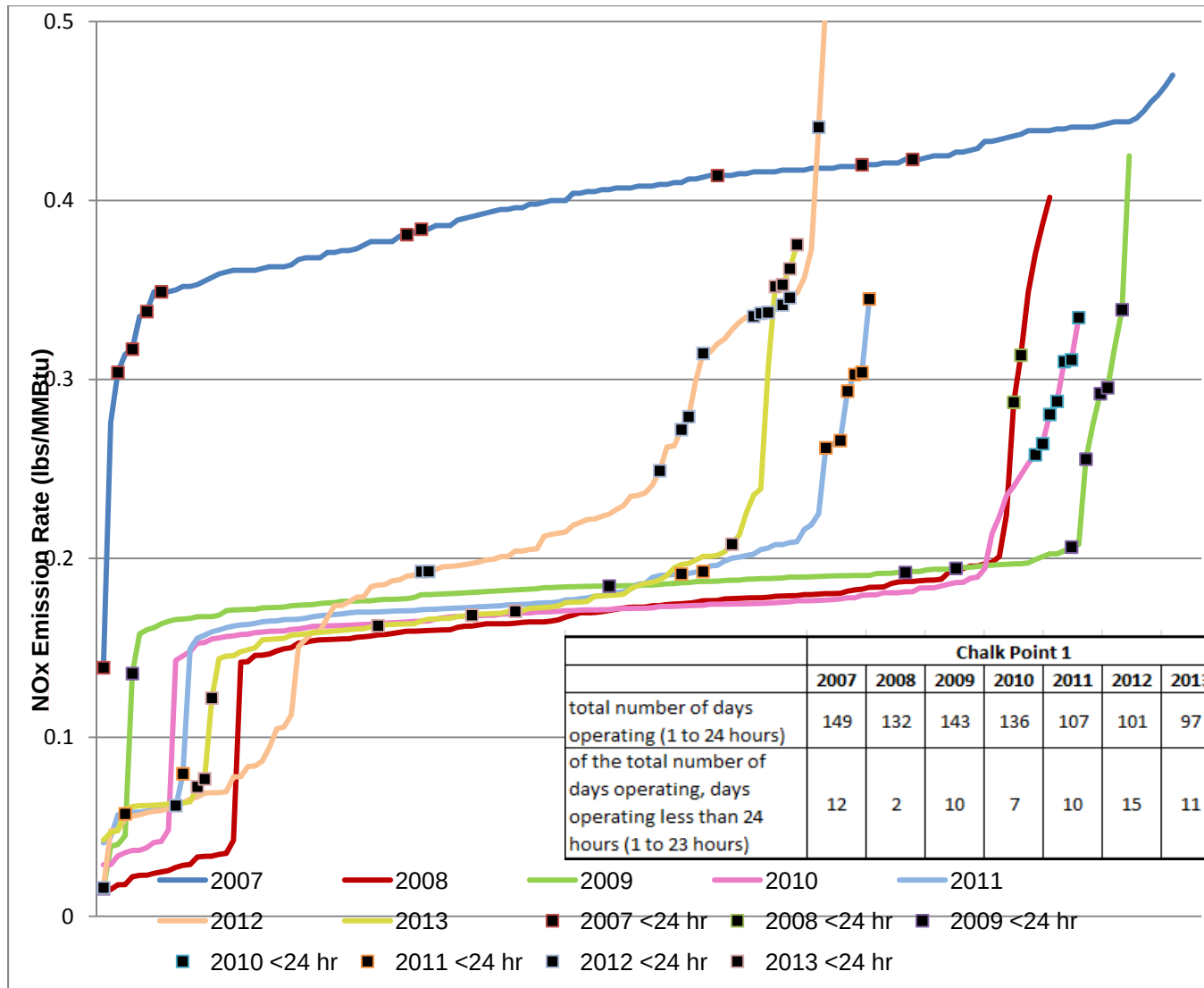
Brandon Shores Unit 1 (Coal, SCR) – Daily OS NOx Emission Rate, Sorted



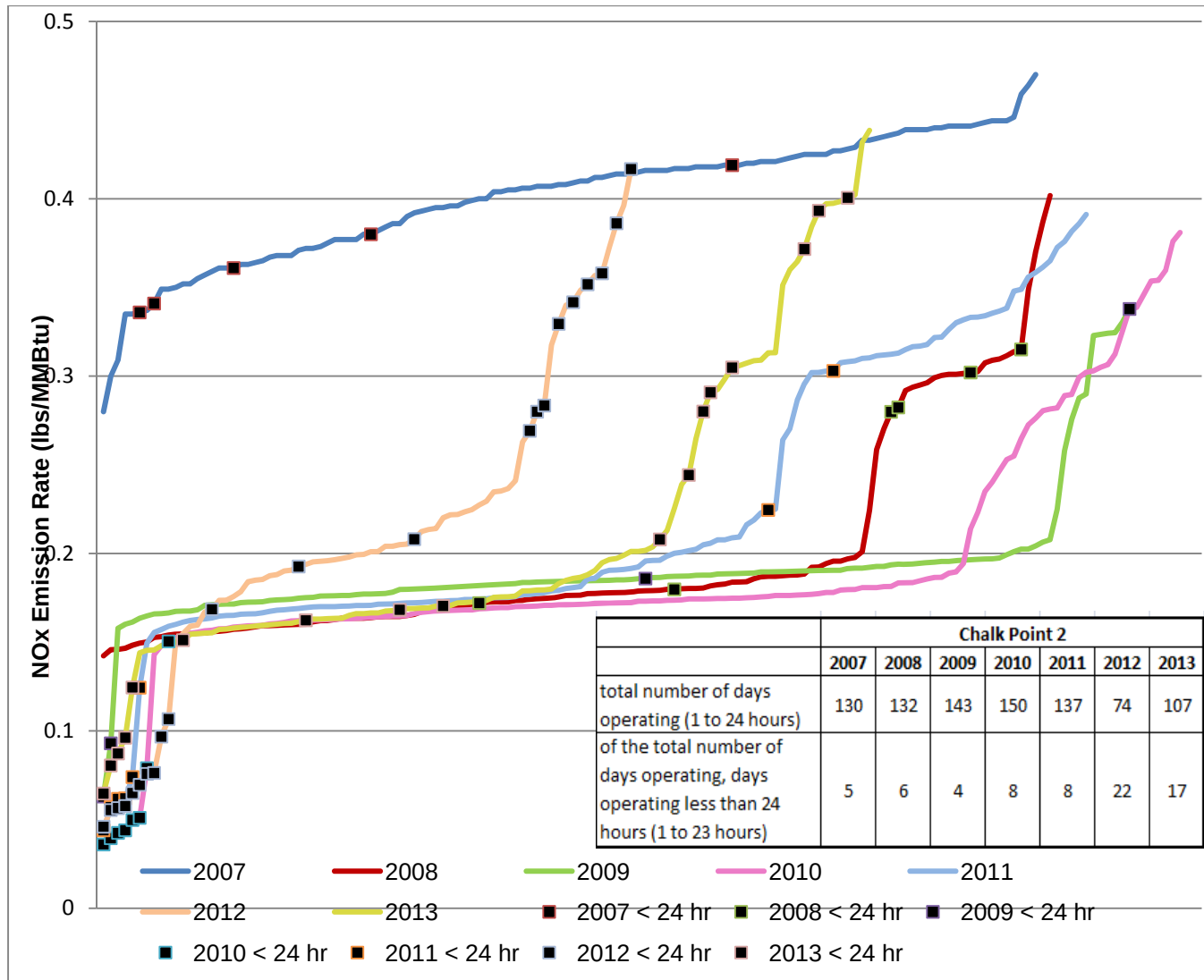
Brandon Shores Unit 2 (Coal, SCR) – Daily OS NOx Emission Rate, Sorted



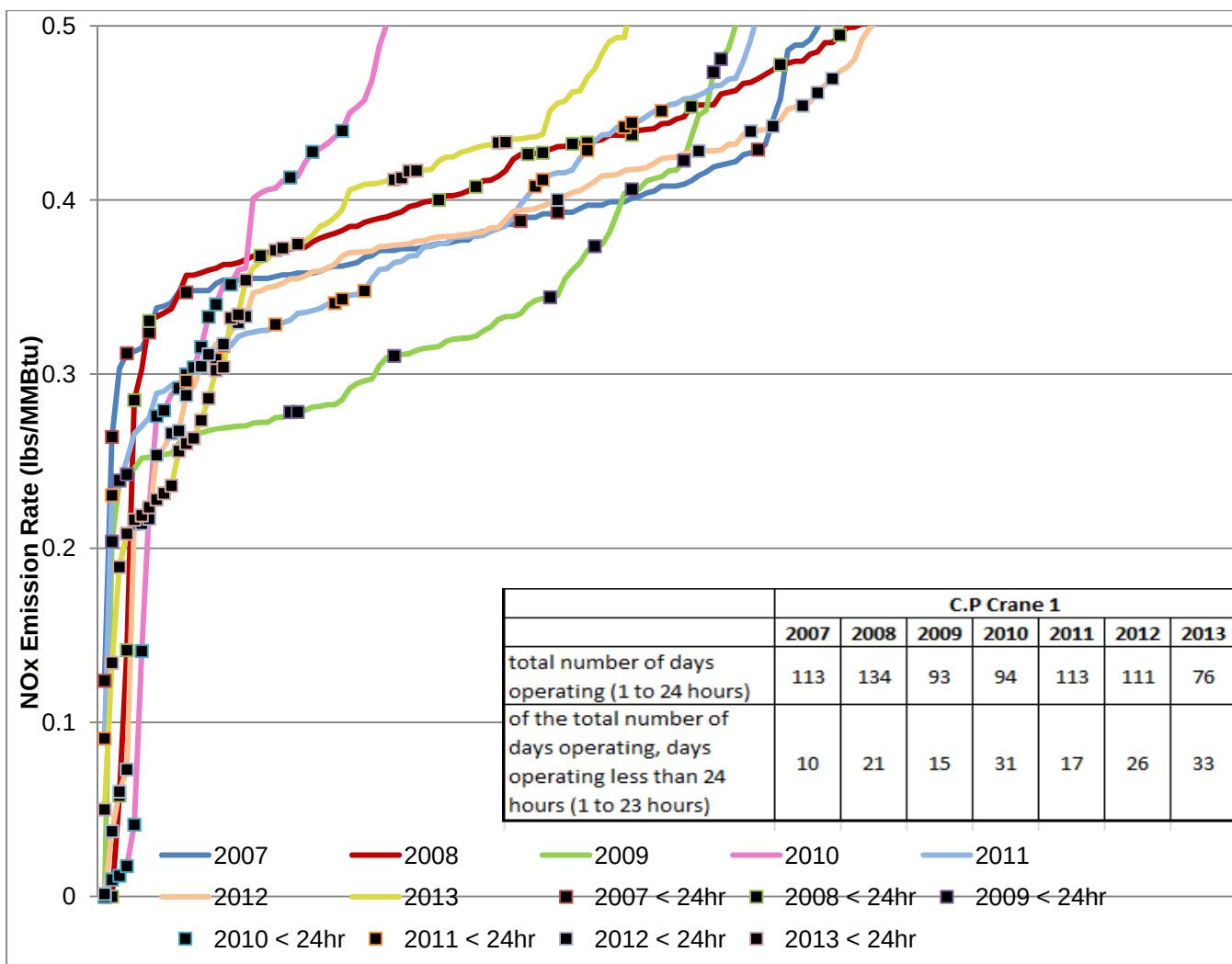
Chalk Point Unit 1 (Coal, SCR) – Daily OS NOx Emission Rate, Sorted



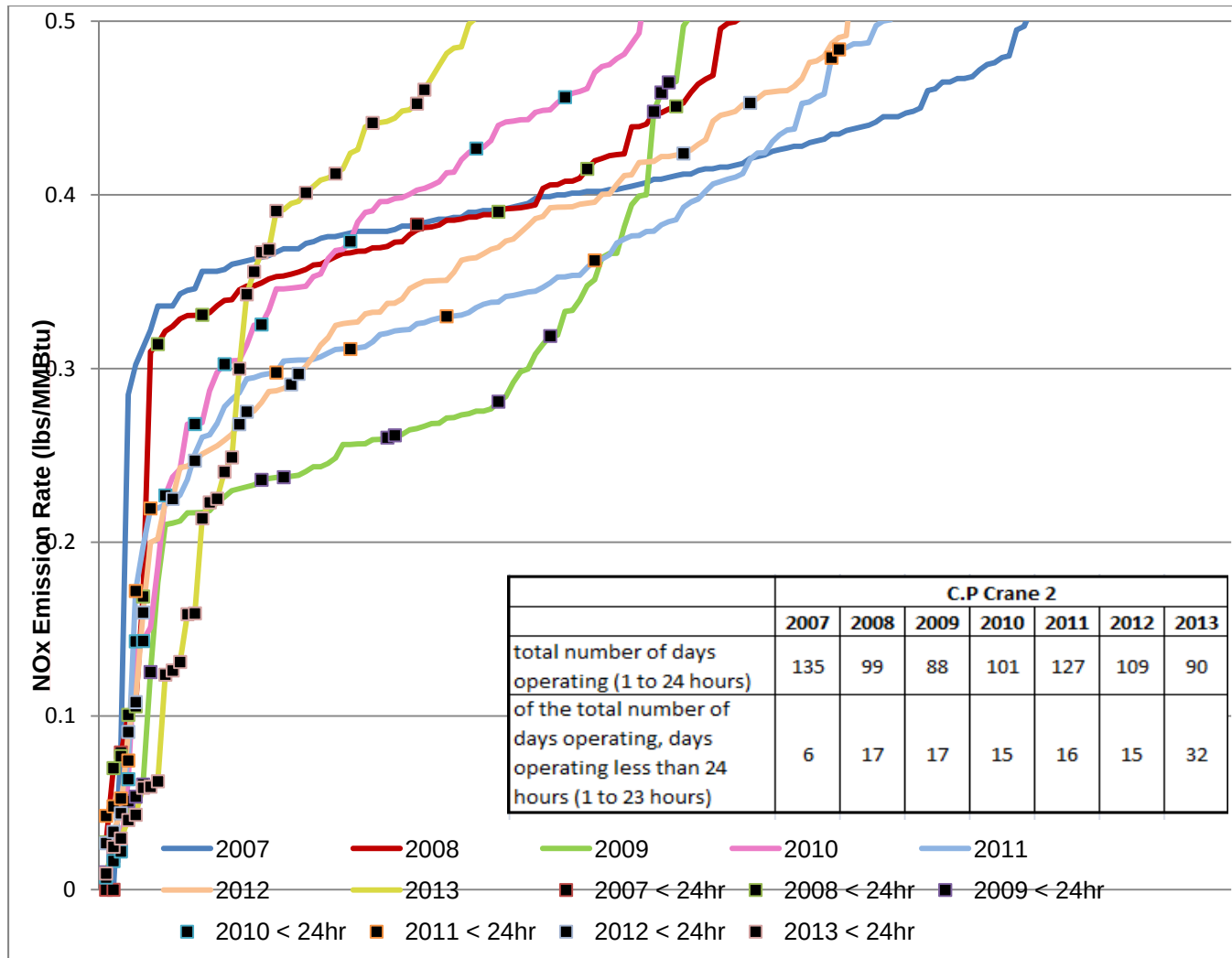
Chalk Point Unit 2 (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



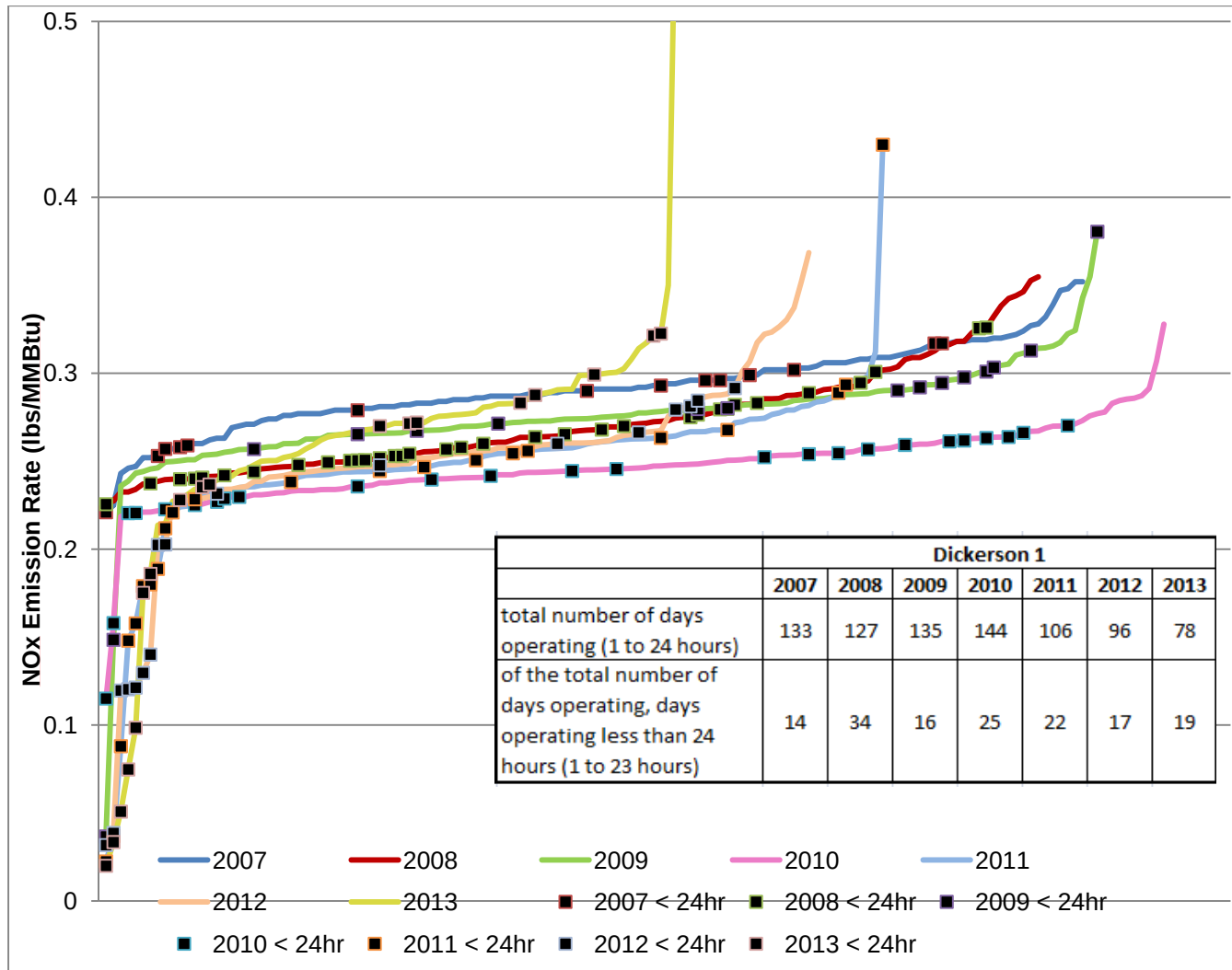
C.P. Crane Unit 1 (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



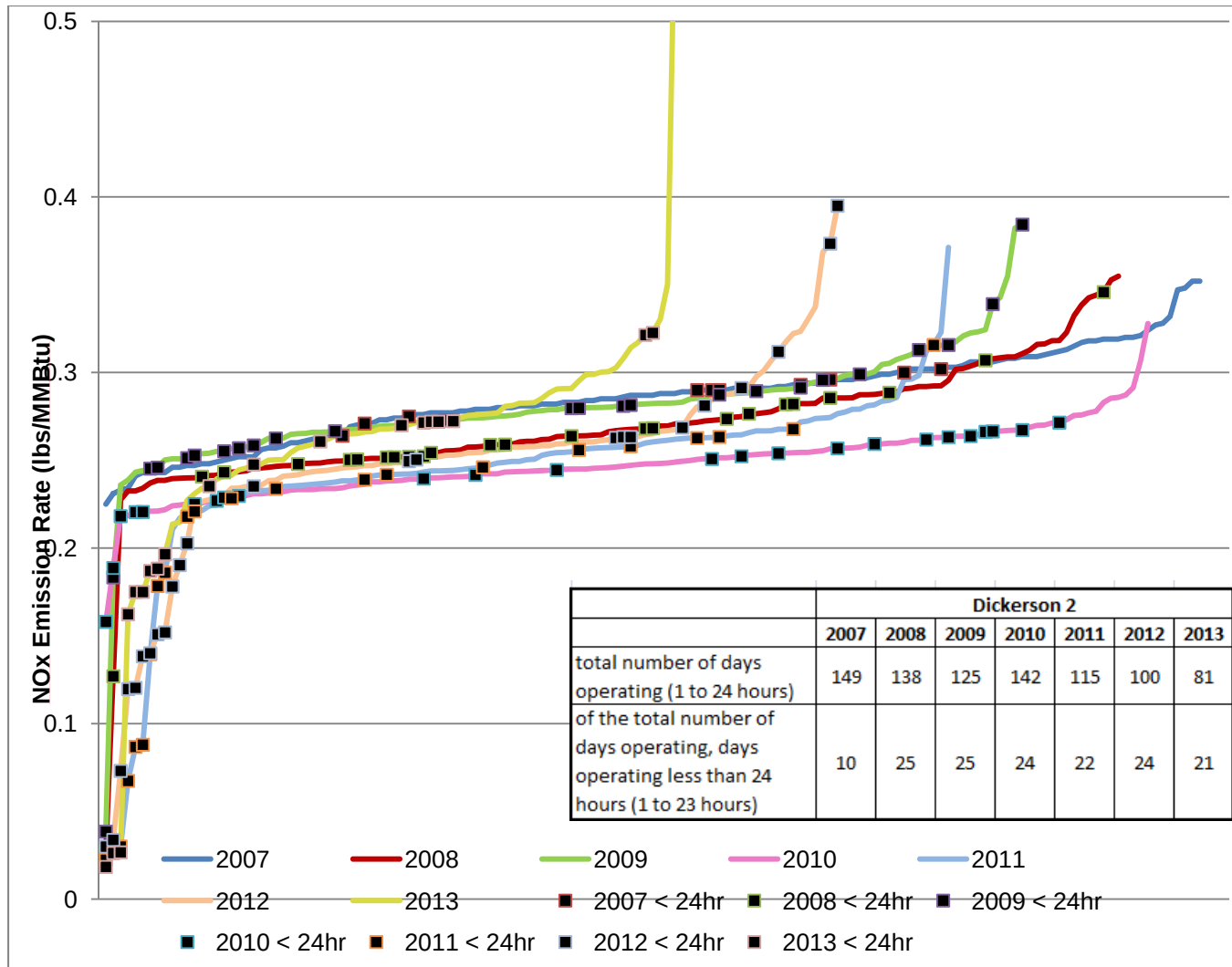
C.P. Crane Unit 2 (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



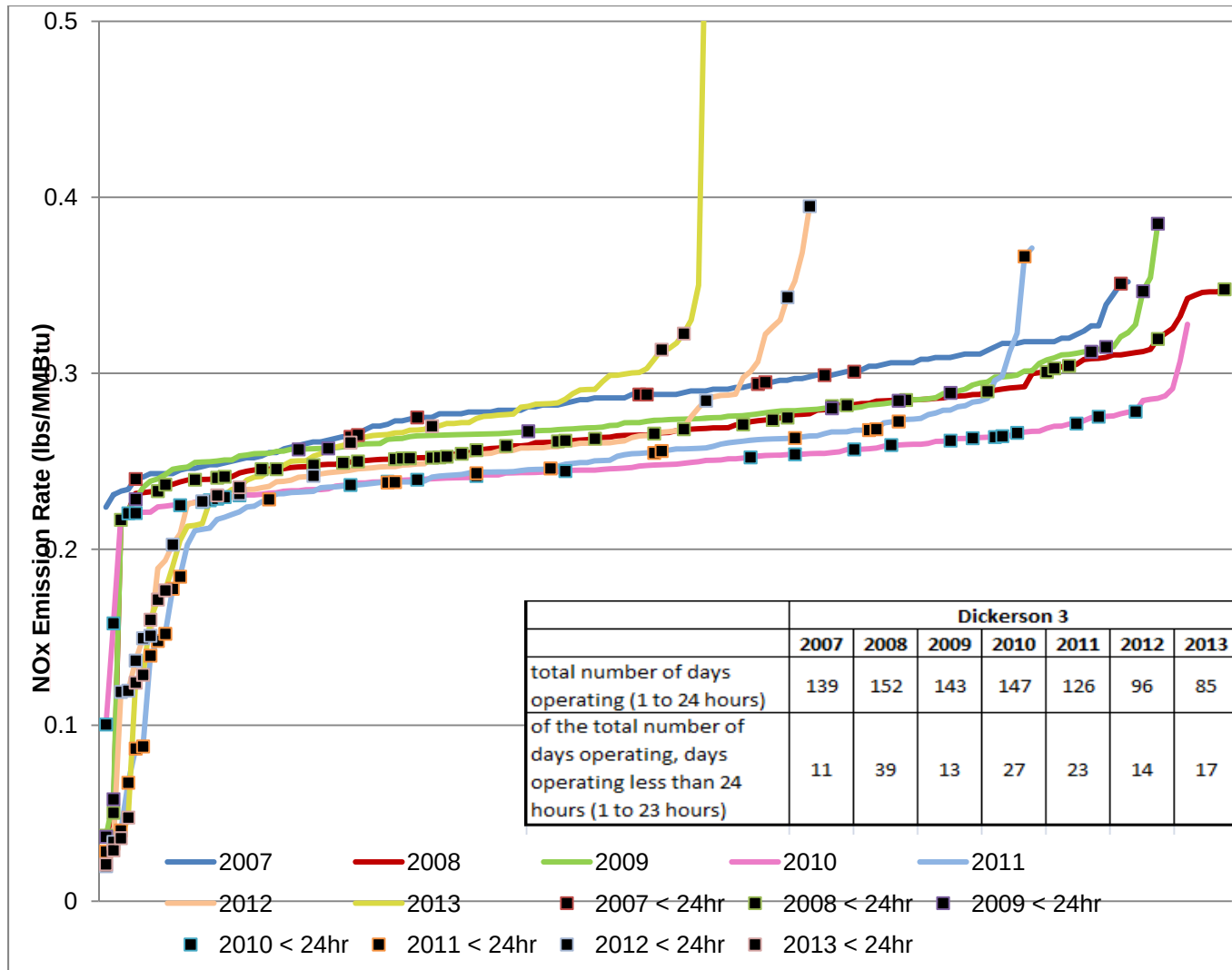
Dickerson Unit 1 (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



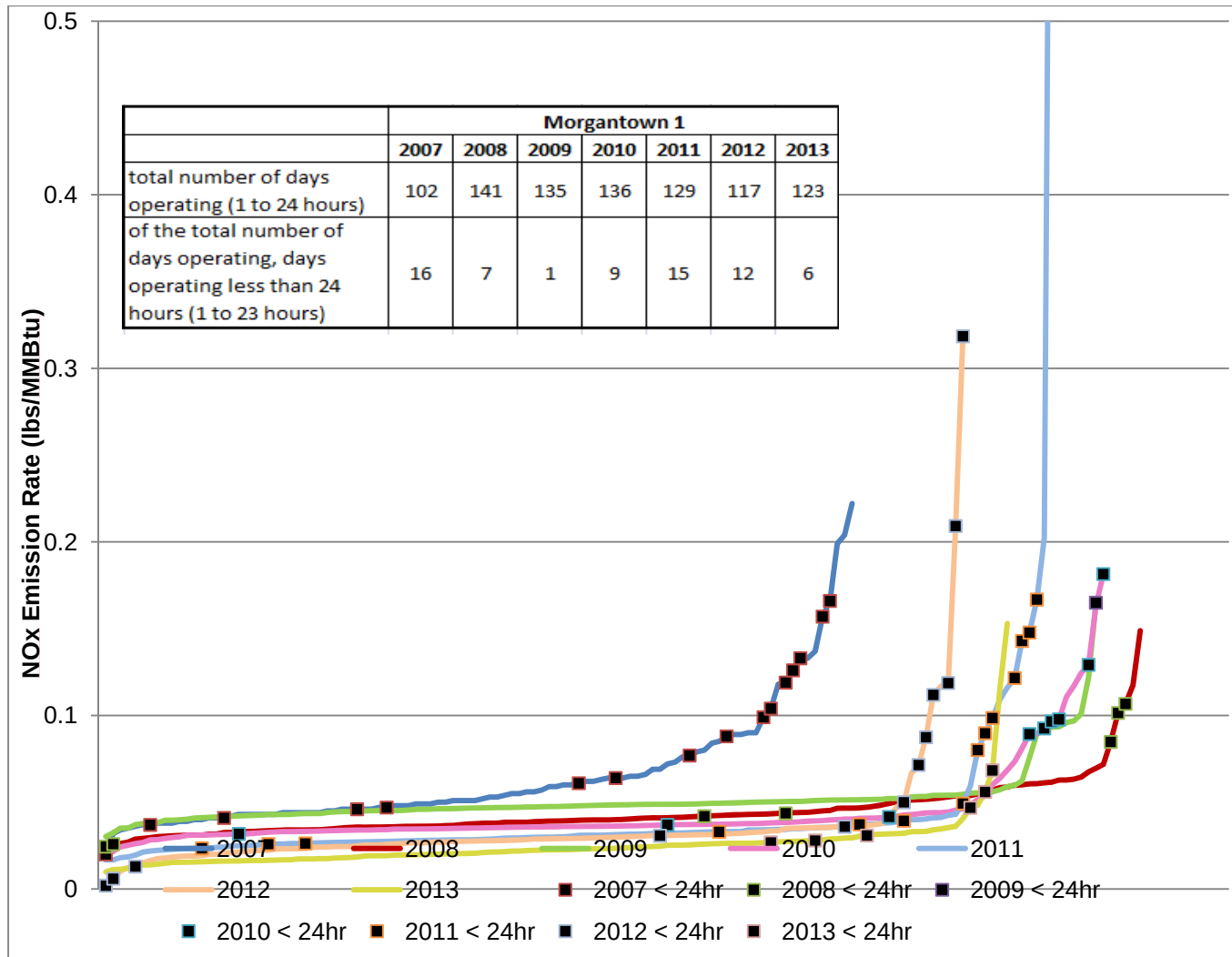
Dickerson Unit 2 (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



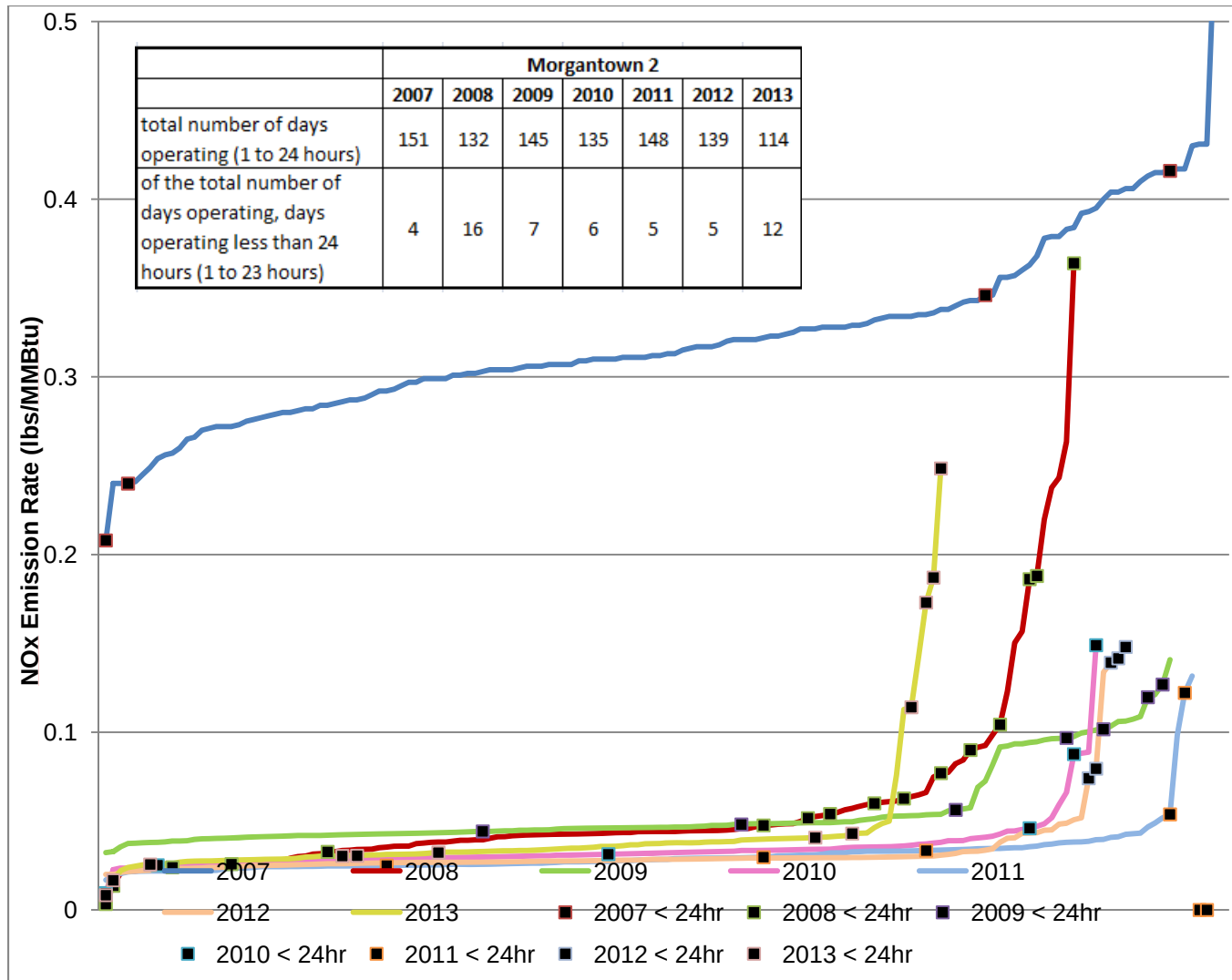
Dickerson Unit 3 (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



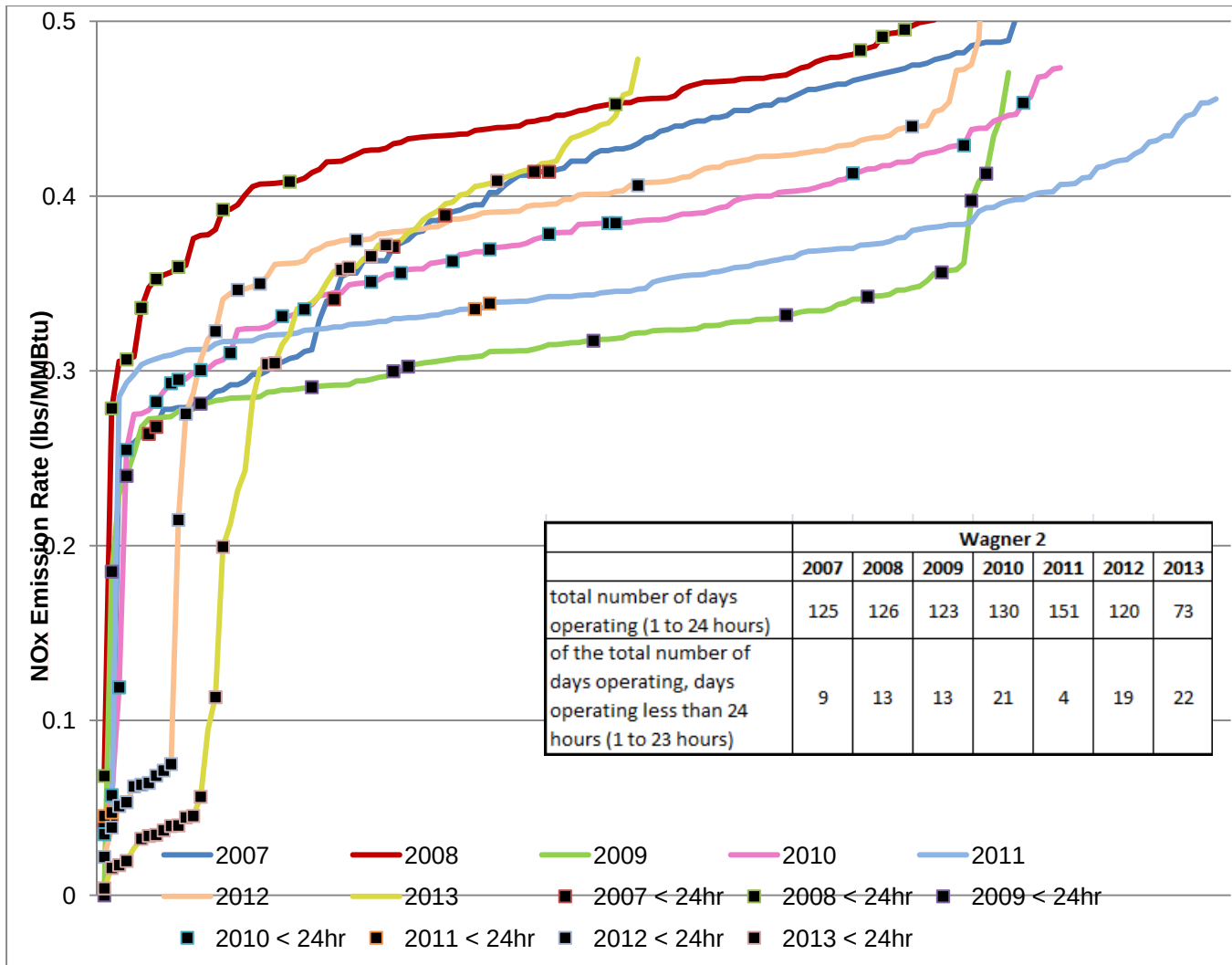
Morgantown Unit 1 (Coal, SCR) – Daily OS NOx Emission Rate, Sorted



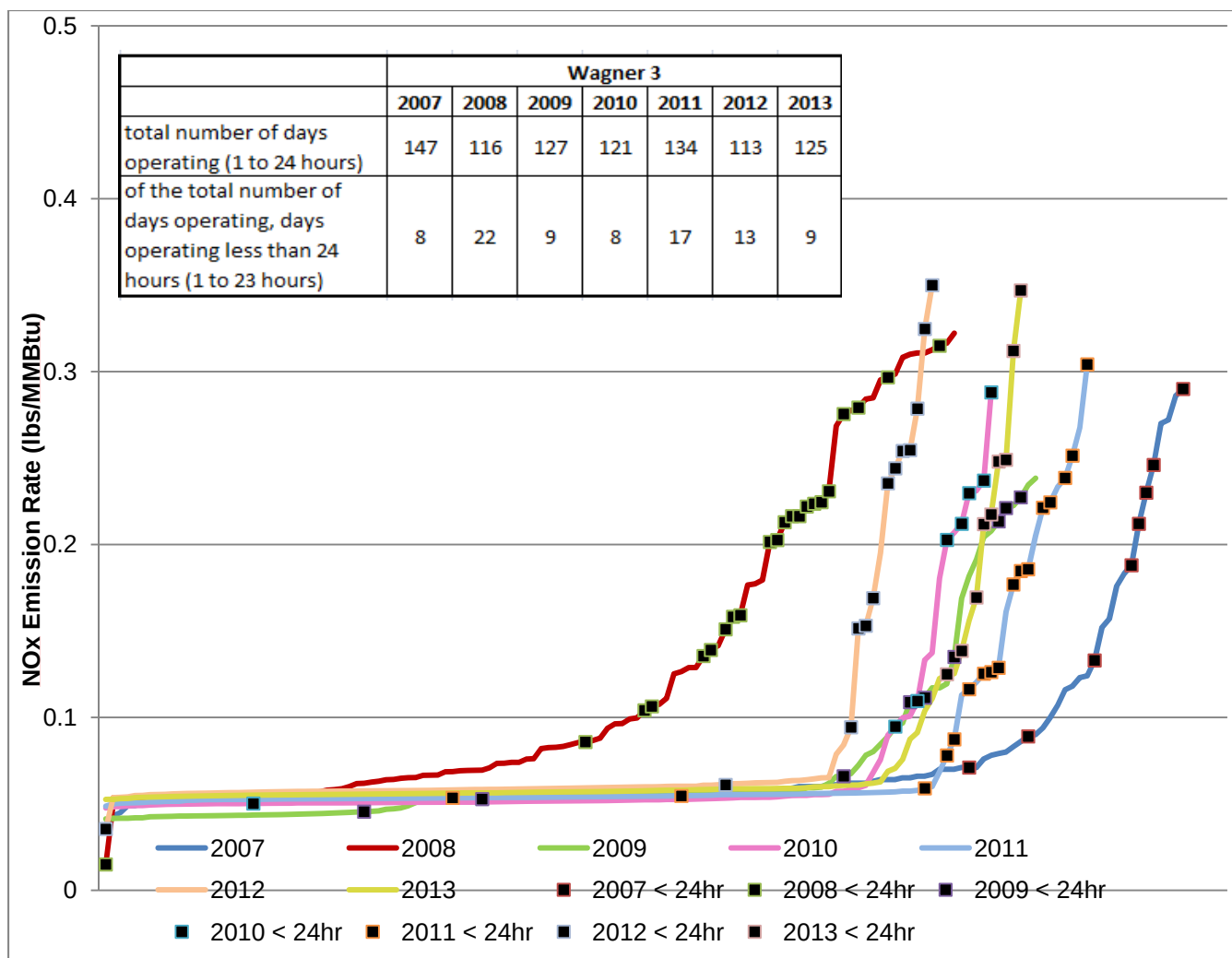
Morgantown Unit 2 (Coal, SCR) – Daily OS NOx Emission Rate, Sorted



H.A. Wagner Unit 2 (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



H.A. Wagner Unit 3 (Coal, SNCR) – Daily OS NOx Emission Rate, Sorted



Appendix D

Andover Technology Partners Report & EPA Chapter 5

Report 1.

