Department of the Environment

TECHNICAL SUPPORT DOCUMENT

FOR

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

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Amendments to Control of NO_x Emissions from Coal-Fired EGU's
COMAR 26.11.38

I. Introduction

A. Ozone NAAQS and Designations

On March 12, 2008, the U.S. Environmental Protection Agency (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 75 ppb 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 EPA's nonattainment classifications.

1. <u>Baltimore area – "moderate" nonattainment area</u>
   This area includes: Anne Arundel County, Baltimore County, Baltimore City, Carroll County, Harford County, and Howard County.

2. <u>Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE – "marginal" nonattainment area</u>
   This area includes one jurisdiction in Maryland: Cecil County.

3. <u>Washington, DC-MD-VA – "marginal" nonattainment area</u>
   This area includes: Calvert County, Charles County, Frederick County, Montgomery County, and Prince George's County.

Under federal 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 was required to submit a state implementation plan (SIP) revision by June 2015 that included an attainment demonstration. On June 1, 2015 EPA recognized that monitored data from the Baltimore nonattainment area showed compliance with the 2008 8-hour ozone standard for the 2012-2014 monitoring period and published a final "Clean Data Determination" for the Baltimore nonattainment area (80 FR 14041). Due to this Clean Data Determination, the requirement to submit an attainment demonstration and associated documents related to attainment of the standard are suspended for as long as the area continues to attain the 2008 8-hour ozone standard. This suspension remains in effect until: 1) such a time, if ever, that EPA redesignates the area to attainment, or 2) subsequently determines that the area has violated the standard. Mild weather played a role in the cleaner monitored data seen in 2013 and 2014. The Maryland Department of the Environment (MDE or the Department) recognizes the clean data may not endure and is continuing to develop the moderate area attainment demonstration and SIP. If monitoring data shows nonattainment in the future, the Clean Data Determination will be rescinded and the attainment SIP will again be required.

The other ozone nonattainment areas in Maryland have also shown very promising monitored data. On August 19, 2015 EPA proposed a 1 year extension for the Maryland portion of two multi-state nonattainment areas (Washington, DC and Philadelphia). Maryland has one monitor in each area that, through 2014, was just above the standard. EPA rules only allow this kind of an extension when data shows the monitors in the area of concern are at or below the standard for the attainment year.

Whenever EPA establishes a new ozone standard, states with an ozone nonattainment area of "moderate" or higher classification must consider technological advances, the stringency of the revised ozone standard, and the presence in the nonattainment area of new sources subject to reasonably available control technologies. 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	7/20/18†
Philadelphia – Wilmington – Atlantic City	07/20/12	Cecil	Marginal	7/20/15**
Washington DC	07/20/12	Calvert Charles Frederick Montgomery Prince George's	Marginal	7/20/15**

*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.

† Updated as of August 19, 2015.

** In August 2015, EPA proposed an extension to 7/20/2016.

Ozone is produced when volatile organic compounds (VOCs) and nitrogen oxides ($NO_{x)}$ react in the presence of heat and sunlight. MDE has found through a research partnership with the University of Maryland that NO_x reductions are more effective at reducing ozone levels than VOC reductions. Under the CAA, sources in ozone nonattainment areas are subject to enforceable emission limitations and control measures appropriate to attain and maintain the applicable ozone standard. Maryland has been working with the industries and the public to implement measures to reduce NO_x emissions for over 20 years. Modeling shows how the existing measures and future measures will help the state meet the current ozone standard.

On November 25, 2014, EPA proposed adoption of a lower ozone standard in the range of 65 to 70 ppb. The proposed updates will improve public health protection, particularly for children, the elderly, and people of all ages who have lung diseases such as asthma. The updates also will improve protection for trees, plants, and ecosystems. A large body of scientific evidence, spanning several decades is reviewed in the EPA's Regulatory Impact Analysis (RIA), found at the link mentioned below. By court order, the EPA must finalize the standard by October 1, 2015.

References

http://www.epa.gov/airquality/ozonepollution/implement.html
http://www.epa.gov/ozonedesignations/2008standards/state.htm
http://www.epa.gov/groundlevelozone/actions.html
http://www.epa.gov/ozonepollution/pdfs/20150819fr.pdf

B. Maryland Historic Design Values

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 (HAA). Again, recent studies of ozone chemistry have shown that NO_x reductions are the most effective strategy for reducing ozone levels in Maryland.

The progress the State has made on air pollution over the past 10 years is remarkable. In recent years Maryland has implemented the Maryland HAA, the toughest power plant emissions law on the East Coast, and the Maryland Clean Cars Program. Maryland power plants have invested $2.6 billion in technology to comply with the Maryland HAA. In addition, Maryland has implemented the Federal Tier 2 Vehicle Standards that have dramatically reduced NO_x from mobile sources starting in 2004.

Ground-level ozone levels dropped in Maryland and many other eastern states after 2004 due to the NO_x SIP call that drove deep NO_x reductions at power plants across 22 states in the East. 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 East resulting in much lower ozone pollution. See Chapter VI for additional historic background on ozone pollution.

Maryland achieved statewide attainment of the fine particulate standard in 2008. As noted above, this year, for the first time in more than three decades, the EPA found that the metropolitan Baltimore area is meeting the current ozone standard. Data shows that the area did not exceed the current ozone standard for the first time since measurements began in 1980.

Stricter controls on local emissions, such as this regulatory action, and federal and regional controls on upwind sources of emissions will be needed to attain and maintain compliance with the current and pending ozone standards.

References

http://www.mde.maryland.gov/programs/air/pages/md_haa.aspx

http://www.epa.gov/ttn/naaqs/ozone/rto/sip/index.html
http://www.epa.gov/airquality/greenbk/adden.html

C. Health and Environmental Impacts

1. 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 nitrogen dioxide (NO_2) exposure. These health benefits include fewer asthma attacks, hospital and emergency room visits, lost work and school days, and lower premature mortality.

2. Impacts on the Chesapeake Bay

More than one-third of the nitrogen 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 will reduce the amount of nitrogen entering the Bay each year.

3. Impacts on Vegetation and Agriculture

Exposure to ozone has been associated with a wide array of adverse impacts on vegetation and the ecosystem. These effects include those that damage or impair the intended use of the plant or ecosystem. 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

This action is expected to reduce NO_x emissions and is part of a series of initiatives that will allow Maryland to attain and maintain compliance with the current ozone standard. As noted above, Maryland has three nonattainment areas under the 2008, 75 ppb ozone standard. As described earlier, MDE has found through a research partnership with the University of Maryland that NO_x reductions are more effective at reducing ozone levels than VOC reductions. Sources in ozone nonattainment areas are subject to enforceable emission limitations and control measures appropriate to attain and maintain the applicable standard. (See Appendix A - POWER PLANT CONTROLS IN MARYLAND - MDE PRESENTATION TO AQCAC – 8/5/2015 for more detailed information).

NO_x emissions from coal-fired electric generating units (EGUs) continue to comprise a large percentage of ozone season NO_x emissions - in large part due to high electricity demand days. In order to address NO_x emissions during the 2015 ozone season, the Department promulgated emergency regulations under COMAR 26.11.38 that became effective on May 1, 2015. Because emergency regulations are only effective for 180 days, the Department concurrently proposed identical regulations through the normal regulatory adoption process (Phase I). The Notice of Final Action for the Phase I regulations was published on August 21, 2015, and the regulations became effective on August 31, 2015.

This regulatory action (Phase II or proposed regulations) is designed to achieve further NO_x emission reductions beyond 2015. Phase II requires the owner or operator of units that have not installed SCR technology to choose from four options which are detailed in Section III below. The proposed regulations will result in increased public health protections.

In addition to these regulations, all coal-fired EGU's remain subject to Maryland's HAA as implemented in COMAR 26.11.27, as well as all applicable federal regulations.

A. Affected Sources

The proposed regulations apply to the following 13 coal-fired EGUs 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); and
- Dickerson Generating Station (Units 1, 2 and 3).

Under the 2007 Maryland HAA, most active coal-fired EGUs added NO_x reduction technologies that utilize chemical reductants to lower NO_x emissions. These technologies included SCR, SNCR, and SACR. The Maryland HAA 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 allowed the units flexibility to comply under all modes of operation. The implementing regulation allowed systemwide 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 (Talen Energy) consisting of Brandon Shores Units 1 and 2, H. A. Wagner Units 2 and 3, and C. P. Crane Units 1 and 2 (Raven/Talen 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).

Prior owners of these two systems installed SCR, SNCR and SACR at all units subject to the requirements of the Maryland HAA. The practice of demonstrating compliance by allowing a system of units to combine to meet the requirement is often referred to as "averaging" and allows companies to find the most cost-effective way to reduce emissions from within their system. 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. Larger, "baseload" units were equipped with SCR while smaller, "load following" units were equipped predominantly with SNCR or SACR. Overall, the controls yielded a 75 percent reduction in annual 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. See Appendix B – MARYLAND COAL-FIRED POWER PLANT CAPACITY FACTORS.

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 Maryland HAA without having to always run the NOx pollution controls in a manner that optimizes NO_x emission reductions. This lead to emissions being higher on high energy demand days when ozone levels are likely to be highest because of the weather. 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 had increased steadily since 2008. An evaluation of performance data related to units equipped with SCR and SNCR can be found in Appendix C - MARYLAND COAL-FIRED EGUS WITH SCR AND SNCR RATES AND TONS.

The Department's analysis revealed that while coal-fired units equipped with SNCRs operated less than units equipped with SCR 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 all coal-fired EGUs 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 (the annual and ozone season caps), but contributed significantly to high ozone levels on the days that are most important. The operation of installed controls is much less expensive than the installation of the controls. Optimization of existing controls can produce substantial additional emission reductions and ozone benefits very cost-effectively.

Most of the existing electricity generating capacity in Maryland is old. The remaining useful life of a unit is a factor in choosing to equip units with less costly SNCR controls. SCRs can reduce NO_x emissions over 90 percent. SNCRs are less efficient at reducing NO_x emissions than SCRs, achieving a 20-40 percent emission reduction depending on the unit.

Table II-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/Talen Power

† Facilities operated by NRG

III. Proposed Regulation Requirement Details

The proposed amended Regulations .01, .05, and .06 (as renumbered) and new Regulations .04 and .07 under COMAR 26.11.38 Control of NO_x Emissions from Coal-Fired Electric Generating Units require NO_x control strategies beyond 2015.

A. Proposed Amendments – Regulations .01, .05, and .06 (as renumbered)

The proposed action adds new definitions to existing Regulation .01. The proposed action adds compliance demonstration requirements to Regulation .05 (as renumbered) and adds reporting requirements to Regulation .06 (as renumbered). The existing reporting from 2015 and beyond includes specific daily and monthly reporting requirements for owners and operators of coal-fired EGUs to demonstrate compliance with the requirements of the regulation. The proposed regulations require additional data demonstration for NO_x limitations depending on which option under Regulation .04 is chosen. The Department will review the compliance reports and may request additional information if necessary.

B. Proposed New Regulations – Regulations .04 and .07

The proposed action adds new Regulation .04 which gives EGUs four options to comply with the 2020 (Phase II) NO_x emission reduction requirements. The owners or operators of specific coal-fired electric generating units - C.P. Crane Units 1 and 2, Chalk Point Unit 2, Dickerson Units 1, 2, and 3 and H.A. Wagner Unit 2- must select and implement one of the following compliance options.

1. The first option (Regulation .04B(1)) requires the installation and operation of an SCR on the unit by June 1, 2020.

Under option one, an owner or operator must install and continuously operate an SCR control system at all times, not to exceed a NO_x emission rate of 0.09 lbs/MMBtu during the ozone season based on a 30-day rolling average. The NO_x emission rate (0.09 lbs/MMBtu) was based upon a comprehensive review of literature on SCR installations and represents an achievable emission rate associated with state-of-the-art SCR technology at coal units. This rate is designed to ensure that any new SCRs that are installed represent the most advanced technology.

In all cases, this would require removal and replacement of the SNCR with a SCR. Chapter V discusses the relatively high costs associated with this option. The expected performance and cost-effectiveness at a specific unit can be linked to how much that unit is used to generate electricity. Site-specific limitations may also be a factor in whether this option is selected. This option will entail significant costs and lead time to design and install the SCR controls.

2. The second option (Regulation .04B(2)) requires the unit to permanently retire by June 1, 2020.

Under this option, the unit must be retired from the electricity grid by June 1, 2020. Deactivation of coal-fired EGUs removes NOx emissions that were produced from older, lesser controlled units. The market will determine which energy source will replace the energy capacity loss from the retired coal-fired energy. Cost impacts are indeterminate.

3. The third option (Regulation .04B(3)) requires the unit to permanently switch fuel from coal to natural gas by June 1, 2020.

The third option is to retrofit the coal-fired unit to operate on natural gas or to replace the coal-fired boiler with a natural gas-fired boiler.

Chapter V discusses the costs associated with this option. The feasibility of this option will be affected by the proximity of the unit to adequately-sized natural gas pipelines and the availability of natural gas as a fuel. This option may also entail significant costs and lead time to design and install a new boiler or retrofit an existing boiler to operate on natural gas.

4. The fourth option (Regulation .04B(4)) requires a systemwide NOx 24-hour block average or NOx mass cap be met by June 1, 2020 and deeper ozone season NOx reductions in 2016, 2018 and 2020.

The fourth option allows affected units to choose between meeting a daily systemwide NOx tonnage cap of 21 tons per day for every day of the ozone season or meeting a systemwide NOx emission rate of 0.13 lbs/MMBtu as a 24-hour block average. The rate and the cap in option 4 are consistent with levels assuming SCR controls on all units. If option 4 is selected, more stringent 30-day systemwide rolling average NO_x emission rates must be met starting in May 2016, 2018 and 2020.

- In 2016 - Meet a 30-day systemwide rolling average NO_x emission rate of 0.13 lbs/MMBtu during the ozone season;
- In 2018 – Meet a 30-day systemwide rolling average NO_x emission rate of 0.11 lbs/MMBtu during the ozone season; and
- In 2020 - Meet a 30-day systemwide rolling average NO_x emission rate of 0.09 lbs/MMBtu during the ozone season

By 2020, if option 4 is chosen, ozone season NOx reductions would be 40% less than allowed ozone season emissions without option 4.

The fourth option requirements are anticipated to be met through averaging emissions from well performing SCR units and emissions from the SNCR units.

5. Electric system reliability during the ozone season.

Option 4 – Regulation .04B(4) also includes provisions to ensure that the reliability of the electrical system is maintained as detailed in Regulation .07 Electric System Reliability During Ozone Seasons.

The electricity grid in Maryland is well supported and includes adequate backup generation for high energy demand days. In rare instances, the grid operator PJM Interconnection, LLC

(PJM) needs more units to be made available and issues emergency warnings and actions, per PJM Manual 13, to insure reliability.

- The regulation would allow for 12 total hours per year of emissions to be excluded only from the calculation of daily limits in .04B(4).
- The reliability safety valve does not come into play until 2020.
- MDE research indicates fewer instances of emergency reliability call-outs in the future.
- Four new natural gas units are scheduled for construction and operation before 2020.
- New regulatory systems being put into place by PJM also appear to set the stage for a very stable, reliable energy system in the 2020 time frame.

C. The Proposed Regulations and Amendments 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

.01 Definitions.

A. (text unchanged)

B. Terms Defined.

(1) (text unchanged)

(2) "Emergency operations" means an event called when PJM Interconnection, LLC or a successor independent system operator, acts to invoke one or more of the Warning or Action procedures in accordance with PJM Manual 13, Revision 57, as amended, to avoid potential interruption in electric service and maintain electric system reliability.

[(2)] *(3)* (text unchanged)

[(3)] *(4)* (text unchanged)

[(4)] *(5)* (text unchanged)

[(5)] *(6)* (text unchanged)

(7) "30-day rolling average emission rate" means a value in lbs/MMBtu calculated by:

(a) Summing the total pounds of pollutant emitted from the unit during the current operating day and the previous 29 operating days;

(b) Summing the total heat input to the unit in MMBtu during the current operating day and the previous 29 operating days; and

(c) Dividing the total number of pounds of pollutant emitted during the 30 operating days by the total heat input during the 30 operating days.