Reliability of SCR and FGD systems for high pollutant Removal Efficiencies on Coal Fired Utility Boilers

The 2004 MEGA Symposium. Paper #04-A-56-AWMA
Prepared By: Andover Technologies and the U.S. EPA

Report 2.

EPA for Transport Rule

Chapter 5 Emission Control Technologies

EPA Base Case v.4.10 includes a major update of emission control technology assumptions. For this base case EPA contracted with engineering firm Sargent and Lundy to perform a complete bottom-up engineering reassessment of the cost and performance assumptions for sulfur dioxide (SO₂) and nitrogen oxides (NO_x) emission controls.

5.2.1 Combustion Controls

The EPA Base Case v.4.10 representation of combustion controls uses equations that are tailored to the boiler type, coal type, and combustion controls already in place and allow appropriate additional combustion controls to be exogenously applied to generating units based on the NO_x emission limits they face. Characterizations of the emission reductions provided by combustion controls are presented in Table 3-1.3 in Appendix 3-1.

Report 3.

Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants

Prepared For:

Northeast States for Coordinated Air Use Management, 89 South Street, Suite 602
Boston, MA

Prepared By: James E. Staudt, Ph.D. Andover Technology Partners, M.J. Bradley & Associates LLC, March 31, 2011

Summarizes NO_x reduction capabilities of SCR and SNCR.

Reliability of Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Systems for High Pollutant Removal Efficiencies on Coal Fired Utility Boilers

The 2004 MEGA Symposium, Paper # 04-A-56-AWMA

Prepared by

James E. Staudt¹, Sikander R. Khan², and Manuel J. Oliva²

¹ Andover Technology Partners, 112 Tucker Farm Road, North Andover, MA 01845

² Office of Air and Radiation, United States Environmental Protection Agency

ABSTRACT

SCR and FGD are making a significant contribution to the control of NO_x and SO₂ emissions from coal-fired generating units. These technologies are expected to contribute to further reductions in pollutant emissions in response to proposed emission reduction rules. The ability of these technologies to make significant contributions to pollution reduction in a cost-effective manner depends, in part, on the reliability of these technologies in providing high levels of pollution reduction.

A study of reliability of these technologies in providing high levels of pollutant reduction was conducted. The study included a review of CEMS data and input from operators of facilities. Operators of facilities that use these technologies were provided a questionnaire to collect their input on the reliability of these technologies. Information collected included emissions reductions guaranteed and achieved, reliability overall, and reliability by system component. The information provided by users was compiled and analyzed for statistical trends. In this paper we will present summary results of this study.

INTRODUCTION

Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) are technologies used to reduce emission of air pollution from power plants, especially, coal-fired plants. These technologies are currently in use at many coal-fired generating plants and are likely to be installed on many more in response to proposed emission regulations.¹ The reliability of these technologies plays an important role in influencing: 1) the ability of these technologies to achieve the necessary reduction in pollution emissions, and 2) the cost of achieving the necessary reduction in pollution emissions. Articles by others have raised questions about the reliability of SCR systems in providing high levels of NO_x control, i.e., approaching 90% NO_x removal.² Reference 2 explored reliability of operational SCR systems through an analysis of continuous emission monitoring system (CEMS) data. However, Reference 2 acknowledges that various plant operations – such as unit start up or shut down - can introduce artifacts in CEMS data that will affect the inferred level of NO_x reduction. Reference 2 describes the filtering techniques used by the authors in an effort to compensate for these artifacts.

In this effort, we explore some of the important considerations for estimating effectiveness of control equipment through a review of CEMS data. Examples are used to provide insight on how to best screen and interpret this data.

A major part of this effort, however, was associated with collecting and evaluating input from facility operators. Information on the operating approaches they use and their experience with reliability of SCR and FGD systems were of interest. Questionnaires were prepared and sent to many utility companies. Some companies chose not to participate, but several did choose to participate. Data was collected for 23 SCR systems and 14 FGD systems. These represent a fraction of the total installations in the US, and may not be statistically representative. But, certain trends can be observed from the data.

REVIEW OF CEMS DATA

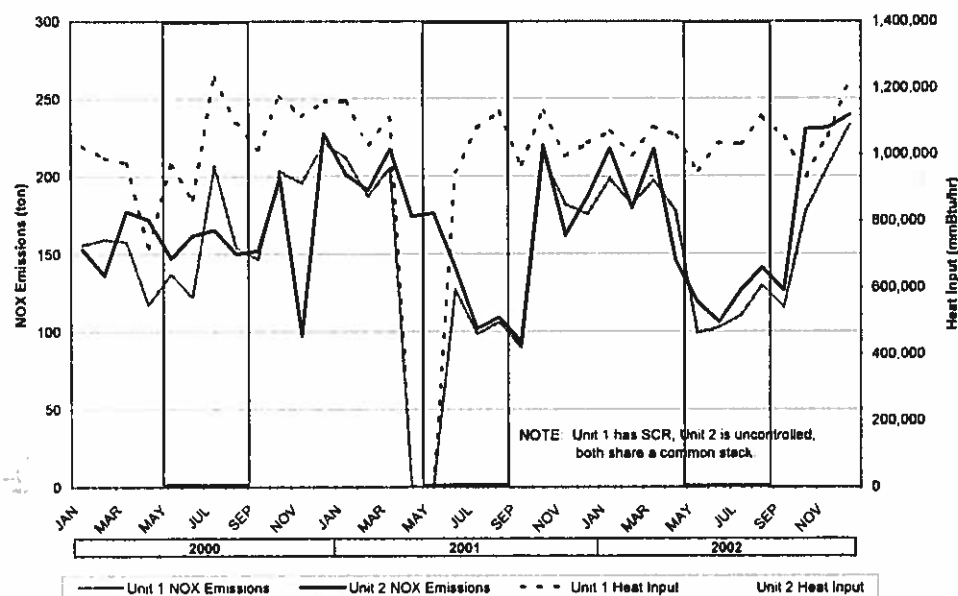
The Clean Air Markets Division of the US Environmental Protection Agency (EPA) collects hourly air emissions data from sources subject to reporting requirements of Part 75 under programs such as the Acid Rain Program. This hourly data, along with unit characteristics is made available to the public via the EPA website.³ Although EPA provides this data for use by the public, certain operational characteristics such as the efficiency of add-on control devices is difficult to derive from this data alone. For example, facilities often monitor emissions at common stacks for multiple units where emissions from uncontrolled and controlled units are monitored together. In such cases distinguishing the contribution of emissions of the controlled unit from those of the uncontrolled unit may not be possible.

Figure 1 provides the NO_x emissions over a three-year period for a facility in the eastern United States where two tangential coal-fired units of similar size share a common stack with a single CEMS monitoring the common stack. As shown in Figure 1, the reported NO_x emissions for both units follow a very close pattern, even though one unit has an operational SCR and actually has much lower NO_x emissions during the ozone season (May 1 – September 30). An SCR was installed on Unit 1 in June 2001 and is operated during the ozone season. Unit 2 does not have an add-on NO_x emissions control device. The incorrect representation of NO_x emissions results from the methodology used by the CEMS in allocating emissions between the units. Total NO_x emissions from the common stack are allocated to the individual units on the basis of heat input without consideration to the actual emissions from each unit – only the total is measured. As a result, the hourly data from the CEMS at this plant cannot be used to determine SCR characteristic information for the unit with the SCR.

In addition to common stack issues, hourly data may not always be from CEMS as certain sources may use alternative Part 75 methods to develop hourly emissions. For example, during periods of CEMS downtime units may use acceptable substitute data. Also, a limited number of units do not need to install CEMS and may use other methods to determine hourly emission such as default emission rates. Finally, units that install add-on control devices, such as an SCR, under Part 75 requirements are installing the device to meet NO_x allowance demands. That is to say that these units have an emissions “cap” that they are required to meet and can reduce emissions to meet their “cap” by using add-on controls or by purchasing additional

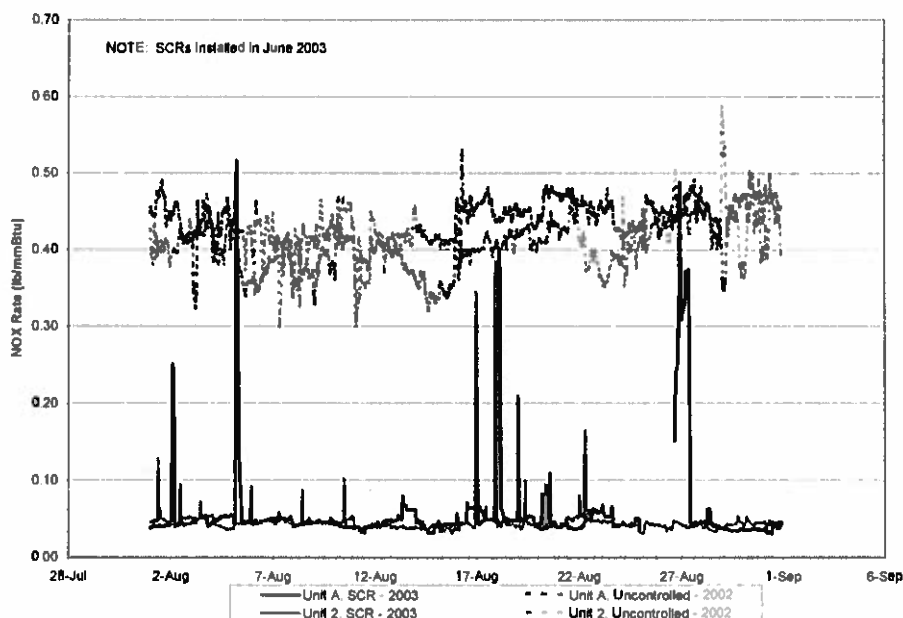
allowances. Economics is a powerful driver in this type of compliance system, and facilities that have add-on controls rarely use these controls to their maximum capacity unless there is an economic incentive to do so. Therefore, use of EPA hourly data from sources subject to Part 75 reporting requirements should not be used to characterize add-on control efficiencies without carefully analyzing how the data are derived and what they represent.

Figure 1. Combined NO_x Emissions from a unit with SCR and a unit without SCR



Although care must be taken to assure CEMS hourly data accurately reflects the operations of a unit, it is possible to estimate add-on control performance for carefully screened data sets. For example, Figure 2 provides a comparison of hourly NO_x emission rates of two coal-fired units (each from a different facility) which installed SCR prior to the ozone season of 2003. As shown in this figure, the NO_x emission rates during the month of August 2002 for each unit were approximately 0.42 lb/MMBtu prior to SCR installation (dashed lines). The NO_x emission rates during the month of August 2003 for each unit were approximately 0.04 lb/MMBtu after SCR installation and optimization (solid lines). Both units averaged a percent reduction of approximately 89% in NO_x emission rates after SCR installation. Similar data analysis for other CEMS-monitored units has demonstrated NO_x achievable emission rates of 0.04 lb/MMBtu with SCR.

Figure 2. Example of NO_x Emission Reductions with SCR Installation



A screen of all CEMS monitored (under Part 75) coal fired units equipped with SCR that were operating in the third quarter of 2003 resulted in 22 units with NO_x rates equal to or less than 0.07 lb/MMBtu. These 22 units included only coal-fired boilers that either had single stacks or shared a common stack or multiple stacks with other coal-fired boilers also equipped with SCR control devices. The average emissions rate of the 22 units during the third quarter of 2003 is 0.058 lb/MMBtu with a standard deviation of 0.010 lb/MMBtu. Of these 22 units, 15 units had emission rates from 0.04 to 0.06 lb/MMBtu. Without information on the value of the SCR inlet NO_x level, it is not possible to estimate the percent reduction resulting from SCR. But, if the average emission rate into the SCR were assumed to be 0.50 for the 22 units, the average NO_x reduction level for these units would be approximately 88 percent. For the 15 units with 0.06 lb/MMBtu or lower emissions, the average NO_x reduction level would be approximately 90 percent.

As mentioned earlier, CEMS data may not reflect the maximum capabilities of the SCR installations. In some cases, the operating decisions may have an impact on the SCR NO_x removal rates estimated from such data. For example, due to operating or economic reasons, operators might choose to get less NO_x removal than is possible from their SCR systems. To better understand plant specific situations, facility owners were surveyed.

RESPONSES TO SCR QUESTIONS

Because the focus of this effort was to evaluate reliability of high efficiency SCR's, the discussion will initially focus on high NO_x reduction SCRs (85% or greater NO_x reduction). Subsequently, results from such SCRs will be compared with results from older SCRs built for lower removal efficiencies. Data was collected on 23 high efficiency SCRs (85% removal or higher) and from owners of two older SCRs that are not designed for high removal efficiencies.

Of the high removal efficiency SCRs, the average unit size was 814 MW, the largest unit was 1300 MW, the smallest unit was 349 MW and the standard deviation in size was 265 MW. Fuels fired included bituminous coals, subbituminous coals (Powder River Basin, PRB) and bituminous/subbituminous coal blends.

OPERATION

Although most of the high removal efficiency facilities must meet total mass emission requirements over a period of time, about half of the facilities responded that they control to specific emission rates rather than tonnage over a period of time. 52% of the respondents indicated that they control to a specific emissions rate and the remainder (48%) reported that they control to a total tonnage level. Since a review of state permits for each unit was outside the scope of this work, it is not possible to determine whether the state or local requirements differed from the SIP Call requirements. But, it is most likely that units that are controlled to specific levels are operated in this manner with the intent of targeting a cumulative mass emission for the period. However, this could not be confirmed.

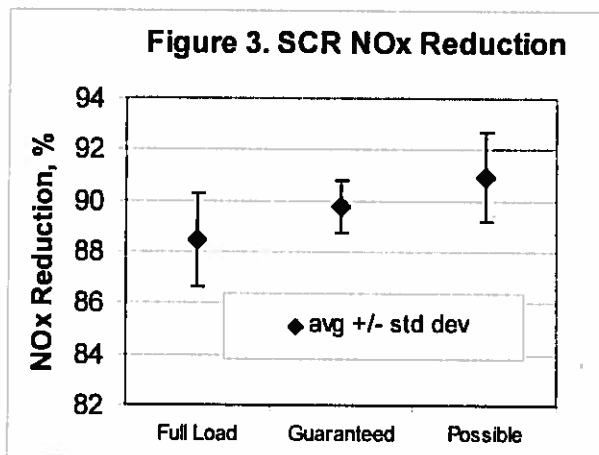
Most of these SCRs were designed to achieve an emissions rate for a particular coal and firing condition. The impact is that if the NO_x emissions from the boiler are less than the design basis, the percent reduction will likely be less than the design or guaranteed rate.

The average operating hours for these high removal efficiency units was about 5,300 hours, which is within the warranty period in most cases. The unit with the most operating hours was 10,000 hours and the unit with the least had only 1,500. Standard deviation of the operating hours was 2,475 hours. So, it could be argued that these responses may reflect initial operating experience and it will be necessary to wait for long-term experience. In a later section these results are compared to units with longer operating experience but lower NO_x removal.

NO_x REDUCTION

The operators were asked to provide the typical full-load NO_x reduction, the designed or guaranteed NO_x reduction, and an estimate of the best removal rate they thought the system could achieve on a regular basis if they had a reason to operate it at higher removal rates.

As shown on Figure 3, the SCRs, on average are currently providing between 88% and 89% NO_x reduction (This is consistent with the results of Reference 2). The error bars show plus and minus one standard deviation. The guaranteed reduction on average is nearly 90% NO_x reduction, with a narrower deviation than the actual operating reduction. And, if necessary, these units could provide, on average, close to 91% NO_x reduction on a regular basis. The highest NO_x reduction reported was 93%, by five units, or over 20% of those responding. In



every case the highest regular reduction estimated to be possible was equal to or greater than the guaranteed NOx reduction. Therefore, all of the operators are confident of the SCR's ability to achieve the guaranteed reduction on a regular basis. The fact that the operating full-load NOx reduction rates are slightly less than the guaranteed rates is likely because the NOx levels into the SCR are probably less than the maximum expected for the design conditions. If the units are being operated to maintain a particular outlet NOx emissions rate, as many are,

then the operating NOx removal rate is going to be lower than the design or guaranteed rate. Thus, if SCR NOx reduction performance were inferred from CEMS data, this could cause an artifact suggesting poorer NOx reduction than is actually possible.

All of the high removal efficiency units responded that initial performance tests were performed and on all of the units the initial performance tests were passed.

All of the units responded that the SCR is operated at part load conditions and about one third of them responded that they operate during start up or shut down, but only while gas temperature is adequate for SCR operation. During start up or shut down the gas temperature can drop below the necessary gas temperature for SCR operation. As a result, if the unit is being shut down for start up, the outlet emissions rate may indicate higher than normal on the CEMS. Thus, if SCR NOx reduction performance were inferred from CEMS data, this could introduce an artifact suggesting poorer NOx reduction than is actually occurring during normal SCR operation.

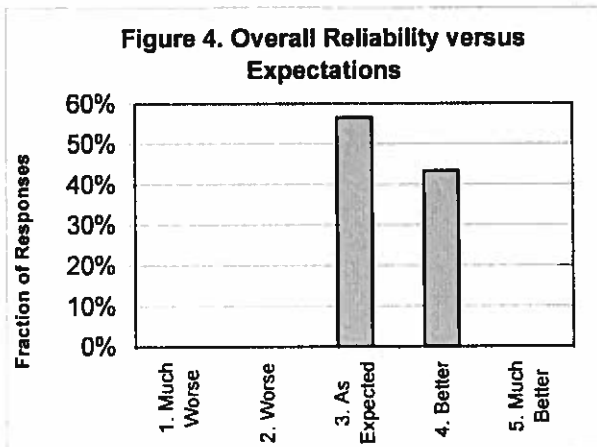
RELIABILITY RELATIVE TO EXPECTATIONS

The survey also polled the reliability of the SCR and its components versus expectations. The following categories were evaluated:

- Performance in general
- Reagent Storage/Handling
- Ammonia Injection
- Instrumentation and Controls
- Catalyst Activity
- Ash Deposition/Pluggage
- SCR Reactor and Structural
- Dampers and Ductwork

Respondents could indicate one of the following for each category:

1. Much worse than expectations
2. Worse than expectations
3. Met expectations
4. Better than expected
5. Much better than expected



As shown on Figure 4, all of the high removal SCR's generally performed as expected or better than expected (either 3 or 4). Responses for SCR components varied.

In the following paragraphs we will examine the reliability of SCR components.

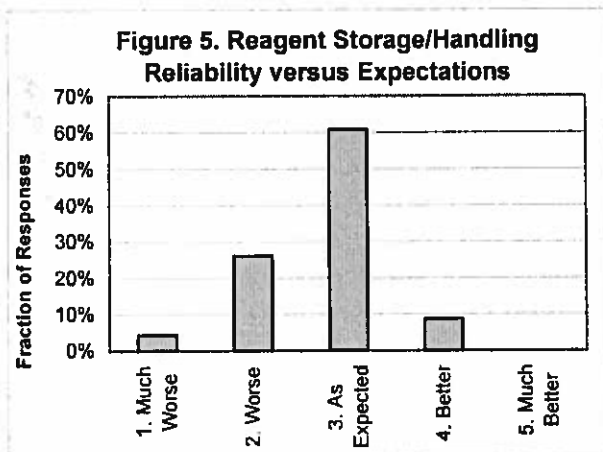


Figure 5. shows the distribution of responses regarding Reagent Storage and Handling. Ammonia or Urea storage and Handling was very problematic for some respondents. Fortunately, all of those respondents that indicated a performance shortcoming in this system (answered 1 or 2) also indicated that the problem was short term and correctable. Some indicated separately that the long-term reliability of some urea conversion systems remains a question.

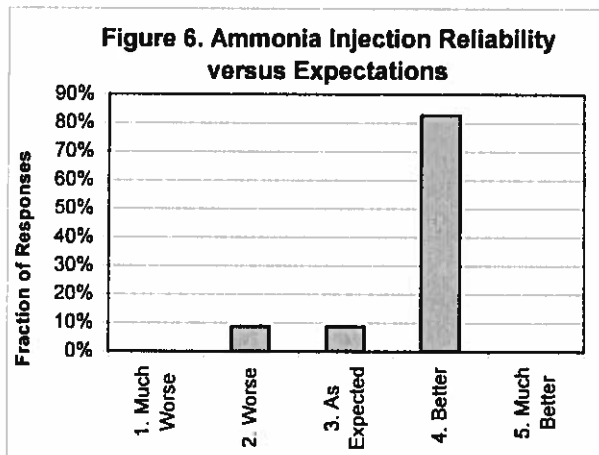


Figure 6 shows the distribution of responses regarding ammonia injection equipment. Fortunately, most respondents found this equipment to meet or exceed expectations. Furthermore, in the small number of cases where reliability of ammonia injection equipment was worse than expected, the problems were short term and correctable. So, these problems should not adversely affect reliability in the long term.

Figure 7 shows the distribution of responses regarding instrumentation and controls. Fortunately, most respondents found this equipment to meet or exceed expectations – in several cases much better than expectations. Furthermore, in the small number of cases where reliability of instrumentation and controls was worse than expected, the problems were short term and correctable. So, these problems should not adversely affect reliability in the long term.

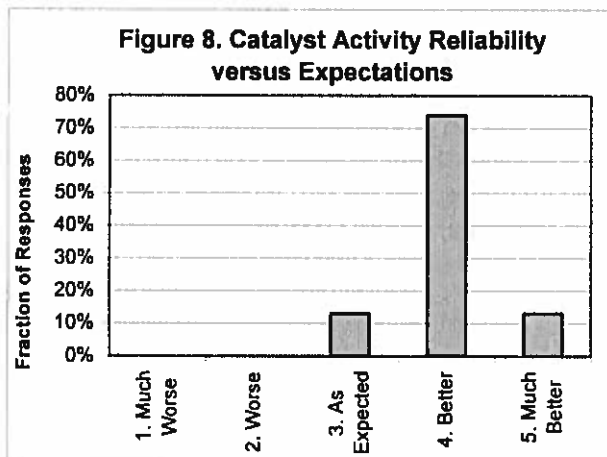
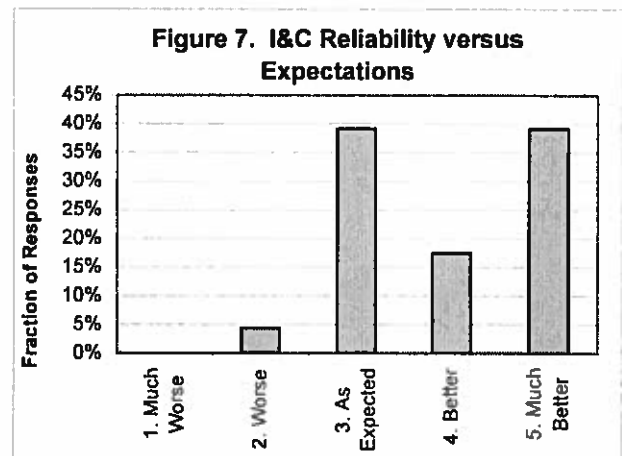


Figure 8 shows the distribution of responses regarding catalyst activity. All respondents found catalyst activity meeting or exceeding expectations – in some cases much better than expectations. However, it is important to note that since most of these units had only a few thousand operating hours, these responses may not be indicative of long-term catalyst performance. Long-term catalyst behavior can only be determined with more time.

Figure 9 shows the distribution of responses regarding ash deposition and plugging. Although most respondents found ash deposition and plugging meeting or exceeding expectations, a significant number of respondents found ash deposition and plugging to be much worse than expectations. Moreover, all of those responding that ash deposition and plugging were much worse than expected also indicated that this is expected to be a long-term problem. Therefore, this is likely to impact future reliability and a solution to this problem would be very desirable.

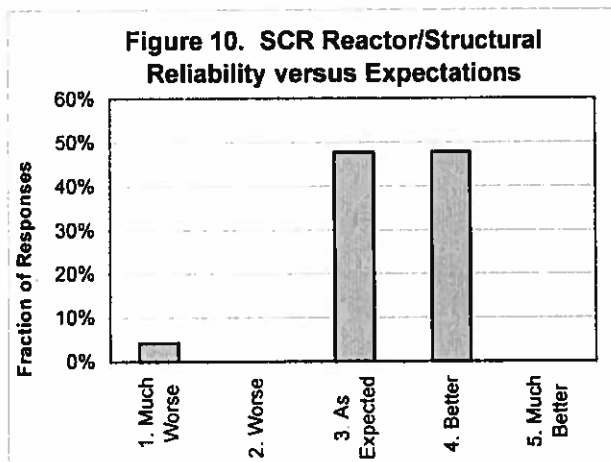
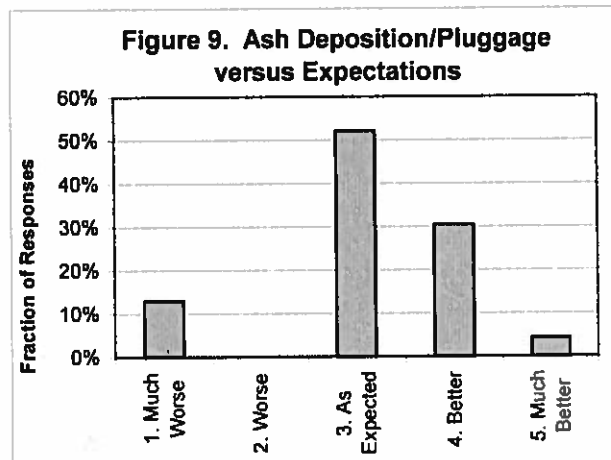
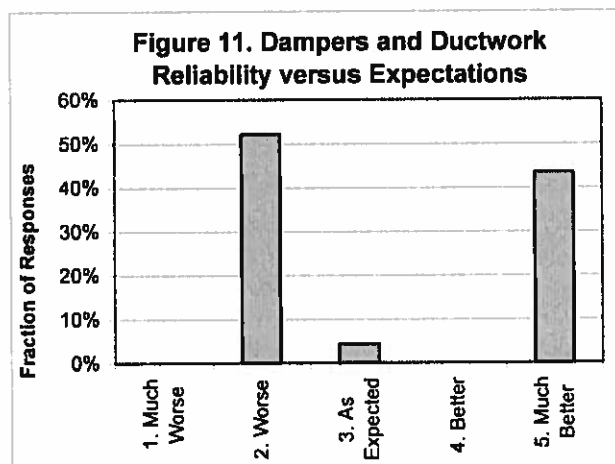


Figure 10 shows the distribution of responses regarding the reliability of the SCR reactor and other structural components. Most respondents found the reliability of this equipment to meet or exceed expectations. Furthermore, in the small number of cases where reliability of the SCR reactor or other structural components was much worse than expected, the problems were short term and correctable. So, these problems should not adversely affect reliability in the long term.

Figure 11 shows the distribution of responses regarding the reliability of the SCR dampers and ductwork. Included in this is experience with expansion joints. Experience was mostly either very good or bad – little in between. Fortunately, for the facilities that reported that reliability of the SCR dampers or ductwork or expansion joints was worse than expected, the large majority of them reported that the problems were short term and/or correctable. So, in some cases there will be a long-term impact on reliability. But, these are likely to be the minority of cases.



In summary, all high NOx reduction SCR respondents found that their systems met or exceeded expectations overall. Where shortcomings in performance were noted, in most cases the shortcomings were short term or correctable. However, ash plugging and dampers and ductwork may be an ongoing reliability problem. And, the long-term reliability of urea conversion systems may also be a question.

Comparisons with Lower Removal Units

Although the focus of this effort was evaluating the performance of high NOx removal SCRs, in the process of collecting information, information was received from two facilities designed to achieve lower removal rates than what has been achieved from the retrofit units that were discussed so far. These two units also have been in operation for several years, unlike most of the high removal rate retrofit units that were retrofit onto existing units in recent years.

Figure 12 shows the results of overall reliability for all respondents as a function of the NOx reduction that they are actually delivering. Note that some of the data points represent more than one response. The only unit that was rated below expectations (1 or 2) provides 75% reduction (which is also higher than the design NOx reduction for that unit). So, there's no apparent trend that higher reduction results in worse reliability, except possibly if you

operate significantly above the design removal rate.

Figure 13 shows the results of overall reliability for all respondents as a function of the operating hours. The higher NOx reduction units have fewer operating hours. As in Figure 10, there is not a clear trend toward poorer reliability over time. Of course, there are only a few data points at higher operating hours and it would be better to have more data. Of possible significance is the fact that the two

units with high operating hours were among the first SCR installations on coal-fired boilers in the United States. So, there could be "first of a kind" issues with these two units, especially the one with more hours that showed reliability below the operator's expectations (and is also operated well above its designed NOx removal rate). In this one installation some issues have been corrected, but efforts continue to address others.

Figure 12. SCR Overall Reliability

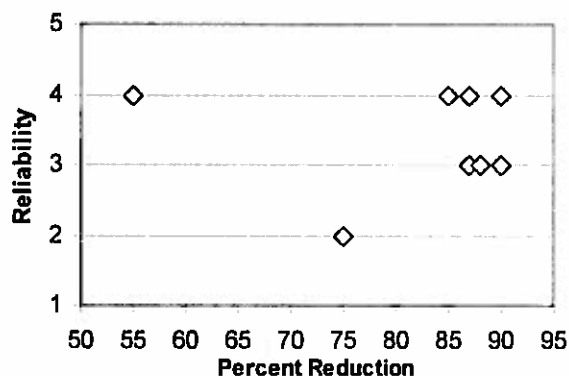
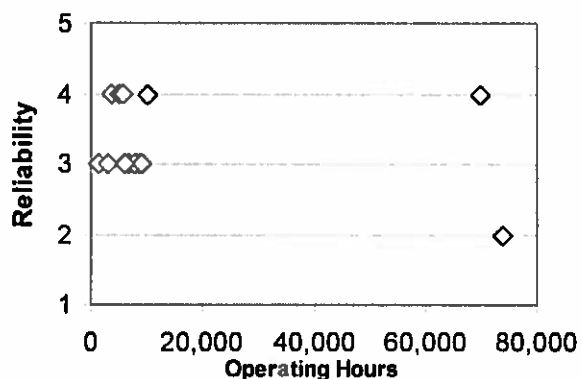


Figure 13. SCR Overall Reliability



Summary on SCR Reliability

In this effort, responses were received for 25 SCR systems – 23 of them high NO_x removal systems of 85% removal or better. Based upon operation of a few thousand hours, all are capable of achieving their design NO_x removal rate if necessary and all are meeting or exceeding expectations for reliability. Some units have had reliability issues with specific components of the SCR system. But, overall reliability is satisfactory. Because these high removal SCRs have generally operated for a few years or less, these results should be considered representative for initial operation. Longer operation may reveal other issues. Comparison against two lower removal systems that have been operating for several years showed no clear trend in reliability as a function of removal efficiency or operating hours. Of course, since there are only a few data points for longer operating hours or lower efficiency, it is difficult to reach any firm conclusions.

RESPONSES TO FGD QUESTIONS

In this effort information was gathered on reliability of FGD systems. There are three basic types of FGD systems that were evaluated: 1) Limestone-based wet FGD; 2) Lime-based wet FGD, and ; 3) Lime-based Spray Dryer Absorber (SDA). Unfortunately, it was not possible to collect as many responses for FGD technology as for SCR technology. This is partly because many FGD systems were installed much earlier than SCR systems. So, while most SCR systems in the United States reflect the current state-of-the-art, most FGD systems were installed many years ago when technology was less advanced than today's state-of-the-art and also when prevailing regulations did not require or encourage higher SO₂ removal efficiencies. Nevertheless, information was obtained on Limestone-based wet FGD systems serving five boilers (some with multiple boilers served by a single FGD tower), on seven different Lime-based wet FGD systems serving seven boilers (some serving only a portion of a boiler's flue gas), and on only two Lime-based Spray Drier Absorbers serving two boilers.

The largest boiler reviewed of all of the FGD systems was 750 MW, the smallest was 80 MW. In one case a single limestone FGD system served multiple boilers. In another case a lime wet FGD system scrubbed only a portion of the boiler gases.

OPERATION

Almost all of the FGD systems are operated with the intention of maintaining a particular emissions rate or percent reduction. Since a review of the state permits for each unit was outside the scope of this work, it is not possible to determine whether the state or local requirements differed from the Federal requirements. Because all or most of these units are Title IV affected units, it is likely units are controlled to specific levels with the intent of targeting a cumulative mass emission for the period. However, this was not confirmed.

Unlike the high NO_x reduction SCRs, most of these FGD systems have been in operation for at least a few years. The average operating history of Limestone-based FGD systems was 44,000 operating hours, the maximum was 60,000 operating hours and the minimum was 40,000 operating hours. The average operating history of Lime-based FGD systems was 114,000 operating hours, the maximum was 254,000 operating hours and the minimum was estimated 20,000 operating hours. The two SDA systems had about 70,000 to 80,000 operating hours.

SO₂ REDUCTION

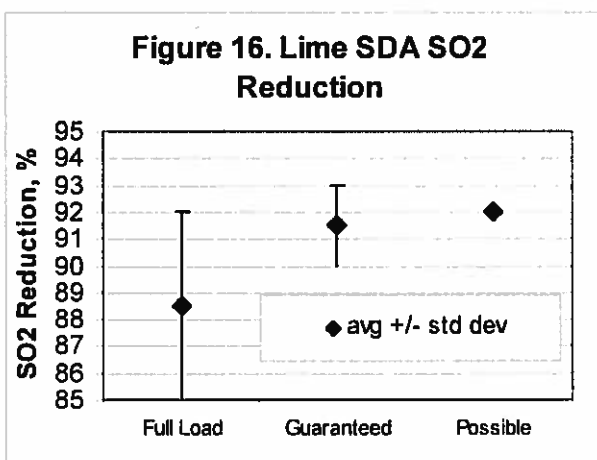
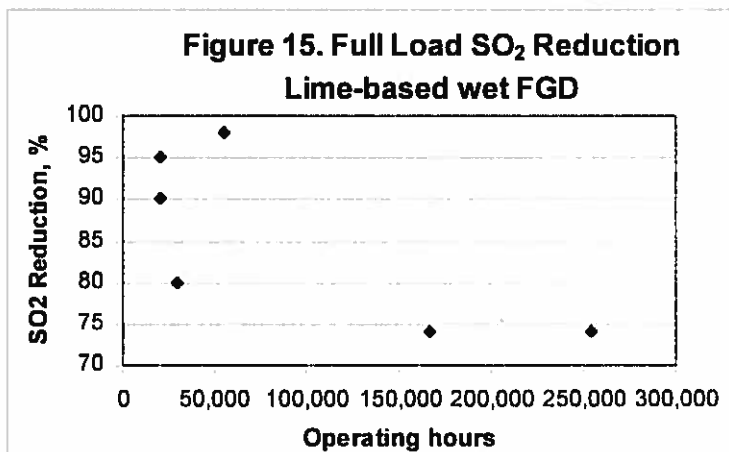
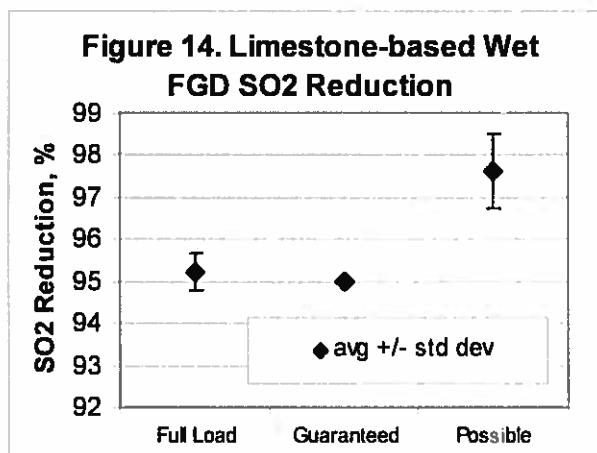
All of the Limestone wet FGD systems are designed and guaranteed for 95% SO₂ reduction, and all operate at or better than that level of SO₂ removal. Respondents indicated that some of the systems could operate at higher SO₂ removal efficiencies, as indicated in Figure 14. Not all systems had acceptance tests upon commissioning. But, those that had, passed the acceptance test.