[(6)] *(8)* (text unchanged)

[(7)] *(9)* (text unchanged)

(10) "24-hour systemwide block average emission rate" means a value in lbs/MMBtu calculated by:

(a) Summing the total pounds of pollutant emitted from the system during 24 hours between midnight of one day and ending the following midnight;

(b) Summing the total heat input to the system 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 system hours between midnight of one day and ending the following midnight by the total heat input during 24 system hours between midnight of one day and ending the following midnight.

.02 (text unchanged)

.03 (text unchanged)

.04 Additional NO_x Emission Control Requirements.

A. This regulation applies to C.P. Crane units 1 and 2, Chalk Point unit 2, Dickerson units 1, 2, and 3 and H.A. Wagner unit 2.

B. General Requirements. The owner or operator of the affected electric generating units subject to this regulation shall choose from the following:

(1) Not later than June 1, 2020:

(a) Install and operate a selective catalytic reduction (SCR) control system; and

(b) Meet a NO_x emission rate of 0.09 lbs/MMBtu, as determined on a 30-day rolling average during the ozone season;

(2) Not later than June 1, 2020, permanently retire the unit;

(3) Not later than June 1, 2020, permanently switch fuel from coal to natural gas for the unit;

(4) Not later than June 1, 2020, meet either a NO_x emission rate of 0.13 lbs/MMBtu as determined on a 24-hour systemwide block average or a systemwide NO_x tonnage cap of 21 tons per day during the ozone season.

C. When option B(4)of this regulation is selected:

(1) Not later than May 1, 2016, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.13 lbs/MMBtu during the ozone season.

(2) Not later than May 1, 2018, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.11 lbs/MMBtu during the ozone season.

(3) Not later than May 1, 2020, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.09 lbs/MMBtu during the ozone season.

D. In order to calculate the 24-hour systemwide block average emission rate and systemwide NO_x tonnage cap under §B(4) of this regulation and the systemwide rolling average emission rates under §C of this regulation:

(1) The owner or operator shall use all affected electric generating units within their system as those terms are defined in Regulation .01B of this chapter; and

(2) The unit(s) NOx emissions from all operations during the entire operating day shall be used where the unit(s) burn coal at any time during that operating day.

E. Beginning June 1, 2020, if the unit(s) included in a system, as that system existed on May 1, 2015, is no longer directly or indirectly owned, operated, or controlled by the owner, operator, or controller of the system:

(1) The remaining units within the system shall meet either:

(a) The requirements of §B(1)—(3) of this regulation; or

(b) A NOx emission rate of 0.13 lbs/MMBtu as determined on a 24-hour systemwide block average and the requirements of §C(3) of this regulation.

(2) The unit(s) no longer included in the system shall meet the requirements of §B(1)—(3) of this regulation.

F. For the purposes of this regulation, the owner includes parent companies, affiliates, and subsidiaries of the owner.

[.04] *.05* Compliance Demonstration Requirements.

A. (text unchanged)

B. Procedures for Demonstrating Compliance with NO_x Emission Rates under this Chapter.

(1) Compliance with the NO_x emission rate limitations in Regulations .03B(1) and D(2)*, .04B(1)(b), B(4), C(1), C(2), C(3),and E(1)(b),* and [.04].*05*A(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 Regulation .03B(1), *.04C(1), C(2) and C(3)* of this chapter, in order to calculate the 30-day systemwide rolling average emission rates, if 29 system operating days are not available from the current ozone season, system operating days from the previous ozone season shall be used.

(3) For §.04B(1)(b), in order to calculate the 30-day rolling average emission rates, if 29 operating days are not available from the current ozone season, operating days from the previous ozone season shall be used.

[.05] *.06* Reporting Requirements.

A. (text unchanged)

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 under Regulation [.04].*05*A(2) of this chapter;

(2) The reporting information as required under Regulation [.04].*05*A(3) of this chapter; [and]

(3) The 30-day systemwide rolling average emission rate for each affected electric generating unit to demonstrate compliance with Regulation .03B(1), *.04C(1), C(2) and C(3)* of this chapter*, as applicable*[.]*;*

(4) For an affected electric generating unit which has selected the compliance option of Regulation .04B(1) of this chapter, beginning June 1, 2020, the 30-day rolling average emission rate calculated in lbs/MMBtu;

(5) For an affected electric generating unit which has selected the compliance option of Regulation .04B(4) of this chapter, beginning June 1, 2016, the 30-day rolling average emission rate and 30-day systemwide rolling average emission rate calculated in lbs/MMBtu;

(6) For an affected electric generating unit which has selected the compliance option of Regulation .04B(4) of this chapter, beginning June 1, 2020, data, information, and calculations which demonstrate the systemwide NO_x emission rate as determined on a 24-hour block average or the actual systemwide daily NO_x emissions in tons for each day during the month; and

(7) For an affected electric generating unit which has selected the compliance option of Regulation .04E(1)(b) of this chapter, beginning June 1, 2020, data, information, and calculations which demonstrate the systemwide NO_x emission rate as determined on a 24-hour block average for each day during the month.

.07 Electric System Reliability During Ozone Seasons.

A. In the event of emergency operations, a maximum of 12 hours of operations per system per ozone season may be removed from the calculation of the NO_x limitations in Regulation .04B(4) of this chapter from the unit(s) responding to the emergency operations provided that:

(1) Within one business day following the emergency operation, the owner or operator of the affected electric generating unit(s) notifies the Manager of the Air Quality Compliance Program of the emergency operations taken by PJM Interconnection; and

(2) Within five business days following the emergency operation, the owner or operator of the affected electric generating unit(s) provides the Department with the following information:

(a) PJM documentation of the emergency event called and the unit(s) requested to operate;

(b) Unit(s) dispatched for the emergency operation;

(c) Number of hours that the unit(s) responded to the emergency operation and the consecutive hours that will be used towards the calculation of the NO_x *limitations in §.04B(4) of this chapter; and*

(d) Other information regarding efforts the owner or operator took to minimize NO_x *emissions in accordance with Regulation .03A(1) of this chapter on the day that the emergency operation was called.*

B. Any partial hour in which a unit operated in response to emergency operations under §A of this regulation shall constitute a full hour of operations.

IV. The Analyses

The Department has 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. The relevant analyses are presented in this chapter and Appendix A with supporting data included in the other Appendices.

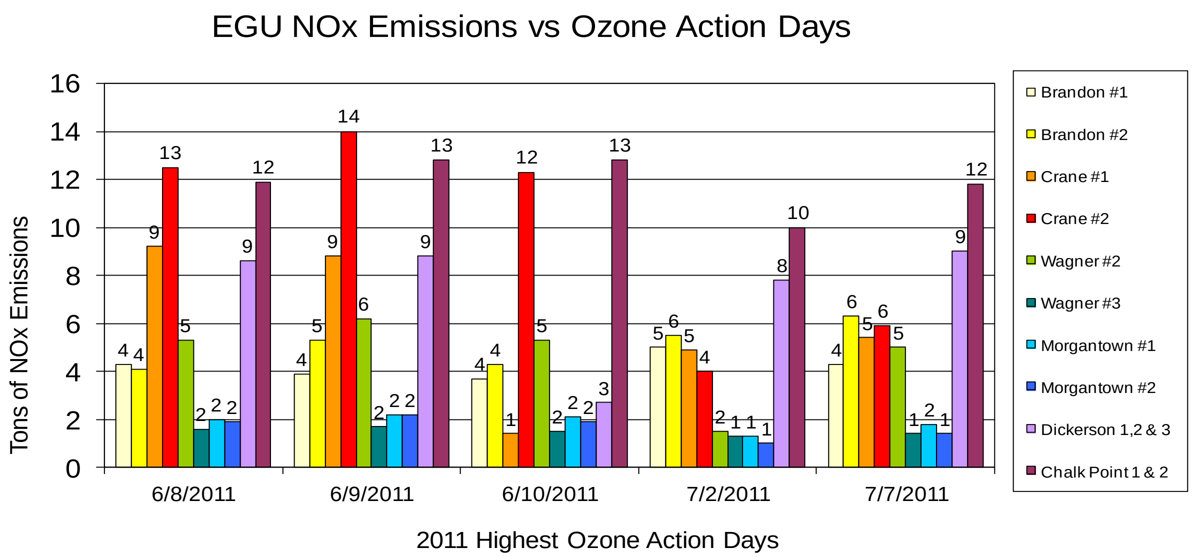
A. Peak Day Electricity Generation and High NO_x Emissions

The Department has engaged in extensive analysis of NO_x emissions data from EGUs 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 EGUs in Maryland comply with the Maryland HAA, the annual and ozone season caps in the HAA 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.

Modeling provides predictions over the ozone season and is a useful tool to develop control strategies. However where the model is less likely to predict emission rate variances on peak days, review of historic data and engineering calculations are an additional tool. The Department has performed various analyses to calculate predicted peak day emissions including analysis of historic daily maximums. As stated earlier, the Baltimore Nonattainment Area is required to prepare a SIP that includes the reduction strategies, modeling analyses and other evidence demonstrating compliance with the 75 ppb ozone standard. EPA has selected 2011 as the base year for these analyses and the Department has performed extensive analyses on data from this year.

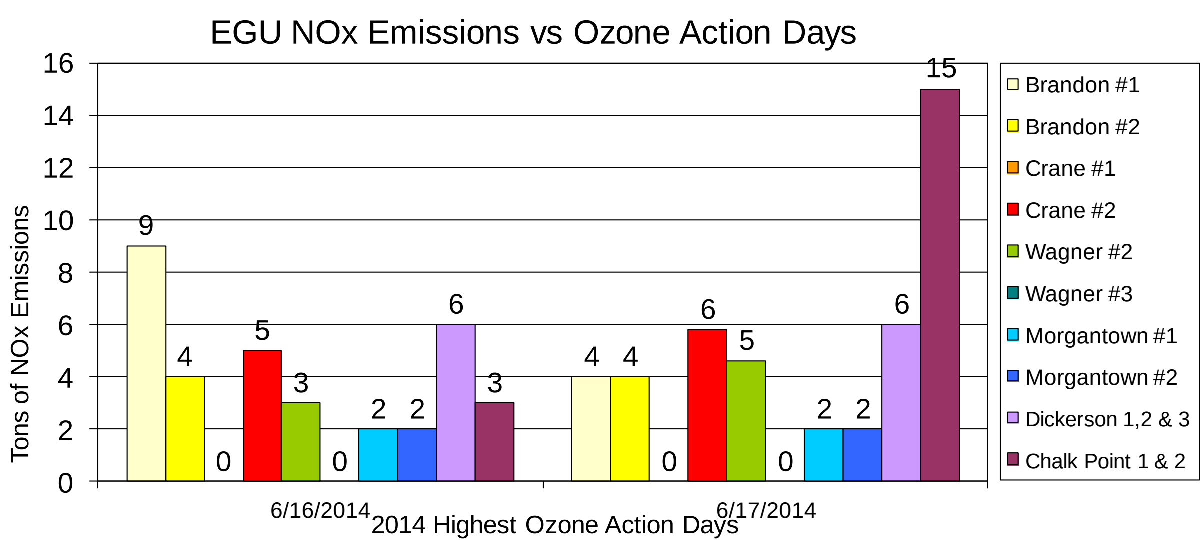
The 2011 ozone season was a fairly typical summer with 29 ozone exceedance days and the highest 8-hour ozone average of 114 ppb. The 2013 and 2014 ozone seasons were very mild with 9 and 5 exceedance days, respectively, and the highest 8-hour ozone average of 81 ppb in 2014. Examples of peak day emissions from Maryland coal-fired units during the summers of 2011 and 2014 are illustrated below.

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



NO_x emissions from coal-fired EGUs 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).

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



NO_x emissions from coal-fired EGUs 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.

Comparison of NO_x emissions from coal-fired EGUs on 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 SNCR or SACR controls. 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 or SACR controls. In the 2011 examples, all units are operating to meet higher electricity demand and are examples of peak days. The units with the highest emissions are almost always the units equipped with SNCR. As the highest ozone action days 2011 chart exhibits, emissions from SNCR controlled units contributed over 50% of the total daily NO_x emissions. During this period, the SNCR units produced less energy than the SCR units.

The data above demonstrates that peak day NOx emissions are dominated by the smaller units that have installed SNCR or SACR control technologies. This proposed action focuses on achieving further emission reductions on these peak days.

B. Technical Analyses in Appendix A

Appendix A includes MDE technical analyses supporting several elements of the proposed regulation. These elements include: the 21 ton per day daily cap, the 0.13 lb/MMBTU 24-hour block average rate, the reliability safety valve, and other measures that Maryland is pursuing to attain and maintain the ozone standard and other issues.

C. Air Quality Modeling

The Department participates in regional and local modeling efforts to design and evaluate the impacts of various policy and technology options. The Department collaborates with University of Maryland College Park (UMD) researchers and the Ozone Transport Commission (OTC) Modeling Committee to analyze various NO_x emission reduction strategies that can be implemented. Preliminary modeling analyses have been completed with the best available emissions inventories, meteorology and chemistry. Various emission reduction scenarios have been analyzed for EGUs and other emission sectors, including the coal-fired units under this regulation, as well as states upwind of Maryland that contribute to high ozone in Maryland. Air quality modeling results are provided in Appendix E- AIR QUALITY MODELING RESULTS.

The Comprehensive Air Quality Model with Extensions (CAMx) photochemical model is used to track the contribution of specific sources to ozone formation. Preliminary modeling results using CAMx have shown that local emissions contribute about 30% to the ozone problem in Maryland's nonattainment areas. These preliminary findings support the need for additional substantive NO_x reductions in Maryland. Measured data also supports the finding that about 30% of high ozone in Maryland is generated by in-State emissions.

The Community Multi-Scale Air Quality Modeling System (CMAQ) photochemical model simulates the formation and transport 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 EGU existing controls. Preliminary modeling results indicated that when coal fired EGUs across the eastern U.S., including those in Maryland, operate at their worst rates (non-optimized), ozone levels increased by about 1-2 ppb. In other words, consistently operating installed controls on coal-fired units across the East could reduce ozone levels by approximately 1-2 ppb. Having coal fired EGUs across the East operate their controls at optimized levels will help drive deeper NOx reductions and provide much needed public health protection. MDE has taken legal action and is also working with upwind states to address this issue.

MDE projects the implementation of new Regulation .04 requirements will (in combination with the Phase I requirements) result in ozone season NOx reductions between 2,507 and 2,627 tons depending on the option chosen. Option 4 achieves the higher 2,627 tons per ozone season level of reductions. If option 4 is chosen, ozone season average NO_x emissions will also be reduced by approximately 13 percent in 2016, 27 percent in 2018 and 40 percent in 2020. The early reductions will not be achieved if option 1, 2 or 3 are chosen.

MDE ozone modeling conducted for the options in Regulation .04 results in an approximate 0.1 ppb ozone reduction in 2020. This is in addition to the Phase I reductions which lower ozone by about 0.5 ppb starting in May 2015. See also Appendix A and E.

D. The Effectiveness of NO_x Reductions

The information in italics below summarizes research on the effectiveness of NO_x reductions in reducing ozone levels in Maryland and the Mid-Atlantic.

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

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

This white paper presents observational evidence of the response of ambient ozone (O_3) to nitrogen oxides (NOx) emissions. In the eastern US, natural biogenic sources usually dominate hydrocarbon reactivity, making NOx the limiting precursor to ozone. NOx 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 NOx 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 O_3, NOx concentrations, and NOx emissions, we can estimate the increase in ambient ozone concentrations due to not running NOx 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 O_3 produced per ppb NOx 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 NOx 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 NOx 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 NOx (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. NOx concentrations plummeted after 2003, but have shown little decrease since 2010. In conclusion, the observations verify the predictions from chemical transport models – if NOx emissions revert to levels seen in previous years, ozone concentrations are likely to rise. Other factors held constant, every increase of 100 tons NOx 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 NOx reductions. This has now changed and it can be seen that since the mid-2000's that Maryland has transitioned into a NOx limited regime, NOx reductions now provide a greater benefit in reducing ozone levels in Maryland (Hosley, et al., 18 January 2013).