For the lime-based wet FGD systems, of the seven systems that responded, only

three of them were designed to achieve 90% or more SO₂ removal for the flue gas they treated.¹ The other facilities were older facilities that were designed for lower SO₂ removal rates – on the order of 70-80% removal. As shown in Figure 15, which shows full load SO₂ reduction of lime-based wet FGD plotted against operating hours, more recently installed systems operate at

much higher flue gas SO₂ removal rates than previously installed systems.

Figure 16 shows the SO₂ removal efficiencies reported for the two SDA-equipped facilities. As shown, both systems normally operate at removal efficiencies in the range of 85% to over 90% removal efficiency. Both were designed for guaranteed SO₂ removal efficiencies of somewhat over 90% removal and facility operators project that about 92% removal is achievable on a regular basis with these systems if necessary.



¹ One of the systems treated a fraction of the total flue gas for the boiler. We consider the percent reduction for the flue gas treated here. Also, two installations have same percent reduction and operating hours, which explains why there are apparently only six points displayed on Figure 13.

RELIABILITY RELATIVE TO EXPECTATIONS

The survey also polled the reliability of the FGD and its components versus expectations. The following categories were evaluated:

- Performance in general
- Reagent Storage/Handling
- Slurry Injection/Atomization
- Instrumentation and Controls
- Pumps, Tanks, chemical hardware
- Corrosion or scale build up
- Waste disposal or handling
- FGD reactor vessel or structural
- Dampers or Ductwork
- Fabric Filter, for SDA

Respondents could indicate one of the following for each category:

1. Much worse than expectations
2. Worse than expectations
3. Met expectations
4. Better than expected
5. Much better than expected

Because for each SO₂ control technology – Limestone-based wet FGD, Lime-based wet FGD, and Spray Drier Absorber (SDA) technology – there are a limited number of responses, the results of this analysis will be presented in a different way than for the SCR analysis.

Figure 17 shows the results of responses to questions regarding reliability versus expectations – in general and for specific components - for the limestone-based wet FGD. As shown, for all cases the reliability in general met or exceeded expectations. Only in the case of waste disposal and handling did reliability fail to meet expectations. Fortunately, in every case the reliability shortcoming was short term and correctable.

Figure 18 shows the results of responses to questions regarding reliability versus expectations – in general and for specific components - for the lime-based wet FGD. As shown, for all cases the reliability in general met or exceeded expectations. As in the case of limestone wet FGD, waste disposal and handling did not exhibit reliability meeting expectations. In some cases dampers and ductwork failed to meet expectations. In this case it was unclear to the respondents whether or not the reliability shortcomings are a short-term or long-term problem.

Figure 19 shows the results of responses to questions regarding reliability versus expectations – in general and for specific components - for the lime-based Spray Drier Absorber technology. Only two facilities responded in this case. As shown, in one case the reliability in general and for all components met reliability expectations. In the other case, the facility operator reported that performance in general failed to meet expectations. And the same user also reported that several components of the SDA system failed to be as reliable as expected. This user also

reported that all of the areas where reliability failed to meet expectations were long-term issues, except for corrosion/scale build up and reactor structural which were short-term problems. It should also be noted that with only two facilities responding, it would be very desirable to collect more information in the future from other facilities to compare with these results.

Figure 17. Limestone wet FGD Reliability Versus Expectations

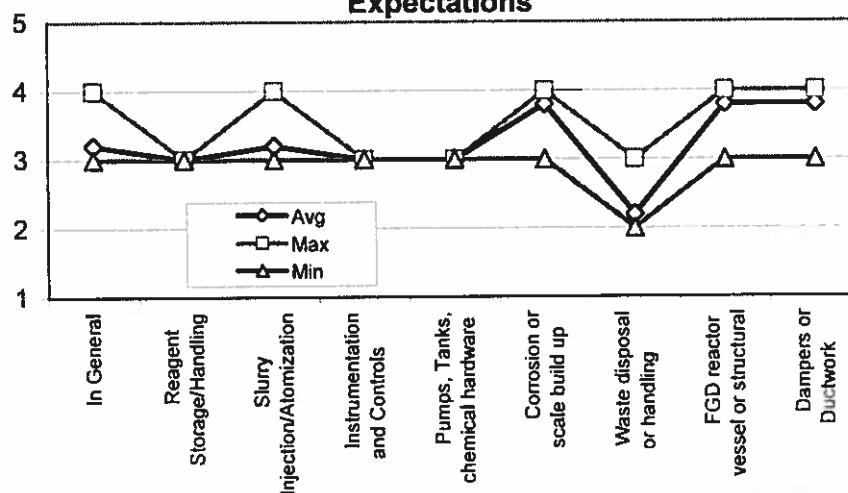
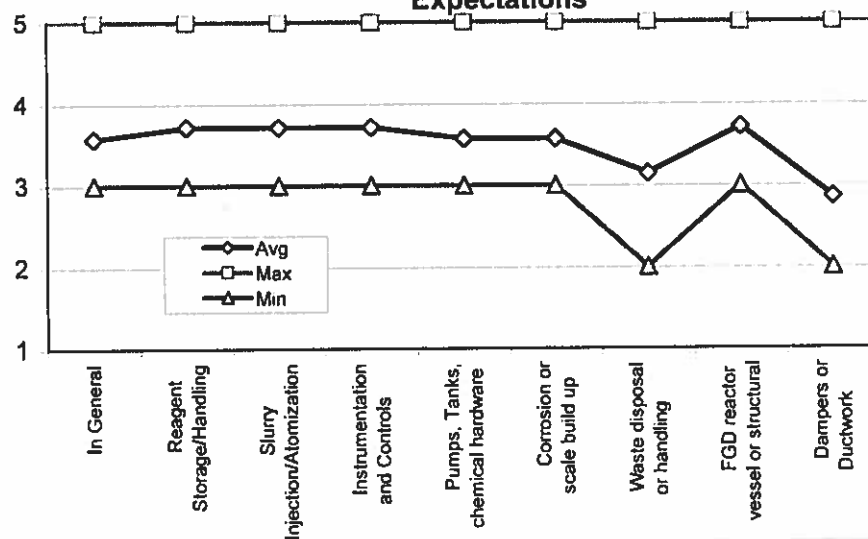
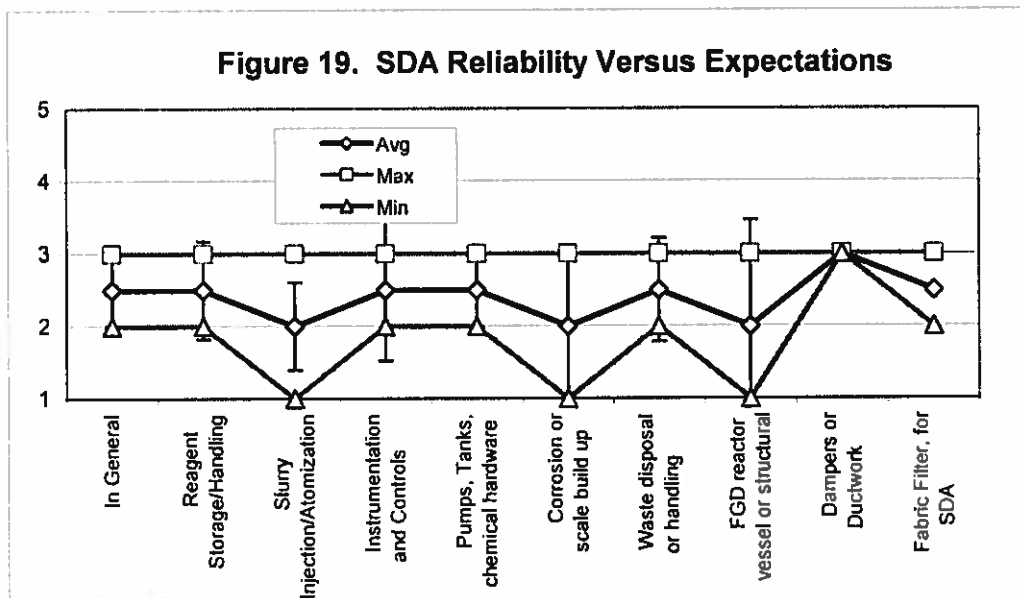


Figure 18. Lime Wet FGD Performance Versus Expectations

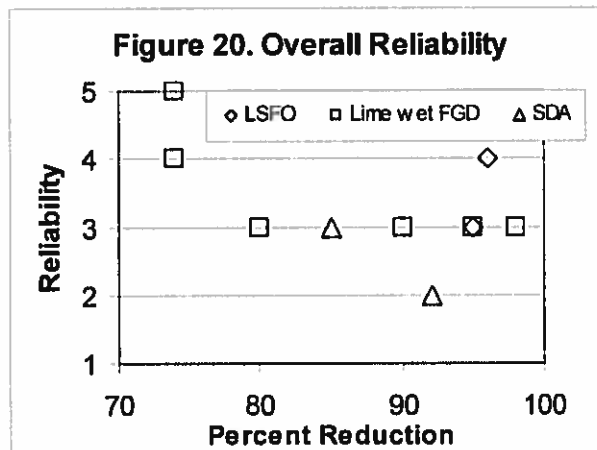


Reliability Key
 5 = Much Better Than Expected
 4 = Better Than Expected
 3 = As Expected
 2 = Worse Than Expected
 1 = Much Worse Than Expected



Summary on FGD Reliability

Figure 20 is a plot of overall reliability reported against reported full-load SO_2 reduction. With one exception – an SDA system – all systems met or exceeded expectations regarding reliability. In some cases there were individual components that failed to meet expectations regarding reliability, but overall reliability met expectations.



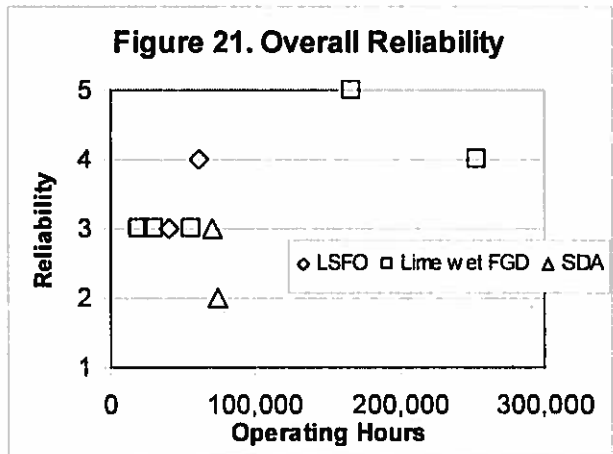
As shown on Figure 20, reliability for systems with under 80 percent reduction were reported to exceed expectations. For those systems operating above 80 percent, all but one were reported to have met or exceeded expectations for reliability. One of the two SDA systems that we received information on reported reliability that was below expectations. But, in both cases the responses showed that over 90% SO_2 removal was possible on a regular basis if necessary. Thus, there is no clear trend toward poor reliability at high SO_2 removals.

Figure 21 shows Overall Reliability for the different technologies reported against Operating Hours. There is no clear trend toward increasing or decreasing reliability versus operating hours.

However, it would be very beneficial to collect more data on FGD systems, especially SDA technology.

CONCLUSIONS

This effort explored the reliability of SCR systems at providing high levels of NO_x removal. CEMS data was evaluated. But, while CEMS data provided some useful information regarding the emission rates being achieved, it is not possible to ascertain the actual emissions reductions accurately because of artifacts associated with the way CEMS data is collected and reported. These artifacts are complicated by operating decisions that facility owners make that will affect the data. For this reason, facility owners were contacted for their input on how they operate the facilities.



The results of an effort to collect information from facility operators on the reliability of SCR and FGD systems at providing high levels of NO_x and SO₂ reduction are summarized in this paper. It is always desirable to collect information from as many members of a population as possible to ensure that the sample is as representative of the population as possible. To this end, numerous facility owners were contacted. Only a portion of those facility owners chose to participate in this survey. Nevertheless, some very important insights have been garnered from this effort. All of the high NO_x reduction SCRs that are represented in this survey met or exceeded expectations regarding reliability in general. Some facilities experienced less-than-expected reliability on some specific SCR system components; however, these were in most cases short term or correctable. And, because other aspects of the SCR exceeded expectations for reliability, reliability in general was viewed by the respondent as meeting or exceeding expectations.

Since the high NO_x reduction SCR systems that are represented in this survey generally had only a few thousand operating hours, it could be argued that the results of this survey may not be representative for long-term operation. However, because an SCR has only a limited number of wear parts, it is likely that the experience reflected here can provide useful insights for all of the SCR components except possibly for the SCR catalyst, which is known to degrade over time, or possibly the urea conversion technology, for which there is limited long-term experience. There are high NO_x removal facilities in the US with more operating hours. Many of these facilities were invited to participate; however, the facility owners chose not to. Nevertheless, the fact that all of the high NO_x removal facilities that responded were operating over 85% reduction regularly, were typically guaranteed for about 90% reduction and all replies indicated that at least guaranteed NO_x reductions could be reliably achieved if desired, indicates that 90% NO_x reduction is a reasonable estimate to use for the NO_x removal that is *possible* from SCR. Whether facility owners choose to achieve such removal rates is a business decision that they make.

With regard to FGD, a fewer number of facilities were available to collect information from, particularly with regard to high levels of removal. As shown in Figure 15, high removal

systems have only been installed in more recent years. So, removal rates on systems installed 20 or more years ago are not representative of what is possible with current technology. But, the more recently installed wet (lime and limestone) systems were mostly guaranteed at 95% reduction or better with higher reductions in the range of 97-98% reported as being possible on a reliable basis, if needed. Only two dry FGD systems were evaluated, and both of them were reported to be capable of over 90% SO₂ removal, if needed.

With regard to FGD reliability, in every case except for one SDA system, performance overall met or exceeded owner expectations. Therefore, there is reason to believe that the FGD systems will perform as expected (albeit, with some specific components that may perform more or less reliably than other components). That only two responses were received for SDA systems raises the question regarding how representative this sample is for SDA systems. Therefore, there may be some benefit in collecting more information in the future for all three FGD technologies, but especially for SDA technology.

DISCLAIMER

The views and opinions expressed here are those of the author(s) alone and do not necessarily represent the policies of the U.S. Environmental Protection Agency.

REFERENCES

¹ EPA, Clean Air Markets Division, "Economic & Energy Analysis for the Proposed Interstate Air Quality Rulemaking", January 28, 2004

² Cicanowicz, J. Edward, and Smith, Lowell, L., "SCR Performance Analysis Hints at Difficulty in Achieving High NO_x Removal Targets", Power Engineering, November 2002, pp 82-90

³ EPA Website - <http://www.epa.gov/airmarkets>

5 Emission Control Technologies

EPA Base Case v.4.10 includes a major update of emission control technology assumptions. For this base case EPA contracted with engineering firm Sargent and Lundy to perform a complete bottom-up engineering reassessment of the cost and performance assumptions for sulfur dioxide (SO₂) and nitrogen oxides (NO_x) emission controls. In addition to the work by Sargent and Lundy, Base Case v.4.10 includes two Activated Carbon Injections (ACI) options (Standard and Modified) for mercury (Hg) control²⁷. Capture and storage options for carbon dioxide (CO₂) have also been added in the new base case.

These emission control options are listed in Table 5-1. They are available in EPA Base Case v.4.10 for meeting existing and potential federal, regional, and state emission limits. It is important to note that, besides the emission control options shown in Table 5-1 and described in this chapter, EPA Base Case v.4.10 offers other compliance options for meeting emission limits. These include fuel switching, adjustments in the dispatching of electric generating units, and the option to retire a unit.

Table 5-1 Summary of Emission Control Technology Retrofit Options in EPA Base Case v.4.10

SO₂ Control Technology Options	NO_x Control Technology Options	Hg Control Technology Options	CO₂ Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Standard Activated Carbon Injection (SPAC-ACI) System	CO ₂ Capture and Sequestration
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	Modified Activated Carbon Injection (MPAC-ACI) System	
	Combustion Controls	SO ₂ and NO _x Control Technology Removal Cobenefits	

5.1 Sulfur Dioxide Control Technologies

Two commercially available Flue Gas Desulfurization (FGD) technology options for removing the SO₂ produced by coal-fired power plants are offered in EPA Base Case v.4.10: Limestone Forced Oxidation (LSFO) — a wet FGD technology — and Lime Spray Dryer (LSD) — a semi-dry FGD technology which employs a spray dryer absorber (SDA). In wet FGD systems, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose SO₂ content exceeds 3lb SO₂/MMBtu, so this technology is provided only to plants which have the option to burn coals with sulfur content no greater than 3 lbs SO₂/MMBtu. In EPA Base Case v.4.10 when a unit retrofits with an LSD SO₂ scrubber, it loses the option of burning BG, BH, and LG coals due to their high sulfur content.

In EPA Base Case v.4.10 the LSFO and LSD SO₂ emission control technologies are available to existing "unscrubbed" units. They are also available to existing "scrubbed" units with reported removal efficiencies of less than fifty percent. Such units are considered to have an injection technology and classified as "unscrubbed" for modeling purposes in the NEEDS database of

²⁷The mercury emission controls options and assumptions in EPA Base Case v.4.10 do not reflect mercury control updates that are currently under way at EPA in support of the Utility MACT initiative and do not make use of data collected under EPA's 2010 Information Collection Request (ICR).

existing units which is used in setting up the EPA base case. The scrubber retrofit costs for these units are the same as regular unscrubbed units retrofitting with a scrubber. Scrubber efficiencies for existing units were derived from data reported in EIA Form 767. In transferring this data for use in EPA Base Case v.4.10 the following changes were made. The maximum removal efficiency was set at 98% for wet scrubbers and 93% for dry scrubber units. Existing units reporting efficiencies above these levels in Form 767 were assigned the maximum removal efficiency in NEEDS v.4.10 indicated in the previous sentence.

As shown in Table 5-2, existing units that are selected to be retrofitted by the model with scrubbers are given the maximum removal efficiencies of 98% for LSFO and 93% for LSD. The procedures used to derive the cost of each scrubber type are discussed in detail in the following sections.

Table 5-2 Summary of Retrofit SO₂ Emission Control Performance Assumptions

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal	98% with a floor of 0.06 lbs/MMBtu	93% with a floor of 0.065 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-4 for examples	Calculated based on characteristics of the unit: See Table 5-4 for examples
Heat Rate Penalty		
Cost (2007\$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs SO ₂ /MMBtu
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, LD, LE, and LG	BA, BB, BD, BE, SA, SB, SD, LD, and LE

Potential (new) coal-fired units built by the model are also assumed to be constructed with a scrubber achieving a removal efficiency of 98% for LSFO and 93% for LSD. In EPA Base Case v.4.10 the costs of potential new coal units include the cost of scrubbers.

5.1.1 Methodology for Obtaining SO₂ Controls Costs

The Sargent and Lundy update of SO₂ and NO_x control costs is notable on several counts. First, it brought costs up to levels seen in the marketplace in 2009. Incorporating these costs into EPA's base case carries an implicit assumption, not universally accepted, that the run up in costs seen over the preceding 5 years and largely attributed to international competition, is permanent and will not settle back to pre-2009 levels. Second, a revised methodology, based on Sargent and Lundy's expert experience, was used to build up the capital, fixed and variable operating and maintenance components of cost. That methodology, which employed an engineering build up of each component of cost, is described here and in the following sections. Detailed example cost calculation spreadsheets for both SO₂ and NO_x controls are included in Appendices 5-1 and 5-2 respectively. The Sargent and Lundy reports in which these spreadsheets appeared can be downloaded via links to the Appendices 5-1A, 5-1B, 5-2A, and 5-2B links found at www.epa.gov/airmarkets/progsregs/epaipm/BaseCasev410.html.

Capital Costs: In building up capital costs three separate cost modules were included for LSD and four for LSFO: absorber island, reagent preparation, waste handling (LSFO only), and everything else (also called "balance of plant") with the latter constituting the largest cost module, consisting of fans, new wet chimney, piping, ductwork, minor waste water treatment, and other costs required for treatment. For each of the four modules the cost of foundations, buildings, electrical equipment, installation, minor, physical and chemical wastewater treatment, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. The major variables affecting capital cost are unit size and the SO₂ content of the fuel with the latter having the greatest impact on the reagent and waste handling facilities. In addition, heat rate affects the amount of flue gas produced and consequently the size of each of the modules. The quantity of flue gas is also a function of coal rank since different coals have different typical heating values.

Table 5-3 Capital Cost Modules and Their Governing Variables for SO₂ and NO_x Emission Controls

Module	Retrofit Difficulty (1 = average)	Coal Rank Factor (B _{it} = 1, PRB = 1.05, Lignite = 1.07)	Heat Rate (Btu/kWh)	SO ₂ Rate (lb/MMBtu)	NO _x Rate (lb/MMBtu) ⁵	Unit Size (MW)
SO₂ Emission Controls – Wet FGD and SDA FGD						
Absorber Island	X	X	X	X		X
Reagent Preparation	X		X	X		X
Waste Handling	X		X	X		X
Balance of Plant ¹	X	X	X			X
NO_x Emission Controls – SCR and SNCR						
SCR/SNCR Island ²	X	X	X		X ³	X
Reagent Preparation ³					X	
Air Heater Modification ⁴	X	X	X	X		X
Balance of Plant ⁵ – SCR	X	X	X			X
Balance of Plant ¹ – SNCR					X	X

Notes:

¹“Balance of plant” costs include such cost items as ID and booster fans, new wet chimneys, piping, ductwork, minor waste water treatment, auxiliary power modifications, and other electrical and site upgrades.

²The SCR island module includes the cost of inlet ductwork, reactor, and bypass. The SNCR island module includes cost of injectors, blowers, distributed control system (DCS), and reagent system.

³Only applies to SCR.

⁴On generating units that burn bituminous coal whose SO₂ and content exceeds 3 lbs/MMBtu, air heater modifications used to control SO₃ are needed in conjunction with the operation of SCR and SNCR.

⁵For SCR, the NO_x rate is frequently expressed through the calculated NO_x removal efficiency.

Once the key variables that figure in the cost of the four modules are identified, they are used to derive costs for each base module in equations developed by Sargent and Lundy based on their experience with multiple engineering projects. The base module costs are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction fees. The resulting value is the capital, engineering, and construction cost (CECC) subtotal. To obtain the total project cost (TPC), the CECC subtotal is increased by 5% to account for owner's home office costs, i.e., owner's engineering, management, and procurement costs. The resulting sum is then increased by another 10% to build in an Allowance for Funds used During Construction (AFUDC) over the 3-year engineering and construction cycle. The resulting value, expressed in \$/kW, is the capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): These are the costs incurred in running the emission control device. They are proportional to the electrical energy produced and are expressed in units of \$ per MWh. For FGD, Sargent and Lundy identified four components of VOM: (a) costs for reagent usage, (b) costs for waste generation, (c) make up water costs, and (d) cost of additional power required to run the control (often called the "parasitic load"). For a given coal rank and a pre-specified SO₂ removal efficiency, each of these components of VOM cost is a function of the generating unit's heat rate (Btu/kWh) and the sulfur content (lb SO₂/MMBtu) of the coal (also referred to as the SO₂ feed rate). For purposes of modeling, the total VOM includes the first three of these component costs. The last component – cost of additional power – is factored into IPM, not in the VOM value, but through a capacity and heat rate penalty as described in the next paragraph. Due to the differences in the removal processes, the per MWh cost for waste handling, makeup water, and auxiliary power tend to be higher for LSFO while reagent usage cost and total VOM (excluding parasitic load) are higher for LSD.

Capacity and Heat Rate Penalty: The amount of electrical power required to operate the FGD device is represented through a reduction in the amount of electricity that is available for sale to the grid. For example, if 1.6% of the unit's electrical generation is needed to operate the scrubber, the generating unit's capacity is reduced by 1.6%. This is the "capacity penalty." At the same time, to capture the total fuel used in generation both for sale to the grid and for internal load (i.e., for operating the FGD device), the unit's heat rate is scaled up such that a comparable reduction (1.6% in the previous example) in the new higher heat rate yields the original heat rate²⁸. The factor used to scale up the original heat rate is called "heat rate penalty." It is a modeling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency). Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO₂ rate, and the heat rate of the model plant.

Fixed Operating and Maintenance Costs (FOM): These are the annual costs of maintaining a unit. They represent expenses incurred regardless of the extent to which the emission control system is run. They are expressed in units of \$ per kW per year. In calculating FOM Sargent and Lundy took into account labor and materials costs associated with operations, maintenance, and administrative functions. The following assumptions were made:

²⁸ Mathematically, the relationship of the heat rate and capacity penalties (both expressed as positive percentage values) can be represented as follows:

$$\text{Heat Rate Penalty} = \left(\frac{1}{\left(1 - \frac{\text{Capacity Penalty}}{100} \right)} - 1 \right) \times 100$$

- FOM for operations is based on the number of operators needed which is a function of the size (i.e., MW capacity) of the generating unit and the type of FGD control. For LSFO 12 additional operators were assumed to be required for a 500 MW or smaller installation and 16 for a unit larger than 500 MW. For LSD 8 additional operators were assumed to be needed.
- FOM for maintenance is a direct function of the FGD capital cost
- FOM for administration is a function of the FOM for operations and maintenance.

Table 5-4 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalty for the two SO₂ emission control technologies (LSFO and LSD) included in EPA Base Case v.4.10 for an illustrative set of generating units with a representative range of capacities and heat rates.

Table 5-4 Illustrative Scrubber Costs (2007\$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.4.10

Scrubber Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)
LSFO Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming 3 lb/MMBtu SO ₂ Content Bituminous Coal	9,000	-1.5	1.53	1.66	747	22.5	547	10.5	473	7.8	430	7.2	388	5.9
	10,000	-1.67	1.7	1.84	783	22.8	573	10.8	496	8.0	451	7.4	407	6.1
	11,000	-1.84	1.87	2.03	817	23.2	598	11.0	517	8.2	470	7.6	425	6.3
LSD Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming 2 lb/MMBtu SO ₂ Content Bituminous Coal	9,000	-1.18	1.2	2.13	641	16.4	469	8.1	406	6.1	385	5.3	385	4.9
	10,000	-1.32	1.33	2.36	670	16.7	491	8.3	424	6.3	403	5.5	403	5.1
	11,000	-1.45	1.47	2.60	698	17.0	511	8.5	442	6.5	420	5.7	420	5.2

5.2 Nitrogen Oxides Control Technology

The EPA Base Case v.4.10 includes two categories of NO_x reduction technologies: combustion and post-combustion controls. Combustion controls reduce NO_x emissions during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Post-combustion controls operate downstream of the combustion process and remove NO_x emissions from the flue gas. All the specific combustion and post-combustion technologies included in EPA Base Case v.4.10 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

The EPA Base Case v.4.10 representation of combustion controls uses equations that are tailored to the boiler type, coal type, and combustion controls already in place and allow appropriate additional combustion controls to be exogenously applied to generating units based on the NO_x emission limits they face. Characterizations of the emission reductions provided by combustion controls are presented in Table 3-1.3 in Appendix 3-1. The EPA Base Case v.4.10 cost assumptions for NO_x Combustion Controls are summarized in Table 5-5. Table 5-6 provides a mapping of existing coal unit configurations and incremental combustion controls applied in EPA Base Case v.4.10 to achieve state-of-the-art combustion control configuration.

Table 5-5 Cost (2007\$) of NO_x Combustion Controls for Coal Boilers (300 MW Size)

Boiler Type	Technology	Capital (\$/kW)	Fixed O&M (\$/kW-yr)	Variable O&M (mills/kWh)
Dry Bottom Wall-Fired	Low NO _x Burner without Overfire Air (LNB without OFA)	45	0.3	0.07
	Low NO _x Burner with Overfire Air (LNB with OFA)	61	0.4	0.09
Tangentially-Fired	Low NO _x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	24	0.2	0.00
	Low NO _x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	33	0.2	0.03
	Low NO _x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	38	0.3	0.03
Vertically-Fired	NO _x Combustion Control	29	0.2	0.06
Scaling Factor				
The following scaling factor is used to obtain the capital and fixed operating and maintenance costs applicable to the capacity (in MW) of the unit taking on combustion controls. No scaling factor is applied in calculating the variable operating and maintenance cost. LNB without OFA & LNB with OFA = (\$ for X MW Unit) = (\$ for 300 MW Unit) x (300/X)^{0.359} LNC1, LNC2 and LNC3 = (\$ for X MW Unit) = (\$ for 300 MW Unit) x (300/X)^{0.359} Vertically-Fired = (\$ for X MW Unit) = (\$ for 300 MW Unit) x (300/X)^{0.553} where (\$ for 300 MW Unit) is the value obtained using the factors shown in the above table and X is the capacity (in MW) of the unit taking on combustion controls.				

Table 5-6 Incremental Combustion NO_x Controls in EPA Base Case v.4.10

Boiler Type	Existing NO_x Combustion Control	Incremental Combustional Control
Cell	LNB NGR	OFA LNB AND OFA
Cyclone	--	OFA
Stoker/SPR	--	OFA
Tangential	-- LA LNB LNB + OFA LNC1 LNC2 OFA ROFA	LNC3 LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC2 TO LNC3 LNC1 LNB
Vertical	--	NO _x Combustion Control - Vertically Fired Units
Wall	-- LA LNB LNF OFA	LNB AND OFA LNB AND OFA OFA OFA LNB

5.2.2 Post-combustion Controls

The EPA Base Case v.4.10 includes two post-combustion retrofit control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Base Case v.4.10 oil/gas steam units are eligible for SCR only. NO_x reduction in an SCR system takes place by injecting ammonia (NH₃) vapor into the flue gas stream where the NO_x is reduced to nitrogen (N₂) and water H₂O abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten. As its name implies, SNCR operates without a catalyst. In SNCR a nitrogenous reducing agent (reagent), typically ammonia or urea, is injected into, and mixed with, hot flue gas where it reacts with the NO_x in the gas stream reducing it to nitrogen gas and water vapor. Due to the presence of a catalyst, SCR can achieve greater NO_x reductions than SNCR. However, SCR costs are higher.

Table 5-7 summarizes the performance and applicability assumptions in EPA Base Case v.4.10 for each NO_x post-combustion control technology and provides a cross reference to information on cost assumptions.

Table 5-7 Summary of Retrofit NO_x Emission Control Performance Assumptions

Control Performance Assumptions	Selective Catalytic Reduction (SCR)		Selective Non-Catalytic Reduction (SNCR)
Unit Type	Coal	Oil/Gas	Coal
Percent Removal	90% down to 0.06 lb/MMBtu	80%	Pulverized Coal: 35% Fluidized Bed: 50%
Size Applicability	Units ≥ 25 MW	Units ≥ 25 MW	Units ≥ 25 MW
Costs (2007\$)	See Table 5-8	See Table 5-9	See Table 5-8

Potential (new) coal-fired, combined cycle, and IGCC units are modeled to be constructed with SCR systems and designed to have emission rates ranging between 0.01 and 0.06 lb NO_x/MMBtu. EPA Base Case v.4.10 cost assumptions for these units include the cost of SCR

5.2.3 Methodology for Obtaining SCR Costs for Coal Units

As with the update of SO₂ control costs, Sargent and Lundy employed an engineering build-up of the capital, fixed and variable operating and maintenance components of cost to update post-combustion NO_x control costs. This section describes the approach used for SCR. The next section treats SNCR. Detailed example cost calculation spreadsheets for both technologies can be found in Appendix 5-2.

For cost calculation purposes the Sargent and Lundy methodology calculates plant specific NO_x removal efficiencies, i.e., the percent difference between the uncontrolled NO_x rate²⁹ for a model plant and the cost calculation floor NO_x rate corresponding to the predominant coal rank used at the plant (0.07 lb/MMBtu for bituminous and 0.05 lb/MMBtu for subbituminous and lignite coals). For example, a plant that burns subbituminous coal with an uncontrolled NO_x rate of 0.1667 lb/MMBtu, and a cost calculation floor NO_x rate of 0.05 lb/MMBtu would have a removal efficiency of 70%, i.e., $(0.1667 - 0.05)/0.1667 = 0.1167/0.1667 = .70$. The NO_x removal efficiency so obtained figures in the capital, VOM, and FOM components of SCR cost.

Capital Costs: In building up SCR capital costs, four separate cost modules were included: SCR island (e.g., inlet ductwork, reactor, and bypass), reagent preparation, air pre-heater modification, and balance of plant (e.g., ID or booster fans, piping, and auxiliary power modification). Air pre-heater modification cost only applies for plants that burn bituminous coal whose SO₂ content is 3 lbs/MMBtu or greater, where SO₃ control is necessary. Otherwise, there is no air pre-heat cost. For each of the four modules the cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. All four capital cost modules, except reagent preparation, are functions of retrofit difficulty, coal rank, heat rate, and unit size. NO_x rate (expressed via the NO_x removal efficiency) affects the SCR and reagent preparation cost modules. Not shown in Table 5-3, heat input (in Btu/hr) also impacts reagent preparation costs. As noted above, the SO₂ rate becomes a factor in SCR cost for plants that combust bituminous coal with 3 lbs SO₂/MMBtu or greater, where air pre-heater modifications are needed for SO₃ control.

As with FGD capital costs, the base module costs for SCR are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction fees. The resulting value is the capital, engineering, and construction cost (CECC) subtotal. To obtain the total project cost (TPC) the CECC subtotal is increased by 5% to account for owner's home office costs, i.e., owner's engineering, management, and procurement costs. Whereas the resulting sum is then increased by another 10% for FGD, for SCR it is increased by 6% to factor in an Allowance for Funds used During Construction (AFUDC) over the 2-year engineering and construction cycle (in contrast to the 3-year cycle assumed for FGD). The resulting value, expressed in \$/MW, is the capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): For SCR Sargent and Lundy identified four components of VOM: (a) costs for the urea reagent, (b) costs of catalyst replacement and disposal, (c) cost of required steam, and (d) cost of additional power required to run the control

²⁹ More precisely, the uncontrolled NO_x rate for a model plant in EPA Base Case v.4.10 is the capacity weighted average of the Mode 1 NO_x rates of the generating units comprising the model plant. The meaning of "Mode 1 NO_x rate" is discussed in section 3.9.2 and Appendix 3-1 ("NO_x Rate Development in EPA Base Case v.4.10).

(i.e., the “parasitic load”). As was the case for FGD, the last component – cost of additional power – is factored into IPM, not in the VOM value, but through a capacity and heat rate penalty as described earlier. Of the first three of these component costs, reagent cost and catalyst replacement are predominant while steam cost is much lower in magnitude. NO_x rates and heat rates are key determinates of reagent and steam costs, while NO_x rate (via removal efficiency), capacity factor, and coal rank are key drivers of catalyst replacement costs.

Capacity and Heat Rate Penalty:

Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific SCR heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO₂ rate, and the heat rate of the model plant.

Fixed Operating and Maintenance Costs (FOM): For SCR the following assumptions were made:

- FOM for operations is based on the assumption that one additional operator working half-time is required.
- FOM for maintenance is assumed to \$193,585 (in 2007\$) for generating units less than 500 MW and \$290,377 (in 2007\$) for generating units 500 MW or greater
- There was assumed to be no FOM for administration for SCR.

Table 5-8 presents the SCR and SNCR capital, VOM, and FOM costs and capacity and heat rate penalties for an illustrative set of coal generating units with a representative range of capacities, heat rates, and NO_x removal efficiencies. The illustrations include and identify plants that do and do not burn bituminous coal with 3 lbs SO₂/MMBtu or greater.

Table 5-8 Illustrative Post Combustion NO_x Controls for Coal Plants Costs (2007\$) for Representative Sizes and Heat Rates under the Assu Assumptions in EPA Base Case v.4.10

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost (\$/kW)	Fixed O&M (\$/kW- yr)	Capital Cost (\$/kW)	Fixed O&M (\$/kW- yr)	Capital Cost (\$/kW)	Fixed O&M (\$/kW- yr)	Capital Cost (\$/kW)	Fixed O&M (\$/kW- yr)	Capital Cost (\$/kW)	Fixed O&M (\$/kW- yr)
SCR Minimum Cutoff: ≥ 25 MW	9,000	-0.54	0.54	1.15	221	2.5	177	0.8	163	0.7	155	0.5	147	0.4
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.56	0.56	1.24	240	2.5	193	0.8	178	0.7	169	0.5	162	0.4
NO _x rate: 0.5 lb/MMBtu	11,000	-0.58	0.59	1.33	258	2.5	209	0.8	193	0.7	184	0.5	176	0.4
SO ₂ rate: 2.0 lb/MMBtu														
SNCR - Non-FBC Minimum Cutoff: ≥ 25 MW	9,000			0.88	45	1	Size Not Modeled							
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.05	0.05	0.98	47	1								
NO _x rate: 0.5 lb/MMBtu	11,000			1.08	48	1								
SO ₂ rate: 2.0 lb/MMBtu														
SNCR - Fluidized Bed Minimum Cutoff: ≥ 25 MW	9,000			0.88	34	0.9	18	0.4	14	0.2	11	0.2	9	0.1
Maximum Cutoff: None Assuming Bituminous Coal	10,000	-0.05	0.05	0.98	35	0.9	19	0.4	14	0.2	12	0.2	10	0.1
NO _x rate: 0.5 lb/MMBtu	11,000			1.08	36	0.9	19	0.4	14	0.2	12	0.2	10	0.1
SO ₂ rate: 2.0 lb/MMBtu														

Note:

If a coal plant burns bituminous coal with a SO₂ content above 3.0 lb/MMBtu then the capital costs will increase due to the required air preheater modification. For example, a 100 MW coal boiler with an SCR burning bituminous coal at a heat rate of 11,000 Btu/kWh and an SO₂ rate of 4.0 lb/MMBtu will have a capital cost of 296 \$/kW, a 36 \$/kW increase in capital costs from an identical boiler burning coal with an SO₂ rate of 2.0 lb/MMBtu.

5.2.4 Methodology for Obtaining SCR Costs for Oil/Gas Steam units

The cost calculations for SCR described in section 5.2.3 apply to coal units. For SCR on oil/gas steam units the cost calculation procedure employed in EPA's most recent previous base case was used. However, capital costs were scaled up by 2.13 to account for increases in the component costs that had occurred since the assumptions were incorporated in that base case. All costs were expressed in constant 2007\$ for consistency with the dollar year cost basis used throughout EPA Base Case v4.10. Table 5-9 shows that resulting capital, FOM, and VOM cost assumptions for SCR on oil/gas steam units. The scaling factor for capital and fixed operating and maintenance costs, described in footnote 1, applies to all size units from 25 MW and up.

Table 5-9 Post-Combustion NO_x Controls for Oil/Gas Steam Units in EPA Base Case v.4.10

Post-Combustion Control Technology	Capital (\$/kW)	Fixed O&M (\$/kW-yr)	Variable O&M (mills/kWh)	Percent Removal
SCR ¹	75	1.08	0.12	80%

Notes:

The "Coefficients" in the table above are multiplied by the terms below to determine costs. "MW" in the terms below is the unit's capacity in megawatts.

This data is used in the generation of EPA Base Case v.4.0

¹ SCR Cost Equations:

SCR Capital Cost and Fixed O&M: $(200/\text{MW})^{0.35}$

The scaling factors shown above apply up to 500 MW. The cost obtained for a 500 MW unit applies for units larger than 500 MW.