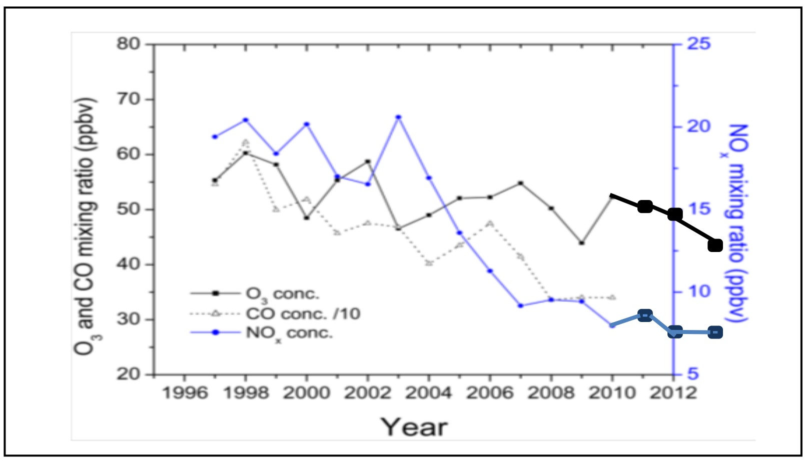


***Figure 1,** Trends in trace gas concentrations. Taken from He et al., (2013b), these observations show the temporal trends and relationship of O_3, NOx, and CO. Measurements from 1200-1800 LT in the ozone season are shown. Data for 2011-2013 are estimates added for this report, after the original publication in ACP. The interannual 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 NOx reductions will result in greater ozone reductions than has been seen in the past.

References

Jacob, D.J., "Introduction to Atmospheric Chemistry" Princeton Univ. Press, ed. 2004. 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 NOx 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.

V. Economic Analysis

A. Cost Categories

The 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 make it difficult to determine the precise compliance costs to regulated entities.

Capital Cost

Capital costs include direct costs such as equipment, engineering, plant modifications and installation, and indirect costs like contingency, escalation, and allowance for funds used during construction (AFUDC).

Capital costs are annualized over a given length of time. The formula used to annualized capital costs is presented below:

Annualized Capital Costs = Total Capital Costs x Annualization Factor

Where:

$$\text{Annualization Factor} = \frac{i(1+i)^n}{(1+i)^n - 1}$$

i = Interest Rate
n = Length of Time

Annual Operating Costs

Annual operating costs include fuel, maintenance materials, reagents (*e.g. urea, anhydrous ammonia*), electricity to operate the control device, catalyst replacement, personnel and ammonia testing.

B. Factors Influencing Compliance Cost Estimates

A review of factors affecting the cost of compliance is presented in two sections, requirements before 2015 and the proposed requirements after 2015.

(i) 2015 NO_x Emission Control Requirements

As a result of prior regulations such as the Maryland HAA, all of the coal-fired EGUs 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 requires all coal-fired EGUs to operate and optimize both NO_x pollution and combustion controls during the ozone season to minimize NO_x emissions. The annual operating and maintenance cost for a single unit can range from $430,000 to $4.3 million (2014 dollars). Assumptions for NO_x Emission Reduction Estimates for 2015 quoted from the NPA May 29, 2015.

(ii) Additional NO_x Emission Control Requirements Beyond 2015

Affected sources have adequate lead time to analyze compliance options and projected changes in energy markets to select the most cost-effective compliance option.

- **1st Option (Regulation .04B(1))- requires the installation of an SCR on the unit by June 1, 2020.**
  This option would require coal-fired EGUs equipped with NO_x pollution control technologies such as SNCR or SACR to remove and replace them with SCR and complete operational testing no later than June 1, 2020. Coal-fired EGUs opting to retrofit with SCR technology in order comply with the new regulation have to consider the following factors which include increased operating and maintenance expenses (includes reagent, reagent supply, and catalyst costs) and staffing costs, labor costs, installation costs, and variable capital costs. Estimated costs for state-of-the-art SCR controls can range from $40 to $200 million dollars (2014 dollars) per unit, with the additional cost of operating and optimizing the SCR NO_x pollution control ranging from $430,000 to $4.3 million (2014 dollars) on a per unit basis. Retrofit costs in addition to other factors, such as physical layout of the plant may add additional costs to the installation of SCR on some existing coal-fired EGUs .

- **2nd Option (Regulation .04B(2)) - requires the unit to permanently retire by June 1, 2020**
  The second option is retirement of the unit. Many of the coal-fired EGUs subject to this regulation were constructed between 1957 and 1963 and are less efficient than newly constructed units and are reaching the end of their useful life. Alternative fuel sources such as natural gas and tightening emission standards, are leading owners of aging coal-fired EGUs to permanently retire the units. Risks related to unit retirements include service reliability and the loss of those units during periods of extreme demand. Proposed construction of natural gas EGUs and transmission of electricity from out of state may address reliability concerns associated with retirement of coal-fired EGUs. In the case of a unit retirement, the company will lose revenue and may face decommissioning costs.

- **3rd Option (Regulation .04B(3)) - requires the unit to permanently switch fuel from coal to natural gas by June 1, 2020.**
  Under the third option, coal-fired EGUs can convert from coal to natural gas in order to comply with the regulation. Factors to consider include possible equipment modifications, availability of natural gas supply, site-specific constraints, and fuel prices. Costs associated with conversion from coal to natural gas are typically 15 to 30 percent (based on 2013 estimates) of the cost of installing a new natural gas boiler, while the installed costs of natural gas combined cycle generation is approximately $1 million/MW of capacity. However, several studies have noted that it could be more cost effective to construct a new natural gas-fired unit than to retrofit an existing coal-fired unit to natural

gas. A new natural gas combined cycle unit between 25 – 300 megawatts could cost an estimated $25 million to $300 million dollars (2014 dollars). While retrofitting an existing coal-fired unit to natural gas could be the least costly option for some units as opposed to installing SCR NO_x pollution control technology, this option may not be feasible for some units due to availability of natural gas and infrastructure requirements.

References

Ingraham, John, Marshall, Jim and Randy Flanagan, PE. "*Practical Considerations for Converting Industrial Coal Boilers to Natural Gas."* Power Magazine. Web. March 1, 2014.

Congressional Research Service Report (CRS) for Congress, "*Power Plants: Characteristics and Cost*". Kaplan, Stan. November 13, 2008.

- **4th Option** (**Regulation .04B(4)) – requires a systemwide NOx 24-hour block average or NOx mass cap be met by June 1, 2020.**
  Under the fourth compliance option, affected generating units must meet more stringent NO_x 30-day systemwide rolling average rates in 2016, 2018 and 2020. Affected units must also choose between meeting a 24-hour systemwide NO_x emission rate or a systemwide daily NO_x tonnage cap. The rates and caps will be met through averaging and operation curtailment resulting in lost revenue. The Department is unable to estimate the lost revenue.

C. Cost Information Supplied by Affected Utility Owners in 2014

	RAVEN POWER		NRG	
	Crane 1-2	Wagner 2	Dickerson 1-3	Chalk Pt 2
Total Capital Cost	**$110,000,000**	**$40,000,000**	**$200,000,000**	**$122,000,000**
SCR Cost $/kW				
Annual Costs				
Maintenance Costs	$1,000,000	$390,000	$2,000,000	$1,220,000
Reagent Cost			$848,844	$740,132
Electricity Cost			$280,868	$244,897
Catalyst Cost			$1,188,333	$865,833
Capital Recovery	$13,226,550	$4,809,655	$24,048,274	$14,669,447
Total Annual Cost	**$14,226,550**	**$5,199,655**	**$28,366,319**	**$17,740,309**

Calculation of Total Annualized Project Costs for Installation of SCR

1	Capital Costs to be Financed		$200,000,000	$40,000,000
2	Interest Rate for Financing (i)		3.5%	3.5%
3	Time Period of Financing (n)	(Assume 10 years)*	10	10
4	Annualization Factor = $\frac{i(1+i)^n}{(1+i)^n - 1}$		0.120241368	0.120241368
5	Annual Capital Cost (Capital Recovery)	(Calculate 1 x 4)	$24,048,274	$15,030,171
6	Annual Cost of Operation and Maintenance **		$4,330,000	$3,080,000
7	Total Annual Cost of Pollution Control Project	(5 + 6)	**$28,366,319**	**$17,740,309**

* While actual payback schedules may differ across projects and companies, assume equal annual payments over a 10-year period for consistency in comparing projects

** For recurring costs that occur less frequently than once a year, prorate the cost over the relevant number of years (e.g., for pumps replaced once every three years, include one-third of the cost in each year).

D. Electric Power Generation in Maryland – Potential New Sources

1. Natural Gas Expansion in Maryland

Electric utilities are continuously searching for ways to minimize costs, improve availability, and reduce emissions while meeting increased demand for electricity. With the growth in energy consumption in Maryland, the State's electric generating facilities face challenges. An estimated two-thirds of in-state power is generated from EGUs that are more than 30 years old and are approaching retirement. These EGUs are often costlier to maintain, less efficient, and dirtier. PJM projects at least 16,000 megawatts (MW) of power in the region will be lost through 2021 resulting from the retirement of old coal units. PJM protects and predicts grid reliability.

Natural gas has often been the fuel of choice for meeting intermediate or shoulder loads because it has been slightly more expensive than coal, but cheaper than petroleum. While there is currently enough capacity with coal-fired EGUS to meet electricity demand, the expansion of the natural gas industry in the last few years has resulted in an increase in the contribution of natural gas to total electricity generation in the United States. Depending on the price of natural gas coupled with sufficient natural gas reserves and pipelines, Maryland could increase the utilization of natural gas as a fuel through encouraging the development of natural gas combined cycle (NGCC) plants, liquefied natural gas (LNG) facilities, and transmission pipelines. Because NGCC plants are highly advanced and very efficient (fuel efficiencies can approach 60 percent), these plants can often run as a base load power plant. In addition, NGCC units are essentially factory produced, with the lowest capital costs ($ per kW) available and the flexibility to operate efficiently over a wide range of capacity utilization. With the lack of economic and regulatory hurdles often associated with coal-fired units, the prospects for a substantial expansion of gas generation and renewable energy sources to meet electricity demand are good.

The proposed regulation provides coal-fired EGUs the opportunity to switch to natural gas as opposed to installing SCR. The potential proliferation of new natural gas-fired EGUs demonstrates this is a viable fuel for both peak and off-peak electricity generation. These new NGCC plants are expected to create additional employment opportunities.

2. Future Natural Gas Utility Planning in Maryland

There are currently four NGCC plants and one LNG facility proposed for construction in Maryland. These projects are described below.

- Mattawoman Energy Project is a proposed natural gas-fueled, 859 megawatts combined cycle generating station featuring two H-class combustion turbines and two duct-fired heat recovery steam generators that is slated for construction in Brandywine, Maryland, with an estimated completion date of 2017. The turbines will use low-NO_x combustion technology and will be equipped with SCR systems to control NO_x emissions. Fuel to the plant will be supplied via interstate gas pipeline owned by Dominion Transmission. The company estimates that the plant will supply the power needs of approximately 859,000 homes in Maryland, and create approximately 700-800 construction jobs – with 25 direct jobs to operate the plant and 32 indirect jobs to support the plant.

- Old Dominion Electric Coop Wildcat Point is a proposed state-of-the-art, combined-cycle, natural gas-fired power plant slated for construction on the Rock Springs site in Cecil County, Maryland. The plant which will be supplied natural gas via the Transco pipeline will generate approximately 1,000 megawatts - enough to power 390,000 homes in the region annually. According to the company, Wildcat Point will create up to 600 construction jobs and approximately 30 permanent jobs.

- Keys Energy Center is a proposed natural gas-fired combined-cycle plant in Prince George's County, Maryland scheduled to be on line by mid-2017. The facility is expected to bring 735 megawatts of electrical generation to Maryland and meet the average consumption needs of approximately 500,000 Maryland homes. The project is expected to employ a construction workforce of 200 to 400 people over a two-year period, with approximately 25 full-time workers to oversee the operation of the plant. Natural gas will be provided to the plant by a pipeline owned by Dominion Transmission.

- Competitive Power Ventures (CPV) St. Charles is a proposed state-of-the-art 661 megawatt natural gas-fired combined cycle power plant in Charles County, Maryland. According to the company, the plant will be supplied natural gas from the Cove Point LNG terminal or another existing pipeline and will generate enough electricity to power more than 650,000 homes. The project will create approximately 350-400 construction jobs at its peak and it will create an additional 24 permanent jobs when operational.

- Dominion Cove Point LNG Terminal Project is a proposed expansion of the existing facility currently used for storing and exporting domestically produced liquefied natural gas (LNG). The terminal is located along the Chesapeake Bay in Lusby, Maryland. The terminal expansion includes the construction of a liquefaction plant and additional storage facilities. The project is expected to create 3,000 construction jobs during the three-year period and will require about 75 employees. In addition, based on a U.S. Department of Commerce formula, Dominion Resources estimates another 14,000 permanent jobs created indirectly resulting from the project nationally in businesses ranging from pipe manufacturers to accounting firms.

Overall, the five proposed projects are expected to result in the creation of at least 5,000 construction and 170 permanent jobs in Maryland. While there is a large degree of uncertainty regarding possible retirement of existing coal-fired power plants and resulting job losses, the expansion of the natural gas electric generation sector can be a catalyst for economic growth in Maryland.

References

Mattawoman Energy: http://www.pandafunds.com/invest/mattawoman/
Old Dominion Electric Coop Wildcat Point: http://wildcatpoint.com/
Keys Energy Center: http://keysenergycenter.com/
Completive Power Ventures (CPV) St. Charles: http://www.cpvstcharles.com/about-sc.php
Dominion Cove Point LNG Terminal: https://www.dom.com/business/gas-transmission/cove-point/

VI. APPENDICES

Appendix A

Power Plant Controls in Maryland – MDE Presentation to AQCAC 8/5/15

Department of the Environment

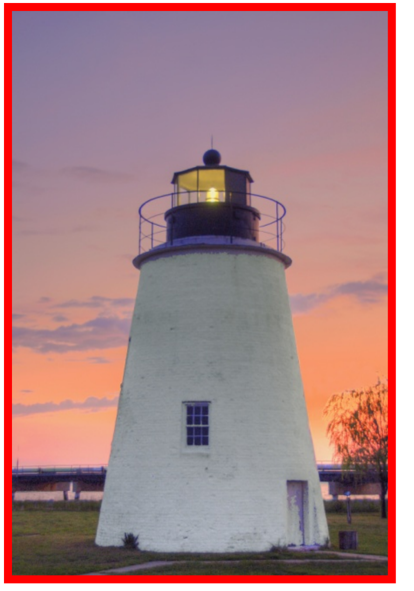
Power Plant Controls in Maryland

Tad Aburn, Air Director
AQCAC Meeting - August 5, 2015

MDE

Topics Covered

- Status of New NOx Regulations
- Background on power plant controls
- Progress in cleaning the air
- The current process to adopt additional power plant controls
- The proposed regulation



How Did We Get to Today?