Example for 275 MW unit:

SCR Capital Cost (\$/kW) = $75 * (200/275)^{0.35} \approx 67$ \$/kW

SCR FOM Cost (\$/kW-yr) = $1.08 * (200/275)^{0.35} \approx 0.97$ \$/kW-yr

SCR VOM Cost (mills/kWh) = 0.12 mills/kWh

Reference:

Cost Estimates for Selected Applications of NO_x Control Technologies on Stationary Combustion Boilers, Bechtel Power Corporation for US EPA, June 1997

5.2.5 Methodology for Obtaining SNCR Costs

In the Sargent and Lundy cost update for SNCR a generic NO_x removal efficiency of 25% is assumed. However, the capital, fixed and variable operating and maintenance costs of SNCR on circulating fluidized bed (CFB) units are distinguished from the corresponding costs for other boiler types (e.g. cyclone, and wall fired).

Capital Costs: Due to the absence of a catalyst and, with it, the elimination of the need for more extensive reagent preparation, the Sargent and Lundy engineering build up of SNCR capital costs includes three rather than four separate cost modules: SNCR (injectors, blowers, distributive control system, reagent system), air pre-heater modification, and balance of plan (e.g., ID or booster fans, piping, and auxiliary power modification). For CFB units, the SNCR and balance of plan module costs are 75% of what they are on other boiler types. The air pre-heater modification cost module is the same as for SCR and there is no cost difference between CFB and other boiler types. As with SCR the air heater modification cost only applies for plants that burn bituminous coal whose SO₂ content is 3 lbs/MMBtu or greater, where SO₃ control is necessary. Otherwise, there is no air pre-heat cost. For each of the three modules the cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. Unit size affects all three modules. Retrofit difficulty, coal rank, and heat rate impact the SNCR and air heater modification modules. The SO₂ rate impacts the air pre-heater modification module. NO_x rate

(expressed via the NO_x removal efficiency) and heat input (not shown in Table 5-3) affect the balance of plan module.

The base module costs for SNCR are summed to obtain total bare module costs. This total is increased by 30% to account for additional engineering and construction fees. The resulting value is the capital, engineering, and construction cost (CECC) subtotal. To obtain the total project cost (TPC) the CECC subtotal is increased by 5% to account for owner's home office costs, i.e., owner's engineering, management, and procurement costs. Since SNCR projects are typically completed in less than a year, there is no Allowance for Funds used During Construction (AFUDC) in the SNCR capital cost factor that is used in EPA Base Case v.4.10.

Variable Operating and Maintenance Costs (VOM): Sargent and Lundy identified two components of VOM for SNCR: (a) cost for the urea reagent and (b) the cost of dilution water. The magnitude of the reagent cost predominates the VOM with the cost of dilution water at times near zero. There is no capacity or heat rate penalty associated with SNCR since the only impact on power are compressed air or blower required for urea injection and the reagent supply system.

Capacity and Heat Rate Penalty:

Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific SNCR heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO₂ rate, and the heat rate of the model plant.

Fixed Operating and Maintenance Costs (FOM): The assumptions for FOM for operations and for administration are the same for SNCR as for SCR, i.e.,

- FOM for operations is based on the assumption that one additional operator working half-time is required.
- There was assumed to be no FOM for administration for SCR.

FOM for maintenance materials and labor was assumed to be a direct function of base module cost, specifically, 1.2% of those costs divided by the capacity of the generating unit expressed in kilowatts.

Detailed example cost calculation spreadsheets for SNCR can be found in Appendix 5-2.

5.2.6 SO₂ and NO_x Controls for Units with Capacities from 25 MW to 100 MW (25 M ≤ capacity < 100 MW)

In EPA Base Case v.4.10 coal units with capacities between 25 MW and 100 MW are offered the same SO₂ and NO_x emission control options as larger units. However, for purposes of modeling, the costs of controls for these units are assumed to be equivalent to that of a 100 MW unit. This assumption is based on several considerations. First, to achieve economies of scale, several units in this size range are likely to be ducted to share a single common control, so the 100 MW cost equivalency assumption, though generic, would be technically plausible. Second, single units in this size range that are not grouped to achieve economies of scale are likely to have the option of hybrid multi-pollutant controls currently under development.³⁰ These hybrid controls achieve cost economies by combining SO₂, NO_x and particulate controls into a single control unit. Singly, the costs of the individual control would be higher for units below 100 MW than for a 100 MW unit,

³⁰ See, for example, the Greenidge Multi-Pollutant Control Project, which was part of the U.S. Department of Energy, National Energy Technology Lab's Power Plant Improvement Initiative. A joint effort of CONSOL Energy Inc. AES Greenidge LLC, and Babcock Power Environmental, Inc., information on the project can be found at www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/bib_greenidge.html.

but when combined in the Multi-Pollutant Technologies (MPTs) their costs would be roughly equivalent to the cost of individual controls on a 100 MW unit. While MPTs are not explicitly represented in EPA Base Case v.4.10, single units in the 25-100 MW range that take on combinations of SO₂ and NO_x controls in a model run can be thought of as being retrofit with an MPT.

Illustrative scrubber, SCR, and SNCR costs for 25-100 MW coal units with a range heats rates can be found by referring to the 100 MW “Capital Costs (\$/kW)” and “Fixed O&M” columns in Table 5-4 and Table 5-8. The Variable O&M cost component, which applies to units regardless of size, can be found in the fifth column in these tables.

5.3 Biomass Co-firing

Under most climate policies currently being discussed, biomass is treated as “carbon neutral,” i.e., a zero contributor of CO₂ to the atmosphere. The reasoning is that the CO₂ emitted in the combustion of biomass will be reabsorbed via photosynthesis in plants grown to replace the biomass that was combusted. Consequently, if a power plant can co-fire biomass and thereby replace a portion of fossil fuel, it reduces its CO₂ emissions by approximately the same proportion, although combustion efficiency losses may somewhat diminish the proportion of CO₂ reduction. Roughly speaking, by co-firing enough biomass to produce 10% of a coal plant’s power output, a co-fired plant can realize close to an effective 10% reduction in CO₂ emitted.

Biomass co-firing is provided as a fuel choice for all coal-fired power plants in EPA Base Case v.4.10. However, logistics and boiler engineering considerations place limits on the extent of biomass that can be fired. The logistic considerations arise because it is only economic to transport biomass a limited distance from where it is grown. In addition, the extent of storage that can be devoted at a power plant to this relatively low density fuel is another limiting factor. Boiler efficiency and other engineering considerations, largely due to the relatively higher moisture content and lower heat content of biomass compared to fossil fuel, also plays a role in limiting the level of co-firing.

In EPA Base Case v.4.10 the limit on biomass co-firing is expressed as the percentage of the facility level power output that is produced from biomass. Based on analysis by EPA’s power sector engineering staff, a maximum of 10% of the facility level power output (not to exceed 50 MW) can be fired by biomass. In EPA Base Case v.4.10 “facility level” is defined as the set of generating units which share the same ORIS code³¹ in NEEDS v.4.10.

The capital and FOM costs associated with biomass co-firing are summarized in Table 5-10. Developed by EPA’s power sector engineering staff³², they are on the same cost basis as the

³¹ The ORIS plant locator code is a unique identifying number (originally assigned by the Office of Regulatory Information Systems from which the acronym derived). The ORIS code is given to power plants by EIA and remains unchanged under ownership changes.

³² Among the studies consulted in developing these costs were:

(a) Briggs, J. and J. M. Adams, *Biomass Combustion Options for Steam Generation*, Presented at Power-Gen 97, Dallas, TX, December 9 – 11, 1997.

(b) Grusha, J and S. Woldehanna, K. McCarthy, and G. Heinz, *Long Term Results from the First US Low NO_x Conversion of a Tangential Lignite Fired Unit*, presented at 24th International Technical Conference on Coal & Fuel Systems, Clearwater, FL., March 8 – 11, 1999.

(c) EPRI, *Biomass Cofiring: Field Test Results: Summary of Results of the Bailly and Seward Demonstrations*, Palo Alto, CA, supported by U.S. Department of Energy Division of Energy Efficiency and Renewable Energy, Washington D.C.; U.S. Department of Energy Division Federal Energy Technology Center, Pittsburgh PA; Northern Indiana Public Service Company, Merrillville, IN; and GPU Generation, Inc., Johnstown, PA: 1999. TR-113903.

(d) Laux S., J. Grusha, and D. Tillman, Co-firing of Biomass and Opportunity Fuels in Low NO_x

costs shown in Table 4-16 which resulted from EPA's comparative analysis of electricity sector costs as described in Chapter 4.

Table 5-10 Biomass Cofiring for Coal Plants

Size of Biomass Unit (MW)	5	10	15	20	25	30	35	40	45	50
Capital Cost (2007\$/kW From Biomass)	488	411	371	345	327	312	300	290	282	275
Fixed O&M (2007\$/kW-yr)	24.2	16.2	11.7	9.4	8.0	11.1	9.9	8.9	8.1	7.5

The capital and FOM costs were implemented by ICF in EPA Base Case v.4.10 as a \$/MMBtu biomass fuel cost adder. The procedure followed to implement this was first to represent the discrete costs shown in Table 5-10 as continuous exponential cost functions showing the FOM and capital costs for all size coal generating units between 0 and 50 MW in size. Then, for every coal generating unit represented in EPA Base Case 4.10, the annual payment to capital for the biomass co-firing capability was derived by multiplying the total capital cost obtained from the capital cost exponential function by an 11% capital charge rate. (This is the capital charge rate for environmental retrofits found in Table 8-1 and discussed in Chapter 8.) The resulting value was added to the annual FOM cost obtained from the FOM exponential function to obtain the total annual cost for the biomass co-firing for each generating unit.

Then, the annual amount of fuel (in MMBtus) required for each generating unit was derived by multiplying the size of a unit (in MW) by its heat rate (in Btu/kWh) by its capacity factor (in percent) by 8,760 hours (i.e., the number of hours in a year). Dividing the resulting value by 1000 yielded the annual fuel required by the generating unit in MMBtus. Dividing this number into the previously calculated total annual cost for biomass co-firing resulted in the cost of biomass co-firing per MMBtu of biomass combusted. This was represented in IPM as a fuel cost adder incurred when a coal units co-fires biomass.

5.4 Mercury Control Technologies

As previously noted, the mercury emission controls options and assumptions in EPA Base Case v.4.10 do not reflect mercury control updates that are currently under way at EPA in support of the Utility MACT initiative and do not make use of data collected under EPA's 2010 Information Collection Request (ICR). The following discussion is based on EPA's earlier work on mercury controls.

For any power plant, mercury emissions depend on the mercury content of the fuel used, the combustion and physical characteristics of the unit, and the emission control technologies deployed. In the absence of emission policies that would require the installation of mercury emission controls, mercury emission reductions below the mercury content of the fuel are strictly due to characteristics of the combustion process and incidental removal resulting from non-mercury control technologies, i.e., the SO₂, NO_x, and particulate controls. While the base case itself does not include any federal mercury control policies, it does include some State mercury reduction requirements. IPM has the capability to model mercury controls that might be installed in response to such State mercury control policies. These same controls come into play in model runs that analyze possible federal mercury policies relative to the base case. The technology specifically designated for mercury control in such policy runs is Activated Carbon Injection (ACI) downstream of the combustion process.

Burners, PowerGen 2000 - Orlando, FL,

www.fwc.com/publications/tech_papers/powgen/pdfs/clrw_bio.pdf.

Tillman, D. A., *Cofiring Biomass for Greenhouse Gas Mitigation*, presented at Power-Gen 99, New Orleans, LA, November 30 – December 1, 1999.

(e) Tillman, D. A. and P. Hus, *Blending Opportunity Fuels with Coal for Efficiency and Environmental Benefit*, presented at 25th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., March 6 – 9, 2000

The following discussion is divided into three parts. Sections 5.4.1 and 5.4.2 treat the two factors that figure into the unregulated mercury emissions resulting under EPA Base Case v.4.10. Section 5.4.1 discusses how mercury content of fuel is modeled in EPA Base Case v.4.10. Section 5.4.2 looks at the procedure used in the base case to capture the mercury reductions resulting from different unit and (non-mercury) control configurations. Section 5.4.3 explains the mercury emission control options that are available under EPA Base Case v.4.10. A major focus is on the cost and performance features of Activated Carbon Injection. Each section indicates the data sources and methodology used.

5.4.1 Mercury Content of Fuels

Coal: The assumptions in EPA Base Case v.4.10 on the mercury content of coal (and the majority of emission modification factors discussed below in Section 5.4.2) are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR).³³ A two-year effort initiated in 1998 and completed in 2000, the ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies, (2) obtaining "accurate information on the amount of mercury contained in the as-fired coal used by each electric utility steam generating unit . . . with a capacity greater than 25 megawatts electric [MWe]), as well as accurate information on the total amount of coal burned by each such unit," and (3) obtaining data by coal sampling and stack testing at selected units to characterize mercury reductions from representative unit configurations.

The ICR second component resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content and other characteristics of coal burned at coal-fired utility units greater than 25 MW. To make this data usable in EPA Base Case v.4.10, these data points were first grouped by IPM coal types and IPM coal supply regions. (IPM coal types divide bituminous, sub-bituminous, and lignite coal into different grades based on sulfur content. See Table 5-11.) Next, a clustering analysis was performed on the data using the SAS statistical software package. Clustering analysis places objects into groups or clusters, such that data in a given cluster tend to be similar to each other and dissimilar to data in other clusters. The clustering analysis involved two steps. First, the number of clusters of mercury concentrations for each IPM coal type was determined based on the range of mercury and SO₂ concentrations for that coal type. Each coal type used one, two or three clusters. To the greatest extent possible the total number of clusters for each coal type was limited to keep the model size and run time within feasible limits. Second, the clustering procedure was used to group each coal type within each IPM coal supply region into the previously determined number of clusters and show the resulting mercury concentration for each cluster. The average of each cluster is the mercury content of coal finally used in EPA Base Case v.4.10 for estimating mercury emissions. IPM input files retain the mapping between different coal type-supply region combinations and the mercury clusters. Table 5-11 below provides a summary by coal type of the number of clusters and their mercury concentrations.

³³Data from the ICR can be found at <http://www.epa.gov/ttn/atw/combust/utiltox/mercury.html>.

Table 5-11 Mercury Clusters and Mercury Content of Coal by IPM Coal Types

Coal Type by Sulfur Grade	Mercury Emission Factors by Coal Sulfur Grades (lbs/TBtu)		
	Cluster #1	Cluster #2	Cluster #3
Low Sulfur Easter Bituminous (BA)	3.19	4.37	--
Low Sulfur Western Bituminous (BB)	1.82	4.86	--
Low Medium Sulfur Bituminous (BD)	5.38	8.94	21.67
Medium Sulfur Bituminous (BE)	19.53	8.42	--
High Sulfur Bituminous (BG)	7.10	20.04	14.31
High Sulfur Bituminous (BH)	7.38	13.93	34.71
Low Sulfur Subbituminous (SA)	4.24	5.61	--
Low Sulfur Subbituminous (SB)	6.44	--	--
Low Medium Sulfur Subbituminous (SD)	4.43	--	--
Low Medium Sulfur Lignite (LD)	7.51	12.00	--
Medium Sulfur Lignite (LE)	13.55	7.81	--
High Sulfur Lignite (LG)	14.88	--	--

Oil, natural gas, and waste fuels: The EPA Base Case v.4.10 also includes assumptions on the mercury content for oil, gas and waste fuels, which were based on data derived from previous EPA analysis of mercury emissions from power plants.³⁴ Table 5-12 provides a summary of the assumptions on the mercury content for oil, gas and waste fuels included in EPA Base Case v.4.10.

Table 5-12 Assumptions on Mercury Concentration in Non-Coal Fuel in EPA Base Case v.4.10

Fuel Type	Mercury Concentration (lbs/TBtu)
Oil	0.48
Natural Gas	0.00 ¹
Petroleum Coke	23.18
Biomass	0.57
Municipal Solid Waste	71.85
Geothermal Resource	2.97 - 3.7

Note:

¹The values appearing in this table are rounded to two decimal places. The zero value shown for natural gas is based on an EPA study that found a mercury content of 0.00014 lbs/TBtu. Values for geothermal resources represent a range.

5.4.2 Mercury Emission Modification Factors

Emission Modification Factors (EMFs) represent the mercury reductions attributable to the specific burner type and configuration of SO₂, NO_x, and particulate matter control devices at an electric generating unit. An EMF is the ratio of outlet mercury concentration to inlet mercury concentration, and depends on the unit's burner type, particulate control device, post-combustion NO_x control and SO₂ scrubber control. In other words, the mercury reduction achieved (relative to

³⁴"Analysis of Emission Reduction Options for the Electric Power Industry," Office of Air and Radiation, US EPA, March 1999.

the inlet) during combustion and flue-gas treatment process is (1-EMF). The EMF varies by the type of coal (bituminous, sub-bituminous, and lignite) used during the combustion process.

Deriving EMFs involves obtaining mercury inlet data by coal sampling and mercury emission data by stack testing at a representation set of coal units. As noted above, EPA's EMFs were initially based on 1999 mercury ICR emission test data. More recent testing conducted by the EPA, DOE, and industry participants³⁵ has provided a better understanding of mercury emissions from electric generating units and mercury capture in pollution control devices. Overall the 1999 ICR data revealed higher levels of mercury capture for bituminous coal-fired plants than for subbitumionous and lignite coal-fired plants, and significant capture of ionic Hg in wet-FGD scrubbers. Additional mercury testing indicates that for bituminous coals, SCR systems have the ability to convert elemental Hg into ionic Hg and thus allow easier capture in a downstream wet-FGD scrubber. This improved understanding of mercury capture with SCRs was incorporated in EPA Base Case v.4.10 mercury EMFs for unit configurations with SCR and wet scrubbers.

Table 5-13 below provides a summary of EMFs used in EPA Base Case v.4.10. Table 5-14 provides definitions of acronyms for existing controls that appear in Table 5-13. Table 5-15 provides a key to the burner type designations appearing in Table 5-13.

5.4.3 Mercury Control Capabilities

EPA Base Case v.4.10 offers two options for meeting mercury reduction requirements: (1) combinations of SO₂, NO_x, and particulate controls which deliver mercury reductions as a co-benefit and (2) Activated Carbon Injection (ACI), a retrofit option specifically designed for mercury control. These two options are discussed below.

³⁵ For a detailed summary of emissions test data see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, February 2005. This report can be found at www.epa.gov/ttnatw01/utility/hgwhitepaperfinal.pdf.

Table 5-13 Mercury Emission Modification Factors Used in EPA Base Case v.4.10

Burner Type	Particulate Control	Post Combustion Control – NO_x	Post Combustion Control - SO₂	Bituminous EMF	Subbitumionous EMF	Lignite EMF
Cyclone	Cold Side ESP	SNCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP	SNCR	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	SCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.58
Cyclone	Cold Side ESP	SCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	None	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP	None	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	None	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FF	SNCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	SCR	None	0.11	0.27	1
Cyclone	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FF	None	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	None	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FF	None	None	0.11	0.27	1
Cyclone	Cold Side ESP + FGC	SNCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC	SNCR	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	SCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.58
Cyclone	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	None	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	None	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC + FF	SCR	None	0.11	0.27	1
Cyclone	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FGC + FF	None	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FGC + FF	None	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FGC + FF	None	None	0.11	0.27	1
Cyclone	Fabric Filter	SNCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.58
Cyclone	Fabric Filter	SNCR	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	SCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Fabric Filter	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	None	Wet FGD	0.1	0.27	0.58
Cyclone	Fabric Filter	None	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	None	None	0.11	0.27	1
Cyclone	Hot Side ESP	SNCR	None	0.9	1	1
Cyclone	Hot Side ESP	SNCR	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP	SNCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP	SCR	None	0.9	1	1
Cyclone	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP	SCR	Dry FGD	0.9	1	1

Burner Type	Particulate Control	Post Combustion Control – NO _x	Post Combustion Control - SO ₂	Bituminous EMF	Subbitumionous EMF	Lignite EMF
Cyclone	Hot Side ESP	None	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP	None	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP	None	None	0.9	1	1
Cyclone	Hot Side ESP + FF	None	None	0.11	0.27	1
Cyclone	Hot Side ESP + FGC	SNCR	None	0.9	1	1
Cyclone	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP + FGC	SNCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	SCR	None	0.9	1	1
Cyclone	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP + FGC	SCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	None	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP + FGC	None	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	None	None	0.9	1	1
Cyclone	No Control	SNCR	None	1	1	1
Cyclone	No Control	SNCR	Wet FGD	0.45	0.6	1
Cyclone	No Control	SNCR	Dry FGD	1	1	1
Cyclone	No Control	SCR	None	1	1	1
Cyclone	No Control	SCR	Wet FGD	0.1	0.7	1
Cyclone	No Control	SCR	Dry FGD	1	1	1
Cyclone	No Control	None	Wet FGD	0.45	0.6	1
Cyclone	No Control	None	Dry FGD	1	1	1
Cyclone	No Control	None	None	1	1	1
Cyclone	PM Scrubber	None	None	0.8	1	1
FBC	Cold Side ESP	SNCR	None	0.65	0.65	0.62
FBC	Cold Side ESP	SNCR	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.62
FBC	Cold Side ESP	None	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP	None	Dry FGD	0.45	0.45	1
FBC	Cold Side ESP	None	None	0.65	0.65	0.62
FBC	Cold Side ESP + FF	SNCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FF	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FF	None	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FF	None	None	0.05	0.43	0.43
FBC	Cold Side ESP + FGC	SNCR	None	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	SNCR	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.62
FBC	Cold Side ESP + FGC	None	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	None	Dry FGD	0.45	0.45	1
FBC	Cold Side ESP + FGC	None	None	0.65	0.65	0.62
FBC	Cold Side ESP + FGC + FF	SNCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	None	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	None	None	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	None	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	Wet FGD	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	SCR	None	0.05	0.43	0.43

Burner Type	Particulate Control	Post Combustion Control – NO _x	Post Combustion Control - SO ₂	Bituminous EMF	Subbitumionous EMF	Lignite EMF
FBC	Fabric Filter	SCR	Wet FGD	0.05	0.27	0.43
FBC	Fabric Filter	SCR	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	None	Wet FGD	0.1	0.43	0.43
FBC	Fabric Filter	None	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	None	None	0.05	0.43	0.43
FBC	Hot Side ESP	SNCR	None	1	1	1
FBC	Hot Side ESP	SNCR	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP	None	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP	None	None	1	1	1
FBC	Hot Side ESP + FGC	SNCR	None	1	1	1
FBC	Hot Side ESP + FGC	SNCR	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP + FGC	None	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP + FGC	None	None	1	1	1
FBC	No Control	SNCR	None	1	1	1
FBC	No Control	SNCR	Wet FGD	1	1	1
FBC	No Control	SNCR	Dry FGD	0.45	0.45	1
FBC	No Control	SCR	None	1	1	1
FBC	No Control	SCR	Wet FGD	0.1	0.7	1
FBC	No Control	SCR	Dry FGD	0.45	0.45	1
FBC	No Control	None	Wet FGD	1	1	1
FBC	No Control	None	Dry FGD	0.45	0.45	1
FBC	No Control	None	None	1	1	1
PC	Cold Side ESP	SNCR	None	0.64	0.97	1
PC	Cold Side ESP	SNCR	Wet FGD	0.34	0.65	0.56
PC	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	SCR	None	0.64	0.97	1
PC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
PC	Cold Side ESP	None	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	None	None	0.64	0.97	1
PC	Cold Side ESP + FF	SNCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SNCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	None	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FF	None	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	None	None	0.2	0.75	1
PC	Cold Side ESP + FGC	SNCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.65	0.56
PC	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56

Burner Type	Particulate Control	Post Combustion Control – NO _x	Post Combustion Control - SO ₂	Bituminous EMF	Subbitumionous EMF	Lignite EMF
PC	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	None	None	0.64	0.97	1
PC	Cold Side ESP + FGC + FF	SNCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SNCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	None	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FGC + FF	None	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	None	None	0.2	0.75	1
PC	Fabric Filter	SNCR	None	0.11	0.27	1
PC	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
PC	Fabric Filter	SNCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	SCR	None	0.11	0.27	1
PC	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	None	Dry FGD	0.05	0.75	1
PC	Fabric Filter	None	None	0.11	0.27	1
PC	Hot Side ESP	SNCR	None	0.9	0.9	1
PC	Hot Side ESP	SNCR	Wet FGD	0.58	0.75	1
PC	Hot Side ESP	SNCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	SCR	None	0.9	0.9	1
PC	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	None	Wet FGD	0.58	0.8	1
PC	Hot Side ESP	None	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	None	None	0.9	0.94	1
PC	Hot Side ESP + FF	SNCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SNCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	None	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	None	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	None	None	0.11	0.27	1
PC	Hot Side ESP + FGC	SNCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	0.75	1
PC	Hot Side ESP + FGC	SNCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	SCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	None	Wet FGD	0.58	0.8	1
PC	Hot Side ESP + FGC	None	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	None	None	0.9	0.94	1

Burner Type	Particulate Control	Post Combustion Control – NO _x	Post Combustion Control - SO ₂	Bituminous EMF	Subbitumionous EMF	Lignite EMF
PC	Hot Side ESP + FGC + FF	SNCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	SNCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	None	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FGC + FF	None	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	None	None	0.11	0.27	1
PC	No Control	SNCR	None	1	1	1
PC	No Control	SNCR	Wet FGD	0.58	0.7	1
PC	No Control	SNCR	Dry FGD	0.6	0.85	1
PC	No Control	SCR	None	1	1	1
PC	No Control	SCR	Wet FGD	0.1	0.7	1
PC	No Control	SCR	Dry FGD	0.6	0.85	1
PC	No Control	None	Wet FGD	0.58	0.7	1
PC	No Control	None	Dry FGD	0.6	0.85	1
PC	No Control	None	None	1	1	1
PC	PM Scrubber	SNCR	None	0.9	0.91	1
PC	PM Scrubber	SCR	None	0.9	1	1
PC	PM Scrubber	None	None	0.9	0.91	1
Stoker	Cold Side ESP	SNCR	None	0.65	0.97	1
Stoker	Cold Side ESP	SNCR	Wet FGD	0.34	0.73	0.56
Stoker	Cold Side ESP	SNCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	SCR	None	0.65	0.97	1
Stoker	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Stoker	Cold Side ESP	SCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
Stoker	Cold Side ESP	None	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	None	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SNCR	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.73	0.56
Stoker	Cold Side ESP + FGC	SNCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	SCR	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Stoker	Cold Side ESP + FGC	SCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56
Stoker	Cold Side ESP + FGC	None	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	None	None	0.65	0.97	1
Stoker	Fabric Filter	SNCR	None	0.11	0.27	1
Stoker	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
Stoker	Fabric Filter	SNCR	Dry FGD	0.1	0.75	1
Stoker	Fabric Filter	SCR	None	0.11	0.27	1
Stoker	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Stoker	Fabric Filter	SCR	Dry FGD	0.1	0.75	1
Stoker	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
Stoker	Fabric Filter	None	Dry FGD	0.1	0.75	1

Burner Type	Particulate Control	Post Combustion Control – NO _x	Post Combustion Control - SO ₂	Bituminous EMF	Subbitumionous EMF	Lignite EMF
Stoker	Fabric Filter	None	None	0.11	0.27	1
Stoker	Hot Side ESP	SNCR	None	1	1	1
Stoker	Hot Side ESP	SNCR	Wet FGD	0.58	1	1
Stoker	Hot Side ESP	SNCR	Dry FGD	1	1	1
Stoker	Hot Side ESP	SCR	None	1	1	1
Stoker	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Stoker	Hot Side ESP	SCR	Dry FGD	1	1	1
Stoker	Hot Side ESP	None	Wet FGD	0.58	1	1
Stoker	Hot Side ESP	None	Dry FGD	1	1	1
Stoker	Hot Side ESP	None	None	1	1	1
Stoker	Hot Side ESP + FGC	SNCR	None	1	1	1
Stoker	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	1	1
Stoker	Hot Side ESP + FGC	SNCR	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	SCR	None	1	1	1
Stoker	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Stoker	Hot Side ESP + FGC	SCR	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	None	Wet FGD	0.58	1	1
Stoker	Hot Side ESP + FGC	None	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	None	None	1	1	1
Stoker	No Control	SNCR	None	1	1	1
Stoker	No Control	SNCR	Wet FGD	0.58	1	1
Stoker	No Control	SNCR	Dry FGD	1	1	1
Stoker	No Control	SCR	None	1	1	1
Stoker	No Control	SCR	Wet FGD	0.1	0.7	1
Stoker	No Control	SCR	Dry FGD	1	1	1
Stoker	No Control	None	Wet FGD	0.58	1	1
Stoker	No Control	None	Dry FGD	1	1	1
Stoker	No Control	None	None	1	1	1
Stoker	PM Scrubber	None	None	1	1	1
Other	Cold Side ESP	SNCR	None	0.64	0.97	1
Other	Cold Side ESP	SNCR	Wet FGD	0.34	0.73	0.56
Other	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	SCR	None	0.64	0.97	1
Other	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Other	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
Other	Cold Side ESP	None	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	None	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SNCR	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.73	0.56
Other	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Other	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56
Other	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	None	None	0.64	0.97	1

Burner Type	Particulate Control	Post Combustion Control – NO _x	Post Combustion Control - SO ₂	Bituminous EMF	Subbitumionous EMF	Lignite EMF
Other	Fabric Filter	SNCR	None	0.45	0.75	1
Other	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
Other	Fabric Filter	SNCR	Dry FGD	0.4	0.75	1
Other	Fabric Filter	SCR	None	0.11	0.27	1
Other	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Other	Fabric Filter	SCR	Dry FGD	0.4	0.75	1
Other	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
Other	Fabric Filter	None	Dry FGD	0.4	0.75	1
Other	Fabric Filter	None	None	0.11	0.27	1
Other	Hot Side ESP	SNCR	None	1	1	1
Other	Hot Side ESP	SNCR	Wet FGD	0.58	1	1
Other	Hot Side ESP	SNCR	Dry FGD	1	1	1
Other	Hot Side ESP	SCR	None	1	1	1
Other	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Other	Hot Side ESP	SCR	Dry FGD	1	1	1
Other	Hot Side ESP	None	Wet FGD	0.58	1	1
Other	Hot Side ESP	None	Dry FGD	1	1	1
Other	Hot Side ESP	None	None	1	1	1
Other	Hot Side ESP + FF	None	None	0.11	0.27	1
Other	Hot Side ESP + FGC	SNCR	None	1	1	1
Other	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	1	1
Other	Hot Side ESP + FGC	SNCR	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	SCR	None	1	1	1
Other	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Other	Hot Side ESP + FGC	SCR	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	None	Wet FGD	0.58	1	1
Other	Hot Side ESP + FGC	None	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	None	None	1	1	1
Other	Hot Side ESP + FGC + FF	None	None	0.11	0.27	1
Other	No Control	SNCR	None	1	1	1
Other	No Control	SNCR	Wet FGD	0.58	0.7	1
Other	No Control	SNCR	Dry FGD	1	1	1
Other	No Control	SCR	None	1	1	1
Other	No Control	SCR	Wet FGD	0.1	0.7	1
Other	No Control	SCR	Dry FGD	1	1	1
Other	No Control	None	Wet FGD	0.58	0.7	1
Other	No Control	None	Dry FGD	1	1	1
Other	No Control	None	None	1	1	1
Other	PM Scrubber	None	None	0.9	0.91	1

Table 5-14 Definition of Acronyms for Existing Controls

Acronym	Description
ESP	Electro Static Precipitator - Cold Side
HESP	Electro Static Precipitator - Hot Side
ESP/O	Electro Static Precipitator - Other
FF	Fabric Filter
FGD	Flue Gas Desulfurization - Wet
DS	Flue Gas Desulfurization - Dry
SCR	Selective Catalytic Reduction
PMSCRUB	Particulate Matter Scrubber

Table 5-15 Key to Burner Type Designations in Table 5-13

“PC” refers to conventional pulverized coal boilers. Typical configurations include wall-fired and tangentially fired boilers (also called T-fired boilers). In wall-fired boilers the burner’s coal and air nozzles are mounted on a single wall or opposing walls. In tangentially fired boilers the burner’s coal and air nozzles are mounted in each corner of the boiler.

“Cyclone” refers to cyclone boilers where air and crushed coal are injected tangentially into the boiler through a “cyclone burner” and “cyclone barrel” which create a swirling motion allowing smaller coal particles to be burned in suspension and larger coal particles to be captured on the cyclone barrel wall where they are burned in molten slag.

“Stoker” refers to stoker boilers where lump coal is fed continuously onto a moving grate or chain which moves the coal into the combustion zone in which air is drawn through the grate and ignition takes place. The carbon gradually burns off, leaving ash which drops off at the end into a receptacle, from which it is removed for disposal.

“FBC” refers to “fluidized bed combustion” where solid fuels are suspended on upward-blowing jets of air, resulting in a turbulent mixing of gas and solids and a tumbling action which provides especially effective chemical reactions and heat transfer during the combustion process.

“Other” refers to miscellaneous burner types including cell burners and arch- , roof- , and vertically-fired burner configurations.

Mercury Control through SO₂ and NO_x Retrofits

In EPA Base Case v.4.10, units that install SO₂, NO_x, and particulate controls, reduce mercury emissions as a byproduct of these retrofits. Section 5.4.2 described how EMFs are used in the base case to capture the unregulated mercury emissions depending on the rank of coal burned, the generating unit's combustion characteristics, and the specific configuration of SO₂, NO_x, and particulate controls (i.e., hot and cold-side electrostatic precipitators (ESPs), fabric filters (also called "baghouses") and particulate matter (PM) scrubbers). These same EMFs would be available in mercury policy runs to characterize the mercury reductions that can be achieved by retrofitting a unit with SCR, SNCR, SO₂ scrubbers and particulate controls. The absence of a federal mercury emission reduction policy means that these controls appear in the base case in response to SO₂, NO_x, or particulate limits or state-level mercury emission requirements. However, in future model runs where mercury limits are present these same SO₂ and NO_x controls could be deliberately installed for mercury control if they provide the least cost option for meeting mercury policy limits.

Activated Carbon Injection (ACI)

The technology specifically designated for mercury control is Activated Carbon Injection (ACI) downstream of the combustion process in coal fired units. A comprehensive ACI update, which will incorporate the latest field experience through 2010, is being prepared by Sargent and Lundy (the same engineering firm that developed the SO₂ and NO_x control assumptions used in EPA Base Case v.4.10). It will be incorporated in a future EPA base case. The ACI assumptions in the current base case release are the result of a 2007 internal EPA engineering study.

Based on this study, it is assumed that 90% removal from the level of mercury in the coal is achievable with the application of one of three alternative ACI configurations: Standard Powered Activated Carbon (SPAC), Modified Powered Activated Carbon (MPAC), or SPAC in combination with a fabric filter. The MPAC option exploits the discovery that by converting elemental mercury to oxidized mercury, halogens (like chlorine, iodine, and bromine) can make activated carbon more effective in capturing the mercury at the high temperatures found in industrial processes like power generation. In the MPAC system, a small amount of bromine is chemically bonded to the powdered carbon which is then injected into the flue gas stream either upstream of both the particulate control device (ESP or fabric filter) and the air pre-heater (APH), between the APH and the particulate control device, or downstream of both the pre-existing APH and particulate control devices but ahead of a new dedicated pulsed-jet fabric filter. (The latter is known as the TOXECONTM approach, an air pollution control process patented by EPRI.)

Table 5-16 presents the capital, FOM, and VOM costs as well as the capacity and heat rate penalty for the five Hg emission control technologies included in EPA Base Case v.4.10 for an illustrative set of generating units with a representative range of capacities.

Table 5-16 Illustrative Activated Carbon Injection Costs (2007\$) for Representative Sizes under the Assumptions in EPA Base Case v.4.10

Control Type	Capacit y Penalty (%)	Heat Rate Penalty (%)	Capacity (MW)											
			100			300			500			700		
			Capital Cost (\$/kW)	Fixed O&M (\$/kW- yr)	Variable O&M cost (mills/kWh)	Capital Cost (\$/kW)	Fixed O&M (\$/kW -yr)	Variable O&M cost (mills/kWh)	Capital Cost (\$/kW)	Fixed O&M (\$/k W-yr)	Variable O&M cost (mills/kWh)	Capital Cost (\$/kW)	Fixed O&M (\$/kW -yr)	Variable O&M cost (mills/kWh)
MPAC_Baghouse Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	3	0.1	0.16	2	0.05	0.17	2	0.04	0.17	2	0.03	0.16
MPAC_CESP Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	8	0.1	0.57	6	0.1	0.61	5	0.1	0.61	5	0.1	0.59
SPAC_Baghouse Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	5	0.1	0.22	4	0.1	0.23	3	0.1	0.23	3	0.1	0.23
SPAC_ESP Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	27	0.5	2.29	21	0.3	2.46	18	0.3	2.44	17	0.3	2.39
SPAC_ESP+Toxecon Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	-0.43	0.43	269	4.3	2.44	202	2.5	2.61	176	2.1	2.59	161	2.0	2.54

The applicable ACI option depends on the coal type burned, its SO₂ content, the boiler and particulate control type and, in some instances, consideration of whether an SO₂ scrubber (FGD) system or SCR NO_x post-combustion control are present. Table 5-17 shows the ACI assignment scheme used in EPA Base Case v.4.10 to achieve 90% mercury removal.