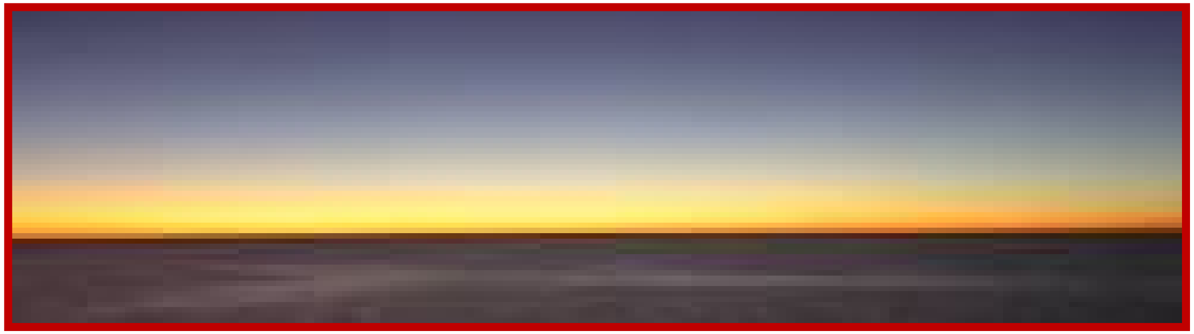
- This is not a new issue
- Discussions with stakeholders for over 3 years
  - Almost every piece of the new regulation being discussed today has been discussed in multiple stakeholder meetings in the past
- In January of 2015, AQCAC actually approved an earlier version of the regulation being discussed today
  - At that meeting, AQCAC heard from stakeholders …
    - Full support for 2015 requirements of the rule
    - Some pushed for more flexibility related to the 2020 requirements designed to drive peak day emissions down

Current Status

- MDE has moved ahead with the 2015 requirements to insure that the immediate public health protections from the 2015 reductions are achieved
  - Adopted through an emergency regulation that became effective on May 1, 2015
  - Working quite well
- MDE has taken a second look at the 2020 requirements
  - Proposing a fourth option to meet the 2020 requirements that will provide equal or greater public health protection
    - While also protecting jobs and supporting a healthy and sustainable economy
- This new "Option 4" for the 2020 requirements is the focus of the new regulatory language being proposed by MDE today

The Maryland Ozone Plan

- Maryland has a comprehensive strategy to address ozone based upon two decades of research and progress
- The regulation being discussed today is part of that strategy
  - The new regulation protects public health and promotes a healthy and sustainable economy
- The new regulation provides equal or greater public health protection compared to the earlier proposal
  - The first three options for compliance are identical to the earlier proposal
  - Choosing the new Option 4 comes with increased responsibility for earlier pollution reductions
  - Choosing Option 4 also insures lower ozone in 2020
    - An additional 120 tons of NOx reductions in the ozone season

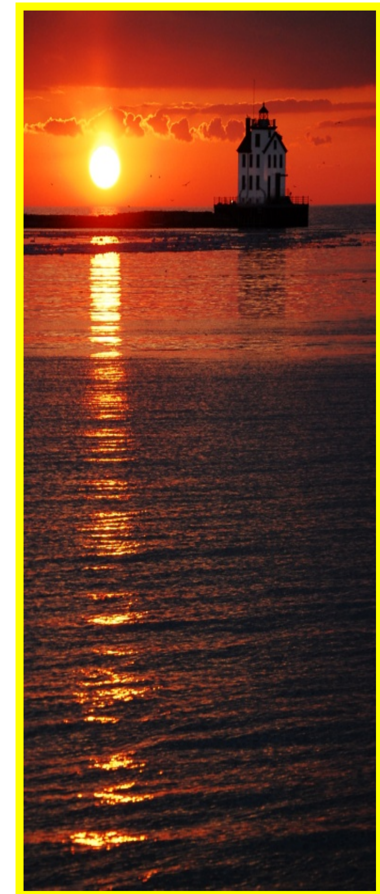



Twenty Years of Power Plant Controls

Power Plant Controls

Moving on to Round 8

- A long History of Power Plant regulation in Maryland
  - 1995 - Reasonably Available Control Technology for Nitrogen Oxides (NOx RACT)
  - 1996 - Acid Rain Program
  - 1999 - Ozone Transport Commission (OTC) NOx Budget Program
  - 2004 - EPA NOx SIP Call
  - 2005 - Updated NOx RACT
  - 2006 to 2012 - Healthy Air Act
  - 2015 - New daily NOx minimization rule
  - Today's requested action - Deeper reductions from 2016 to 2020



1996 Acid Rain Requirements

- Established under Title IV of Clean Air Act amendments of 1990
- Cap and trade program to address acid rain
- Controlled sulfur dioxide (SO2) and nitrogen oxide (NOx)
- SO2
  - 41% reduction by 2002
- NOx
  - 33% reduction by 2002

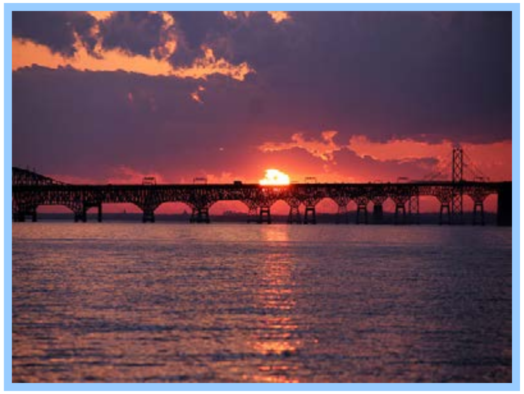
MARYLAND

Reasonably Available Control Technology

- … or RACT
- 1995 and 2006 update
- Drove investment in a host of combustion related modifications
  - Low NOx Burners
  - Separated Overfire Air
  - More
- Did not drive post combustion controls like
  - Selective Catalytic Reduction (SCR) technology
  - Selective Non-Catalytic Reduction (SNCR) technology
- Resulted in small but meaningful NOx reductions in Maryland

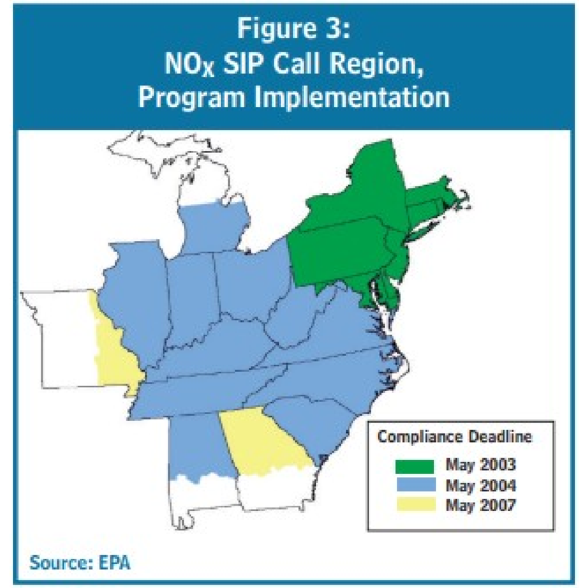
OTC NOx Budget Program

- Regional cap and trade effort between 13 states in the OTC – 1999 to 2003
- Established annual & ozone season caps
  - Market based concepts
    - Allowed banking and trading
- Regional summertime NOx caps for OTC states:
  - 2003 caps drove an approximate 60% to 70% regional NOx reduction during the ozone season from 1990 levels
- Replaced by the NOx SIP Call (a larger NOx Budget Trading Program) in 2003/2004



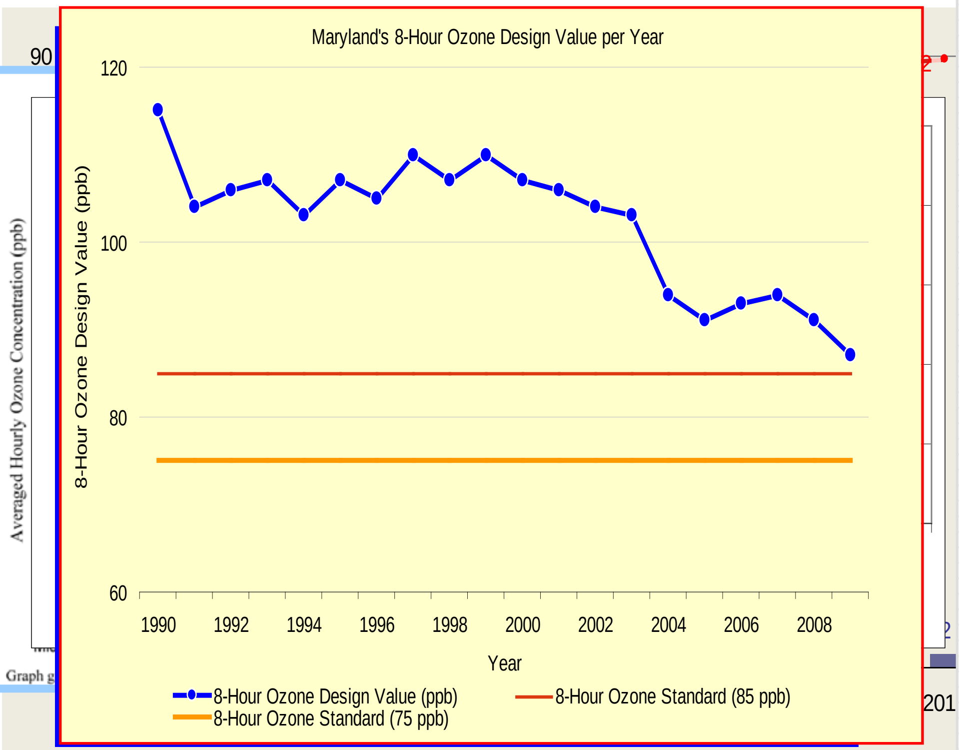
NOx SIP Call

- 20-State cap and trade program to reduce NOx
- 1998 … EPA final rule
- Implemented by EPA "calling in" SIPs (State Implementation Plans) for 20 states and requiring NOx reductions
  - Had a model rule that states could opt into
- Patterned after OTC NOx Budget Program
- Designed to reduce regional NOx 28% from 1996 emissions levels by 2007
- A major success story for reducing transport
- Still allowed unconstrained trading



Why the NOx SIP Call Worked?

Ground Level Ozone Drops Dramatically in the Same Time Frame



The classic ozone transport story

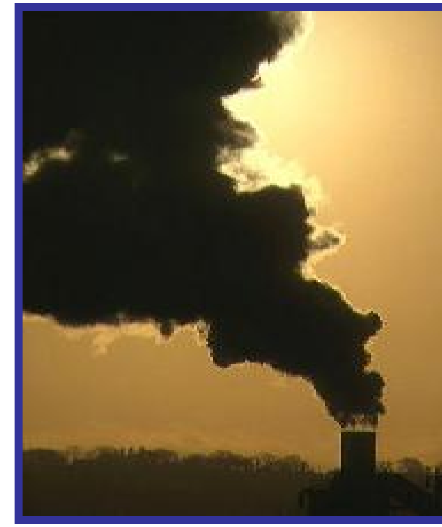
- Incoming ozone levels (as high as 80 ppb) collect in an elevated reservoir over night
- Real world programs like the NOx SIP call have shown that
  - Adding regional controls
  - Results in regional NOx emission reductions …
  - Which lead to reduced ozone in the elevated reservoir …
  - Which lead to lower ozone at ground level and public health protection!

Maryland Healthy Air Act (HAA) of 2006

- Most significant control program ever implemented in Maryland
- Partially a response to the problems with unlimited trading
  - Location does matter for ozone
- To implement the NOx SIP Call some Maryland power plants opted to purchase allowances instead of investing into controls

The Healthy Air Act

- Again, most significant emission reducing program ever adopted in Maryland
- Widely applauded by the environmental community
- Environmental community and utilities worked with MDE as partners to design and implement the law
- Almost $2.6 Billion investment for clean air by Maryland utilities
- Helped to dramatically clean the air
  - Fine particle levels dropped dramatically
  - Ozone levels dropped dramatically
  - Mercury emissions dropped dramatically



A Multi-Pollutant Approach

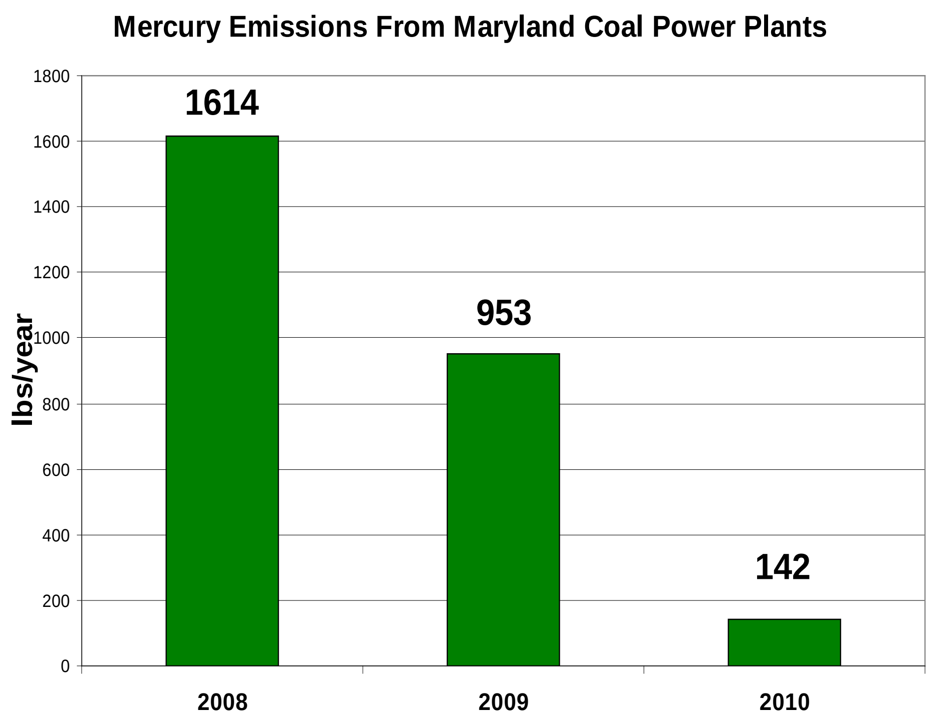
- HAA driven by multiple pollutants
  - HAA required reductions in 4 key pollutants at the States largest power plants
    - Mercury
    - Sulfur dioxide (SO2)
    - Nitrogen oxide (NOx)
    - Greenhouse gases
    - Also drove reductions in direct particulate, hydrogen chloride and other air toxics

So … What Controls Were Installed?

- 6 Flue Gas Desulfurizers (FGDs)
- 2 Baghouses
- 2 Hydrated Limestone injection systems
- 7 SCRs*
- 6 SNCRs
- 6 PAC (Powdered Activation Carbon) injection systems
- These controls were installed on coal units ranging in size from 125-700 MW.
  - All in a 2 to 3 year window

The Results – Mercury & Other Air Toxics

- Mercury
  - Exceeded 2012 90% reduction requirement in 2010
- Hydrogen Chloride (HCl) reduced 83%
- Direct particulate matter reduced 60%



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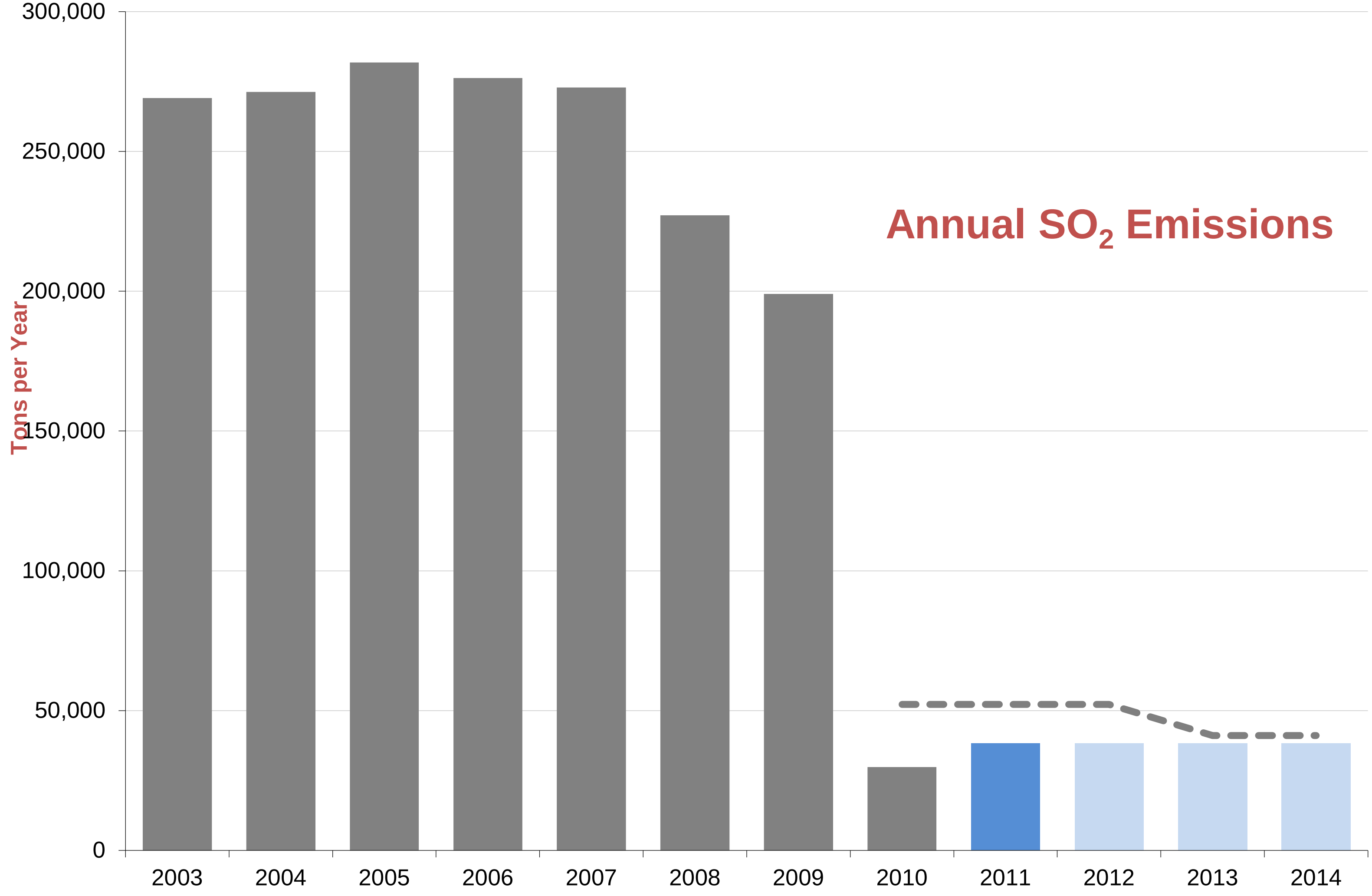
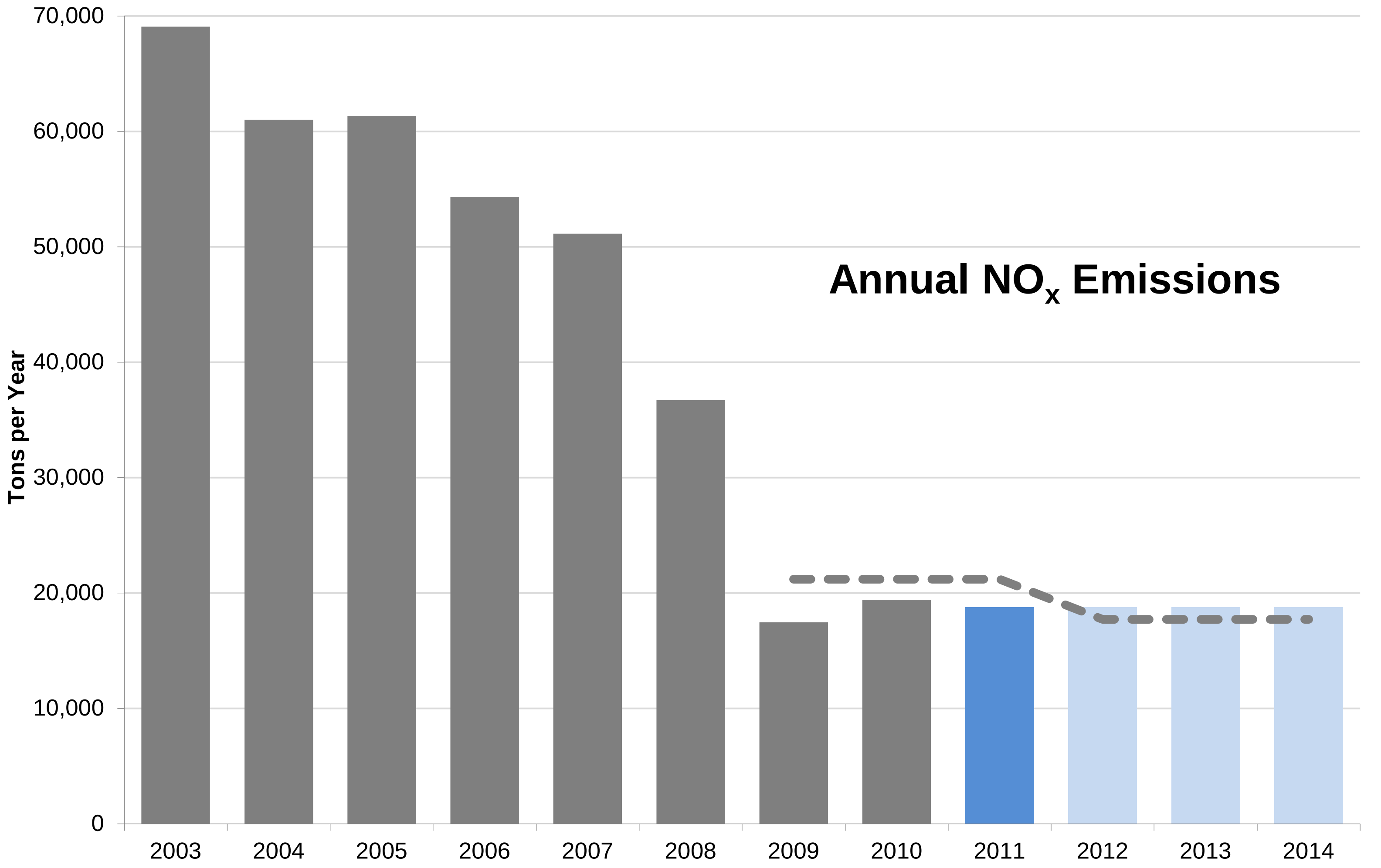
The Results – SO2



The Results – NOx



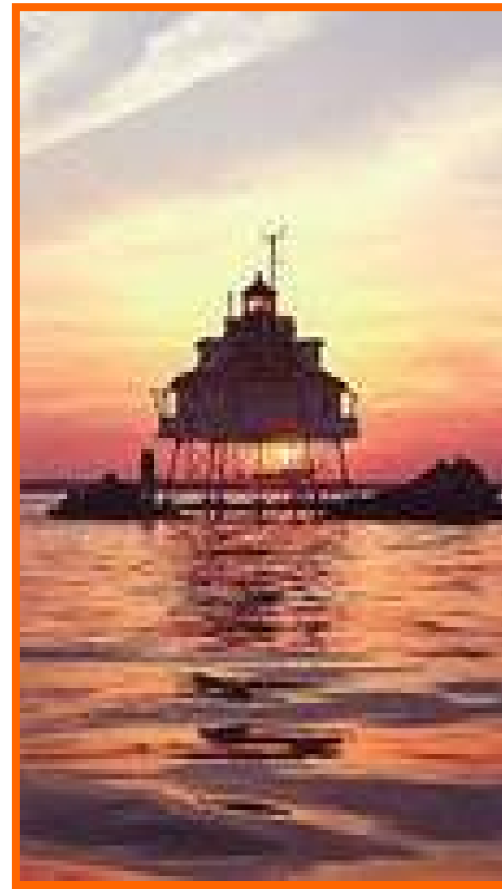
Others on Maryland's Healthy Air Act

- Constellation Energy
  - “We recently completed the installation of a major air quality control system, including scrubbers, a baghouse, and other equipment at one of our major coal facilities in Maryland,” said Paul Allen, senior vice president and chief environmental officer of Constellation Energy.
  - “These systems work effectively and result in dramatically lower emissions of mercury, sulfur dioxide, particulate matter, and acid gases. We know from experience that constructing this technology can be done in a reasonable time frame, especially with good advance planning; and there is meaningful job creation associated with the projects.”
    - March 16, 2011 press release

- The National Wildlife Federation
  - Maryland’s Healthy Air Act would save 96 lives each year in 2010 compared to 27 lives saved under existing federal air rules
  - The Healthy Air Act’s curbs on air pollution will save 17,350 workdays each year in 2010, compared to 4,925 workdays saved under federal air rules.

Summary

- Maryland has already implemented aggressive pollution controls on Maryland power plants
- The controls generated very deep reductions …
  - For the year and for the summer ozone season
    - Not for each day
- These controls have been very effective and did what they were supposed to do
  - Maryland is measuring attainment for fine particulates
  - 8-hour ozone levels have dropped dramatically under the 85 and 75 ppb ozone standard
- The current ozone standard (75 ppb) requires us to refocus on:
  - The worst ozone days where not only is ozone most likely to form, but high electricity demand drives higher than normal emissions
  - Daily emission reductions - not ozone season average reductions



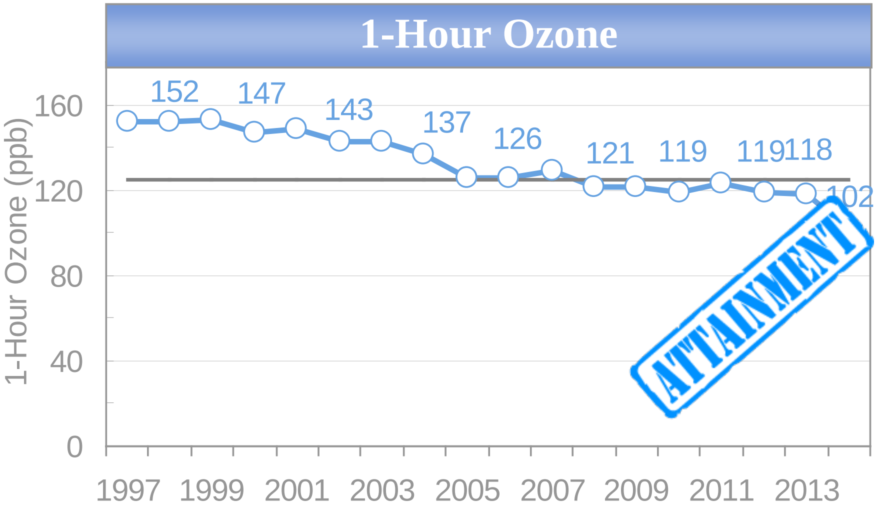
MARYLAND

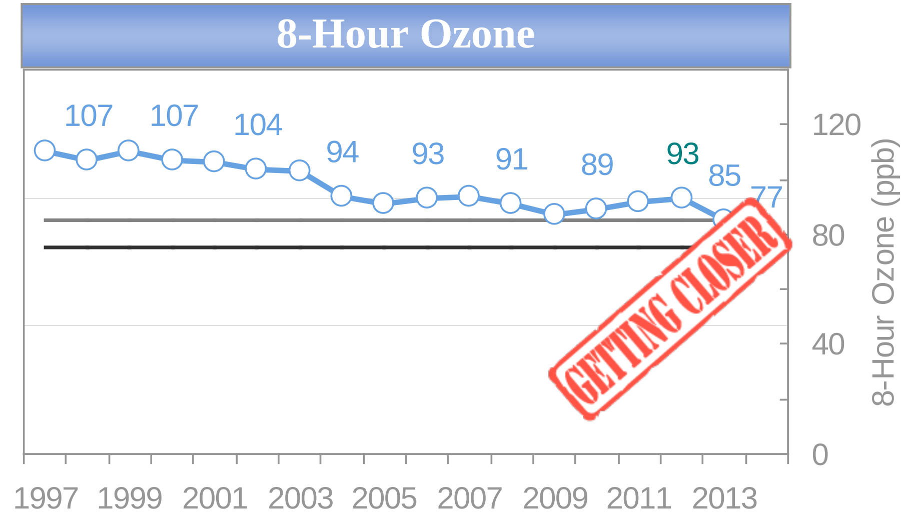

Cleaning the Air
Dramatic Progress Over the
Past 10 Years

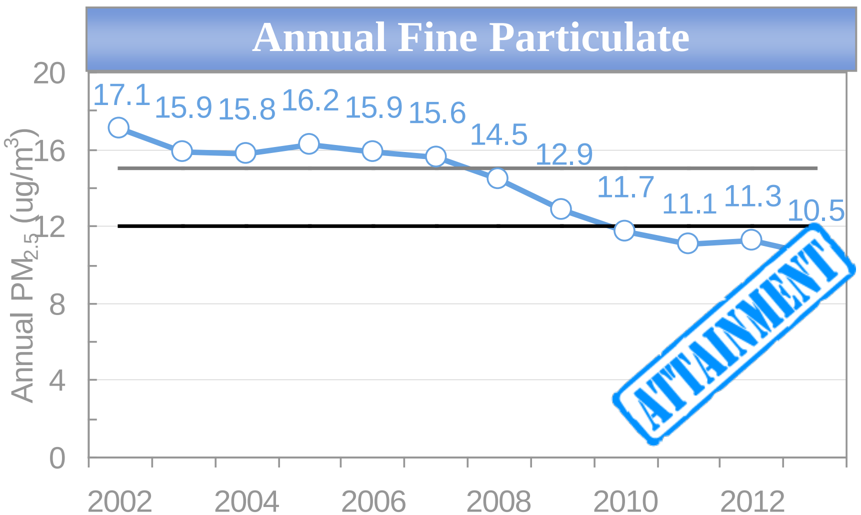
Maryland's Air Quality Challenges

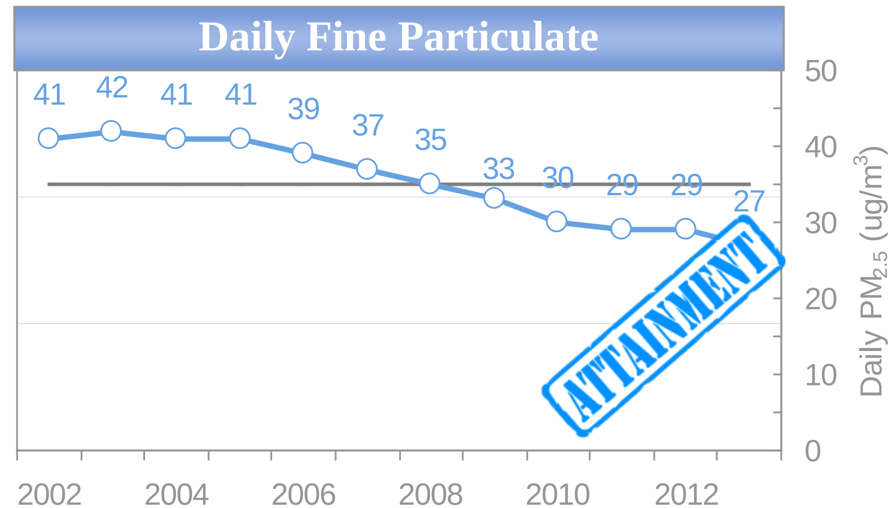
- Ground level ozone has improved dramatically but we still monitor levels above the health based standard
  - New ozone standard expected by the end of 2015
  - Will continue to push Maryland to seek more emission reductions
- Fine particle levels are currently meeting all standards
  - Continue to trend down
- Maryland is the fourth most vulnerable state to sea level rise
  - One of the major impacts from climate change
- Mercury and other air toxics are a priority
- Contribution of air pollution sources to nitrogen deposition in the Chesapeake Bay is a major issue