Table 5-17 Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection (ACI) in EPA Base Case v.4.10
Applicability of Activated Carbon Injection

Coal Type	SO ₂ in Coal (lb/MMBtu)	Boiler Type	Particulate Control Type	FGD System	SCR System	Toxecon Required?	ACI Type With 90% Hg Reduction
Bit/Sub-bit/Lig	< 1.6	Non-CFB	CS-ESP or BH (no FGC)	--	No	No	MPAC
Bit/Sub-bit/Lig	--	Non-CFB	CS-ESP or BH (no FGC)	LSD	--	No	MPAC
Bit/Sub-bit/Lig	--	CFB	CS-ESP or BH (no FGC)	--	--	No	MPAC
Bit	< 1.6	Non-CFB	CS-ESP	Non-LSD	Yes	No	SPAC
Bit	≥ 1.6	Non-CFB	CS-ESP or BH	--	--	No	SPAC
Sub-bit/Lig	≥ 1.6	Non-CFB	CS-ESP	--	--	Yes	SPAC
Sub-bit/Lig	≥ 1.6	Non-CFB	BH	--	--	No	SPAC
Bit/Sub-bit/Lig	--	Non-CFB	HESP	--	--	Yes	SPAC
Bit/Sub-bit/Lig	--	--	HESP or CS-ESP (with FGC)	--	--	Yes	SPAC
Bit/Sub-bit/Lig	< 1.6	Non-CFB	BH	No	Yes	No	MPAC
Bit/Sub-bit/Lig	< 1.6	Non-CFB	CS-ESP (no FGC)	No	Yes	No	MPAC
Bit/Sub-bit/Lig	--	--	No Control	--	--	Yes	SPAC
Bit/Sub-bit/Lig	< 1.6	--	BH	Non-LSD	Yes	No	SPAC
Sub-bit/ Lig	< 1.6	--	CS-ESP (no FGC)	Non-LSD	Yes	Yes	SPAC
Bit/Sub-bit/Lig	--	--	Cyclone	--	--	Yes	SPAC

Notes:

Legends:		If the existing equipment provides 90% Hg removal, no ACI system is required.
ACI	Activated carbon injection	
BH	Baghouse	
Bit	Bituminous coal	"--" means that the category type has no effect on the ACI application.
CFB	Circulating fluidized-bed boiler	
CS-ESP	Cold side electrostatic precipitator	
FGC	Flue gas conditioning	
HESP	Hot electrostatic precipitator	
Lig	Lignite	
MPAC	Modified powdered activated carbon	
SPAC	Standard powdered activated carbon	
Sub-bit	Subbituminous coal	

Appendix 5-1 Example Cost Calculation Worksheets for SO₂ Control Technologies in EPA Base Case v.4.10



IPM Model – Revisions to Cost and Performance for
APC Technologies

Project No. 12301-007
August 20, 2010

Wet FGD Cost Development Methodology – Final

Table 3. Example Complete Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	← User Input (Greater than 100 MW)
Retrofit Factor	B		1	← User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	← User Input
SO ₂ Rate	D	(lb/MMBtu)	3	← User Input
Type of Coal	E		Bituminous	← User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	M	(%)	1.69	(1.05E*(0.155*D))/F*G Should be used for model input.
Makeup Water Rate	N	(1000 gph)	58	(1.674*D+74.66)*A*F*G/1000
Limestone Cost	P	(\$/ton)	16	
Waste Disposal Cost	Q	(\$/ton)	30	
Aux Power Cost	R	(\$/kWh)	0.06	
Makeup Water Cost	S	(\$/1000)	1	
Operating Labor Rate	T	(\$/hr)	60	Labor cost including all benefits

Capital Cost Calculation

Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty

$$\text{BMR} (\$) = 550000 \cdot (B) \cdot ((F \cdot G) \cdot 0.6) \cdot ((D/2) \cdot 0.02) \cdot (A \cdot 0.716)$$

$$\text{BMF} (\$) = 100000 \cdot (B) \cdot ((D \cdot G) \cdot 0.3) \cdot (A \cdot 0.716)$$

$$\text{BMW} (\$) = 100000 \cdot (B) \cdot ((D \cdot G) \cdot 0.45) \cdot (A \cdot 0.716)$$

$$\text{BMB} (\$) = 1010000 \cdot (B) \cdot ((F \cdot G) \cdot 0.4) \cdot (A \cdot 0.716)$$

$$\text{BMWW} (\$) =$$

$$\text{BM} (\$) = \text{BMR} + \text{BMF} + \text{BMW} + \text{BMB} + \text{BMWW}$$

$$\text{BM} (\$/\text{kW}) =$$

Total Project Cost

$$A1 = 10\% \text{ of BM}$$

$$A2 = 10\% \text{ of BM}$$

$$A3 = 10\% \text{ of BM}$$

$$\text{CECC} (\$) - \text{Excludes Owner's Costs} = \text{BM} + A1 + A2 + A3$$

$$\text{CECC} (\$/\text{kW}) - \text{Excludes Owner's Costs} =$$

$$B1 = 5\% \text{ of CECC}$$

$$\text{TPC} (\$) - \text{Includes Owner's Costs} = \text{CECC} + B1$$

$$\text{TPC} (\$/\text{kW}) - \text{Includes Owner's Costs} =$$

$$B2 = 10\% \text{ of (CECC + B1)}$$

$$\text{TPC} (\$) - \text{Includes Owner's Costs and AFUDC} = \text{CECC} + B1 + B2$$

$$\text{TPC} (\$/\text{kW}) - \text{Includes Owner's Costs and AFUDC} =$$

Example

Comments

\$ 48,024,000

Base absorber island cost

\$ 22,287,000

Base reagent preparation cost

\$ 13,713,000

Base waste handling cost

\$ 84,898,000

Base balance of plant costs including:
ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc...

\$

Base wastewater treatment facility, beyond minor physical/chemical

\$ 168,702,000

treatment
Total base cost including retrofit factor

333

Base cost per kW

\$ 16,670,000

Engineering and Construction Management costs

\$ 16,670,000

Labor adjustment for 6 x 10 hour shift premium, per diam, etc...

\$ 16,670,000

Contractor profit and fees

\$ 218,712,000

Capital, engineering and construction cost subtotal

433

Capital, engineering and construction cost subtotal per kW

\$ 10,830,000

Owners costs including all "home office" costs (owners engineering,

\$ 227,548,000

management, and procurement activities)

455

Total project cost without AFUDC

\$ 22,755,000

AFUDC (Based on a 3 year engineering and construction cycle)

\$ 250,303,000

Total project cost

601

Total project cost per kW



IPM Model – Revisions to Cost and Performance for
APC Technologies

Project No. 12301-007
August 20, 2010

Wet FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	← User Input (Greater than 100 MW)
Retrofit Factor	B		1	← User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	← User Input
SO ₂ Rate	D	(lb/MMBtu)	3	← User Input
Type of Coal	E		Bituminous	← User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	M	(%)	1.59	(1.05e*(0.155*D))/F*G Should be used for model input.
Makeup Water Rate	N	(1000 gph)	36	(1.674*D+74.68)/A*F*G/1000
Limestone Cost	P	(\$/ton)	15	
Waste Disposal Cost	Q	(\$/ton)	30	
Aux Power Cost	R	(\$/kWh)	0.06	
Makeup Water Cost	S	(\$/1000)	1	
Operating Labor Rate	T	(\$/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO (\$/kW yr) = (if MW>500 then 16 additional operators else 12 operators)*2080*T/(A*1000)	\$	3.00	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) = BM*0.015/(B*A*1000)	\$	5.00	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO+0.4*FOMM)	\$	0.15	Fixed O&M additional administrative labor costs
FOMWW (\$/kW yr) =	\$	-	Fixed O&M costs for wastewater treatment facility
FOM (\$/kW yr) = FOMO + FOMM + FOMA + FOMWW	\$	8.15	Total Fixed O&M costs

Variable O&M Cost

VOMR (\$/MWh) = K*P/A	\$	0.37	Variable O&M costs for limestone reagent
VOMW (\$/MWh) = L*Q/A	\$	1.36	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	\$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	\$	0.08	Variable O&M costs for makeup water
VOMWW (\$/MWh) =	\$	-	Variable O&M costs for wastewater treatment facility
VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	\$	1.81	

SDA FGD Cost Development Methodology – Final

Table 3. Example Complete Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	← User Input (Greater than 50 MW)
Retrofit Factor	B		1	← User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9900	← User Input
SO ₂ Rate	D	(lb/MMBtu)	2	← User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO ₂ Rate)
Type of Coal	E		PRB	← User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6762*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO ₂ removal)
Waste Rate	L	(ton/hr)	10	(0.6016*(D^2)+31.1917*D)*A*G/2000
Aux Power	M	(%)	1.36	(0.000547*D^2+0.00649*D+1.3)*F*G Should be used for model input.
Makeup Water Rate	N	(1000 gph)	17	(0.04698*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	(\$/ton)	95	
Waste Disposal Cost	Q	(\$/ton)	30	
Aux Power Cost	R	(\$/kWh)	0.06	
Makeup Water Cost	S	(\$/1000)	1	
Operating Labor Rate	T	(\$/hr)	60	Labor cost including all benefits

Capital Cost Calculation

Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty

$$\text{BMR (\$)} = \text{if}(A > 800 \text{ then } (A * 0.2000) \text{ else } 566000 * (A * 0.716)) * B * (F * G)^0.6 * (D/4)^0.01$$

$$\text{BMF (\$)} = \text{if}(A > 800 \text{ then } (A * 48700) \text{ else } 300000 * (A * 0.716)) * B * (D * G)^0.2$$

$$\text{BMB (\$)} = \text{if}(A > 800 \text{ then } (A * 129900) \text{ else } 799000 * (A * 0.716)) * B * (F * G)^0.4$$

$$\text{BM (\$)} = \text{BMR} + \text{BMF} + \text{BMW} + \text{BMB}$$

$$\text{BM (\$/kW)} =$$

Total Project Cost

$$A1 = 10\% \text{ of BM}$$

$$A2 = 10\% \text{ of BM}$$

$$A3 = 10\% \text{ of BM}$$

$$\text{CECC (\$)} - \text{Excludes Owner's Costs} = \text{BM} + A1 + A2 + A3$$

$$\text{CECC (\$/kW)} - \text{Excludes Owner's Costs} =$$

$$B1 = 5\% \text{ of CECC}$$

$$\text{TPC' (\$)} - \text{Includes Owner's Costs} = \text{CECC} + B1$$

$$\text{TPC' (\$/kW)} - \text{Includes Owner's Costs} =$$

$$B2 = 10\% \text{ of (CECC + B1)}$$

$$\text{TPC (\$)} - \text{Includes Owner's Costs and AFUDC} = \text{CECC} + B1 + B2$$

$$\text{TPC (\$/kW)} - \text{Includes Owner's Costs and AFUDC} =$$

Example

Comments

\$	33,953,000	Base module absorber island cost
\$	20,379,000	Base module reagent preparation and waste recycle/handling cost
\$	47,988,000	Base module balance of plant costs including ID or booster fans, piping, ductwork, electrical, etc...
\$	102,320,000	Total Base module cost including retrofit factor
	341	Base module cost per kW
\$	10,232,000	Engineering and Construction Management costs
\$	10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
\$	10,232,000	Contractor profit and fees
\$	133,016,000	Capital, engineering and construction cost subtotal
	443	Capital, engineering and construction cost subtotal per kW
\$	6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
\$	139,667,000	Total project cost without AFUDC
	466	Total project cost per kW without AFUDC
\$	13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
\$	153,634,000	Total project cost
	512	Total project cost per kW



IPM Model – Revisions to Cost and Performance for
APC Technologies

Project No. 12301-007
August 20, 2010

SDA FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User input
SO ₂ Rate	D	(lb/MMBtu)	2	<--- User input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO ₂ Rate)
Type of Coal	E		PRB	<--- User input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO ₂ removal)
Waste Rate	L	(ton/hr)	10	(0.8018*(D^2)+31.1917*D)*A*G/2000
Aux Power	M	(%)	1.35	(0.000547*D^2+0.00649*D+1.3)*F*G Should be used for model input.
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	(\$/ton)	95	
Waste Disposal Cost	Q	(\$/ton)	30	
Aux Power Cost	R	(\$/kWh)	0.06	
Makeup Water Cost	S	(\$/1000)	1	
Operating Labor Rate	T	(\$/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO (\$/kW yr) = (8 additional operators)*2080*T/(A*1000)	\$	3.33	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) = BM*0.015/(B*A*1000)	\$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA (\$/kW yr) = 0.03*(FOMO+0.4*FOMM)	\$	0.16	Fixed O&M additional administrative labor costs
FOM (\$/kW yr) = FOMO + FOMM + FOMA	\$	8.61	Total Fixed O&M costs

Variable O&M Cost

VOMR (\$/MWh) = K*P/A	\$	1.37	Variable O&M costs for lime reagent
VOMW (\$/MWh) = L*Q/A	\$	0.96	Variable O&M costs for waste disposal
VOMP (\$/MWh) = M*R*10	\$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM (\$/MWh) = N*S/A	\$	0.06	Variable O&M costs for makeup water
VOM (\$/MWh) = VOMR + VOMW + VOMP + VOMM	\$	2.40	

Appendix 5-2 Example Cost Calculation Worksheets for NO_x Post-Combustion Control Technologies in EPA Base Case v.4.10

Sargent & Lundy^{LLC}

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
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SCR Cost Development Methodology – Final

Table 1. Example of the Capital Cost Estimate Work Sheet.

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	600	<-- User Input
Retrofit Factor	B		1	<-- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9880	<-- User Input
NO _x Rate	D	(lb/MMBtu)	0.21	<-- User Input
SO ₂ Rate	E	(lb/MMBtu)	1.71	<-- User Input
Type of Coal	F		PRB	<-- User Input
Coal Factor	G		1.05	Btu=1.0, PRB=1.05, Lignite=1.07
Heat Rate Factor	H		0.988	C/10000
Heat Input	I	(Btu/hr)	5.93E+09	A*C*1000
Capacity Factor	J	(%)	85	<-- User Input
Nox Removal Efficiency	K	(%)	70	
Nox Removal Factor	L		0.875	100
Nox Removed	M	(lb/hr)	8.71E+02	D*I*10 ⁻⁶ *K/100
Urea Rate (100%)	N	(lb/hr)	609	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	689	N*1.13
Aux Power	P	(%)	0.57	0.58*(G*H)/0.43; Auxiliary Power is not used in the Variable O&M Costs.
Urea Cost - 50% wt solution	R	(\$/ton)	310	
Catalyst Cost	S	(\$/m ³)	8000	
Aux Power Cost	T	(\$/kW)	0.06	
Steam Cost	U	(\$/kbtu)	4	
Operating Labor Rate	V	(\$/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation	Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.		
BMR (\$) = 180000*(B)*I*(1+0.2*(A*G*H))*0.92	\$ 65,199,000	SCR (Inlet Ductwork, Reactor, Bypass) Island Cost
BMF (\$) = 410000*(M)*0.25	\$ 2,228,000	Base Reagent Preparation Cost
BMA (\$) = IF E > 3 THEN 55000*(B)*I*(A*G*H)*0.78; ELSE 0	\$ -	Air Heater Modification / SO ₂ Control (Bituminous only & > 3lb/MMBtu)
BMB (\$) = 380000*(B)*I*(A*G*H)*0.42	\$ 5,666,000	ID or booster fans & Auxiliary Power Modification Costs
BM (\$) = BMR + BMF + BMA + BMB	\$ 73,093,000	Total bare module cost including retrofit factor
BM (\$/kW) =	122	Base cost per kW
Total Project Cost		
A1 = 10% of BM	\$ 7,309,000	Engineering and Construction Management costs
A2 = 10% of BM	\$ 7,309,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM	\$ 7,309,000	Contractor profit and fees
CECC (\$) = BM+A1+A2+A3	\$ 95,020,000	Capital, engineering and construction cost subtotal
CECC (\$/kW) =	158	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	\$ 4,751,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = 6% of CECC + B1	\$ 5,986,000	AFUDC (Based on approximately 3% per year for a 2 year engineering and construction cycle)
TPC (\$) = CECC + B1 + B2	\$ 105,757,000	Total project cost
TPC (\$/kW) =	178	Total project cost per kW



IPM Model – Revisions to Cost and Performance for APC Technologies

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SCR Cost Development Methodology – Final

Table 2. Example of the Fixed and Variable O&M Estimate Work Sheet.

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	600	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9680	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.21	<--- User Input
SO2 Rate	E	(lb/MMBtu)	1.71	<--- User Input
Type of Coal	F		PRB	<--- User Input
Coal Factor	G		1.05	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.998	C/10000
Heat Input	I	(Btu/hr)	5.53E+09	A*C*1000
Capacity Factor	J	(%)	85	<--- User Input
Nox Removal Efficiency	K	%	70	
Nox Removal Factor	L		0.875	(J)
Nox Removed	M	lb/hr	8.71E+02	(D*I)/(100-K)/100
Urea Rate (100%)	N	(lb/hr)	609	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	689	N*1.13
Aux Power	P	(%)	0.57	0.56*(G*H)*0.43; Auxiliary Power is not used in the Variable O&M Costs.
Urea Cost 50% wt solution	R	(\$/ton)	310	
Catalyst Cost	S	(\$/m3)	8000	
Aux Power Cost	T	(\$/kWh)	0.06	
Steam Cost	U	(\$/Mlb)	4	
Operating Labor Rate	V	(\$/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Fixed O&M Cost			
FOMO (\$/kW yr) = (1/2 operator time assumed)*2080**V/(A*1000)	\$	0.10	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) = IF A < 500 then \$200.00 ELSE \$300,000	\$	0.50	Fixed O&M additional maintenance material and labor costs
FOM (\$/kW yr) = FOMO + FOMM	\$	0.60	Total Fixed O&M costs
Variable O&M Cost			
VOMR (\$/MWh) = N*R/A/1000	\$	0.31	Variable O&M costs for Urea
VOMW (\$/MWh) = discrete function of A, C, J, K, S	\$	0.35	Variable O&M costs for catalyst replacement & disposal
VOMM (\$/MWh) = O*U/A/1000	\$	0.01	Variable O&M costs for steam
VOM (\$/MWh) = VOMR + VOMW + VOMM	\$	0.66	

SNCR Cost Development Methodology – Final

Table 1. Example of the Capital Cost Estimate Work Sheet (for T-fired boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	<--- User Input
Unit Size	A	(MW)	300	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*G*1000
Capacity Factor	I	(%)	85	<--- User Input
Nox Removal Efficiency	J	(%)	25	
Nox Removed	K	(lb/hr)	1.65E+02	D*H*(100-J)/100
Urea Rate (100%)	L	(lb/hr)	717	K*UF/46*30, IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25, ELSE UF = 0.15
Water Required	M	(lb/hr)	6467	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.77	M*0.12/1000
Urea Cost 50% wt solution	P	(\$/ton)	310	
Aux Power Cost	Q	(\$/kWh)	0.06	
Dilution Water Cost	R	(\$/gal)	1	
Operating Labor Rate	S	(\$/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation	Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty		
BMS (\$) = $B^*F/1.05^*200000^*(A^*G)^0.42$	\$ 2,090,000	SNCR (Injectors, Blowers, DCS, Reagent System) Cost
BMA (\$) = IF E > 3 THEN 65000*(B)*(A*G)^0.78; ELSE 0	\$ -	Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu)
BMB (\$) = $270000^*(A)^0.33^*(K)^0.12$	\$ 3,273,000	Balance of Plant Cost (Piping, Including Site Upgrades)
BM (\$) = BMS + BMA + BMB	\$ 5,363,000	Total bare module cost including retrofit factor
BM (\$/kW) =	18	Base cost per kW
Total Project Cost		
A1 = 10% of BM	\$ 536,000	Engineering and Construction Management costs
A2 = 10% of BM	\$ 536,000	Labor adjustment for 8 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM	\$ 536,000	Contractor profit and fees
CECC (\$) = BM + A1 + A2 + A3	\$ 6,971,000	Capital, engineering and construction cost subtotal
CECC (\$/kW) =	23	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC	\$ 349,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC (\$) = CECC + B1	\$ 7,320,000	Total project cost
TPC (\$/kW) =	24	Total project cost per kW

SNCR Cost Development Methodology – Final

Table 2. Example of the Fixed and Variable O&M Cost Estimate Work Sheet (for T-fired boilers).

Variable	Designation	Units	Value	Calculation
Boiler Type			Tangential	<-- User Input
Unit Size	A	(MW)	300	<-- User Input
Retrofit Factor	B		1	<-- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	10000	<-- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<-- User Input
SO2 Rate	E	(lb/MMBtu)	2	<-- User Input
Type of Coal	F		Bituminous	<-- User Input
Coal Factor	F		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	G		1	C/10,000
Heat Input	H	(Btu/hr)	3.00E+09	A*C*1000
Capacity Factor	I	(%)	85	<-- User Input
Nox Removal Efficiency	J	(%)	25	
Nox Removed	K	(lb/hr)	1.65E+02	D*H/10*6*J/100
Urea Rate (100%)	L	(lb/hr)	717	K*UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	M	(lb/hr)	6457	L*9
Aux Power	N	(%)	0.05	Auxiliary Power is not used in the Variable O&M Costs
Dilution Water Rate	O	(1000 gph)	0.77	M*0.12/1000
Urea Cost 50% wt solution	P	(\$/ton)	310	
Aux Power Cost	Q	(\$/kWh)	0.06	
Dilution Water Cost	R	(\$/gal)	1	
Operating Labor Rate	S	(\$/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Fixed O&M Cost			
FOMO (\$/kW yr) = (1/2 operator time assumed)*2080*S/(A*1000)	\$	0.21	Fixed O&M additional operating labor costs
FOMM (\$/kW yr) = 0.012*BM/A/1000	\$	0.21	Fixed O&M additional maintenance material and labor costs
FOM (\$/kW yr) = FOMO + FOMM	\$	0.42	Total Fixed O&M costs
Variable O&M Cost			
VOMR (\$/MWh) = L*P/A/1000	\$	0.74	Variable O&M costs for Urea
VOMM (\$/MWh) = O*R/A	\$	0.00	Variable O&M costs for dilution water
VOM (\$/MWh) = VOMR + VOMM	\$	0.74	

Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants

March 31, 2011



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Control Technologies to Reduce
Conventional and Hazardous Air Pollutants
from Coal-Fired Power Plants

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March 31, 2011

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Executive Summary

To implement requirements adopted by Congress in the federal Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) is developing new rules to reduce air pollution from fossil fuel power plants. Power plants that burn coal will bear a large responsibility for reducing their emissions further, as the majority of air pollutants from the electric generation sector come from coal combustion.

The major rules addressing power plant pollution that EPA recently proposed are the Clean Air Transport Rule (Transport Rule), and the National Emission Standards for Hazardous Air Pollutants from Electric Utility Steam Generating Units (Air Toxics Rule). The Transport Rule will address the long-range interstate transport of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) in the eastern United States. Both these types of pollutants contribute to formation of small particles (“fine particulates”) in the atmosphere that can be transported long distances into downwind states. These small particles can be inhaled deep into the lungs, causing serious adverse health impacts. Nitrogen oxides also contribute to the formation and long-range transport of ground-level ozone, another pollutant with significant health impacts. The Air Toxics Rule will address emissions of hazardous air pollutants (HAPs) such as mercury, lead, arsenic, along with acid gases such as hydrogen chloride and hydrogen fluoride and organic air toxics (e.g., dioxins and furans). HAPs are chemical pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive problems or birth defects, and that adversely affect the environment.

These regulations will require coal-fired power plants that have not yet installed pollution control equipment to do so and, in some cases, will require plants with existing control equipment to improve performance.

Over the last several decades, state and federal clean air rules to address acid rain and ground-level smog led to power plant owners successfully deploying a range of advanced pollution control systems at hundreds of facilities across the country, providing valuable experience with the installation and operation of these technologies. In addition, many states adopted mercury reduction requirements in the absence of federal rules, leading to new controls and significant reductions of this air toxic from a number of coal power plants over the past several years. This has provided industry with a working knowledge of a suite of air pollution control devices and techniques that can comply with EPA’s proposed Transport Rule and Air Toxics Rule.

This report provides an overview of well-established, commercially available emission control technologies for SO₂ and NO_x, and HAPs, such as mercury, chromium, lead and arsenic; acid gases, such as hydrogen chloride and hydrogen fluoride; dioxins and furans; and other toxic air emissions.

The key findings of the report include:

- **The electric power sector has a range of available technology options as well as experience in their installation and operation that will enable the sector to comply with the Transport Rule and the Air Toxics Rule.**
 - The electric power sector has long and successful experience installing many of the required pollution control systems.

- The first flue gas desulfurization (scrubber) system was installed in 1968 and more than 40 years later, the plant is still in operation and undergoing a performance upgrade.
 - To reduce SO₂ emissions, about 60 percent of the nation's coal fleet has already installed scrubber controls, the most capital intensive of the pollution control systems used by coal-fired power plants.
 - About half of the nation's coal fleet has already installed advanced post-combustion NO_x controls, with the first large-scale coal-fired selective catalytic reduction (SCR) system on a new boiler in the U.S. placed in service in 1993 and the first retrofit in the U.S. placed in service in 1995.
- **Modern pollution control systems are capable of dramatically reducing air pollution emissions from coal-fired power plants.**
- Although scrubbers installed in the 1970s and 1980s typically obtained 80-90 percent SO₂ removal, innovation has led to modern systems now capable of achieving 98 percent or greater removal.
 - SCR can achieve greater than 90 percent NO_x removal.
 - Coal-fired power plants, equipped with baghouse systems, report greater than 90 percent removal of mercury and other heavy metals.
- **Pollution controls that significantly reduce mercury emissions from coal-fired power plants have already been installed, demonstrated, and in operation at a significant number of facilities in the United States. This experience demonstrates the feasibility of achieving the mercury emissions limits in the proposed Air Toxics Rule.**
- In 2001, under cooperative agreements with the Department of Energy, several coal plant operators started full-scale testing of activated carbon injection (ACI) systems for mercury control.
 - Since 2003, many states have led the way on mercury control regulations by enacting statewide mercury limits for coal power plants that require mercury capture rates ranging from 80 to 95 percent. Power plants in a number of these states have already installed and are now successfully operating mercury controls that provide the level of mercury reductions sought in EPA's proposed Air Toxics Rule.
 - At present, about 25 units representing approximately 7,500 MW are using commercial technologies for mercury control. In addition, the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources, has reported about 55,000 MW of new bookings.

- **A wide variety of pollution control technology solutions are available to cost-effectively control air pollution emissions from coal-fired power plants, and many technologies can reduce more than one type of pollutant.**
- A variety of pollution control solutions are available for different plant configurations.
 - The air pollutants targeted by the Transport Rule and the Air Toxics Rule are captured to some degree by existing air pollution controls, and, in many cases, technologies to control one pollutant have the co-benefit of also controlling other pollutants. For example, scrubbers, which are designed to control SO₂, are also effective at controlling particulate matter, mercury, and hydrogen chloride.
 - Dry sorbent injection (DSI) has emerged as a potential control option for smaller, coal-fired generating units seeking to cost-effectively control SO₂ and acid gas emissions.
 - As highlighted below in Table ES-1, because of these “co-benefits,” in many cases it may not be necessary to add separate control technologies for some pollutants.

Table ES-1. Control Technology Emission Reduction Effect

	SO ₂	NOx	Mercury (Hg)	HCl	PM	Dioxins/ Furans
Combustion Controls	N	Y	C	N	N	Y
SNCR	N	Y	N	N	N	N
SCR	N	Y	C	N	N	C
Particulate Matter Controls	N	N	C	N	Y	C
Low Sulfur Fuel	Y	C	N	C	N	N
Wet Scrubber	Y	N	C	Y	C	N
Dry Scrubber	Y	N	C	Y	C*	N
DSI	Y	C	C	Y	N	C
ACI	N	N	Y	N	N	Y

N = Technology has little or no emission reduction effect

Y = Technology reduces emissions

C = Technology is normally used for other pollutants, but has a co-benefit emission reduction effect

* When used in combination with a downstream particulate matter control device, such as a baghouse

- **The electric power sector has a demonstrated ability to install a substantial number of controls in a short period of time, and therefore should be able to comply with the timelines of the proposed EPA air rules.**
 - Between 2001 and 2005, the electric industry successfully installed more than 96 gigawatts (GW) of SCR systems in response to NOx requirements.
 - In response to the Clean Air Interstate Rule (CAIR), about 60 GW of scrubbers and an additional 20 GW of SCR were brought on line from 2008 through 2010. Notably, most companies were “early movers,” initiating the installation process before EPA finalized its rules.

- Available technologies that are less resource and time-intensive will provide additional compliance flexibility. For example, DSI and dry scrubbing technology design and installation times are approximately 12 and 24 months, respectively.

➤ **The electric power sector has access to a skilled workforce to install these proven control technologies.**

- In November 2010, ICAC sent a letter to U.S. Senator Thomas Carper confirming the nation's air pollution control equipment companies repeatedly have successfully met more stringent NO_x, SO₂ and mercury emission limits with timely installations of effective controls and are well prepared to meet new EPA requirements.
 - Also in November 2010, the Building and Construction Division of the AFL-CIO sent a letter to Senator Carper indicating that “[t]here is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development.”
 - Actual installation of pollution control equipment far exceeded EPA's earlier estimate of industry capability that it made during the Clean Air Interstate Rule (CAIR) rulemaking.
 - In response to CAIR, boilermakers increased their membership by 35 percent in only two years (between 1999 and 2001) to meet peak labor demand.

In summary, a range of available and proven pollution control technologies exists to meet the requirements of EPA's proposed Transport Rule and Air Toxics Rule. In many cases, these technologies, some of which have been operating for decades, have a long track record of effective performance at many coal-fired power plants in the U.S.

The electric power sector has shown that it is capable of planning for and installing pollution controls on a large portion of the nation's fossil fuel generating capacity in a relatively short period of time. Suppliers have demonstrated the ability to provide pollution control equipment in a timely manner, and the skilled labor needed to install it should be available to meet the challenge as well. Examples of successful pollution control retrofits are provided throughout this report.

Introduction

The U.S. Environmental Protection Agency (EPA) is currently developing two major air quality rules under the Clean Air Act (“CAA” or “the Act”) to reduce air pollution from power plants: (1) the Transport Rule, and (2) the Air Toxics Rule. These regulations will require certain power plants that have not installed pollution control equipment to do so and others to improve their performance. The discussion that follows provides an overview of these regulations, including a discussion of the sources regulated by the rules and the air pollutants the rules address. Both rules are being developed in response to court decisions overturning prior EPA regulatory programs and have long been anticipated by the electric power sector.

Transport Rule

The Transport Rule—proposed by EPA in July 2010—is designed to reduce the interstate transport of harmful air pollution from power plants in the eastern U.S. as required by the CAA. The “good neighbor” provisions of the Act require states to prohibit air pollution emissions that “contribute significantly” to a downwind state’s air quality problems.¹ For example, EPA found that power plants in West Virginia significantly affect the air quality status of counties in Ohio, Indiana, Pennsylvania, Kentucky, and Michigan—hindering these states from achieving or maintaining federal air quality standards.²

In keeping with the purpose of the “good neighbor” provisions in the Act, the Transport Rule will assist states and cities across the eastern U.S. in complying with the national, health-based fine particulate, or PM_{2.5}, and 8-hour ozone standards by limiting SO₂ and NO_x emissions from power plants in the region. Fine particulates can be inhaled deep into the lungs, and have been linked to increased hospital admissions and emergency room visits for various respiratory or cardiovascular diseases, respiratory illness and symptoms, lung function changes, and increased risk of premature death. Ground-level ozone is a respiratory irritant that adversely affects both people with respiratory disease and healthy children and adults. Exposure to ozone through inhalation can result in reduced lung function and inflamed airways, aggravating asthma or other lung diseases. As with fine particulate matter, ozone exposure is also linked to increased risk of premature death.

The Transport Rule will replace the earlier Clean Air Interstate Rule (CAIR) that EPA had issued in March 2005.³ Under CAIR, EPA limited NO_x and SO₂ emissions from 28 states and the District of Columbia, and directed each state to file a plan for meeting those limits, or emission caps. In July 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit struck down CAIR after finding several flaws in the rule.⁴ In a subsequent ruling, the court determined that CAIR could remain in place until EPA developed a replacement program.⁵

Table 1. The Clean Air Transport Rule

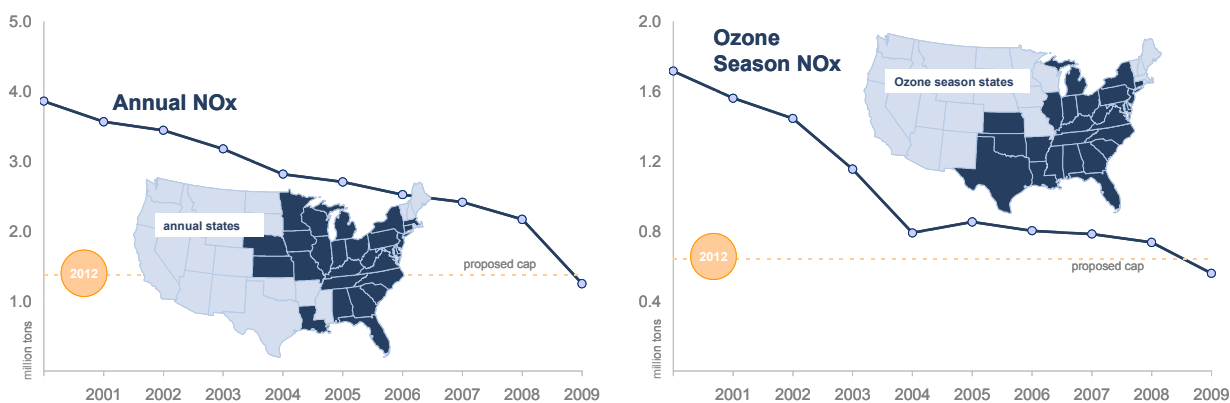
Regulated Pollutants	Affected Sources	Compliance Dates	Regulatory Mechanism
Sulfur dioxide (SO ₂) Nitrogen oxides (NO _x)	Fossil fuel-fired power plants 25 MW and larger in 31 eastern states and DC	Phase 1: 2012 Phase 2: 2014	EPA’s preferred approach would allow intrastate trading among covered power plants with some limited interstate trading

EPA's proposed emissions caps for SO₂ and NO_x are summarized in the following figures. EPA notes in the proposed rule that additional ozone season (May 1 to September 30) NO_x reductions will likely be needed to attain the national ozone standards.⁶ Therefore, the agency plans to propose a new transport rule in 2011, to become final in 2012, to reflect the revised National Ambient Air Quality Standards (NAAQS) for ozone when they are promulgated. While the Transport Rule only proposes to require reductions from the power sector, EPA notes, "it is possible that reductions from other source categories could be needed to address interstate transport requirements related to any new NAAQS."⁷

EPA estimates that the proposed rule would yield \$120 billion to \$290 billion in annual health and welfare benefits in 2014,⁸ which exceed the estimated \$2.8 billion in annual costs that EPA estimates power plants will incur to comply with the rule by a factor of more than 30.⁹ To meet the new requirements, EPA expects plants will employ a wide range of strategies, including operating already

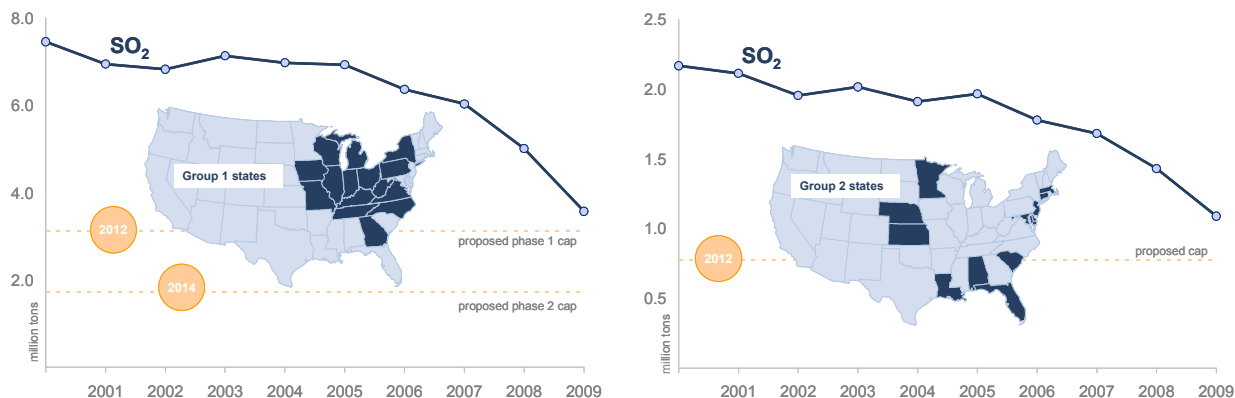
Clean Air Transport Rule: Proposed NO_x Emissions Caps

EPA's proposed Transport Rule would establish two NO_x programs: (1) an annual NO_x program, and (2) an ozone season (summer time) NO_x program (see map below). Annual NO_x emissions would be capped at 1.4 million tons per year beginning in 2012. The 2012 cap represents a 10 percent increase over 2009 emissions levels. Ozone season NO_x emissions would be capped at 0.6 million tons beginning in 2012. The ozone season cap represents a 15 percent increase over 2009 emissions levels.



Clean Air Transport Rule: Proposed SO₂ Emissions Caps

EPA's proposed Transport Rule would establish two independent trading programs for SO₂: (1) group 1 states; and (2) group 2 states (see maps below). SO₂ emissions from group 1 states would be capped at 3.1 million tons per year beginning in 2012 and 1.7 million tons per year beginning in 2014. The 2012 cap represents a 13 percent reduction below 2009 emissions levels. SO₂ emissions from group 2 states would be capped at 0.8 million tons beginning in 2012. The 2012 cap for group 2 states represents a 29 percent reduction below 2009 emissions levels.



installed pollution control equipment more frequently, using low sulfur coal, or installing new control equipment.

Air Toxics Rule

The U.S. EPA's proposed Air Toxics Rule will establish, for the first time, federal limits on hazardous air pollutant (HAP) emissions from coal- and oil-fired power plants. The HAPs covered include mercury, lead, arsenic, hydrogen chloride, hydrogen fluoride, dioxins/furans, and other toxic substances identified by Congress in the 1990 amendments of the CAA. The rule establishes "maximum achievable control technology" (MACT) limits for many of these.

The U.S. EPA's prior effort to regulate HAP emissions from power plants was overturned by court challenges. On February 8, 2008, a federal court held that EPA violated the CAA when it sought to regulate mercury-emitting power plants through the Clean Air Mercury Rule (CAMR), an interstate cap-and-trade program issued by EPA in March 2005.¹⁰ The court concluded that EPA violated the CAA by failing to make a specific health-based finding to remove electric generating units from regulation under CAA section 112.^a

On March 16, 2011, EPA proposed its replacement for CAMR that would establish numerical MACT emission limits for existing and new coal-fired electric power plants that would cover mercury, particulate matter (as the surrogate for non-mercury toxic metals), and hydrogen chloride (as the surrogate for toxic acid gases). The proposed rule would also establish work practice standards for organic air toxics (e.g., dioxins and furans).¹¹ EPA projects the proposed rule will reduce mercury emissions from covered power plants by 91 percent, acid gas emissions by 91 percent, and SO₂ emissions by 55 percent.¹² The projected mercury reductions are in the range of what a number of states already require for coal-fired power plants.¹³ A consent decree with public health and environmental groups requires EPA to finalize the standards by November 16, 2011. Table 2 summarizes elements of the proposed Air Toxics Rule.

EPA estimates that the Air Toxics Rule would yield \$140 billion in annual health and welfare benefits in 2016.¹⁴ The estimated annual cost of the program is \$10.9 billion.¹⁵ EPA emphasizes that the proposed rule would cut emissions of pollutants that are of particular concern for children. Mercury and lead can adversely affect developing brains—including effects on IQ, learning, and memory.

Table 2. The Air Toxics Rule

Regulated Pollutants	Affected Sources	Compliance Dates	Regulatory Mechanism
Mercury Non-mercury metals, such as arsenic, chromium, cadmium, and nickel Organic HAPs (e.g., dioxins/furans) Acid gases (HCl, HF)	Coal- and oil-fired power plants 25 MW and larger	Early 2015 Note: EPA can grant a one year extension for a source to install controls	Numerical emission limits for mercury, other toxic metals, and acid gases; work practice standards for organic air toxics (e.g., dioxins/furans)

^a "EPA's removal of these [electric generating units] from the section 112 list violates the CAA because section 112(c)(9) requires EPA to make specific findings before removing a source listed under section 112; EPA concedes it never made such findings. Because coal-fired [electric generating units] are listed sources under section 112, regulation of existing coal-fired [electric generating units'] mercury emissions under section 111 is prohibited, effectively invalidating CAMR's regulatory approach." *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

Overview of Air Pollution Control Technologies

There are a wide range of technologies available for controlling air pollution emissions from coal-fired power plants. The most appropriate combination of control technologies will vary from plant-to-plant depending on the type and size of the electric generating unit, age, fuel characteristics, and the boiler design.