Progress in Cleaning Maryland's Air





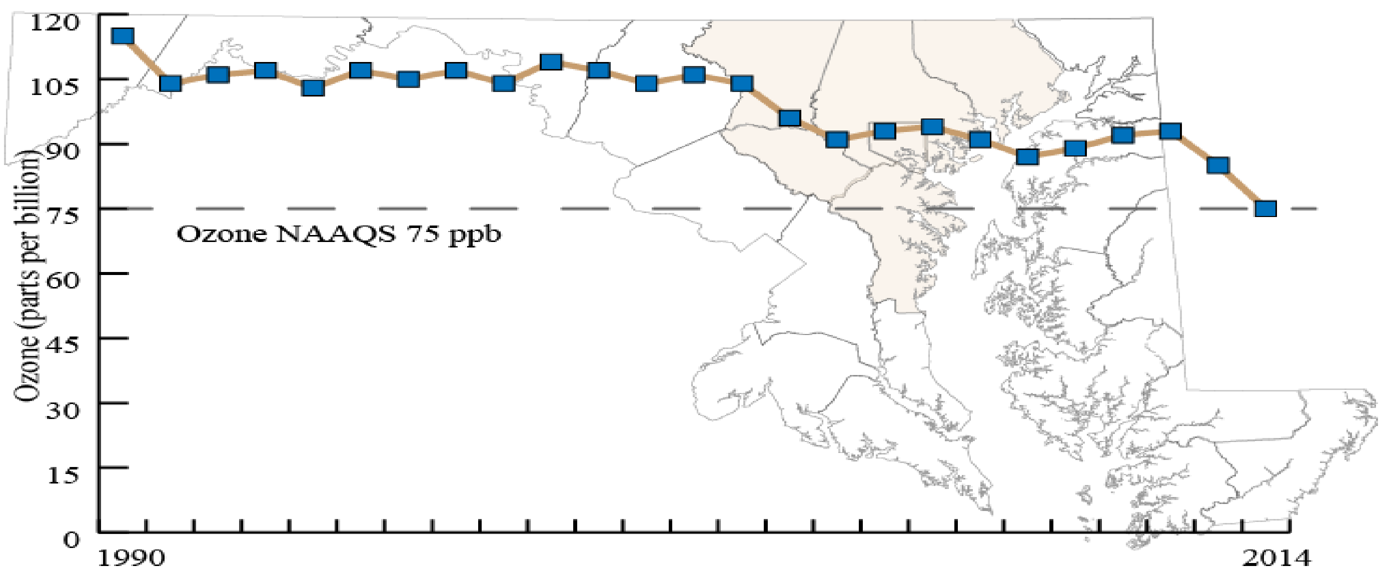




Don't forget ... We do expect EPA to adopt a new tougher 8-Hr ozone standard in the 65 to 70 ppb range by the end of the year

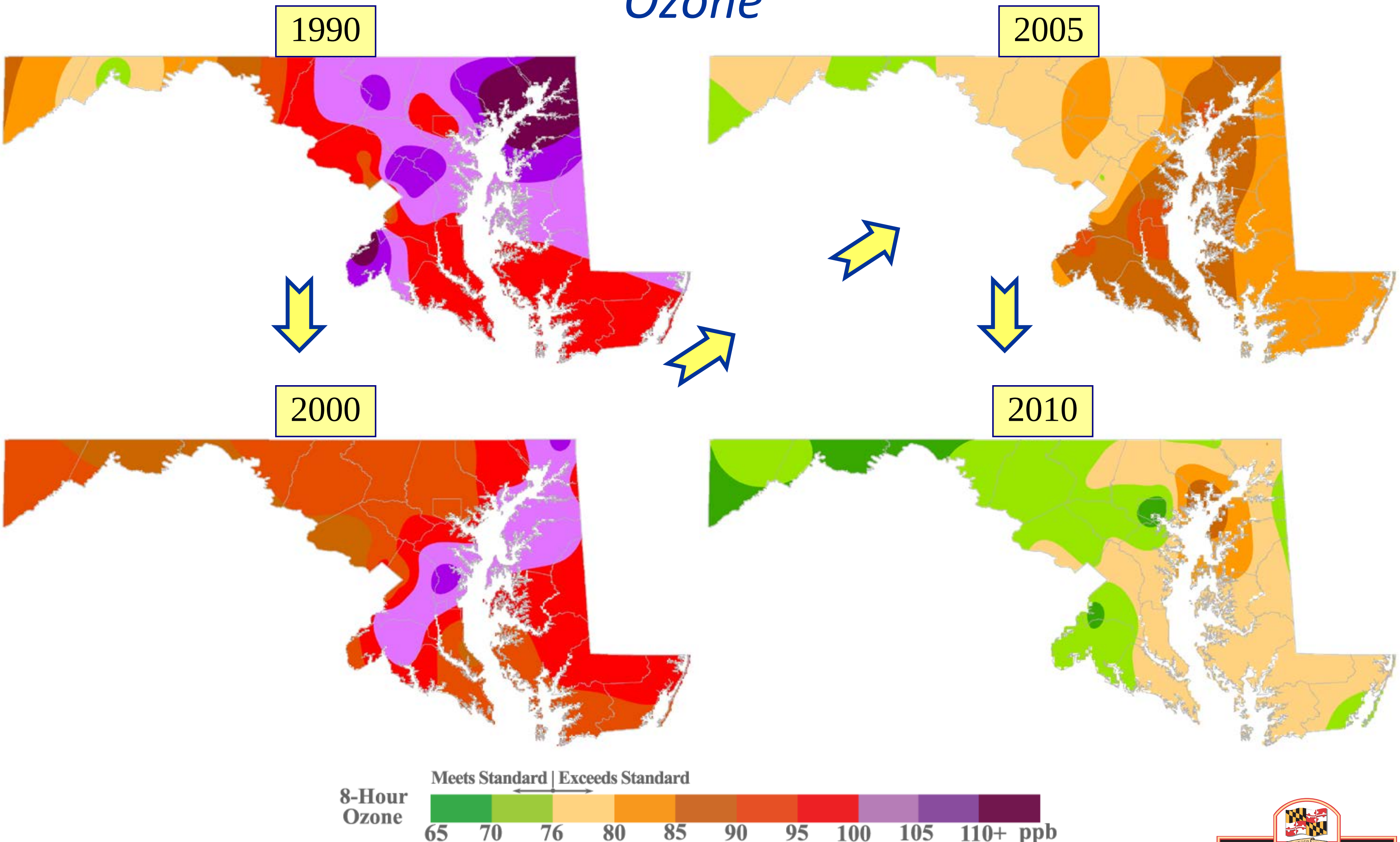
Clean Air Progress in Baltimore

- Baltimore has historically measured some of the highest ozone in the East
- In 2014, The Baltimore area did not exceed the current ozone standard
  - First time in 30 years … weather did play a role
- EPA has now finalized a “Clean Data Determination”
- With hotter, less ozone friendly weather, Baltimore may see higher ozone
- Summer 2015 - Pretty clean so far. Only 1 day of levels above 75 ppb in Baltimore and statewide. Progress appears to be continuing.

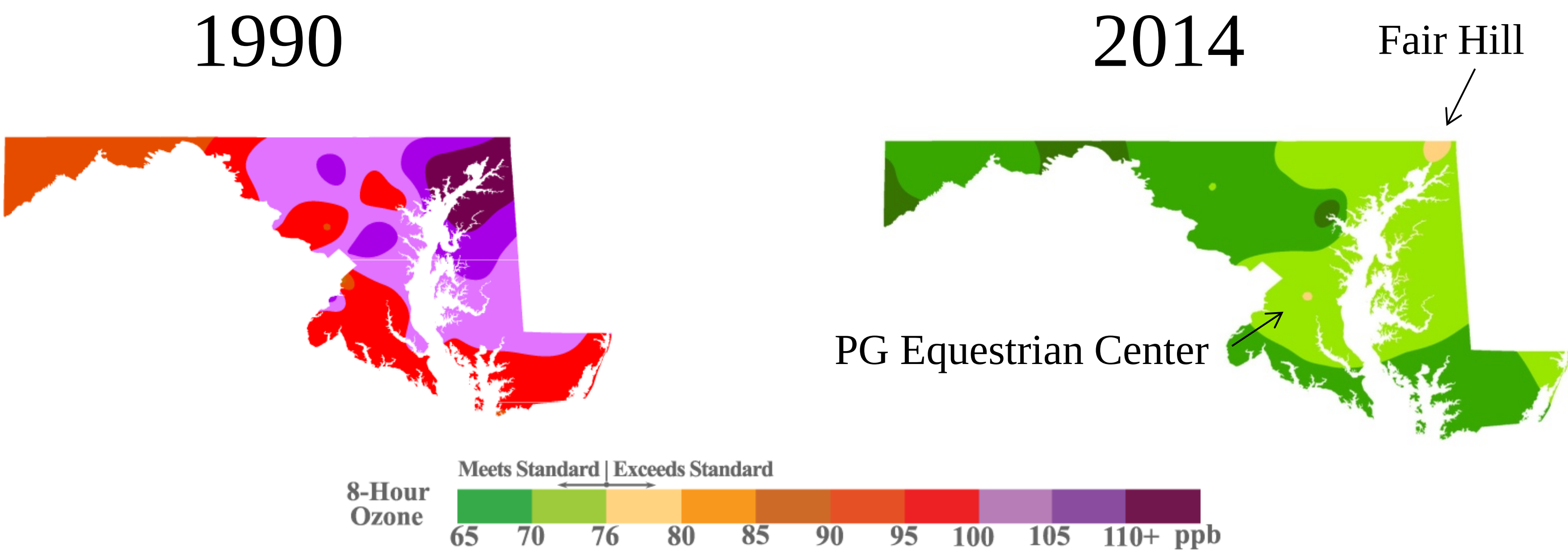


Lower Concentrations & Smaller Problem Areas

Ozone



The Shrinking Ozone Problem



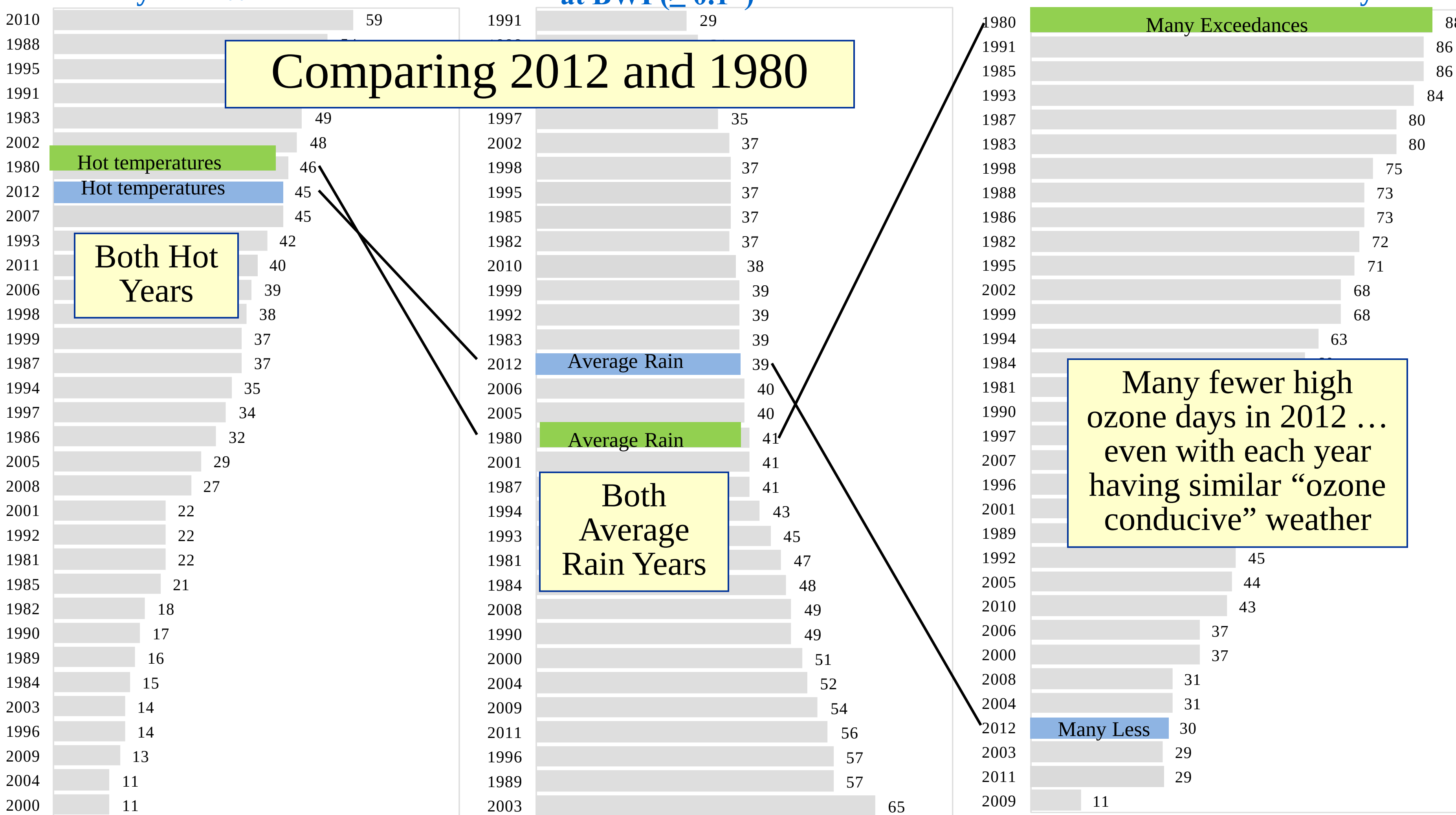
- Presently only Cecil and Prince George's Counties have single monitors that are above the standard.
- Previously approximately 86% of Marylanders were exposed to ozone levels above the standard, now that number is 9%.

Progress - Normalizing the Weather

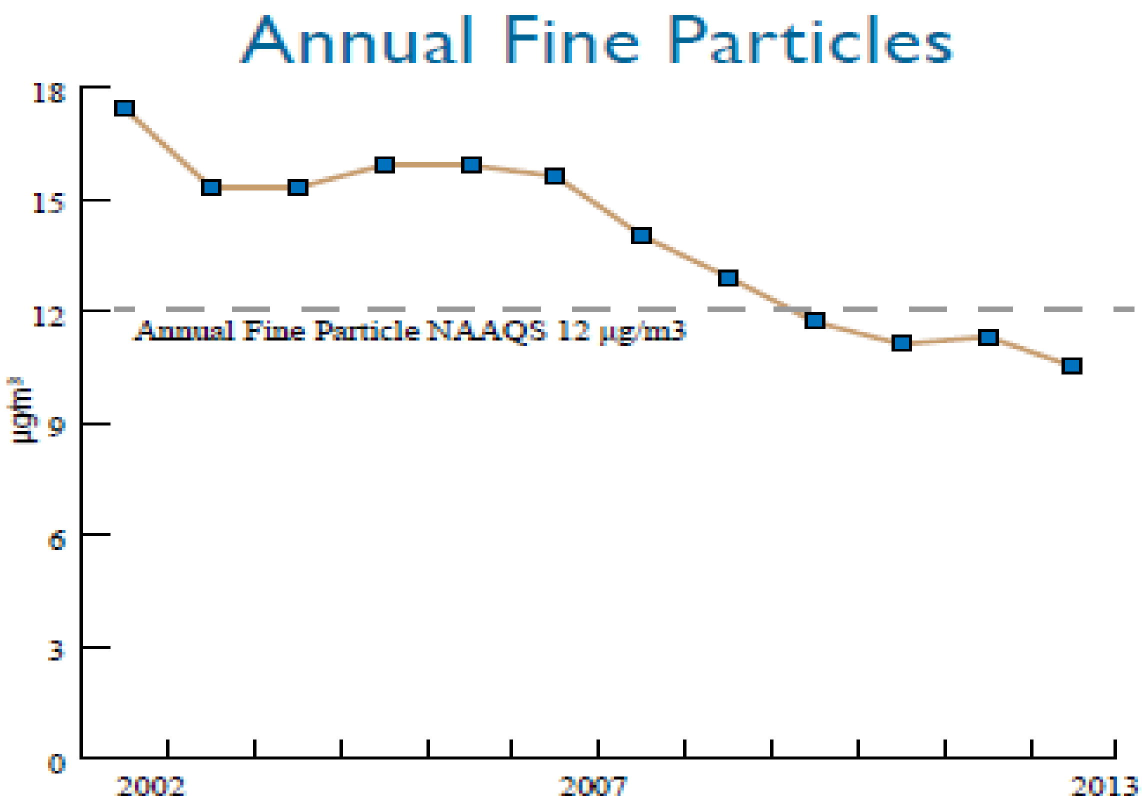
Number of 90 Degree Days at BWI

Number of Rainy Days at BWI (≥ 0.1”)