Many of the air pollutants targeted by the proposed Transport Rule and the Air Toxics Rule are captured to some degree by existing air pollution control devices. Table 3 summarizes the various pollutants and the technologies that are currently being applied or may be applied in the future to control them. In many cases, technologies designed to control one pollutant will also control others. These “co-benefits” may or may not be adequate to achieve compliance with the Transport Rule or the Air Toxics Rule. As a result, in some cases, it may be necessary to add separate control technologies for some pollutants.

Table 3. Control Technology Emission Reduction Effect						
	SO₂	NO_x	Mercury (Hg)	HCl	PM	Dioxins/ Furans
Combustion Controls	N	Y	C	N	N	Y
Selective Non-Catalytic Reduction (SNCR)	N	Y	N	N	N	N
Selective Catalytic Reduction (SCR)	N	Y	C	N	N	C
Particulate Matter Controls (i.e., ESP or baghouse)	N	N	C	N	Y	C
Lower Sulfur Fuel	Y	C	N	C	N	N
Dry Scrubber	Y	N	C	Y	C*	N
Wet Scrubber	Y	N	C	Y	C	N
Dry Sorbent Injection (DSI)	Y	C	C	Y	N	C
Activated Carbon Injection (ACI)	N	N	Y	N	N	Y

N = Technology has little or no emission reduction effect

Y = Technology reduces emissions

C = Technology is normally used for other pollutants, but has a co-benefit emission reduction effect

* When used in combination with a downstream particulate matter control device, such as a baghouse

Methods for Controlling SO₂ Emissions

SO₂ is a highly reactive gas linked to a number of adverse effects on the human respiratory system. In 2008, power plants accounted for 66 percent of the national SO₂ emissions inventory,¹⁶ with the vast majority of this contribution (more than 98 percent) coming from coal-fired power plants.¹⁷

There are two basic options for controlling SO₂ emissions from coal-fired power plants, which is formed from the oxidation of sulfur in the fuel: (1) switching to lower sulfur fuels; and (2) SO₂ capture, including Flue Gas Desulfurization (FGD), or more commonly referred to as “scrubbing.” Table 4 shows the various methods for controlling SO₂ emissions. These methods include those that have been widely used on power plants, such as low sulfur coal and scrubbing, as well as less costly technologies that may be more attractive for smaller boilers, such as dry sorbent injection (DSI).

Table 4. SO₂ Emissions Control Methods

Methods of Control	
Lower Sulfur Fuel	Method – Lower sulfur fuel reduces SO ₂ formation Reagent – None Typical fuel types – Powder River Basin coal and lower sulfur bituminous coal Capital Cost – Low Co-benefits – May reduce NO _x , HCl, and HF emissions
Dry Sorbent Injection	Method – Dry Sorbent Injection captures SO ₂ at moderate rates, downstream PM control device captures dry product Reagent – Trona, sodium bicarbonate, hydrated lime Typical Fuel Types – Most often solid fuels (i.e., coals – lignite, sub-bituminous, bituminous) Capital Costs- Low to moderate Co-benefits – NO _x and HCl and HF reduction, Hg reduction, removal of chlorine, a precursor to dioxins/furans
Dry Scrubber with Fabric Filter	Method – Reagent + water react to capture acid gases and dry product captured in downstream fabric filter Reagent – Hydrated lime Typical Fuel Types – Coal Capital Costs – High Co-benefits – High SO ₂ and Hg capture (esp. bituminous coals), high PM and HCl capture
Wet Scrubber	Method – Reagent + water react to capture acid gases Reagent – Limestone, lime, caustic soda Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil Capital Costs – High Co-benefits – Highest SO ₂ capture, high oxidized Hg and high HCl capture, PM capture
Wet Scrubber Upgrades	Method – Upgrade older scrubbers to provide performance approaching those of new scrubbers Reagent – Limestone, lime, etc. Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil Capital Costs – Low to moderate Co-benefits – Same as wet scrubber
Co-benefit Methods of Control	
None	SO ₂ is a key pollutant that often is the major driver in emission control technology selection

Lower Sulfur Coal

Changing to lower sulfur coal was the most widely used approach for compliance with the Acid Rain Program (Title IV of the 1990 Clean Air Act Amendments). Certain coal types are naturally low in sulfur, such as sub-bituminous coal mined in the Powder River Basin (PRB) of Montana and Wyoming.^b

Some facilities cannot burn 100 percent PRB coal without substantial modifications to the boiler or fuel handling systems. These facilities can blend PRB or another lower sulfur coal with a bituminous coal to reduce emissions. Facilities that are not able to burn lower sulfur coals or facilities needing greater SO₂ emissions reductions may need some form of flue gas treatment.

^b Coal is classified into four general categories, or “ranks.” They range from lignite through sub-bituminous and bituminous to anthracite. Sub-bituminous and bituminous coals are the most widely used coal types, and the SO₂ emissions from burning these fuels can vary by a factor of 10 or more, depending upon the fuel sulfur content and the heating value of the fuel. Lignite fuels have low heating values, making them uneconomical to transport, and are generally limited in use to mine-mouth plants. Anthracite coal is used in very few power plants.

Co-benefits of low sulfur coal – PRB coal is relatively low in nitrogen, which results in lower NO_x emissions. It is also very low in chlorine, so hydrogen chloride (HCl) emissions are low for PRB coal.

Flue Gas Desulfurization (FGD) or “Scrubbing”

As EPA and states have further limited SO₂ emissions, an increasing number of coal-fired power plants have installed FGD systems. FGD controls enable a plant operator to use a wider variety of coals while maintaining low SO₂ emissions. There are two basic forms of FGD – wet and dry. As shown in Table 5, nearly two-thirds of the coal-fired power plant capacity in the United States is scrubbed or is projected to be scrubbed in the near future. Most plant operators have opted for wet FGD systems, particularly on larger coal-fired power plants. In response to the Clean Air Interstate Rule, coal-fired power plants added about 60 gigawatts (GW) of scrubbers in the three year period from 2008 through 2010.¹⁸

Table 5. Coal-Fired Power Plant Scrubbers¹⁹

Scrubber Type	Sum of Capacity (%)	# Boilers	Average Capacity (MW)
FGD (wet)	170 GW (52%)	371	457
FGD (dry)	22 GW (7%)	114	196
Total Scrubbed	192 GW (59%)	485	396
No scrubber	134 GW (41%)	788	171
Total	326 GW	1,273	256

Wet Scrubbers

Wet scrubbers are capable of high rates of SO₂ removal. In a wet FGD system, a lime or limestone slurry reacts with the SO₂ in the flue gas within a large absorber vessel to capture the SO₂, as shown in Figure 1.²⁰ Wet FGD systems may use lime or limestone. Lime is more reactive and offers the potential for higher reductions with somewhat lower capital cost; however, lime is also the more expensive reagent. As a result, limestone-forced oxidation (LSFO) wet scrubber technology is the most widely used form of wet FGD and is more widely used on coal-fired power plants than every other form of FGD combined. State-of-the-art LSFO systems are capable of providing very high levels of SO₂ removal – on the order of 98 percent or more.

The first wet scrubber system in the U.S. was designed by Black & Veatch and installed in 1968 at the Lawrence Energy Center in Kansas. More than 40 years later, the system is still in operation, and the facility is undertaking a major upgrade to improve the system’s performance. The facility is also adding a pulse jet fabric filter.²¹

In the absorber, the gas is cooled to below the saturation temperature, resulting in a wet gas and high rates of capture. Modern wet scrubbers typically have SO₂ removal rates of over 95 percent and can be in the range of 98 percent to 99 percent.²² The reacted

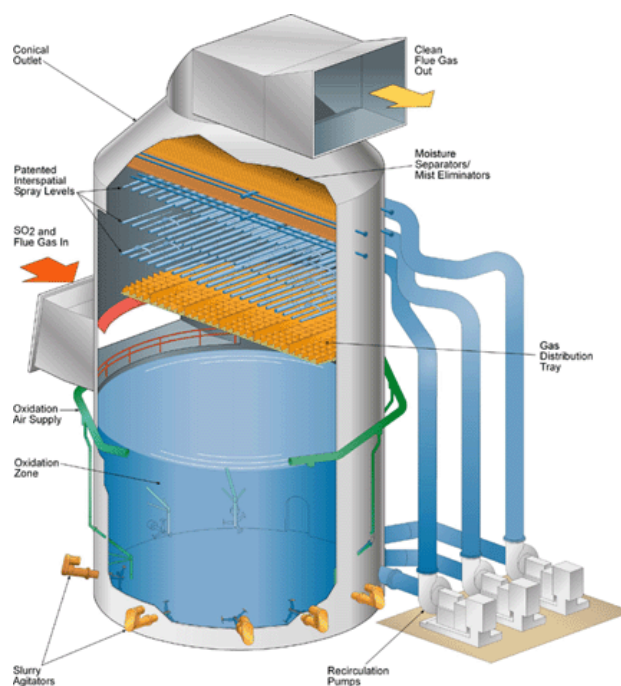


Figure 1. Wet Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

limestone and SO_2 form a gypsum by-product that is often sold for the manufacturing of wallboard.

Because a wet FGD system operates at low temperatures, it is usually the last pollution control device before the stack. The wet FGD absorber is typically located downstream of the PM control device (most often an electrostatic precipitator though many power plants have baghouses) and immediately upstream of the stack. Wet FGD is frequently used to treat the exhaust gas of multiple boilers with the gases being emitted through a common stack. A single absorber can handle the equivalent of 1,000 megawatts (MW) of flue gas.

Wet scrubber retrofits are capital intensive due to the amount of equipment needed, and recent installations for the Clean Air Interstate Rule have been reported to have an average cost of \$390/kW.²³ EPA estimates a capital cost of about \$500/kW (\$2007) for a wet scrubber (limestone forced oxidation) on a 500 MW coal unit.²⁴ There can be, however, a significant variation in costs depending upon the size of the unit and the specifics of the site. Generally, smaller boilers (under 300 MW) have been shown to be significantly more expensive to retrofit with wet scrubbers (capital cost normalized to a \$/KW basis) than larger boilers due to economies of scale. The economies of scale become less significant as boiler size increases.²⁵ As a result, wet scrubbers are a less attractive alternative for controlling SO_2 on small units. Companies can sometimes offset the cost of installing wet scrubber technology by switching to less expensive high sulfur coal supplies. Because of the high capital costs of the technology, wet scrubbers are generally only installed on power plants where the owner expects to operate the plant for an extended number of years.

Due to their complexity and the size of the equipment, EPA estimates that the total time needed to complete the design, installation, and testing of a wet FGD system at a typical 500 MW power plant with one FGD unit is 27 months, and longer if multiple boilers or multiple absorbers are necessary. Actual installation times will vary based upon the specifics of the plant, the need to schedule outages with FGD hook up, and other factors.

Co-benefits of wet FGD – FGDs have been shown to be effective at removing other pollutants including particulate matter, mercury, and hydrochloric acid. For this reason, facilities that are equipped with wet or dry FGD systems may avoid the need to install additional controls for hazardous air pollutants.

Dry Scrubbers

Dry scrubber technology (dry FGD) injects hydrated lime and water (either separately or together as a slurry) into a large vessel to react with the SO_2 in the flue gas. Figure 2 shows a schematic of a dry scrubber.

The term “dry” refers to the fact that, although water is added to the flue gas, the amount of water added is only just enough to maintain the gas above the saturation (dew point) temperature. In most cases, the reaction products and any unreacted lime from the dry FGD process are captured in a downstream fabric filter (baghouse), which helps provide additional capture of SO_2 . Modern dry FGD systems typically provide SO_2 capture rates of 90 percent or more.

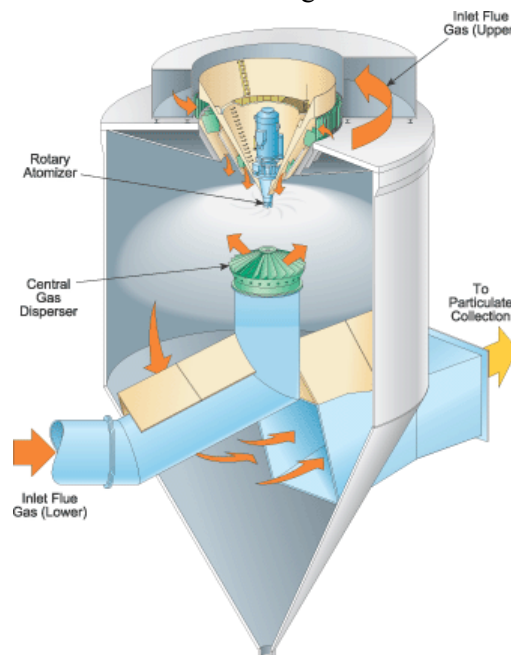


Figure 2. Dry Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

Historically, dry FGDs have been used primarily on low sulfur coals because the reagent, lime, is more expensive than reagents used in wet FGD systems. Also, because the systems are designed to maintain the flue gas temperatures above the dew point, this limits the amount of SO₂ that can be treated by a spray dryer. Another form of dry FGD, circulating dry scrubber systems (CDS), inject the water and lime separately, and have been shown to achieve high SO₂ removal rates in excess of 95 percent on higher sulfur coals. Lime is more costly than limestone, the most commonly used reagent for wet scrubber systems.

Case Study: Dry Scrubber

In Massachusetts, First Light's Mt. Tom Power Plant, a 146 MW coal-fired unit that went into service in 1960, installed state-of-the-art pollution control equipment in 2009 to meet state and federal environmental regulations. In December 2009, the plant installed a circulating dry scrubber to reduce SO₂ and mercury emissions during a routine outage. A precipitator and baghouse were also installed to remove particulate matter emissions. Total project costs were \$55 million, or \$377/kW. The project has reduced the plant's SO₂ emissions by approximately 70 percent, with the plant's 2009 SO₂ emission rate of 0.73 lbs SO₂/mmBtu dropping to 0.22 lbs SO₂/mmBtu in 2010.

Source: U.S. Environmental Protection Agency, Clean Air Markets-Data and Maps; <http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard> (accessed March 17, 2011).

Dry FGD systems tend to be less expensive than wet FGD systems because they are less complex and generally smaller in size. They also use less water. The lower reagent cost of wet FGD and the ability to burn lower cost, higher sulfur coals make wet FGD more attractive for large facilities. EPA estimates a capital cost of about \$420/kW (\$2007) for a dry scrubber (lime spray dryer) on a 500 MW coal unit.²⁶ The Turbosorp system installed at the AES Greenidge plant in New York cost \$229/KW (\$2005).²⁷ Depending upon the specifics of the facility to be retrofit, the cost could be higher in some cases.

Dry FGD systems are less complex and generally require less time to design and install than wet FGD systems. The Institute to Clean Air Companies (ICAC) estimates that dry scrubbers can be installed in a time frame of 24 months.²⁸

Co-benefits of Dry FGD – Dry FGD pollutant co-benefits include greatly enhanced capture of hazardous air pollutants, especially PM, mercury and HCl (as discussed later in the report).

Upgrades to Existing Wet FGD Systems

Modern wet FGD systems are capable of SO₂ removal rates in the range of 98 percent or more. Limestone wet scrubber removal efficiencies have improved dramatically since the 1970s as shown in Figure 3.²⁹ As a result, there are opportunities to improve scrubber performance from many existing scrubbers that were built in the 1970s and 1980s. An advantage of this approach is that substantial SO₂ reductions are possible at a far lower cost than installing a new scrubber and in a much shorter period of time. Each scrubber upgrade is unique, so cost and schedule will vary. Depending upon the scope of a scrubber upgrade, a scrubber upgrade could be implemented in under a year as opposed to three to four years for a new scrubber installation. All key areas of many older FGD systems (absorber, reagent preparation, and dewatering) can benefit from modern upgrades. Because each system is unique, an

effective FGD system-wide upgrade process is most successful after an extensive system review and diagnostics.

There have been numerous examples of FGD upgrades over the last several years that have improved SO₂ removal efficiencies. For example, the Fayette Station Unit 3, a 470 MW tangentially-fired coal unit in Texas, completed an upgrade to its 1988-vintage scrubber in 2010. The plant's control efficiency was increased from about 84 percent to 99 percent, higher than the guaranteed SO₂ removal efficiency of 95.5 percent.³⁰ In Kentucky, E.ON's Trimble County Generating Station Unit 1, a 550 MW tangentially-fired coal boiler, completed a scrubber upgrade in 2006. Its scrubber, installed in the 1980s, was originally designed for 90 percent removal efficiency. The scrubber system is now able to achieve over 99 percent SO₂ removal efficiency.³¹ In Indiana, NiSource upgraded the scrubbers at Schahfer Units 17 and 18 in 2009.³² The scrubber upgrades increased SO₂ removal efficiency from 91 percent to 97 percent.³³

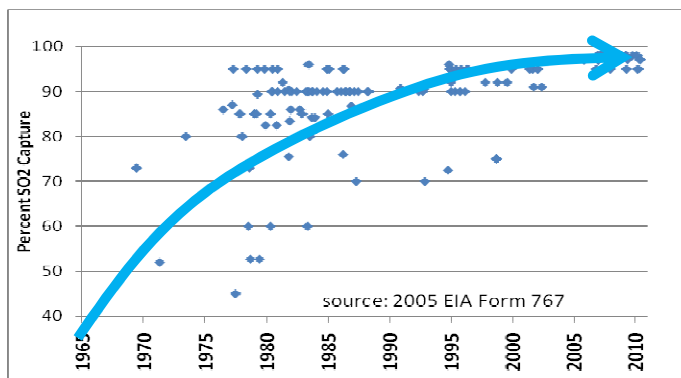


Figure 3. Historical Trends in Limestone Wet Scrubber SO₂ Removal Efficiency of Limestone Wet Scrubbing Systems

Dry Sorbent Injection (DSI)

DSI is the injection of dry sorbent reagents that react with SO₂ and other acid gases, with a downstream PM control device to capture the reaction products.

The most common DSI reagent in use is Trona, a naturally occurring mixture of sodium carbonate and sodium bicarbonate mined in some western states. Other reagents have also been used, such as sodium bicarbonate and hydrated lime. Sodium bicarbonate is capable of higher SO₂ removal efficiencies than Trona because it is more reactive. Trona can achieve varying levels of SO₂ reductions, from a range of 30-60 percent when injected upstream of an ESP, or up to 90 percent when injected upstream of a fabric filter. Fabric filters allow greater contact between the gas and the injected sorbent than ESPs, enabling better removal for any given reagent treatment rate. The level of removal will vary depending upon the circumstances of the facility and the injection system.

DSI equipment is relatively simple and inexpensive when compared to a scrubber and can be installed typically within 12 months.³⁴ Unlike scrubbers that require additional reaction chambers to be installed, in DSI the reaction occurs in the existing ductwork and air pollution control equipment. The basic injection system with storage silo costs around \$20/kW; however, in some cases additional storage and material handling may be necessary that will add cost. But, even with the additional equipment, the capital cost of a DSI system will be substantially less than that of a full wet or dry scrubber, which can cost as high as \$400/kW. Reagents used in DSI are more costly than those used in wet or dry scrubbers, and the reagent is not as efficiently utilized, which can contribute to a higher cost of control in terms of dollars per ton of SO₂ reduced.

Case Study: Dry Sorbent Injection

Conectiv Energy installed a DSI Trona system at Edge Moor Units 3-4 to comply with Delaware's multi-pollutant emissions control rule. The project was several years in planning and operated from 2009 to mid-2010. The emission rates went from 1.2 lbs SO₂/mmBtu to 0.37 lbs SO₂/mmBtu with the use of Trona. Since the purchase of the facility by Calpine in mid-2010, coal is no longer burned thus eliminating the need for the Trona system. In New York, NRG installed a Trona system at its Dunkirk (530 MW) and Huntley stations (380 MW). This project is the first of its kind in the U.S. in which Trona and powder-activated carbon (PAC) are simultaneously injected into the flue gases to control both SO₂ and mercury emissions. The DSI system included several Trona storage and injection systems with equipment buildings, 6000 feet of transport piping, Trona railcar unloading and transfer systems, and associated bulk storage silos. Performance tests indicate that emissions of SO₂ have been reduced by over 55 percent, mercury levels have been reduced by over 90 percent, and particulate levels have been reduced to less than 0.010 lbs/mmBtu.

Source: Pietro, J. and Streit, G. (NRG Energy). "NRG Dunkirk and Huntley Environmental Retrofit Project." Presented to Air & Waste Management Association – Niagara Frontier Section, September 23, 2010.

Co-benefits of DSI – DSI has been shown to be very effective in the capture of the acid gases, HCl and HF. DSI has been shown to enhance mercury capture for facilities that burn bituminous coal by removing sulfur trioxide (SO₃) that is detrimental to mercury capture through ACI. In the case of PRB coals, the impact on mercury capture might be negative. Injection of Trona or sodium bicarbonate can also remove NOx in the range of 10-20 percent, although NOx removal is generally not a principal objective of DSI.³⁵ If DSI is installed at a point in the gas stream that is upstream of the dioxins/furans formation temperature, it is expected to remove the precursor chlorine that leads to their production.

Methods for Controlling NOx Emissions

Nitrogen oxides (NOx) are an acid rain precursor and a contributor to the formation of ground-level ozone, which is a major component of smog. In 2008, power plants accounted for 18 percent of the national NOx emissions inventory. Most of the NOx formed during the combustion process is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NOx; and (2) oxidation of nitrogen that is chemically bound in the coal, referred to as fuel NOx. Controlling NOx emissions is achieved by controlling the formation of NOx through combustion controls or by reducing NOx after it has formed through post-combustion controls. Table 6 summarizes key NOx control technologies.

Table 6. NOx Emissions Control Methods

Methods of Control	
Combustion Controls	Method – Reduce NOx formation in the combustion process itself for levels of reduction that vary by application Reagent – None Typical fuel types – All fuels Capital Cost – Low to moderate Co-benefits – Potential impacts on Hg, CO and precursors of dioxins/furans
Selective Non-Catalytic Reduction	Method – Reagent injected into furnace reacts with and reduces NOx at moderate removal rates of about 30% Reagent – Urea or ammonia Typical Fuel Types – Most often solid or liquid fuels Capital Costs- Low Co-benefits - None
Selective Catalytic Reduction	Method – Reagent reacts with NOx across catalyst bed and reduces NOx at high rates of about 90% Reagent – Ammonia (or urea that is converted to ammonia) Typical Fuel Types – Any fuel Capital Costs – High Co-benefits – Oxidation of Hg for easier downstream capture in a wet scrubber, reduction of dioxins/furans
Co-benefit Methods of Control	
Low Sulfur Coal	Conversion to PRB coal for SO ₂ reduction will also reduce NOx due to lower fuel nitrogen in PRB coal
Dry Sorbent Injection	DSI with Trona can provide NOx reduction of about 10-15%

Combustion Controls

Combustion controls minimize the formation of NOx within the furnace and are frequently the first choice for NOx control because they are usually lower in cost than post-combustion controls. For most forms of combustion control, once installed there is little ongoing cost because there are no reagents or catalysts to purchase. Combustion controls reside within the furnace itself, not in the exhaust gas stream, and include such methods as low NOx burners (LNB), over-fire air (OFA), and separated over-fire air (SOFA). Reburning technology is another combustion control option, but it chemically reduces NOx formed in the primary combustion zone. Reburning technology may also utilize natural gas.

Most utilities have already achieved substantial reductions in NOx emissions from implementation of combustion controls, sometimes in combination with post-combustion controls. There are some facilities that can still benefit from combustion controls, but these are generally the smaller units where utilities have not yet invested in NOx controls.

The capital cost of these combustion controls will vary; however, the capital cost is generally far less than that of more costly post-combustion control options, such as Selective Catalytic Reduction (SCR). The capital costs of combustion controls could be anywhere from about \$10/kW to several times that, but generally fall below \$50/kW. Except for gas reburning, there is little or no increase in operating or fuel costs.

Co-benefits of Combustion NOx Controls – Combustion controls may enhance mercury capture at coal-fired power plants because they can increase the level of carbon in the fly ash. While higher carbon in the

fly ash is generally viewed negatively because it is the result of incomplete combustion, it does provide a real benefit in enhancing mercury capture. Combustion controls can also have a positive impact on CO emissions and on concentrations of organic precursors to dioxins/furans.

Post-Combustion NOx Controls

There are limits to the level of NOx control that can be achieved with combustion controls alone. Therefore, post-combustion controls are necessary to achieve very low emissions of NOx. Combustion NOx controls and post-combustion NOx controls can, and often are, used in combination. About half of the nation's coal fleet has already installed advanced post-combustion NOx controls (Table 7).

Table 7. Coal-Fired Power Plant Post-Combustion NOx Controls³⁶			
Control Type	Sum of Capacity (%)	# Boilers	Average Capacity (MW)
SCR	129 GW (40%)	259	499
SNCR	29 GW (9%)	172	166
Total Post-Combustion NOx	158 GW (49%)	431	366
No Post-Combustion NOx	842 GW (51%)	842	198
Total	324 GW	1,273	255

Selective Catalytic Reduction (SCR)

SCR technology, which has been in use at coal-fired power plants for more than 15 years in the United States, is a post-combustion NOx control system that is capable of achieving greater than 90 percent removal efficiency.³⁷ The first large-scale coal-fired selective catalytic reduction (SCR) system on a new boiler in the U.S. was placed in service in 1993 in New Jersey, and the first retrofit in the U.S. went into service in 1995 at a power plant in New Hampshire.³⁸ About 130 GW of the total coal-fired generating capacity in the U.S. is now equipped with SCR, and more SCRs are planned for existing units. Between 2001 and 2005, the electric industry installed more than 96 GW of SCR systems in response to the NOx SIP Call. Coal plant operators installed an additional 20 GW of SCR from 2008 through 2010 in response to the Clean Air Interstate Rule.³⁹

SCR utilizes ammonia as a reagent that reacts with NOx on the surface of a catalyst. The SCR catalyst reactor is installed at a point where the temperature is in the range of about 600°F-700°F, normally placing it after the economizer and before the air-preheater of the boiler. The SCR catalyst must periodically be replaced. Typically, companies will replace a layer of catalyst every two to three years. Multiple layers of catalysts are used to increase the reaction surface and control efficiency (Figure 4).

SCR system capital costs will vary over a wide range depending upon the difficulty of the retrofit. Some retrofits have been reported to cost under \$100/kW, while others have been reported to cost over \$200/kW.⁴⁰ Operating costs include ammonia reagent, periodic catalyst replacement, parasitic power, and fixed operating costs.

The EPA estimates that the total time needed to complete the design, installation, and testing at a facility with one SCR unit is about 21 months, and longer for plants that have multiple units to be retrofitted with SCR.⁴¹

Selective Non-Catalytic Reduction (SNCR)

SNCR is another post-combustion NO_x control technology. It typically achieves in the range of 25-30 percent NO_x reduction on units equipped with low NO_x burners. SNCR reduces NO_x by reacting urea or ammonia with the NO_x at temperatures around 1,800°F-2,000°F. Therefore, the urea or ammonia is injected into the furnace post-combustion zone itself and, like SCR, reduces the NO_x to nitrogen and water.

The capital cost of SNCR is typically much less than that of SCR, falling in the range of about \$10-\$20/KW, or about \$4 million or less for a 200 MW plant. The operating cost of SNCR is primarily the cost of the ammonia or urea reagent. SNCR is most commonly applied to smaller boilers. This is partly because the economics of SCR are more challenging for small boilers. Furthermore, when emissions regulations allow averaging or trading of NO_x emissions among units under a common cap, installing an SCR on a large boiler allows utilities to over-control the large unit and use less costly technology, such as SNCR or combustion controls, for NO_x control on smaller units.

SNCR systems are relatively simple systems that can be installed in a period of about 12 months.

Hybrid SNCR/SCR

SNCR and SCR may be combined in a “hybrid” manner. In this case, a small layer of catalyst is installed in ductwork downstream of the SNCR

system. With the downstream catalyst, the SNCR system can be operated in a manner that provides higher NO_x removal rates while using the SCR catalyst to mitigate the undesirable ammonia slip from the SNCR system. Although some NO_x reduction occurs across the SCR catalyst, its function is primarily as a means to reduce ammonia slip to an acceptable level. This approach has been demonstrated at the Greenidge power plant in upstate New York, but has not been widely adopted.⁴² For some smaller boilers that can accommodate the needed ductwork modifications necessary for “hybrid” SNCR/SCR, this may be an attractive technology for reducing NO_x emissions beyond what SNCR is able to achieve.

The hybrid SNCR/SCR system installed at Greenidge was part of a multi-pollutant control system designed to demonstrate a combination of controls that could meet strict emissions standards at smaller coal-fired power plants.⁴³ The multi-pollutant control system was installed on AES Greenidge Unit 4, a 107 MW, 1953-vintage tangentially-fired boiler. The facility fires high sulfur eastern U.S. bituminous coal. The multi-pollutant control system consists of a hybrid SNCR/SCR technology to control NO_x, a circulating fluidized bed dry scrubbing technology to control SO₂, mercury, SO₃, hydrogen chloride, and

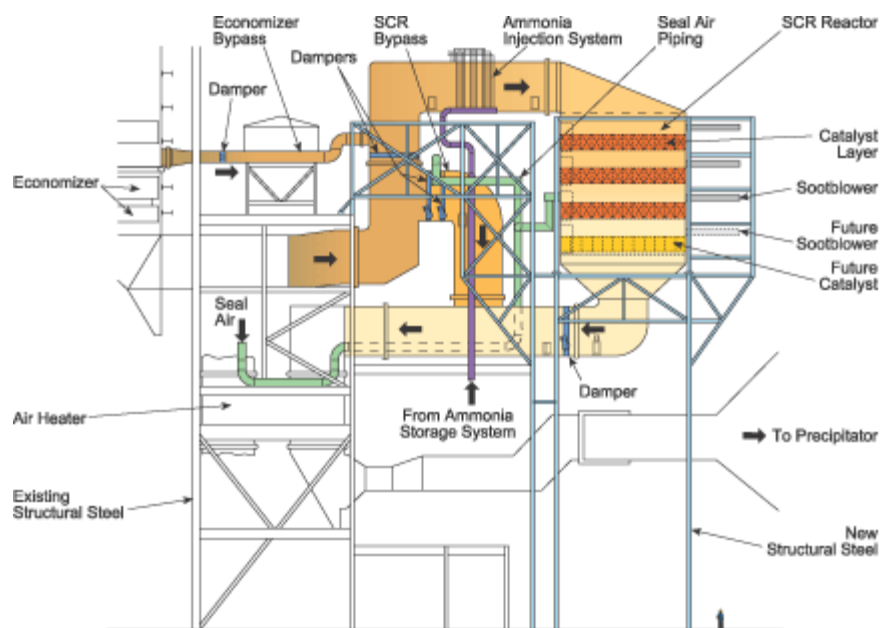


Figure 4. Selective Catalytic Reduction (Retrofit Installation)
Image courtesy of Babcock and Wilcox Company

particulate matter, and an activated carbon injection system to control mercury emissions. Total capital cost of the system was \$349/kW (2005\$), about 40 percent less than the estimated cost of full SCR and wet scrubbers—\$114/kW for the hybrid SNCR/SCR system, \$229/kW for the circulating dry scrubber system and \$6/kW for the activated carbon injection system. The plant has achieved 95 percent SO₂ control, 98 percent mercury removal, and 95 percent SO₃ and HCl removal.⁴⁴

Co-benefits of post-combustion NO_x controls – SNCR has no known co-benefit effects on other pollutants. SCR, on the other hand, has the co-benefit effect of enhancing oxidation of elemental mercury, especially for bituminous coals. The effect of mercury oxidation is to enhance mercury capture in a downstream wet FGD because the resulting ionic mercury is extremely water soluble. Several field and pilot studies conducted in the U.S. have found increases in oxidized ionic mercury with the use of SCR controls.^{45,46,47,48} For example, testing conducted at the Mount Storm coal-fired power plant in West Virginia evaluated the effect of the unit's SCR system on mercury speciation and capture.⁴⁹ The facility fires a medium sulfur bituminous coal. The test program found that the presence of an SCR catalyst can significantly affect the mercury speciation profile. Measurements showed that the SCR catalyst improved the mercury oxidation to levels greater than 95 percent, almost all of which was captured by the downstream wet FGD system. In the absence of the SCR catalyst, the extent of oxidation at the inlet of the FGD system was only about 64 percent. This effect, however, is much reduced with PRB coals because halogen content in PRB coals is low. SCR catalyst can also mitigate emissions of dioxins and furans.^{50,51}

Methods for Controlling Hazardous Air Pollutant Emissions

HAPs from power plants include mercury, acid gases (HCl and HF), heavy metals (nickel, chromium, arsenic, selenium, cadmium, and others), and organic HAPs (dioxins and furans). Many HAPs emitted by power plants are captured to some degree by existing air pollution control technologies. However, EPA's proposed Air Toxics Rule will establish emissions standards that will require additional controls be installed. For each of these HAPs, the potential methods for capture are discussed below.

Control of Mercury Emissions

Mercury is found within coal, with its concentration varying widely by coal type and even within coal types. The mercury is released during combustion and becomes entrained in a power plant's flue gas in one of three forms; particle-bound mercury, gaseous elemental mercury, and gaseous ionic mercury. Table 8 lists available methods to control mercury emissions for coal units.

Table 8. Mercury Emissions Control Methods

Methods of Control	
Activated Carbon Injection (ACI)	Method – Activated carbon adsorbs gaseous Hg, converting to particle Hg that is captured in downstream PM control device Reagent – Powdered Activated Carbon Typical Fuel Types – Any fuel, but downstream PM control needed Capital Costs – Low Co-benefits – Some capture of dioxins/furans
Halogen Addition	Method – Halogen (bromine) addition to flue gas increases oxidized Hg that is easier to capture in a downstream scrubber or in PM control device Reagent – Halogen containing additive Capital Costs – Negligible Co-benefits – None
Co-benefit Methods of Control	
PM Controls (ESP, FF, multicyclone)	Method – Captures particle-bound mercury
Dry Sorbent Injection	Method – Increases co-benefit and ACI Hg capture by removing SO ₃ , which suppresses mercury capture
Dry Scrubber with Fabric Filter	Method – Hg captured in downstream fabric filter
Wet Scrubber	Method – Oxidized mercury captured in wet scrubber
NOx Catalyst	Method – Catalyst in SCR increases oxidation of Hg that is more effectively captured in downstream wet scrubber

Activated Carbon Injection (ACI)

Mercury is often captured using injection of powdered activated carbon (activated carbon injection – ACI) and capture of the injected carbon on a downstream PM capture device (ESP or a baghouse). An ACI system is relatively simple and inexpensive, consisting of storage equipment, pneumatic conveying system, and injection hardware (“injection lances”). Under cooperative agreements with the U.S. Department of Energy, several coal plant operators conducted full-scale testing of ACI systems in 2001.⁵²

ACI has been used to capture mercury by effectively converting some of the gaseous ionic and elemental mercury to a particle-bound mercury that is captured in a downstream particulate matter control device, such as an ESP or fabric filter. ACI is very effective at removing mercury except if high sulfur coals are used, or if SO₃ is injected for flue gas conditioning for ESPs, or if the facility has a hot-side ESP and no downstream air pollution controls. SO₃ interferes with mercury capture by ACI; however, upstream capture of SO₃ by DSI, if one is in place, should enable ACI to be more effective at capturing mercury. Fortunately, most of the installed capacity of boilers firing high sulfur fuels is scrubbed and may not need ACI.

Since 2003, many states have led the way on mercury control regulations by enacting statewide mercury limits for power plants that require mercury capture rates ranging from 80 to 95 percent.⁵³ At present, about 25 units representing about 7,500 MW are using commercial ACI technologies for mercury control. In addition, about 55,000 MW of new bookings are reported by the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources.⁵⁴

ACI systems cost in the range of \$5/kW and can be installed in about 12 months or less, assuming a baghouse is installed. PSEG’s Bridgeport Harbor Generating Station completed the construction and

installation of a baghouse and ACI system in under 2 years. The final connection of the controls was completed during a six to eight week outage.

Case Study: ACI Controls

In response to a 2006 Minnesota state mercury law, Xcel Energy agreed to install an ACI system on the 900 MW Unit 3 at its Sherburne County plant (Sherco 3). The unit, which burns low sulfur western coal from Montana and Wyoming, already had a dry scrubber operating to reduce SO₂ emissions. Once it has been tuned to the unit's operational specifications, the ACI system is expected to reduce the plant's mercury emissions by about 90 percent. The system was completed in December 2009 for a total capital cost of \$3.1 million, or \$3.46/kW. Wisconsin Power and Light installed ACI controls at its Edgewater Generating Station. The system was operational in the first quarter of 2008. Edgewater Unit 5 is a 380 MW plant that fires PRB coal and is configured with a cold-side ESP for particulate control. The total installed costs of the Edgewater Unit 5 ACI system was approximately \$8/kW, or approximately \$3.04 million.

Source: Southern Minnesota Municipal Power Agency. "Sherco 3: Environmental Controls." August 2010, <http://www.smmmpa.com/upload/Sherco%203%20brochure%202010.pdf> (accessed March 17, 2011).

Starns, T., Martin, C., Mooney, J., and Jaeckels, J. "Commercial Operating Experience on an Activated Carbon Injection System, Paper #08-A-170-Mega-AWMA." Power Plant Air Pollutant Control MEGA Symposium. Baltimore, MD. August 25-28, 2008.

Co-benefits of ACI – ACI co-benefits include the reduction of dioxins and furans.

Halogen Addition

For applications where there is inadequate halogen for conversion of elemental mercury to ionic mercury, such as some western coals, the addition of halogen will increase mercury conversion to the ionic form and will permit higher capture efficiency through co-benefit capture or by ACI. Addition of halogen to PRB coals or to activated carbon injected for mercury capture has been shown to make mercury capture from PRB fired boilers with halogen addition generally high.⁵⁵

Co-Benefit Methods for Mercury Capture

Of the three mercury forms previously mentioned, particle-bound mercury is the species more readily captured as a co-benefit in existing emission control devices, such as fabric filters (also called "baghouses") or electrostatic precipitators (ESPs). Ionic mercury has the advantage that it is extremely water soluble and is relatively easy to capture in a wet FGD/scrubber. Ionic mercury is also prone to adsorption onto fly ash or other material, and may thereby become particle-bound mercury that is captured by an ESP or fabric filter. Elemental mercury is less water soluble and less prone to adsorption, thus remains in the vapor phase where it is not typically captured by control devices unless first converted to another form of mercury more readily captured.

Fabric filters generally provide much higher co-benefit mercury capture than ESPs. Bituminous coal-fired boilers with fabric filters can have high rates of mercury capture based on data collected by the U.S. EPA during its Information Collection Request (ICR) supporting the development of the Air Toxics Rule.⁵⁶

Wet scrubbers with SCR controls upstream have been shown to be very effective in removing oxidized (ionic) mercury. Therefore, when a wet scrubber is present, it is beneficial to take measures to increase the oxidation of mercury upstream of the wet scrubber. Catalysts in SCR systems promote oxidation of mercury, and SCR controls upstream of a wet FGD system have been shown to provide high mercury capture in the range of 90 percent when burning bituminous coals.⁵⁷ The precise level of oxidation and capture will vary under different conditions. In a study by the Southern Company, five of its plants with SCR and scrubbers captured an average of 87 percent of mercury over a period of several months.⁵⁸

Co-benefit capture rates of mercury in ESPs, fabric filters, scrubbers, or other devices for bituminous coals are generally greater than that for PRB coals. This is because the higher halogen content (e.g., chlorine) found in eastern coals promotes formation of oxidized mercury.⁵⁹

Acid Gas Control Methods

Strong acids, such as hydrogen chloride (HCl) and hydrogen fluoride (HF), result from the inherent halogen content in the coal that is released during combustion to form acids as the flue gas cools. As with mercury content, the concentration of halogens in the coal varies widely by coal type and even within coal types. Chlorine is of greatest concern because it is usually present in higher concentrations than other halogens in U.S. coals. The U.S. EPA's proposed Air Toxics Rule for power plants sets a numerical emission limit for HCl. The HCl limit also functions as a surrogate limit for the other acid gases, which are not given their own individual emission limits under the proposed rule.

Table 9 shows HCl emission control methods for coal boilers. In principle, wet and dry SO₂ scrubbers can be used for the control of HCl and HF on power plant boilers; however, these are not likely to be necessary because lower cost methods exist. For those facilities with wet or dry scrubbers for SO₂ control, these units will likely provide the co-benefit of HCl capture. For those units that are unscrubbed, these will likely be adequately controlled through retrofit with DSI systems, and a fabric filter.

Table 9. HCl Emissions Control Methods

Methods of Control	
Dry Sorbent Injection	Method – Dry sorbent captures HCl, downstream PM control device captures dry product Regent – Trona, sodium bicarbonate, hydrated lime Typical Fuel Types – Most often solid fuels with PM control Capital Costs – Low to moderate Co-benefits – NO _x and SO ₂ reduction, Hg reduction, removal of chlorine precursor leading to lower dioxins/furans formation
Dry Scrubber with fabric filter	Method – Reagent + water react to capture acid gas and dry product captured in downstream fabric filter Reagent – Hydrated lime Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – High Hg capture (esp. bituminous coal), high SO ₂ capture, high PM capture
Wet Scrubber	Method – Reagent + water react to capture acid gas Reagent – Limestone, lime, caustic soda Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – Highest SO ₂ capture, high oxidized Hg capture, some PM capture
Co-benefit Methods of Control	
Wet or Dry Scrubbers	Method – SO ₂ scrubber has high HCl removal efficiency
Coal Change	Low sulfur PRB coal is also low in chlorine content

Dry Sorbent Injection

Data from DSI commercial projects or pilot testing has indicated that acid gases can be very effectively captured by DSI using Trona, sodium bicarbonate, or hydrated lime. Although DSI is a technology that has not yet seen the wide deployment of other technologies for acid gas controls, like wet or dry scrubbers, data suggest that DSI is an effective technology for controlling emissions of acid gases, including HCl and HF. For example, as shown in Table 10, HCl capture rates of 98 percent have been measured at Mirant's Potomac River station with sorbent injection upstream of the air preheater.⁶⁰ Testing of DSI systems has shown that HCl capture is consistently well above the SO₂ capture rate, and that capture rate of HCl on an ESP was in the mid to upper 90 percent range with SO₂ capture in the 60 percent range. With fabric filters, similar HCl capture efficiencies are possible but at lower sorbent treatment rates.⁶¹ Hydrated lime has also been shown in pilot tests to potentially achieve substantial HCl removal at low capital cost.⁶²

Table 10. HCl and HF Capture at Mirant Potomac River Station

	Trona Injection	Sodium Bicarbonate Injection
HCl (%)	98.8	97.8
HF (%)	78.4	88.0

DSI may be sufficiently effective in removing acid gases in combination with the existing PM control device. In some cases, however, it may be necessary to modify the existing PM control device or to install a new PM control device. If a fabric filter is installed for PM control, this will also facilitate capture of acid gases with DSI, and mercury and dioxins/furans with ACI. Such an approach will be far

less expensive than installing a wet scrubber. As indicated above, DSI equipment is relatively simple and inexpensive when compared to a scrubber and can be installed typically within 12 months.

PM Emissions Control

Toxic metals other than mercury are normally in the particle form and are therefore controlled through particulate matter controls, such as ESPs and fabric filters. The proposed Air Toxics Rule for power plants sets numerical PM emission limits as a surrogate for non-mercury toxic metal emission limits. Table 11 lists PM emission control methods for pulverized coal units.

Table 11. PM Emissions Control Methods	
Methods of Control	
ESP	Method – Electrostatic capture of PM, high capture efficiency Reagent – None Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – Capture particle-bound mercury
Baghouse	Method – Filtration of PM, highest capture efficiency Reagent – None Typical Fuel Types – Gaseous fuels Capital Costs – High Co-benefits – High capture of mercury and other HAPs
Co-benefit Methods of Control	
Scrubber (wet or dry)	Method – Captures PM

Electrostatic Precipitator

An electrostatic precipitator (ESP) uses an electrical charge to separate the particles in the flue gas stream under the influence of an electric field. More than 70 percent of existing coal-fired power plants are reported to have installed ESPs.⁶³

In brief, an ESP works by imparting a positive or negative charge to particles in the flue gas stream. The particles are then attracted to an oppositely charged plate or tube and removed from the collection surface to a hopper by vibrating or rapping the collection surface. An ESP can be installed at one of two locations. Most ESPs are installed downstream of the air heater, where the temperature of the flue gas is between 130°C-180°C (270°F-350°F).⁶⁴ An ESP installed downstream of the air heater is known as a “cold-side” ESP. An ESP installed upstream of the air heater, where flue gas temperatures are significantly higher, is known as a “hot-side” ESP.

The effectiveness of an ESP depends in part on the electrical resistivity of the particles in the flue gas. Coal with a moderate to high amount of sulfur produces particles that are more readily controlled. Low sulfur coal produces a high resistivity fly ash that is more difficult to control. The effectiveness of an ESP also varies depending on particle size. An ESP can capture greater than 99 percent of total PM, while capturing 80 to 95 percent of PM_{2.5}.⁶⁵

Depending upon the particular ESP and the applicable MACT standards, there may not be any need for further controls; however, many ESPs are decades old and were built for compliance with less stringent emission standards in mind. As a result, these facilities may need to make one or both of the following modifications to comply with new MACT standards:

- Upgrade of existing ESP – The existing ESP could be upgraded through addition of new electric fields, use of new high frequency transformer rectifier technology, or other changes. The applicability of this option will depend upon the condition and performance of the existing ESP.
- Replacement of ESP with fabric filter – A fabric filter may be installed in place of the existing ESP. In some cases, the existing ESP casing and support structure could be utilized for the baghouse. A booster fan is likely to be necessary because of the increased pressure drop across the fabric filter.

In recent years, there has been more focus on fabric filters for PM control than ESPs because of the PM capture advantages of fabric filters. As a result, there is not a great deal of available information on recent cost or installation time for ESPs. In general, however, an ESP will likely cost somewhat more and take more time to construct than a fabric filter built for the same gas flow rate because ESPs are somewhat more complex to build than a fabric filter system.

Fabric Filter or Baghouse

A fabric filter, more commonly known as a baghouse, traps particles in the flue gas before they exit the stack. Baghouses are made of woven or felted material in the shape of a cylindrical bag or a flat, supported envelope. The system includes a dust collection hopper and a cleaning mechanism for periodic removal of the collected particles.

According to EPA, a fabric filter on a coal-fired power plant can capture up to 99.9 percent of total particulate emissions and 99.0 to 99.8 percent of PM_{2.5}.⁶⁶ Thirty-five percent of coal-fired power plants in the U.S. have installed fabric filters.⁶⁷

A full baghouse retrofit would generally cost somewhat more than the addition of a downstream polishing baghouse (discussed later); however, because the material and erection of the baghouse is only a portion of the total retrofit cost of any baghouse, most of the costs are the same (ductwork, booster fans, dampers, electrical system modifications, etc.). Increasing the fabric filter size by 50 percent (equivalent to a change in air to cloth ratio of 6.0 to 4.0) would yield much less than a 50 percent impact to project cost over the cost of retrofitting a polishing baghouse, perhaps in the range of 15-20 percent. A fabric filter retrofit (full or polishing) would typically be achievable in 12-24 months from design to completion, depending upon the complexity of the ductwork necessary. For example, in 2009, the Reid Gardner generating station in Nevada completed the installation of three new pulse-jet baghouses in 17 months. The retrofit required the replacement of the plant's existing mechanical separators.⁶⁸

Rather than replacing an ESP with a fabric filter, a power plant with an existing ESP has the option of installing a downstream polishing baghouse (downstream of the existing ESP). This will capture particulate matter that escapes the ESP. Retrofit of a downstream polishing fabric filter will require addition of ductwork, a booster fan, and the fabric filter system. Costs will vary by application, particularly by the amount of ductwork needed. For example, the polishing fabric filter installed on three 90 MW boilers at Presque Isle Power Plant in Michigan cost about \$125/KW (2005\$). This project, however, had very long duct runs for each of the boilers and significant redundancy.⁶⁹ For a project on a single larger unit without the long duct runs, one would expect a lower cost.

Co-benefits of PM controls – PM controls, especially fabric filters, permit higher co-benefit mercury capture. Also, capture of other toxic pollutants through DSI is improved with a fabric filter. This is true

with any situation where sorbent is used to capture a pollutant because a fabric filter permits capture on the filter cake in addition to capture in-flight while ESPs permit only in-flight capture.

Control of Dioxins and Furans

Under the Air Toxics Rule, EPA has proposed a “work practice” standard for organic HAPs, including emissions of dioxins and furans, from coal-fired power plants. Power plant operators would be required to perform an annual tune-up, rather than meeting a specific emissions limit. EPA has proposed a work practice standard because it found that most organic HAP emissions from coal power plants are below current detection levels of EPA test methods. Therefore, it concluded that it is impractical to reliably measure emissions of organic HAPs. While EPA is not proposing numerical emission limits for organic HAPs, for completeness, we discuss below experience in controlling emissions of dioxins and furans from incinerators that may have relevance for co-benefits with coal power plant controls.

Emissions of dioxins and furans result from: (1) their presence in the fuel being combusted; (2) the thermal breakdown and molecular rearrangement of precursor ring compounds, chlorinated aromatic hydrocarbons; or (3) from reactions on fly ash involving carbon, oxygen, hydrogen, chlorine, and a transition metal catalyst. Because dioxins and furans are generally not expected to be present in coal, the second and third mechanisms are of most interest. In both of these mechanisms, formation occurs in the post-combustion zone at temperatures over 500°C (930°F) for the second mechanism or around 250-300°C (480-575°F) for the third mechanism.⁷⁰ Once formed, dioxins and furans are difficult to destroy through combustion. Therefore, it is best to prevent their formation, or alternatively, capture them once formed.

While emissions of dioxins and furans have long been a source of concern for municipal and other waste incinerators, their emissions have not generally been controlled from power plants. Emissions of dioxins and furans are generally expected to be lower in coal combustion than in municipal waste combustion because of the relatively lower chlorine levels and the higher sulfur levels of coal.⁵⁰ Sulfur has been shown to impede dioxins and furans formation.^{50,70,71} Table 12 lists the technologies for control of dioxins and furans and EPA’s previously proposed institutional, commercial, and industrial boiler limits for pulverized coal units.

The extensive experience with control of dioxins and furans at incinerators has provided insights that may be relevant for power plants, while recognizing the important differences between power plants and incinerators. Because dioxins and furans are formed from organic precursors, one way to avoid their formation is to have complete combustion of organics; hence, combustion controls or oxidation catalysts can contribute to their lower formation.⁷⁰ SCR has also been shown to mitigate emissions of dioxins and furans.^{50,51} Data indicate that capture of chlorine prior to the dioxins formation temperature will reduce dioxins/furans formation from municipal waste combustors.⁵⁸ Therefore, dry sorbent injection upstream of the air preheater of a coal boiler may be a means of reducing dioxins/furans formation.

Injection of activated carbon is a means that has been used to capture dioxins and furans emitted by municipal waste incinerators,^{50, 70} and has demonstrated over 95 percent capture of dioxins at a hazardous waste incinerator.⁷² Currently, there are not enough available data to form a definitive conclusion about how effective ACI will be at dioxins/furans capture from power plants because of the different conditions. The information available, however, suggests that it is likely to be useful in reducing dioxins and furans in the event other methods are not adequate in preventing their formation.

Table 12. Dioxins and Furans Emission Control Methods

Methods of Control	
Activated Carbon Injection (ACI)	Method – Activated carbon adsorbs gaseous dioxins/furans, and is captured in downstream PM control device Reagent – Powdered Activated Carbon Typical Fuel Types – Any fuel, but downstream PM control needed Capital Costs – Low Co-benefits – Capture of Hg
Co-benefit Methods of Control	
Combustion Controls	Method – Destruction of organic dioxins/furans precursors
Dry Sorbent Injection	Method – Captures precursor chlorine prior to dioxins/furans formation
CO or NOx Catalyst	Method – Catalyst increases oxidation of organic dioxins/furans precursors

Labor Availability

The installation of air pollution control equipment requires the effort of engineers, managers, and skilled laborers, and past history has shown that the industry has substantial capacity to install the necessary controls. Between 2008 and 2010, coal-fired power plants added approximately 60 GW of FGD controls and almost 20 GW of SCR controls with a total of 80 GW of FGD controls installed under CAIR Phase 1. Between 2001 and 2005, the electric power industry successfully installed more than 96 GW of SCR systems in response to the NOx SIP Call.

Based on a retrospective study of actual retrofit experience, it was determined that EPA and industry dramatically underestimated the ability of the air pollution control industry to support the utility industry in responding to CAIR. The study offered several reasons for why EPA and industry underestimated the capabilities of the labor market: (1) boilermakers will work overtime during periods of high demand; (2) boilermakers frequently travel to different locations for work, supplementing local available labor; (3) boilermakers work in fields other than power, such as refining/petrochemical, shipbuilding, metals industries and other construction trades, and workers can shift industry sectors with appropriate training; and (4) new workers will enter the field—for example, in advance of the NOx SIP Call, boilermakers increased their ranks by 35 percent, mostly by adding new members.⁷³

In November 2010, the Institute of Clean Air Companies (ICAC), an association that represents most of the suppliers of air pollution control technology, sent a letter to U.S. Senator Thomas Carper confirming the nation's air pollution control equipment companies repeatedly have successfully met more stringent NOx, SO₂, and mercury emission limits with timely installations of effective controls and are well prepared to meet new EPA requirements. In its letter, the industry association stated, “based on a history of successes, we are now even more resolute that labor availability will in no way constrain the industry’s ability to fully and timely comply with the proposed interstate Transport Rule and upcoming utility MACT rules. Contrary to any concerns or rhetoric pointing to labor shortages, we would hope that efforts that clean the air also put Americans back to work.”⁷⁴ Also in November 2010, the Building and Construction Trades Department of the AFL-CIO issued a letter concluding that “[t]here is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development.”⁷⁵

The electric industry has long been aware that EPA would be regulating HAPs and other pollutants from coal-fired power plants. As a result, many companies started planning their compliance strategies before EPA even proposed its Air Toxics Rule in March 2011. For example, companies have been evaluating

control technology options and establishing capital budgets.⁷⁶ Similar advance planning occurred after the proposed CAIR rule was released in December 2003. In 2004, when EPA was still working to finalize the rule, companies placed orders for more than 20 GW of FGD controls (wet and dry scrubbers).⁷⁷ Southern Company, for example, had begun planning its FGD installations in 2003, well in advance of the final rule.⁷⁸

Conclusion

EPA's clean air rules—the Transport Rule and the Air Toxics Rule—address one of the nation's largest sources of toxic air pollution, providing important human health protections to millions of people throughout the country. Additionally, thousands of construction and engineering jobs will be created as companies invest in modern control technologies.⁷⁹

The electric power sector has several decades of experience controlling air pollution emissions from coal-fired power plants, which should serve the industry well as it prepares to comply with the Transport Rule and the Air Toxics Rule. Many companies have already moved ahead with the upgrades necessary to comply with these future standards, demonstrating that better environmental performance is both technically and economically feasible.

In most cases, the required pollution control technologies are commercially available and have a long track record of effective performance at many coal-fired power plants in the U.S., with some operating successfully for decades. The electric power sector has demonstrated that it is capable of installing pollution controls on a large portion of the nation's generating fleet in a relatively short period of time. Also, suppliers have demonstrated the ability to deliver pollution control equipment in a timely manner, and the skilled labor needed to install it should be available to meet the challenge as well.

Endnotes

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Appendix E

OTC RACT PRINCIPALS STATEMENT



Statement of Reasonably Available Control Technology Principles

Connecticut

Delaware

District of Columbia

Maine

Maryland

Massachusetts

New Hampshire

New Jersey

New York

Pennsylvania

Rhode Island

Vermont

Virginia

J. Wick Havens
Interim Executive
Director

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Washington, DC 20001
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The Ozone Transport Commission (OTC) is a multi-state organization created under the Clean Air Act (CAA) to advise the U.S. Environmental Protection Agency (EPA) on practical and cost effective solutions to the environmental and public health problem of ground-level ozone transport that negatively affects the Ozone Transport Region (OTR).

Ozone has been shown to cause respiratory illnesses, exacerbate or trigger asthma related episodes, increase respiratory-related emergency room and hospital admissions and compromise the immune system leading to increased incidents of other respiratory illnesses, including pneumonia and bronchitis, and to cause premature death.

In 2014, each OTC state is required under Section 184 of the Clean Air Act to perform a review of the state's control requirements to ensure that all major sources of NO_x and VOC are subject to a RACT (or Reasonably Available Control Technology) level of control under the 2008 national ambient air quality standard (NAAQS) for ozone. OTC's Stationary and Area Sources Committee has conducted extensive analysis of largest contributing sources inside and outside of the region published in a whitepaper. EPA has defined RACT as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. Over time, RACT changes to reflect advances in technology, becoming more stringent as the NAAQS are revised and lowered. In order to protect the public adequately from the adverse health effects associated with ozone and ensure consistency, the OTC recommends the following minimum principles for RACT to assist in attainment and maintenance of the ozone NAAQS:

1. Consistent with EPA guidance, levels of control, and emissions rates, that are achieved in practice by existing similar sources are technologically and economically feasible, considering capacity, fuel, equipment design, control technology, age and site limitations, and therefore represent RACT. Thus, requirements in place in other states for certain sources provide a benchmark for RACT for that source category.
2. Sources that have purchased and installed pollution control technology must run those technologies year round and ensure that, during the ozone season, daily emissions are minimized.
3. For electricity generating units:
 - a. Compliance with the Cross-State Air Pollution Rule or the Clean Air

Interstate Rule cannot substitute for RACT.

- b.** Peaking units need to be assessed with due consideration given to total daily emissions from the category of sources and the economics of meeting peak demands.
- 4. The averaging time for a RACT-based emission limitation should be as short as practicably consistent with the ozone standard and characteristic operation of the source category.

Therefore, the OTC member states strongly believe that the implementation of the aforementioned RACT core principles will strengthen emissions limitations, lower overall emissions, and thereby derive air quality and public health benefits.

Abstained: New Hampshire ,Pennsylvania, Virginia

Adopted by the Commission on June 11, 2014

A handwritten signature in blue ink, appearing to read 'R. M. Summers', is written over a horizontal line.

Robert M. Summers, OTC Chair
Secretary, Maryland Department of Environmental Protection

APPENDIX F

SUMMER STUDY - 2014

Through stakeholder negotiations, MDE requested a voluntary NOx Optimization Study for coal-fired EGUs during the summer of 2014. MDE requested Raven Power and NRG Energy to review, evaluate and optimize NOx control measures at their coal-fired electric generating units (EGUs) and to report their findings to the Department.

MDE requested that an optimization plan be developed which would describe steps to evaluate means by which NOx reduction can be optimized during the agreed-upon time period of July 1 through at least August 31, 2014. The optimization plan is intended to evaluate optimizations in NOx emissions both by reducing NOx generation in the furnace and improving NOx reduction in the post-combustion control device, and to evaluate these optimizations on both a 30-day and a 24-hour basis. MDE requested an interim monthly data report and a final report on the results and findings of the study.

For the effort to minimize emissions on peak days, the Department shall identify and provide Raven Power and NRG with notification of high forecasted ozone days (High Ozone Days) no later than 10 am Eastern Standard Time the prior day. High Ozone Days shall be limited to 10 days during the study period.

GenOn Mid-Atlantic NOx Optimization Plan – Summer 2014

Raven Power NOx Optimization Plan – Summer 2014

Excel files with data available on the Departments website

GenOn Mid-Atlantic NOx Optimization Plan – Summer 2014

GenOn Mid-Atlantic, LLC (“GenOn”) has worked with its three Maryland plants to establish target NOx rates on the coal units for this summer. Each unit has a “summer-long” target rate that the units will follow as well as a “peak day” target rate that the plants will endeavor to meet on those days when MDE calls for additional reductions. GenOn will operate installed NOx controls at the three plants when the units are in operation, except for periods of startup, shutdown, malfunction, or maintenance of the control equipment. The plants will log the events that cause the NOx controls to be taken out of service and also note when the controls are returned to service.

The bullets below describe the measures that each unit will take to control / reduce NOx and document operational limitations this summer.

Morgantown

- Summer SCR NOx Target Rate: 0.040 lb/MBtu
- Peak Day SCR NOx Target Rate: 0.034 lb/MBtu (a 15% reduction from summer avg)
- Units are already optimized for NOx, with SCRs achieving excellent NOx rates.
- Plant is on a catalyst management program to maintain SCR performance and low ammonia slip.
- Plant will keep e-logs for periods of equipment malfunction, maintenance, startups, and shutdowns.
- Peak Day rate will not be achievable if a unit is in startup or shutdown, as SCR permissive temperature is 621 °F, which is not reached until ~325 MW (even with economizer bypass).

Dickerson

- Summer SNCR NOx Target Rate: 0.30 lb/MBtu. This rate is highly dependent on what load the units are operated at over the summer period. Long periods of operation at maximum or minimum load raise the average rate achieved, while operation at mid loads lowers the rate achieved.
- Peak Day SNCR NOx Target Rate: TBD lb/MBtu. SNCR tuning tests and other optimization efforts have not been completed, therefore a Peak Day rate cannot be selected yet.
- As of June 1, SNCR systems have been in operation whenever the units run, except during malfunction, maintenance, startup, and shutdown periods. This will continue through August 31.
- The SNCR manufacturer, FuelTech, has been on site since mid-May for boiler combustion optimization testing, followed by SNCR NOx optimization testing on all three units. These tests will be completed the week of July 7th.
- Use of the SNCR system reduces main steam temperatures by 40-50 °F, which reduces unit load. One of the goals of the optimization testing is to minimize generation derates while the SNCR is in operation.
- Ammonia slip from the SNCR system needs to be carefully controlled. High ammonia slip during testing on Unit 1 in February plugged the air preheater in 3-4 days. Slip is being measured

manually during optimization testing. There is one slip monitor in place on Unit 1 currently, and a monitor for Unit 2 will be installed in July.

- The units have SOFA systems that reduce NO_x from ~0.60 to 0.35 lb/MBtu. Reduction is limited by CO emissions, windbox pressure, steam temperatures, and boiler air flow (FD fan limits). The DCS drives NO_x down until one of these limits is encountered.
- Units have higher NO_x rate at max and min loads. Lowest NO_x is achieved at ~120 MW.
- Due to a common ductwork arrangement, Unit 3 has the best boiler performance (closest to ID fans) while Unit 1 has the worst performance (farthest from fans).
- Units get ramped up and down frequently during the day, which disrupts the DCS optimization process.
- Plant will log periods of equipment malfunction and maintenance.
- Peak Day measures the plant may try on Dickerson units:
 - Sliding boiler pressure for improved low load NO_x
 - GAM, a waterwall slagging treatment to improve steam temperatures.

Chalk Point

Unit 1:

- Summer SCR NO_x Target Rate: 0.060 lb/MBtu, (NO_x ppm set point of 33 ppm).
- Peak Day SCR NO_x Target Rate: 0.050 lb/MBtu, (NO_x ppm set point of 27 ppm, a 18% reduction from summer avg).
- Unit 1 is optimized for NO_x. Chalk also has a catalyst management system to maintain SCR performance and low ammonia slip.

Unit 2:

- Summer SACR NO_x Target Rate: maximum reduction with 1.0 ppm ammonia slip. The NO_x rate at this condition varies with load and inlet NO_x concentration.
- Peak Day SACR NO_x Target Rate: maximum reduction with 1.5 ppm ammonia slip. The NO_x rate at this condition varies with load and inlet NO_x concentration.
- SACR system has an artificial intelligence tuning system which runs continuously. There are 18 ammonia injection lances and 6 ammonia slip monitors across the Unit 2 boiler gas path. The program groups the ammonia injection into 3 zones, then seeks minimum NO_x emissions at a given ammonia slip set point. Ammonia slip is the limiting factor. If ammonia slip increases to ~5 ppm, the APH will plug up (with ammonium bisulfate) within 4-5 days and force the unit off.
- 280 MW is the low NO_x “sweet spot” for this unit.
- Plant will keep e-logs for periods of equipment malfunction and maintenance.

NOX OPTIMIZATION PLAN

Summer 2014

Raven Power:

- Brandon Shores
- H.A. Wagner
- C.P. Crane

June 27, 2014

Introduction

Raven Power Finance LLC (“Raven”) is planning to voluntarily conduct a NO_x Optimization Study during the summer of 2014. The Maryland Department of Environmental Quality (“MDE”) requested this voluntary study in an email attachment from Tad Aburn on June 24, 2014, which requests that Raven evaluate and optimize NO_x control measures at the six coal-fired electric generating units (EGUs) in Raven’s fleet during a specified period of time (“Study”). Those units include Brandon Shores 1 and 2, C. P. Crane 1 and 2 and H.A. Wagner 2 and 3.

MDE requested that an optimization plan (“Plan”) be developed by Raven, which would describe Raven’s steps to evaluate means by which NO_x reduction can be optimized during the agreed-upon time period of July 1 through at least August 31, 2014. As described in the MDE’s request, the Plan is intended to evaluate optimizations in NO_x emissions both by reducing NO_x generation in the furnace and improving NO_x reduction in the post-combustion control device, and to evaluate these optimizations on both a 30-day and a 24-hour basis, as set forth herein.

Affected Unit Information

The following is a summary of the key information and data about each unit in the Raven coal fleet subject to the Study requirements:

	Brandon 1	Brandon 2	Wagner 2	Wagner 3	Crane 1	Crane 2
Max Econ. Load (MW - gross)	690 – 700	690 – 700	146	325	200	180
Min. Load (MW-gross)	260	260	35	144	100	70
Fuel	Bituminous coal, various	Bituminous coal, various	Bituminous coal, various	Bituminous coal, various	Sub-bit coal	Sub-bit coal
Boiler NO_x control	LNB; OFA	LNB; BOOS	LNB	LNB with OFA;	OFA	OFA
Boiler config.	Opposed Wall-fired (5 sets of burners)	Opposed Wall-fired (5 sets of burners + 1 opposed Side-wall set)	Front Wall-fired	Opposed Wall-fired;	Cyclones	Cyclones
NO_x Control Device	SCR after hot-side ESP	SCR after hot-side ESP	SNCR; fixed injection points	SCR	SNCR w/multiple injection levels	SNCR w/multiple injection levels
Reagent for NO_x Control	Urea to ammonia conversion (1°); aqueous ammonia (2°)	Urea to ammonia conversion (1°); aqueous ammonia (2°)	Urea (diluted)	Urea to ammonia conversion	Urea (diluted)	Urea (diluted)

BOOS – Burners out of service

General Provisions of Study

Raven will endeavor to operate all NO_x control equipment in accordance with manufacturer's recommended operating parameters during the Study period of July 1 through at least August 31, except during startup, shutdown, maintenance and malfunction periods. During boiler start-up and shutdown periods, there are times when certain operational conditions, like low temperatures, make operating the controls (i.e., adding ammonia to the flue gas or passing flue gas through catalyst) ineffective and potentially detrimental to the other equipment. Additionally, like all operating equipment, the NO_x controls may experience a malfunction that either causes it to stop operating properly or curtail its effectiveness, or require maintenance to prevent more significant problems later. However, during the Study Raven will endeavor to 1) maintain NO_x controls as effective as reasonably possible during startups and shutdowns, 2) take steps to bring NO_x controls back into full service as quickly as practicable whenever the control equipment experiences a malfunction, and 3) document (and include in the final report) information regarding the cause of the malfunction and the steps for bringing the controls back.

For each unit Raven will endeavor to collect hourly NO_x emission rate (lb/MMBtu and lb/hr) and gross generation (MW) data using existing monitoring devices. Raven will use this information to generate NO_x vs load curves for each unit.

During the Study Tom Weissinger, Raven Power Environmental Director, will be Raven's point of contact. He will coordinate any visits/observations made by MDE and he will be responsible for submitting the monthly and final reports to MDE.

Optimization Plan

Each plant has recently or will be conducting activities to ready the boilers and the NO_x controls for the Study and for minimizing NO_x during the Study period. After these preparatory and preventive maintenance activities are complete, each unit will plan to run for approximately a week when dispatched to establish a baseline level of NO_x (and NO_x-Load curve). Then, each plant will plan to test a number of potential changes or adjustments they believe may help optimize NO_x emissions. These tests, will evaluate one change at a time to determine their individual effects on NO_x. The tests will plan to focus on lowering NO_x generation in the boilers and improve the NO_x control efficiency of the SCR/SNCRs. Due to the limited time of the Study (i.e., not beginning until after July 1), and variations in dispatch (i.e., swings in load up and down) during the summer, the evaluations may be limited in time or scope. If Raven feels it is warranted, additional tests and data collection may be conducted beyond August 31, especially, if a unit was not operating an adequate amount of time during the targeted Study period.

Based on the results of these tests, Raven plans to test the effects of the most promising changes when they are combined (i.e., implementing multiple changes simultaneously). This should be occurring late in July or early August, depending on how much the units have been dispatched and tested.

For the last part of the test period, Raven plans to operate the units with the "best performing" changes made, monitoring both emissions and operational conditions to determine the sustainability of the changes. If certain changes are found to reduce NO_x, but cause operational/dispatch problems after a few days/weeks, then they may only be continued on the High Ozone Days being flagged by MDE.

Otherwise, Raven plans to continue them through the Study period. Raven will endeavor to implement as much/many NO_x controls as feasible on High Ozone Days to minimize the mass emission of NO_x on those days. However, 1) Raven will not adjust dispatch based on the test, and 2) the changes implemented may be modified during the course of the Study period, based on documented results and changes in operation.

A list of the pre-Study activities planned for each unit are included with the Plant-specific test activities attached to this Plan.

Monitoring and Monthly Reporting

Raven will endeavor to collect, at a minimum, the following information during the Study period:

- Data submitted to EPA via Emissions Collection and Monitoring Plan System (ECMPS), including NO_x emissions data (lb/MMBtu and tons/day), gross generation (MW), and heat input (MMBtu/hr);
- Ammonia and urea injection rates (lbs/hr) for each of the NO_x control devices;
- Some indication of ammonia slip, whether it is from an ammonia detection monitor or from a qualitative assessment (e.g., ammonia in the ash or scrubber wastewater);
- NO_x emissions prior to the SCRs, if CEMS are in place;
- Differential pressure across the SCR catalysts, where existing monitors are functional; and
- Flue gas temperature at the SCR inlet.

Raven will endeavor to summarize this data (hourly averages where available) within approximately 15 calendar days of the end of each month in the Study period and send it to MDE. Raven will endeavor to identify which days were identified as High Ozone Days.

By October 31, 2014 Raven will endeavor to submit a final report discussing the results of the NO_x reduction Study. The report is anticipated to include the summarized data from above with NO_x expressed in both units of rate (lb/MMBtu) and mass (tons). It should also include the following:

- summarized results of the evaluations each plant performed for NO_x improvements during the Study period;
- a list of High Ozone Days as identified by MDE, and the NO_x emissions from each plant for each day;
- NO_x vs Generation curves for the Study period; and
- Explanations of operational challenges encountered, (e.g., during periods of startup, shutdown, malfunction, or other abnormally high NO_x emission occurrences) and how they were resolved, if able.

Plant NOx Optimization/Testing Plans

BRANDON SHORES

Pre-Study Preparation					
<u>Pulverizers</u> • Inspections, Preventive Maintenance (PM) and Scheduled Rebuilds of pulverizers <u>Boiler</u> • Inspections, Repairs, and PMs on burners • Inspections of duct work and boiler casing and repairs of leaks to maintain flue gas temperature • Inspections, repair and testing of OFA components <u>SCRs</u> • Vacuum catalyst surface • Inspections, Repairs and PMs of NH3 injection grids and associated piping and valves • Balance injection rates across grid, as needed • Inspections, Repairs and PMs of urea-to-ammonia system and NH3 dilution and blower equipment					
Optimization Test Plan					
Action/Test	Long-term vs. Ozone Day	Variables to Change	Parameters to Monitor	Data collection at Loads and Duration	Potential Issues
IN FURNACE					
Tune burners for high load (baseline), balanced, per design	Long-term	Burner settings; excess air	SCR Inlet NOx; Process CO; furnace slagging; LOI in ash	Low, mid & high 3 – 5 days	Detrimental slagging; increased CO and LOI in ash

Test adjustments in OFA quantity or BOOS airflow, if applicable	Long-term/Ozone Day	OFA flow (% of total air); burner settings; excess air	Max Load reached; SCR Inlet NO _x ; Process CO; furnace slagging; LOI in ash	Low, mid & High Load 1 – 3 days	Load limitation; increased CO and LOI in ash
Unit 2-Test max load achieved using BOOS and 1 mill out.	Long-term/Ozone Day	Mill selection; burner setting; air flow to BOOS; excess air; coal flow;	Max Load reached; SCR Inlet NO _x ; Process CO; furnace slagging; LOI in ash	High Load; 1 – 3 days	Load limitation; CO, LOI in ash
Unit 2 – Test 26 Mill as BOOS instead of 23 Mill	Long-term	Mill selection; burner setting; air flow to BOOS; excess air;	SCR Inlet NO _x ; Process CO; furnace slagging; LOI in ash	Low, mid & High Load 3 days	CO, detrimental slagging; increased CO and LOI in ash
SCRs					
Test Urea feed vs. Aq. NH ₃ feed	Long-term/Ozone Day	NH ₃ feed source	Stack NO _x	2 days	Minimizing time for switch over between feeds;
Maximize NH ₃ feed to SCR	Long-term/Ozone Day	NA	All potential restrictions in NH ₃ supply (e.g., trim valves, urea reactor capacity); Stack NO _x ; NH ₃ in scrubber (slip)	3 days	Increase NH ₃ supply, but without adding NH ₃ slip
Increase urea feed rate	Ozone Day	Urea flow	NH ₃ slip; ammonium bisulfate formation (APH ΔP)	1 day	APH pluggage

H.A. Wagner

Pre-Study Preparation					
<u>Pulverizers</u> • Inspections, Preventive Maintenance (PM) and Scheduled Rebuilds of pulverizers <u>Boilers</u> • Inspections, Repairs, and PMs on burners • Inspections of duct work and boiler casing and repairs of leaks to maintain flue gas temperature (Unit 3) • Inspections, repair and testing of OFA components (Unit 3) <u>SNCR (Unit 2)</u> • Inspections, Repairs and PMs of urea storage and delivery equipment • Inspections, Repairs and PMs of urea injection ports/nozzles <u>SCR (Unit 3)</u> • Vacuum catalyst surface • Inspections, Repairs and PMs of urea-to-ammonia system and NH3 dilution and blower equipment					
Optimization Test Plan					
Action/Test	Long-term vs. Ozone Day	Variables to Change	Parameters to Monitor	Data collection at Loads and Duration	Potential Issues
IN FURNACE					

Tune Unit 2 and Unit 3 burners for NOx optimization	Long-term (baseline)	Excess air; OFA registers (U3); burner registers	NOx conc.; Process CO conc.; furnace slagging; LOI in ash	High load 1 – 7 days	Detrimental slagging; increased CO and LOI in ash
Test alternative burner impeller (adjusted angle to optimize NOx over combustion) on Unit 2	Long-term (baseline)	Burner impeller angle; excess air	NOx conc.; Process CO conc.; furnace slagging; LOI in ash	High load 1 – 7 days	Detrimental slagging; increased CO and LOI in ash
Test co-firing natural gas on Unit 2	Ozone Day	Natural gas and coal flows	NOx conc.; CO conc.	All load range; 2 - 10 days	Supply (pressure) of natural gas when Unit 1 is on gas.
NOx Controls					
Test higher urea injection/load level (higher slip) on Unit 2	Long-term/Ozone Day	Ammonia Slip target/Urea injection.	NOx conc.; NH3 slip conc. and/or Fly ash ammonia odor;	All load range; 1 – 7 days	NH3 slip; ash quality
Test earlier introduction of NH3 during startup of Unit 3	Long-term	Keep bypass damper closed (longer/sooner) during shutdowns/startups; NH3 injection earlier during startup	NOx conc.; NH3 slip conc. and/or Fly ash ammonia odor	During Startups	NH3 slip; furnace pressure issues during startup.
Test lower outlet NOx setpoint; higher NH3 injection/load level (higher slip) on Unit 3	Ozone Day	NOx Outlet set point	NOx conc.; NH3 slip conc. and/or Fly ash ammonia odor	All load range; 4 - 7 days	NH3 slip; ash quality

C.P. Crane

Pre-Study Preparation					
Boilers • Inspections, Repairs, and PMs on cyclones, including primary and secondary air dampers • Inspections, repair and testing of OFA components					
<u>SNCRs</u> • Inspections, Repairs and PMs of urea storage and delivery equipment • Inspections, Repairs and PMs of urea injection ports/probes • PM ammonia slip meters					
Optimization Test Plan					
Action/Test	Long-term vs. Ozone Day	Variables to Change	Parameters to Monitor	Data collection at Loads and Duration	Potential Issues
IN FURNACE					
Tune cyclone for high load, balanced, per design	NA (baseline)	Burner settings; excess air	NOx Conc.; CO conc.; furnace slagging; LOI in ash	Low, mid & high 3 – 5 days	Detrimental slagging; increased CO and LOI in ash
Test Stoichiometry from 0.95 down to 0.88 with constant urea/load control on 100% PRB	Long-term/Ozone Day	Stoichiometry	NOx conc.; CO conc.; Hg conc.; slagging; Max load achieved	All load range; 2 – 3 weeks	High CO at low Stoich; high Hg at high Stoich; Load limitation on Low Stoich.
Test Stoich. Effects on Unit 2 with a blend of	Ozone Day	Stoichiometry	NOx conc.; CO conc.; Hg conc.; slagging; Max load achieved	Load > 200 MWg; 2 – 5 days	

NAPP/PRB achieving max load (same as above test)					
SNCRs					
Test higher urea injection/load level (higher slip)	Long-term/Ozone Day	Ammonia Slip target/Urea injection.	NOx conc.; NH3 slip conc.; Fly ash quality;	All load range; 1 – 7 days	NH3 slip; ash quality; baghouse ΔP
Test higher urea concentration at injector (less diluted)	Long-term/Ozone Day	Urea conc. At injector; urea injection flow rate; injector level selection (500, 600 or 800 level).	NOx conc.; NH3 slip conc.; Fly ash quality;	All load range; 1 – 7 days	Injector nozzle plugging/spray patterns
Optimize injection levels	Long-term/Ozone Day	Urea flow to each injection level	NOx cond. NH3 slip conc.	All load ranges; 1 – 7 days	Nozzle pluggage; baghouse ΔP

Appendix G

NOx Emission Reduction Calculations

MDE staff

Phase 1 calcualtions based on historic 2011-2013 capacity
MDE

Projected Reductions													
EGU	2011 OS Heat Input MMBtu	2011 OS Nox Tons	2012 OS Heat Input MMBtu	2012 OS Nox Tons	2013 OS Heat Input MMBtu	2013 OS Nox Tons	Baseline HI OS Avg mmbtu (11-13 avg)	Baseline Nox tons (11-13 avg)	Baseline Nox Rate lb/mmbtu	Indicator Rates	Projected REG OS Tons @ Indictor Rate	Projected REG OS Tons @ Indictor Rate & Optimization	
Brandon 1	1.46E+07	613.82	1.62E+07	726.77	1.20E+07	485.85	1.43E+07	608.81	0.09	0.08	570.09	570.09	
Brandon 2	1.58E+07	762.21	1.43E+07	892.17	1.19E+07	628.43	1.40E+07	760.94	0.11	0.07	489.88	489.88	
Wagner 2	2.77E+06	516.03	2.19E+06	475.12	1.20E+06	251.35	2.05E+06	414.17	0.40	0.34	349.06	349.06	
Wagner 3	6.47E+06	204.24	4.91E+06	154.72	5.88E+06	174.26	5.75E+06	177.74	0.06	0.07	201.31	177.74	
Crane 1	3.27E+06	688.92	2.79E+06	573.73	1.63E+06	344.27	2.56E+06	535.64	0.42	0.30	384.60	384.60	
Crane 2	3.90E+06	810.97	3.27E+06	668.94	2.44E+06	658.65	3.20E+06	712.85	0.45	0.28	448.39	448.39	
Chalk Point 1	6.34E+06	529.19	5.73E+06	517.96	5.12E+06	404.51	5.73E+06	483.89	0.17	0.07	200.52	200.52	
Chalk Point 2	8.65E+06	988.38	3.58E+06	408.58	5.80E+06	630.94	6.01E+06	675.97	0.22	0.33	992.02	675.97	
Dickerson 1	2.19E+06	273.15	2.03E+06	263.04	1.27E+06	173.65	1.83E+06	236.61	0.26	0.24	182.83	182.83	
Dickerson 2	2.51E+06	312.28	1.76E+06	227.62	1.32E+06	181.59	1.86E+06	240.50	0.26	0.24	186.31	186.31	
Dickerson 3	2.79E+06	344.77	2.12E+06	269.55	1.37E+06	189.18	2.09E+06	267.83	0.26	0.24	209.31	209.31	
Morgantown 1	1.27E+07	244.74	9.46E+06	152.23	9.40E+06	112.29	1.05E+07	169.76	0.03	0.07	368.03	169.76	
Morgantown 2	1.51E+07	233.31	1.30E+07	194.70	8.43E+06	148.52	1.22E+07	192.18	0.03	0.07	425.68	192.18	
All Facility Totals	9.71E+07	6522.01	8.13E+07	5525.11	6.77E+07	4383.49	8.20E+07	5476.87	0.13		5008.00	4236.60	
All Facilites Avg. Tons/Day								35.80			32.73	27.69	Tons/Day
Note all data from CAMD OS Season total data											468.86	1240.27	Tons Total
											3.06	8.11	Tons/Day Reduction
											8.56%	22.65%	

Appendix H

COMPLIANCE PLAN

26.11.38

Description of what needs to go into the Plan referred to in 26.11.38.03A(1):

The Plan shall summarize the data that will be collected to demonstrate compliance with COMAR 26.11.38.03A(2), which states that beginning on May 1, 2015, for each operating day during the ozone season, the owner or operator of an affected electric generating unit shall minimize NO_x emissions by operating and optimizing the use of all installed pollution control technology and combustion controls consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 C.F.R. § 60.11(d)) for such equipment and the unit at all times the unit is in operation while burning any coal.