Number of Maryland’s Ozone Exceedance Days

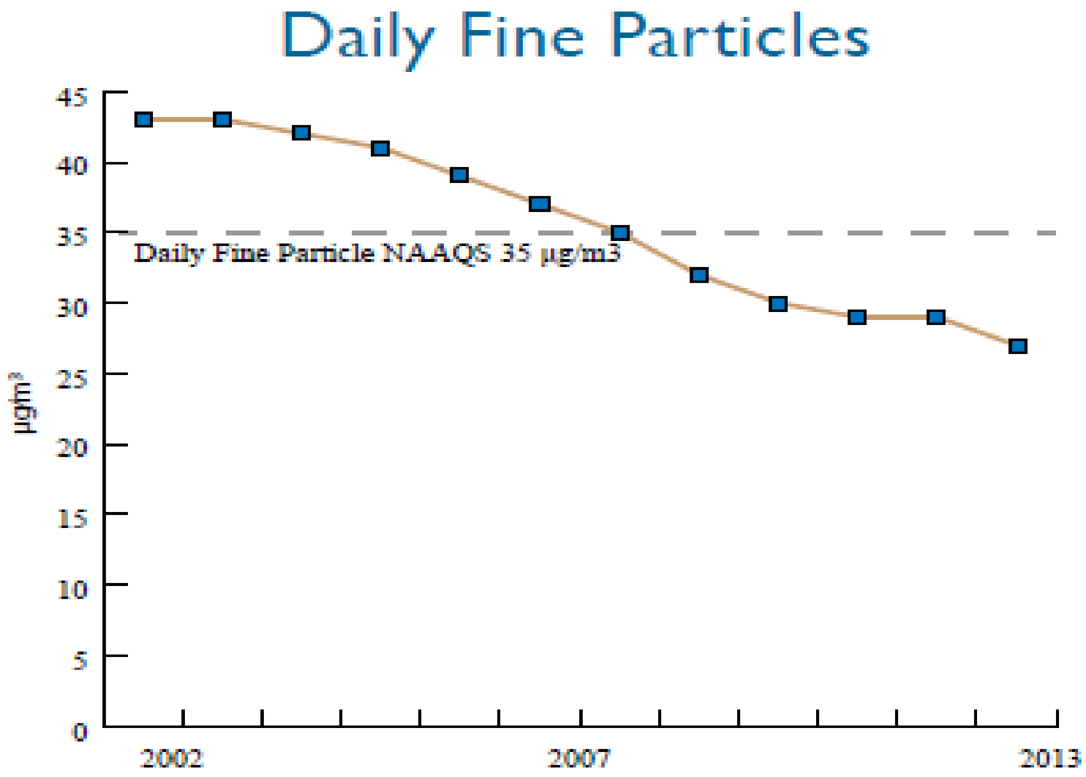


Maryland Annual Fine Particles



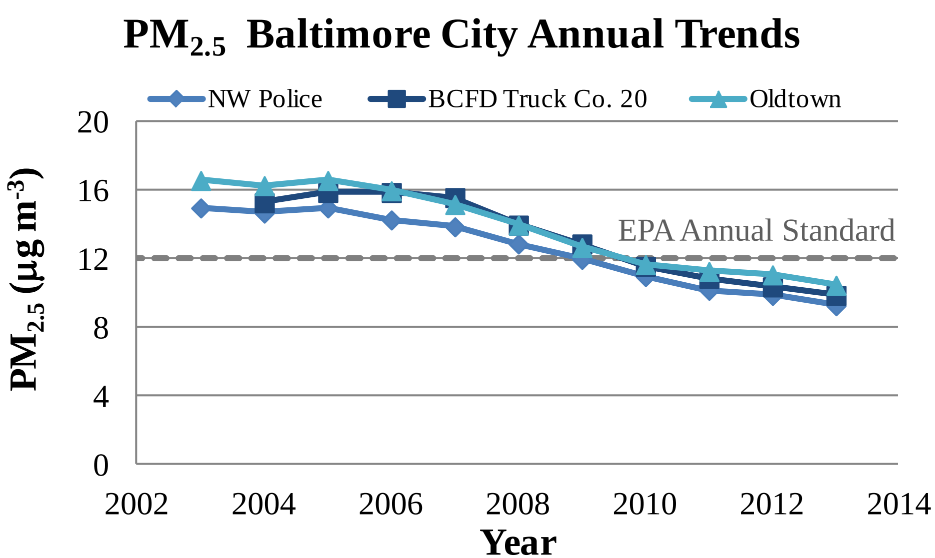
- Maryland is currently attaining the annual fine particle standard across the state
  - The annual standard is 12 µg/m^3
- Fine particulate levels continue to trend down
- This is a major success story as the health risks associated with fine particulate are very significant

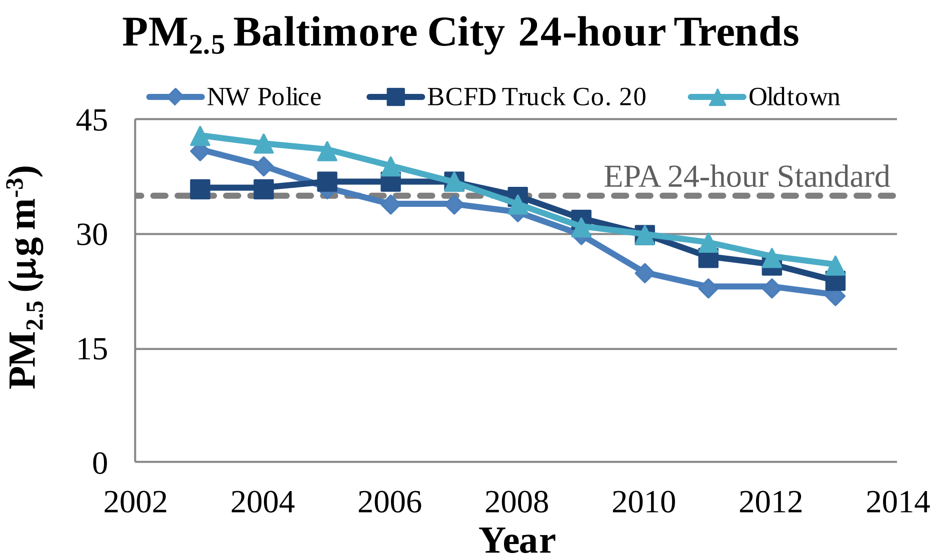
Maryland Daily Fine Particles

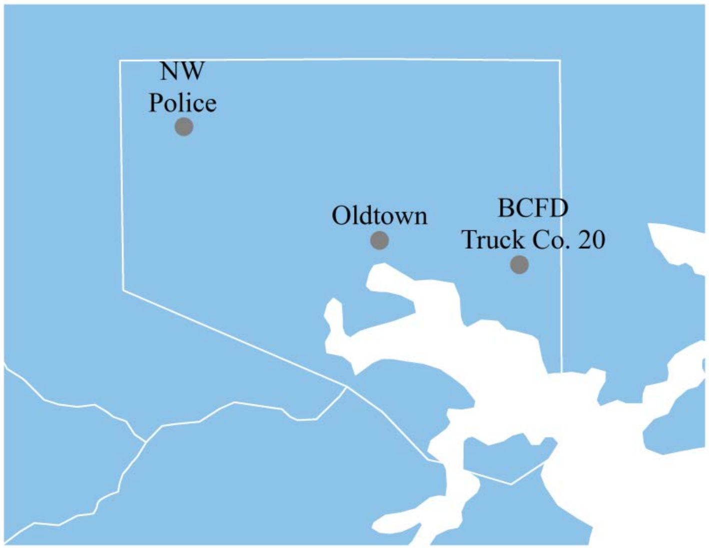


- Maryland is currently attaining the daily fine particle standard across the state.
- The annual standard is 35 µg/m^3

Fine Particulate - Baltimore City Trends







* Trends are made with annual and 24-hour design values.

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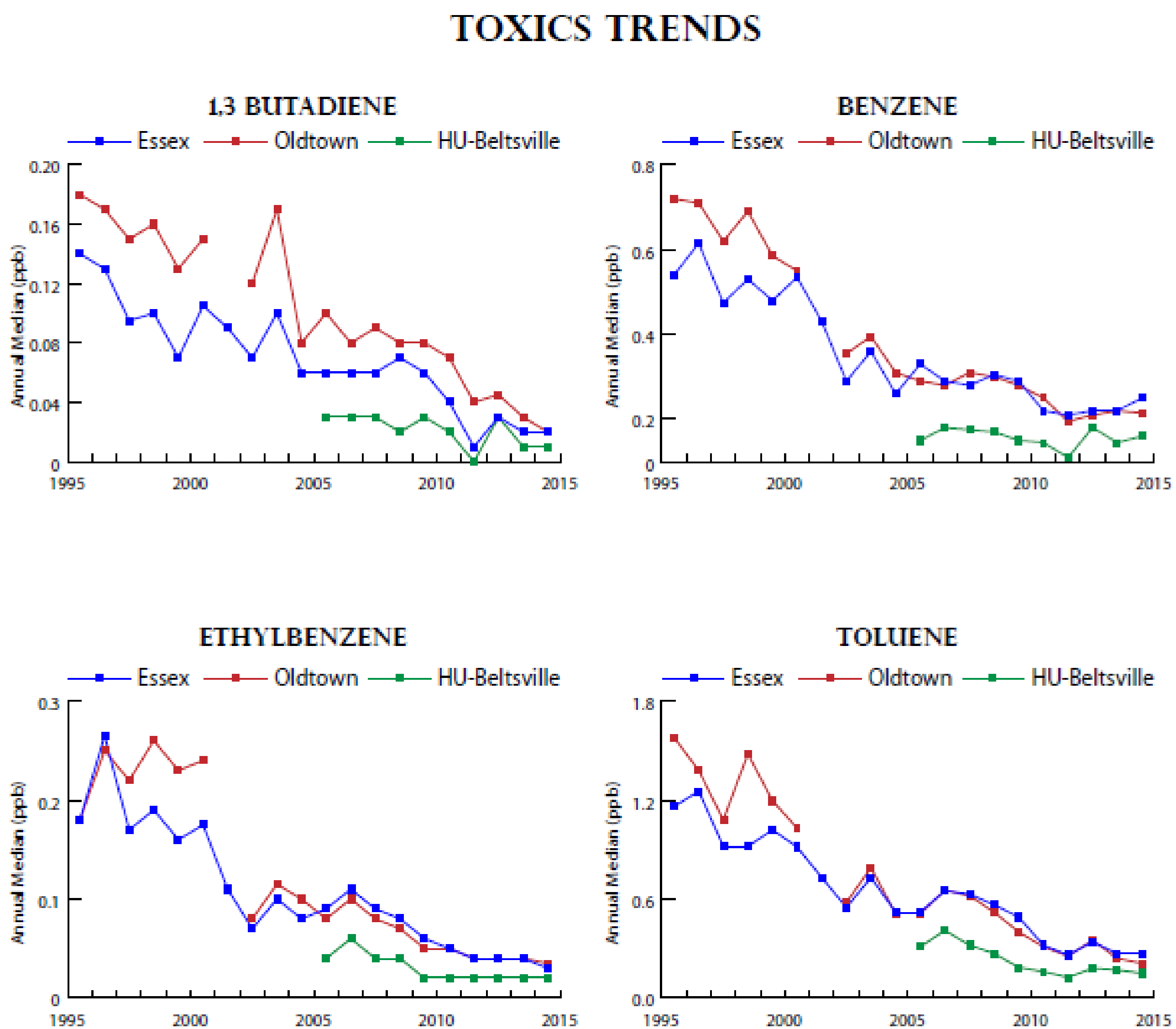
Maryland Air Toxics Trends



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The New Regulations

New NOx Reduction Requirements

- In 2015, MDE must adopt additional NOx reduction requirements for power plants and other sectors to insure continuing progress in reducing ozone levels in the State
- For power plants:
  - Updated NOx RACT (Reasonably Available Control Technology) for power plants
  - NOx reductions for the Maryland SIP (State Implementation Plan) scheduled for late 2015
  - NOx reductions to insure public health protection (the new standard)
- Many other NOx (and volatile organic compound or VOC) strategies for mobile, area and other stationary sources in the works

Issues With NOx Emissions

- The current ozone standard requires us to focus on peak day NOx emissions
- Healthy Air Act (HAA) annual and "ozone season" caps have not forced units to always run emissions controls when they are needed most
- Linked to lower capacity factors at many units
  - Coal units are simply not being asked to run as often as they used to run and allowance prices are very low
- Some units were not always running their control equipment optimally to insure maximize emission reductions

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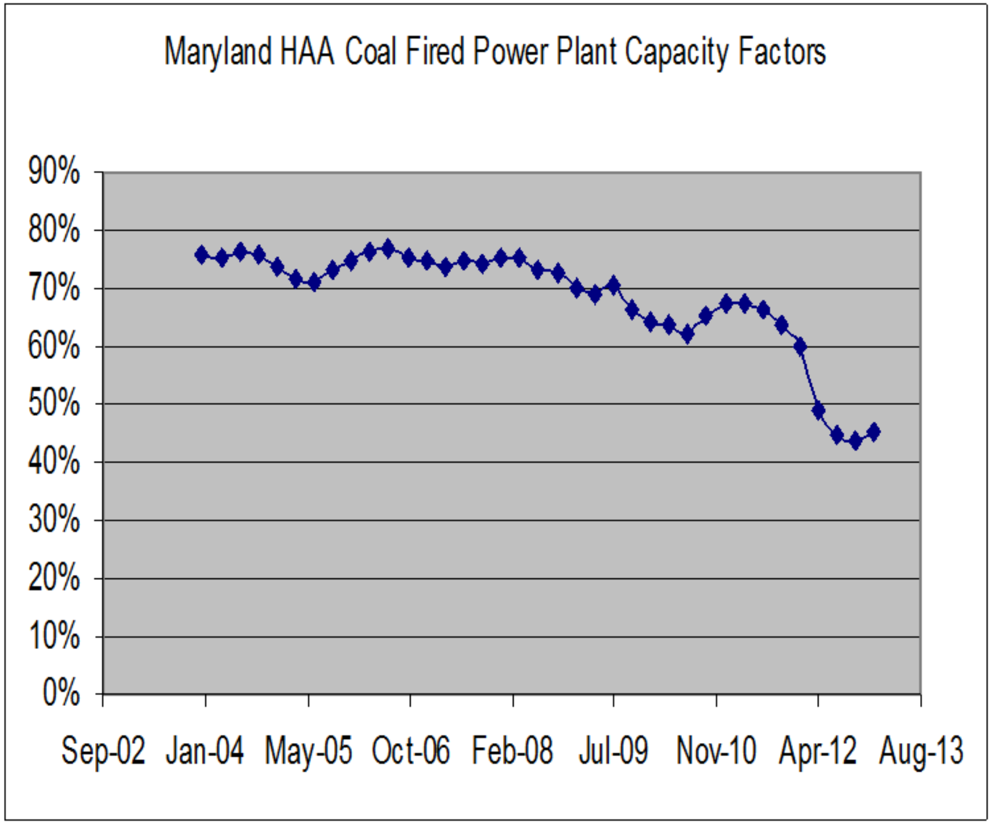
Decreasing Capacity Factors