The Plan shall be fully enforceable by the Department and cover all modes of operation, including but not limited to normal operation, start –up, shutdown, and low capacity operation.

The Plan shall describe how each affected unit will minimize NO_x emissions during each mode of operation.

For start-up and shutdown operation, the plan shall be fully enforceable by the Department and include for each affected unit, at the minimum, a definition of the completion of startup and commencement of shutdown based on MW, general start-up and shutdown procedures for the boiler, the temperature at which NO_x controls become effective, the MW at which the temperature required for NO_x controls to become effective occurs, the duration of time that the affected unit will operate in each of those modes, ramping rates, all measures taken to minimize NO_x emissions during each of those modes, and any information deemed necessary by the Department upon review of the submitted plan.

For low capacity operation, the plan shall be fully enforceable by the Department and include for each affected unit, at the minimum, measures taken to minimize emissions during this mode of operation, and any information deemed necessary by the Department upon review of the submitted plan.

For normal operation, the plan shall be fully enforceable by the Department and include for each affected unit, at the minimum, how the use of all installed pollution control technology and combustion controls will be optimized, general startup and shutdown procedure for the NO_x control technology, the control strategy for the NO_x control technology including percent control setpoints and a description of any cascade control, expected range of NO_x control technology reagent injection rates, and any information deemed necessary by the Department upon review of the submitted plan.

All requirements and indicators included in an approved plan shall be fully enforceable by the Department under the terms of the regulation.

Appendix I

Collaborative Solution to the Ozone Transport Problem

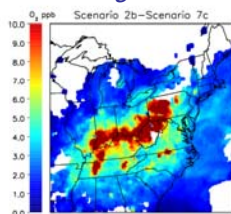
Tad Aburn, Air Director, MDE



Maryland's Proposal for a Collaborative Solution to the Ozone Transport Problem

September 2014 Update

Technical and Policy Framework for Resolving the Issue Through Complementary "Good Neighbor" and "Attainment" SIPs



Tad Aburn, Air Director, MDE
Air Directors Technical Collaborative – September 4, 2014

Martin O'Malley, Governor | Anthony G. Brown, Lt. Governor | Robert M. Summers, Ph.D., Secretary



Topics

- Background
- Why is Maryland Pushing so Hard for "Good Neighbor" Partnerships?
- Technical Analyses to Date
 - Maryland's Modeling and Analysis of Emissions Data
- Maryland's efforts to further reduce emissions from local mobile sources and other emission sectors
- Our Ask of Upwind States
- Timing and Future Efforts
- Discussion





Background – Ozone Transport

- Many, many balls in the air
 - Supreme Court has acted
 - Not real clear on what happens next
 - “Expand the OTR” Petition under Section 176A of the Clean Air Act (CAA)
 - Challenges to EPA over large nonattainment areas (CAA Section 107)
 - Challenges to EPA over “Good Neighbor” SIPs (CAA Section 110A2D)
 - EPA’s Transport Rule Process
 - A collaborative effort between upwind and downwind states to address the ozone transport issue
- Remainder of this presentation will focus on the collaborative effort



Page 3



Background – The Collaborative

- On August 6, 2013- Approximately 30 Air Directors participated in a call to begin a technical collaboration on ozone transport in the East
- There was discussion ... and general agreement ... on beginning technical analyses of a scenario (called “Phase 1”) that would try and capture the progress that could be achieved if:
 - The EPA Tier 3 and Low Sulfur Fuel program is effectively implemented
 - The potential changes in the EGU sector from shutdowns and fuel switching driven by MATS, low cost natural gas and other factors were included
 - The potential changes in the ICI Boiler sector driven by Boiler MACT and low cost natural gas were also included
 - There was also general agreement that, at some point, Commissioner level discussions may take place
- In early April 2014, preliminary discussions between Commissioners began
 - Discussions continue ... potential meeting in October



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Why Is MD Pushing So Hard

- Only state East of the Mississippi designated as a “Moderate” nonattainment area by EPA
- Baltimore is the only nonattainment area in the East required to submit an “Attainment” SIP by June of 2015
 - This SIP must be supported by an “Attainment Demonstration”
 - The Attainment Demonstration must be based upon photochemical modeling and other technical analyses
 - It must show that monitors in the Baltimore area are expected to comply with the ozone standard by 2018
- We have enough modeling and technical analysis completed to understand what Maryland needs in its plan to bring the State into attainment
 - This analysis also shows that most other areas in the East should also attain



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The Key Elements of Maryland's Plan

- Number 1 Need – The Tier 3 Mobile Source and Fuel Standards
 - The most important new program to reduce high ozone in Maryland
- Number 2 – Additional local reductions in Maryland and close-by neighboring states to reduce mobile source emissions
 - New mobile source efforts in the Ozone Transport Region and new Maryland control programs are on the books or in the works
- Number 3 - Good Neighbor SIPs or Commitments to address transport
 - Analysis shows that if power plants in upwind states simply run the controls that have already been purchased ... during the core ozone season ... and planned retirements occur ... that transport for the current ozone standard will be addressed



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Addressing Mobile Sources and ...

... “along the I-95 corridor” controls

- Maryland’s modeling looks at more than just upwind power plants
- New federal control programs for mobile sources, like the Tier 3 vehicle and fuel standards, are critical
- Maryland’s plan ... and the modeling ... includes new controls just in the OTR like:
 - California car programs
 - Aftermarket catalyst initiatives
 - RACT requirements
 - Consumer products and paints
 - Diesel Inspection and Maintenance
 - Non-traditional control efforts
 - Many more

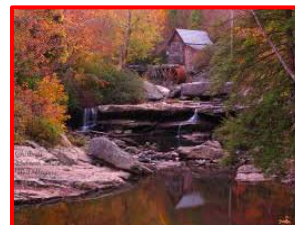


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Modeling the Maryland Plan

- Maryland has conducted preliminary modeling of the Plan and believes that the Plan will allow MD to come very close to meeting the 75 ppb ozone standard
 - Will most likely also allow most other areas in the East to attain the standard by 2018
- MD’s modeling has been conducted primarily with the OTC platform that uses 2007 as the base year and 2018 as the attainment year
 - MD is updating the modeling to use the newer platform based upon EPA modeling efforts
 - This platform uses 2011 as the base year and 2018 as the attainment year
- Based upon early comparisons, it appears that modeling with the new platform will generate consistent results and may, in many areas, show even greater ozone benefits



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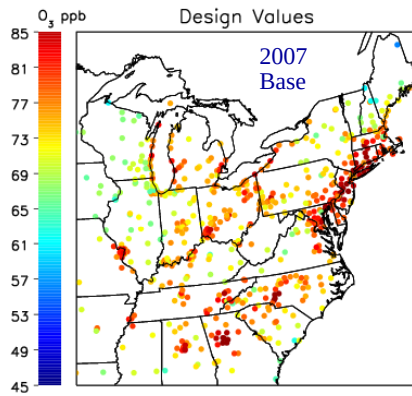




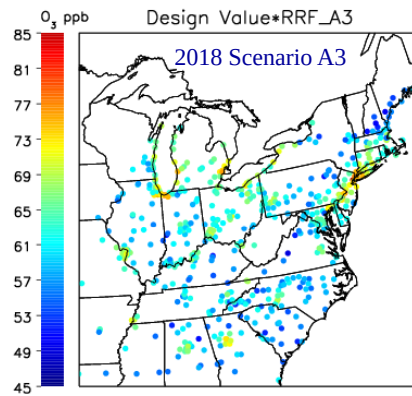
The Bottom Line

*Maryland's plan is currently being modeled as
"Attainment Run #3" or "Scenario A3"*

Before Scenario A3



After Scenario A3



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Bottom Line by Monitor

... Before and After Scenario A3

County	Design Value 2007	After Scenario A3 2018
Harford, MD	90.7	74.7
Prince Georges, MD	85.3	65.1
Fairfield, CT	88.7	70.8
New Castle, DE	81.3	66.3
Bucks, PA	90.7	76.8
Suffolk, NY	88.0	71.0
Camden, NJ	87.5	74.2
Fairfax, VA	85.3	66.9
Franklin, OH	84.7	69.7
Fulton County, GA	90.3	73.7
Wayne, MI	81.3	74.5
Sheboygan, WI	83.3	70.8
Mecklenberg Co, NC	87.0	67.6
Knoxville, TN	80.7	70.7
Jefferson County, KY	80.0	67.0
Lake County, IN	77.5	77.4
Cook County, IL	77.0	75.0

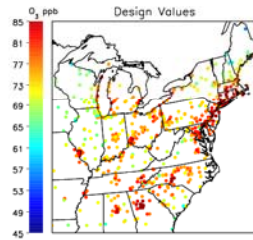
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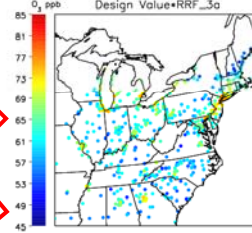


Building the Clean Air Plan

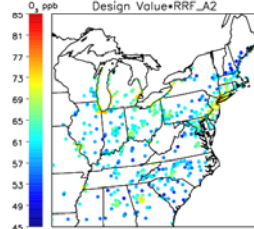
The 2007 Base



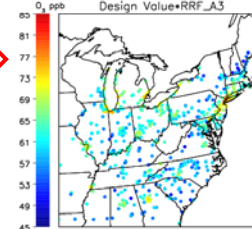
Add the regional controls across the East (Scenario 3a)



Add the "OTR" controls along I 95 corridor (Scenario A2)



Add the new controls just in MD (Scenario A3)



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Updated CMAQ Chemistry?

- For years, Maryland and the University of Maryland have been analyzing model performance aloft, where most transport takes place ... Not always great
- Also analyzing measured data to look at mobile source inventories
- In 2011, the Discover AQ field study in the Mid-Atlantic provided new unique data aloft
- U of M has analyzed aloft chemistry and found some problems with nitrogen chemistry
 - Fails to carry NOx reduction benefits downwind
- Working on new aloft chemistry concepts ... Also looking at inconsistencies in mobile source inventories
 - Will show small, but important additional benefits from regional scale NOx strategies
 - Maybe an extra 1 or 2 ppb benefit in Maryland



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A Little More Detail

- Scenario A3 includes control measures to address local emissions and transport. It includes the following:
 - Implementation of the federal Tier 3 vehicle and fuel standards across the East
 - Implementation of all “on-the-books” federal control programs across the East
 - Implementation of new and old “Inside the Ozone Transport Region” control measures like the new OTC Aftermarket Catalyst initiative and continued implementation of California car standards
 - Implementation of new local measures in certain states like Maryland, Connecticut and New York
 - Good Neighbor SIPs or commitments from 10 upwind states to insure that power plants run previously purchased controls during the core summer ozone season



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Running Power Plant Controls Effectively

- Maryland and several other states have analyzed power plant (Electric Generating Unit or EGU) emissions data from Continuous Emissions Monitors (CEMS) to see how well existing pollution controls are being run
- Changes in the energy market, a regulatory system that is driven by ozone season tonnage caps and inexpensive NO_x allowances have created an unexpected situation where many EGU operators can meet ozone season tonnage caps without operating their control technologies efficiently
 - Sometimes not at all



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How the EGU Data Analysis Was Built

- Maryland began the data analyses in late 2012
 - Looked at EGUs in the 9 upwind states named in the 176A Petition (IL, IN, KY, NC, MI, OH, TN, VA, WV) ... MD and PA
- Shared a draft with Air Directors on April 21, 2013
 - The April 2012 package focused on a bad ozone episode (8 days) in 2011
 - Received comments from numerous states
- Shared a second draft with Air Directors on May 13, 2013
 - This package added a second bad ozone episode in 2012 (10 days) and updated earlier materials – additional comments received
- The 2011 and 2012 episodes analyzed capture two of the worst ozone periods in 2011 and 2012
 - Other states, like Wisconsin and Delaware have done similar analyses and reached similar conclusions
- Third updated, data packages to Air Directors soon
- Using West Virginia EGUs as an example
 - West Virginia has an interesting story

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Summary of Generation in WV - 2012

- Total number of units = 60
- Total heat input capacity = 173,267MMBTU/hr = 17,586 MW
- Total State MW Capacity in %
 - Total number of Coal units = 35 = 88%
 - Total number of NG units = 20 = 9%
 - Total number of other (oil, etc.) units = 5 = 3%
 - Total number of Nuclear units = 0 = 0%
- Total Capacity Coal = 15,489 MW
 - 15 units with SCR = 11,755 MW = 76%
 - 4 units with SNCR = 496 MW = 3%
 - 16 units without SCR/SNCR = 3,237 MW = 21%



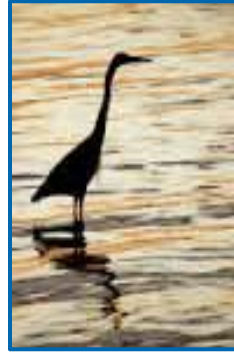
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Summary of Generation in WV - 2018

- Total number of units = 39
- Total heat input capacity = 143,851 MMBTU/hr = 14,493 MW
- Total State MW Capacity in %
 - Total number of Coal units = 19 = 90%
 - Total number of NG units = 20 = 10%
 - Total number of other (oil, etc.) units = 0 = 0%
 - Total number of Nuclear units = 0 = 0%
- Total Capacity Coal = 12,946 MW
 - 15 units with SCR = 11,648 MW = 90%
 - 2 units with SNCR = 191 MW = 1.5%
 - 2 units without SCR/SNCR = 1,107 MW = 8.5%

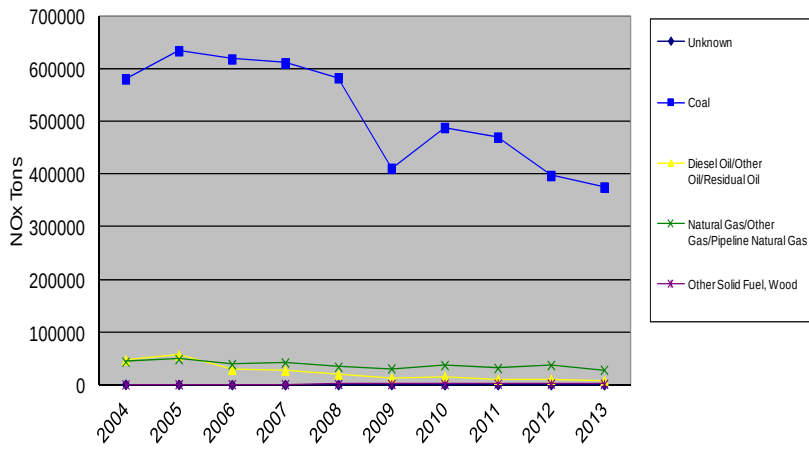


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The MD Analyses Focus on Coal

NOx Emissions by Primary Fuel Type - Ozone Season - Eastern U.S.



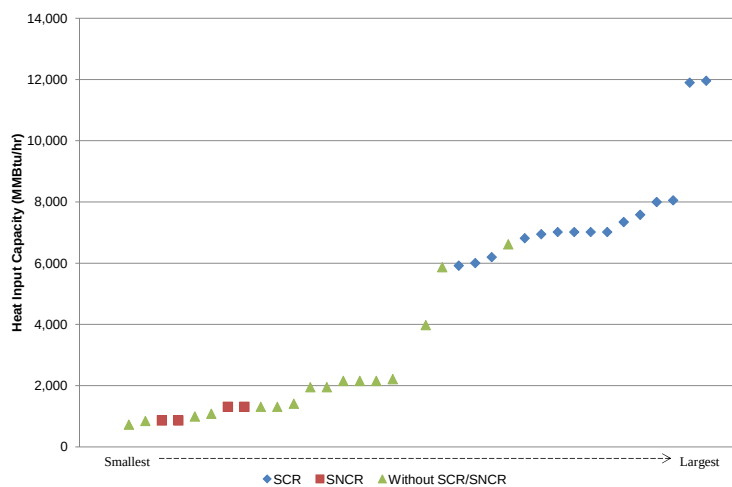
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Controls on Coal WV Units - 2012

... by size ... smallest to largest

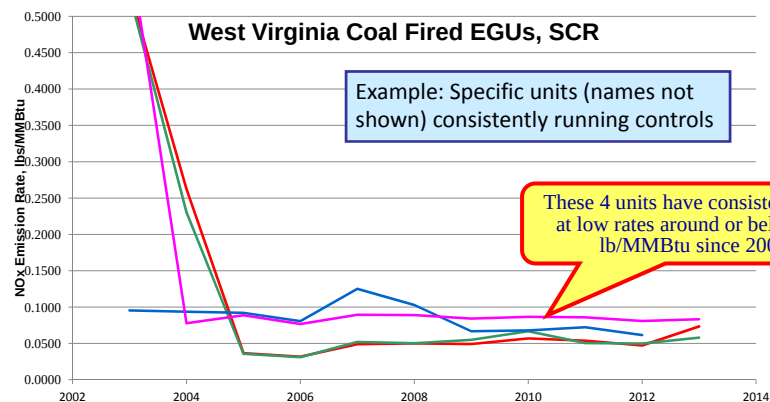


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Running Controls

Average Ozone Season Emission Rates at Specific Units by Year



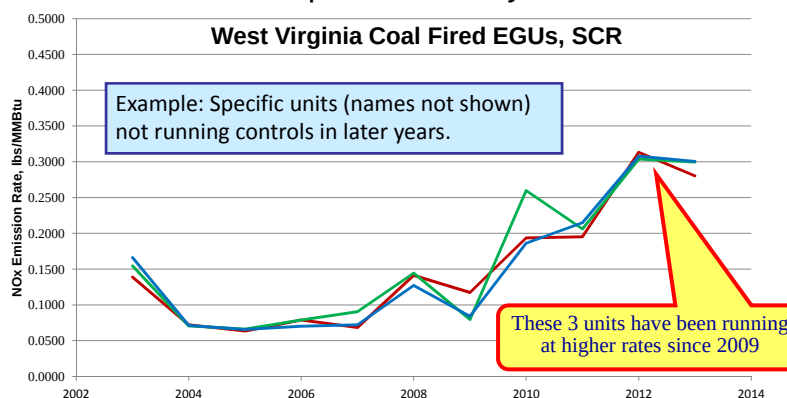
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Not Running Controls as Well

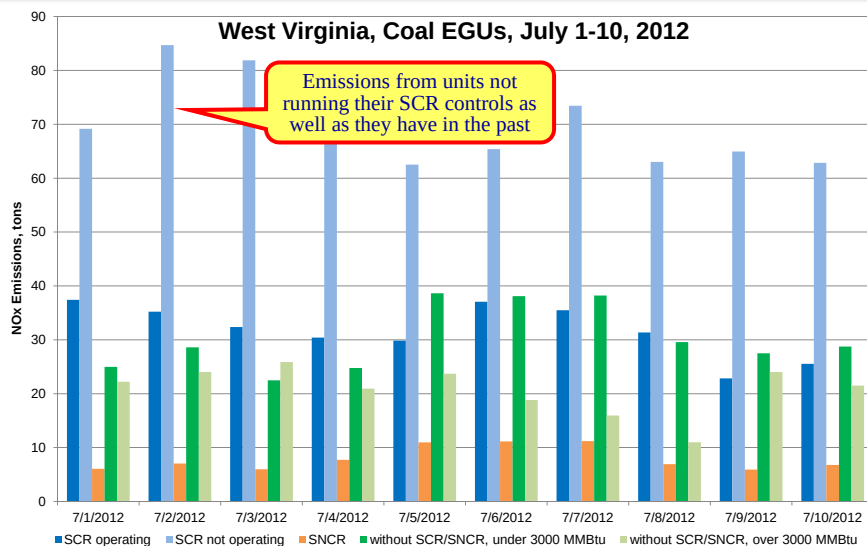
Average Ozone Season Emission Rates at Specific Units by Year



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Actual Emissions – July 1 to 10, 2012

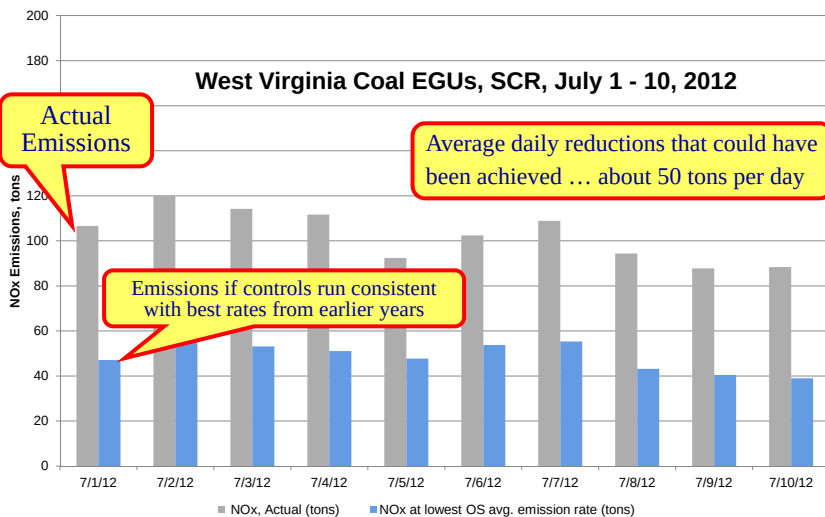


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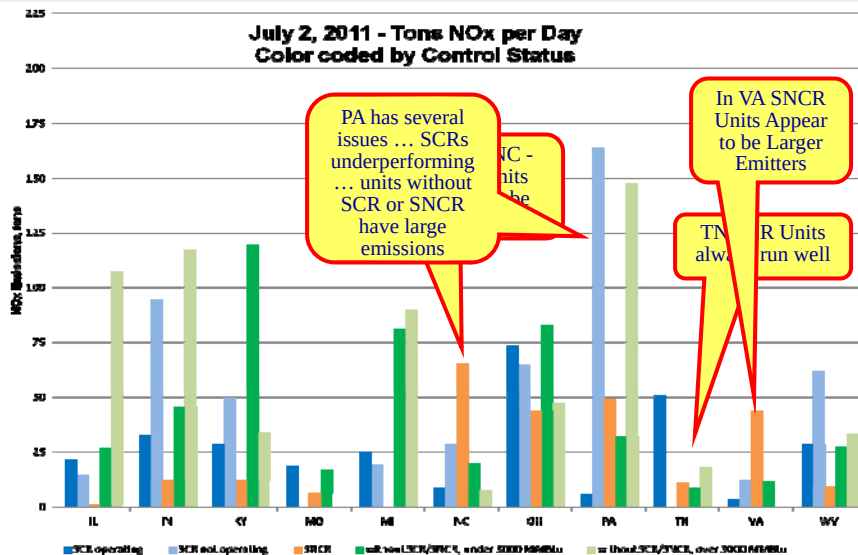
Reductions That Could Have Been Achieved



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11 State Emissions



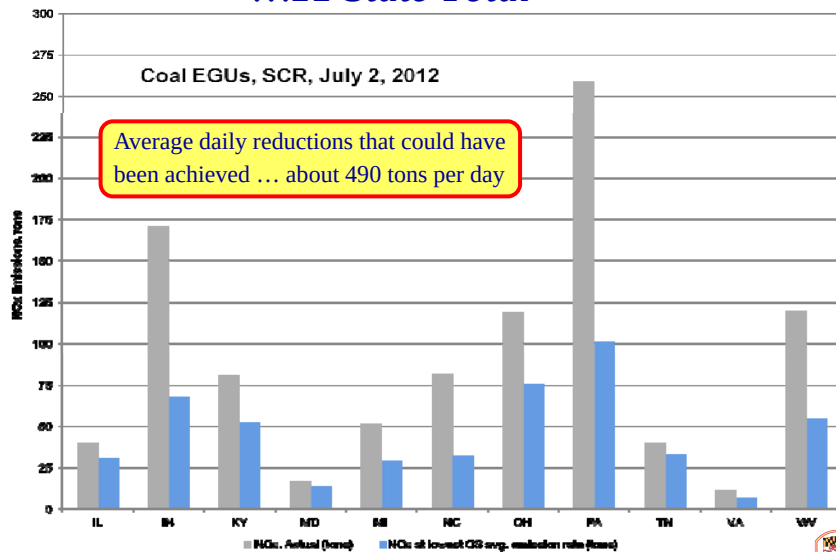
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Reductions That Could Have Been Achieved

...11 State Total



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How Might This Affect Ozone?

- Maryland has performed several very preliminary model runs to look at how much running EGU controls inefficiently might increase ozone levels
- Three runs:
 - Scenario 2B – A worst case run
 - Assumes SCR and SNCR controls are not run at all
 - Scenario 3B – A worst data run
 - Assumes SCR and SCR units all run at worst rates seen in CAMD data - 2005 to 2012
 - Scenario 3C – Based upon CAMD data analysis for EGU performance in 2011 and 2012
 - Assumes that units that had higher ozone season emission rates were operating at the best ozone season rates observed since 2005



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These are Preliminary Runs ...

... as the modeling improves some of the details will change, but the overall conclusions will not

- These are sensitivity runs
 - They are not perfect, but they are clearly meaningful and policy relevant
- From our 2007 platform
 - One month screening runs
 - Input data continues to be enhanced



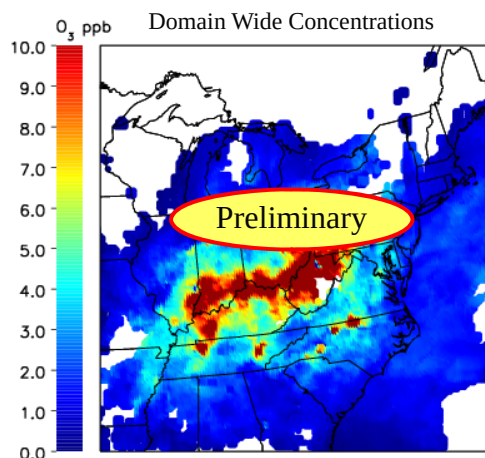
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Lost Ozone Benefits – Worst Case

... no SCR or SNCR controls run at all

- Difference plot between ... 2018 with and without controls



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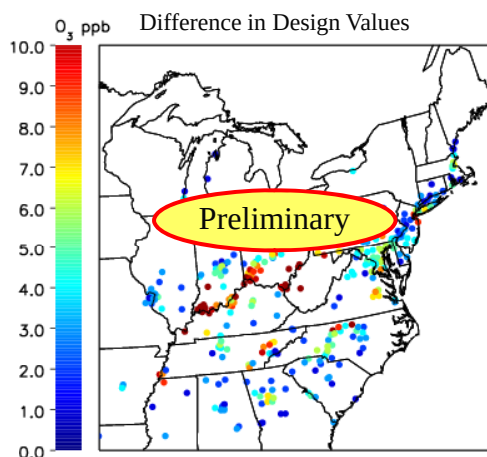




Lost Ozone Benefits – Worst Case

... no SCR or SNCR controls run at all

- Difference plot ... DVs ... 2018 with and without controls



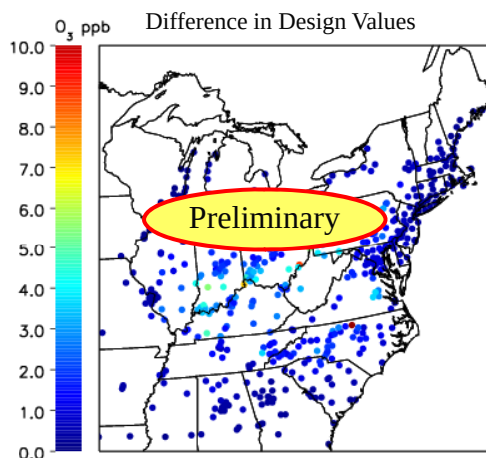
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Lost Ozone Benefits – Worst Data

... SCR or SNCR controls run at highest rates in CAMD data

- Difference plot ... DVs ... 2018 with and without controls



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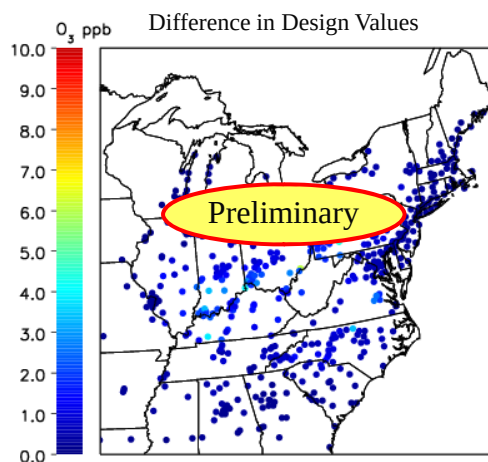




Lost Ozone Benefits – 2011/2012

... based upon 2011 and 2012 CAMD
EGU performance data

- Difference plot ... DVs ... 2018 with and without controls



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Lost Ozone Benefit in PPB

Most Difficult Monitors	Increased Ozone in 2018 – 3 EGU Control Scenarios		
	Worst Case – No SCRs or SNCRs (Scenario 2B)	Using worst rate CAMD Data (Scenario 3B)	Using actual 2011/2012 Data (Scenario 3C)
Harford, MD	4.3	1.2	0.5
Prince Georges, MD	4.6	1	0.5
Fairfield, CT	2	0.3	0.1
New Castle, DE	3.8	0.8	0.4
Bucks, PA	3.1	0.6	0.4
Suffolk, NY	2	0.4	0.2
Camden, NJ	2.7	0.5	0.3
Fairfax, VA	4.4	1	0.5
Franklin, OH	5	0.5	1
Fulton County, GA	2.3	0.3	0.2
Wayne, MI	1.6	0.5	0.2
Sheboygan, WI	1.5	0.1	0.1
Mecklenberg Co, NC	4.1	1.8	1.2
Knoxville, TN	4	0.7	0.5
Jefferson County, KY	6.7	2	1.5
Lake County, IN	1.1	0.2	0.1
Cook County, IL	0.8	0.2	0.1

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Lost Ozone Benefit – Clean Monitors

... EPA will propose a new ozone standard soon ... 60 to 70 ppb range ... designations to most likely be based upon 2014 to 2016 or 2015 to 2017 data

County	2018 – Controls Running Well (Scenario 3A)	Increased Ozone in 2018 – 3 EGU Control Scenarios		
		SCRs or SNCRs (Scenario 2B)	Using worst rate CAMD Data (Scenario 3B)	Using actual 2011/2012 Data (Scenario 3C)
Blair, PA	58.7	76.5	64	62.7
Armstrong, PA	66.4	79.8	70.7	68.8
Washington, OH	60.1	80.5	68.9	66.2
Warren, OH	68.8	79.8	72.1	70.9
Kanawa, WV	64.5	80.2	67.8	66.3
Monogalia, WV	61.4	77.1	64.4	63.1
Oldham, KY	67.2	77.1	70.2	69.1
Boone, KY	57.5	77.2	64.7	61.6
Campbell, KY	61.6	71.3	64.3	63.3
Greene, IN	61.8	84.4	67.3	65.2
Vanderburgh, IN	62.3	74.0	65.8	64.7
Person, NC	60.2	78.1	71.7	63.6
Garrett, MD	58.7	75.9	62.6	61.1

Preliminary

Greater than 70 ppb

65 to 70 ppb

60 to 65 ppb



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Next Steps With this Modeling

- Run for full ozone season
- Run some regional sensitivity tests
- Run with enhanced chemistry and mobile source adjustments from research
 - This will show slightly greater loss of benefit from not always running controls effectively
- Run with 2011/2018 Platform ASAP
- Work with the Midwest Ozone Group (MOG) on this issue
 - Modeling and potential solution
- Continue to refine as part of the Maryland Attainment SIP



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So where do we go from here?



Maryland's Push

... can we work together to submit complementary SIPs?

- The current modeling tells us we are very close to meeting the 75 ppb ozone standard
- New modeling between now and the first half of 2015 will support, supplement and strengthen this conclusion
- EPA's process will not resolve this issue before 2015
- In 2015 ... areas like Baltimore owe Attainment SIPs and modeling
- All states owe "Good Neighbor" SIPs
 - They were actually due in 2011
- Maryland is pushing ...very hard ... on "A package of complementary Attainment and Good Neighbor SIPs" to be finalized in late 2014 or early 2015
 - We have been pushing this since early 2013





How Do We Move Forward?

- Clearly continue the technical collaboration
- Continue Commissioner level discussions when needed
- Begin more serious discussion on making sure EGU controls are run effectively when needed to reduce high ozone levels
- Maryland's push ...
 - Upwind and downwind states submit a package of complementary SIPs in 2015
 - Attainment SIPs from states like Maryland
 - Good Neighbor SIPs from others
 - Supported by collaborative modeling
 - Could "trump" an EPA Transport Rule, alter the 110A2D challenges and the 176A Petition and influence any "CSAPR 2" initiative



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Running EGU Controls Effectively

- Maryland has heard from many Air Directors that they are interested in looking at this issue
- MOG has expressed an interest in working with us on this issue
- Discussion between several Air Directors has already started
 - We can build from those ongoing discussions
- Key Issues
 - How to define "run the controls"?
 - What time frame? – the ozone season? – the core ozone season?
 - How to implement?
 - Good Neighbor SIPs
 - Voluntary agreements with sources
 - Permits
 - Section 126 Petitions
 - Other mechanisms



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Timing

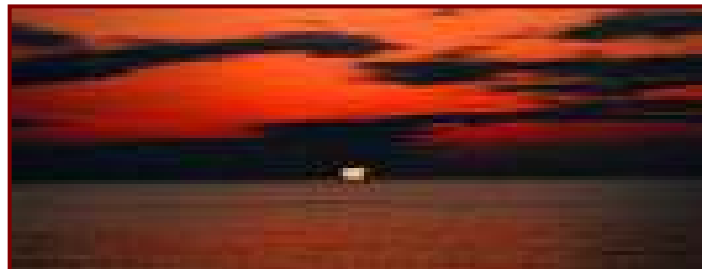
- Maryland Straw Proposal
 - 2014 to Spring 2015
 - Technical collaboration and stakeholder discussions continue
 - Summer 2014 to Spring 2015
 - Commissioner level discussions
 - End of 2014
 - Technical work to support “Complementary Package of SIPs” approaches near “SIP Quality” status
 - Spring 2015 - States submit SIPs
 - This timing works for MD’s SIP, but may also be critical if the “State Solution” is to influence an EPA transport rule, the 176A Petition or son or daughter of CSAPR



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Thanks



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