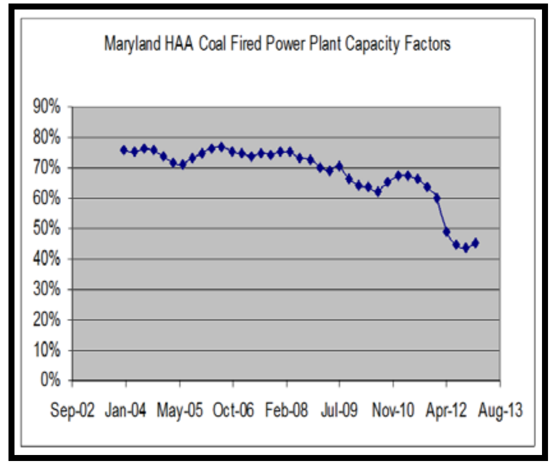
- Capacity factor HAA Coal Fired Units



Capacity Factors of Maryland Coal plants have almost been reduced by 50%

Compliance with the HAA

- All of Maryland's power generators fully comply with the Maryland HAA of 2006
- The HAA used a regulatory scheme that allowed companies to choose where to control within their "system" to most cost-effectively meet the NOx and SO2 caps set in the Act.
  - Some units controlled more – some less
- The HAA set annual caps for SO2 and annual and ozone season caps for NOx
  - Short-term limits (hourly or daily) were not part of the HAA
  - Caps were set assuming that Maryland coal plants would continue to operate at pre-2006 levels

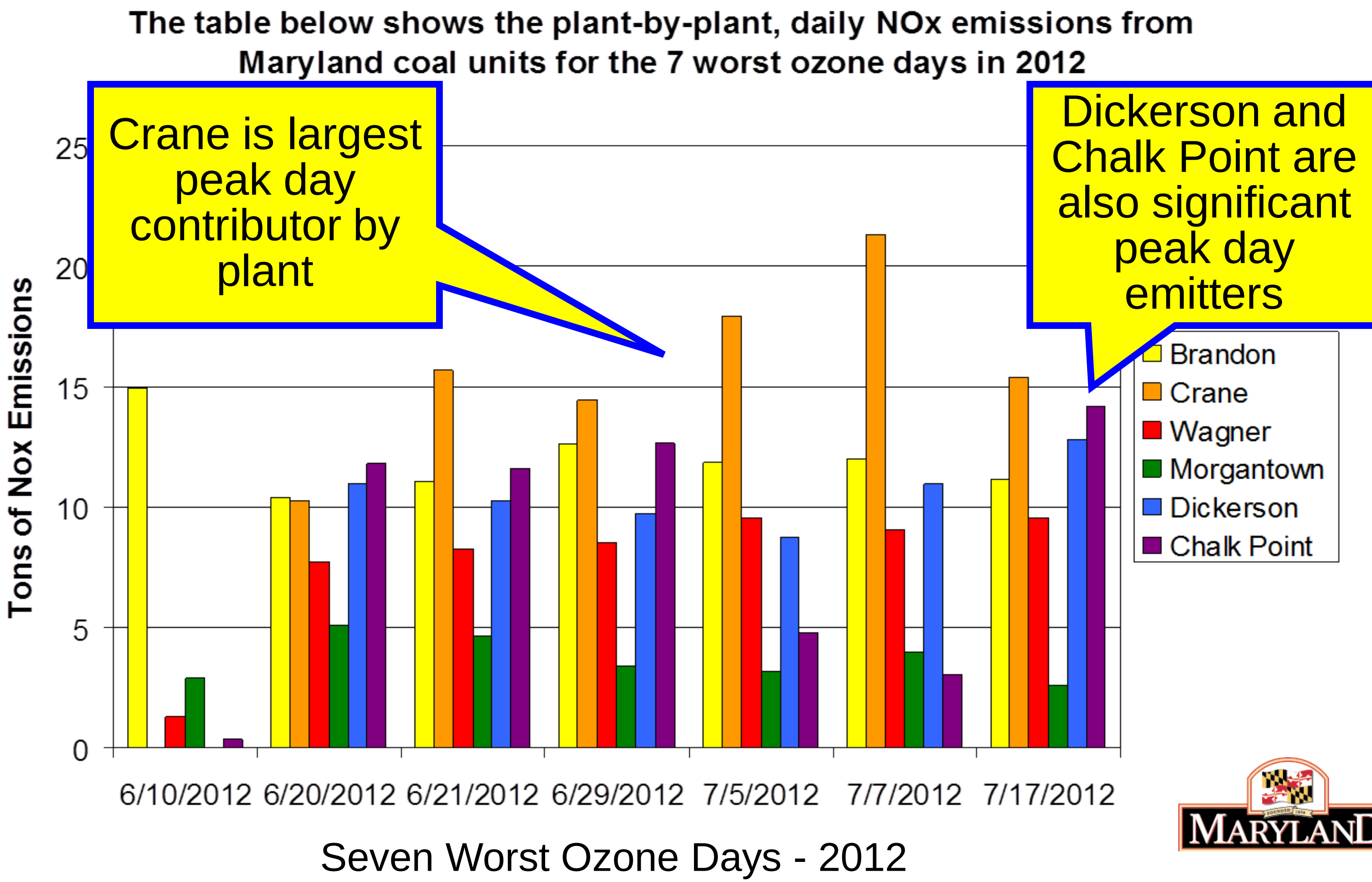


The HAA Worked Well

- The regulatory scheme in the HAA worked very well
  - System wide averaging and ozone season and annual caps did their job
    - Ozone levels are much lower
    - Helped bring Maryland into attainment for both the fine particulate standard and helped Maryland get very close to meeting the current ozone standard
- The remaining ozone problem is very focused:
  - What is happening on the worst days of the summer
  - Requires an enhanced regulatory scheme that focuses on shorter term, daily emission limits

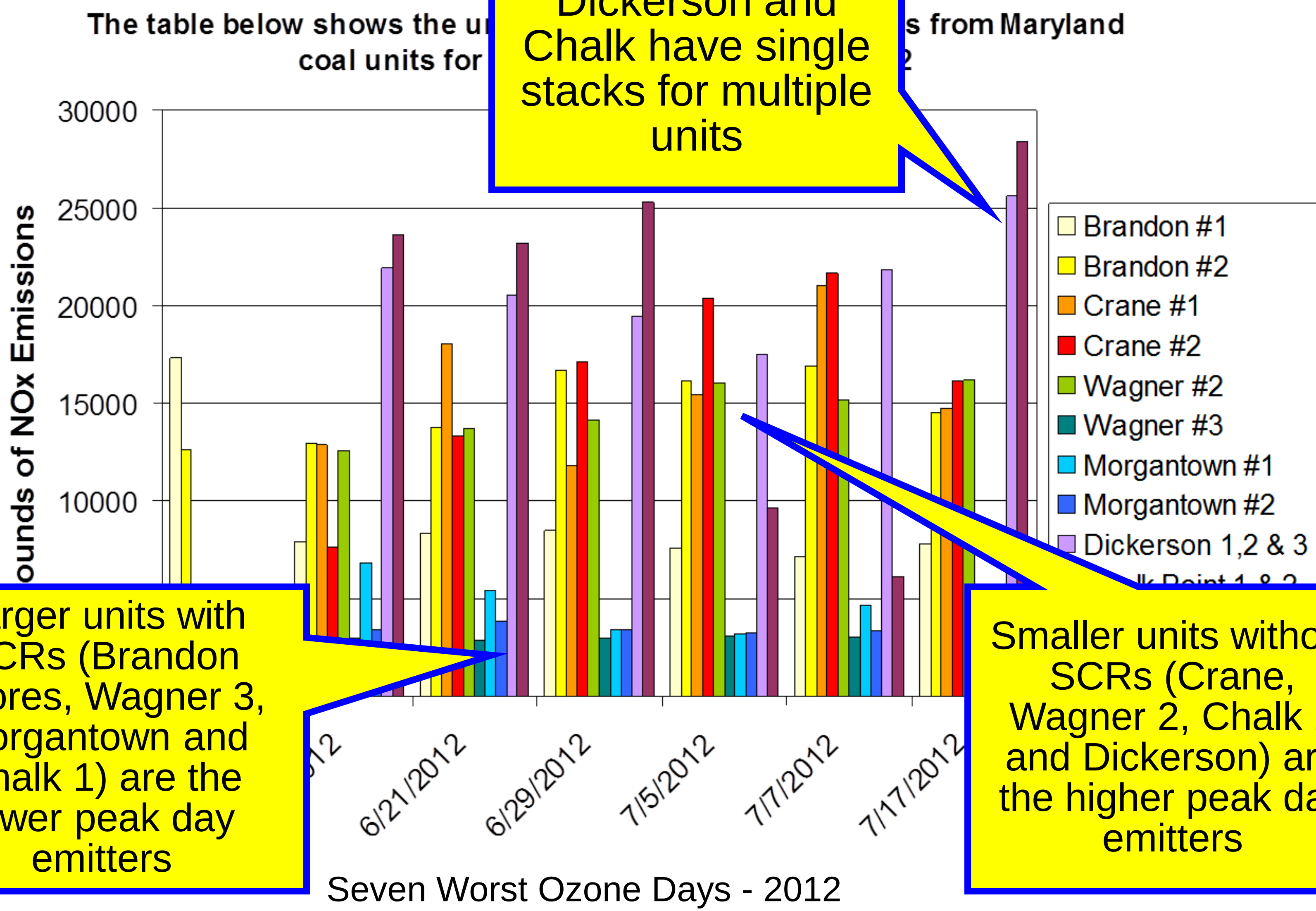
NOx Emissions on Peak Ozone Days

Daily NOx Emissions By Plant



NOx Emissions on Peak Ozone Days

Daily NOx Emissions By Unit



Dickerson and Chalk have single stacks for multiple units

Larger units with SCRs (Brandon Shores, Wagner 3, Morgantown and Chalk 1) are the lower peak day emitters

Smaller units without SCRs (Crane, Wagner 2, Chalk 2 and Dickerson) are the higher peak day emitters

Implementing The New Regulatory Scheme

Daily limits to reduce peak day emissions

- MDE has already moved ahead with the first step of this process:
  - Emergency rule for 2015 requirements became effective on May 1, 2015
  - Requires each unit at each plant to minimize NOx emissions each day of the summer by optimizing the use of existing control equipment
  - Significant immediate NOx reductions (about 9 tons/day) that will provide immediate additional public health protection
- Today's requested action will implement the second step of this new regulatory scheme:
  - Even deeper daily reductions by 2020

A Reminder

… What is already in place

Highlights:

Text with white background is text that is already adopted and in effect because of the emergency regulation that became effective on May 1, 2015. The emergency regulation adopted all of the 2015 requirements to provide immediate public health protection.

The text with the teal blue background is text that is identical to the text in the earlier regulation to implement additional requirements in 2020.

The text with the yellow background is new text to implement a new option to meet the 2020 requirements.

The text with the yellow background that also includes red underlining is the primary new substantive text to implement the new option to meet the 2020 requirements.

The New Regulatory Language

- This is the new substantive language in the regulation
- Adds a fourth option for 2020
  - If selected, the fourth option also drives deeper reductions in 2016, 2018 and 2020, while insuring equal or greater public health protection in 2020

.04 Additional NO_x Emission Control Requirements.

A. This regulation applies to C.P. Crane units 1 and 2, Chalk Point unit 2, Dickerson units 1, 2, and 3 and H.A. Wagner unit 2.

B. General Requirements. The owner or operator of the affected electric generating units subject to this regulation shall choose from the following:

(1) Not later than June 1, 2020:

(a) Install and operate a selective catalytic reduction (SCR) control system; and

(b) Meet a NO_x emission rate of 0.09 lbs/MMBtu, as determined on a 30-day rolling average during the ozone season;

(2) Not later than June 1, 2020, permanently retire the unit;

(3) Not later than June 1, 2020, permanently switch fuel from coal to natural gas for the unit;

(4) Not later than June 1, 2020, meet either a NO_x emission rate of 0.13 lbs/MMBtu as determined on a 24-hour systemwide block average or a systemwide NO_x tonnage cap of 21 tons per day during the ozone season.

C. When option B(4)of this regulation is selected:

(1) Not later than May 1, 2016, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.13 lbs/MMBtu during the ozone season.

(2) Not later than May 1, 2018, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.11 lbs/MMBtu during the ozone season.

(3) Not later than May 1, 2020, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.09 lbs/MMBtu during the ozone season.

Highlighted Regulation - Pages 2 and 3

The New Regulatory Language

New Option 4

.04 Additional NO_x Emission Control Requirements.

A. This regulation applies to C.P. Crane units 1 and 2, Chalk Point unit 2, Dickerson units 1, 2, and 3 and H.A. Wagner unit 2.

B. General Requirements. The owner or operator of the affected electric generating units subject to this regulation shall choose from the following:

(1) Not later than June 1, 2020:

(a) Install and operate a selective catalytic reduction (SCR) control system; and

(b) Meet a NO_x emission rate of 0.09 lbs/MMBtu, as determined on a 30-day rolling average during the ozon season;

(2) Not later than June 1, 2020, permanently retire the unit;

(3) Not later than June 1, 2020, permanently switch fuel from coal to natural gas for the unit;

(4) Not later than June 1, 2020, meet either a NO_x emission rate of 0.13 lbs/MMBtu as determined on a 24-hour systemwide block average or a systemwide NO_x tonnage cap of 21 tons per day during the ozone season.

C. When option B(4) of this regulation is selected:

(1) Not later than May 1, 2016, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.13 lbs/MMBtu during the ozone season.

(2) Not later than May 1, 2018, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.11 lbs/MMBtu during the ozone season.

(3) Not later than May 1, 2020, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.09 lbs/MMBtu during the ozone season.

Highlighted Regulation - Pages 2 and 3

0.13 lb/MMBTU - 24 Hour Average

- Where did this come from?
  - Based upon recommendations from the Ozone Transport Commission (OTC) and the two toughest similar regulations in the East (NJ and DE)
    - OTC recommends 0.125 to 0.15 lb/MMBTU for coal-fired EGUs like those in Maryland as a 24-hour average
    - Delaware's limit for coal-fired EGUs like those in Maryland is 0.125 lb/MMBTU as a 24-hour average
    - New Jersey's limit for coal-fired EGUs like those in Maryland is 0.15 lb/MMBTU as a 24-hour average
  - OTC recommendations and the DE and NJ limits are unit specific, but allow higher rates when units are starting up or shutting down or operating at low capacity
    - The Maryland limit is a system-wide limit that allows no exemptions

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The 21 Tons Per Day Cap

How the cap was determined

.04 Additional NO_x Emission Control Requirements.

A. This regulation applies to C.P. Crane units 1 and 2, Chalk Point unit 2, Dickerson units 1, 2, and 3 and H.A. Wagner unit 2.

B. General Requirements. The owner or operator of the affected electric generating units subject to this regulation shall choose from the following:

(1) Not later than June 1, 2020:

(a) Install and operate a selective catalytic reduction (SCR) control system; and

(b) Meet a NO_x emission rate of 0.09 lbs/MMBtu, as determined on a 30-day rolling average during the ozon season;

(2) Not later than June 1, 2020, permanently retire the unit;

(3) Not later than June 1, 2020, permanently switch fuel from coal to natural gas for the unit;

(4) Not later than June 1, 2020, meet either a NO_x emission rate of 0.15 lbs/MMBtu as determined on a 24-hour systemwide block average or a systemwide NO_x tonnage cap of 21 tons per day during the ozone season.

C. When option B(4) of this regulation is selected:

(1) Not later than May 1, 2016, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.13 lbs/MMBtu during the ozone season.

(2) Not later than May 1, 2018, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.11 lbs/MMBtu during the ozone season.

(3) Not later than May 1, 2020, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.09 lbs/MMBtu during the ozone season.

Highlighted Regulation - Pages 2 and 3

Daily Caps - If SCR Based - High End

- Assumes all units within each system controlled with SCRs
  - High performing SCRs at 0.09 lbs/mmbtu
    - 0.09 lbs/mmbtu is the rate connected to "2020 option 1" … installing an SCR
      - 04B(1)
- Full operation
- NRG system would be at 26.06 tons/day
- Raven system would be at 27.81 tons/day

NRG Units	MAX Heat Rate mmbtu/hr	NOx Rate (lbs/mmbtu)	Daily tons
Chalk Point 1	3130	0.09	3.38
Chalk Point	3130	0.09	3.38
Dickerson 1	1646	0.09	1.78
Dickerson 2	1646	0.09	1.78
Dickerson 3	1646	0.09	1.78
Morgantown 1	6465	0.09	6.98
Morgantown 2	6465	0.09	6.98
Total	24128	**NRG 24 hr tons**	**26.06**

Raven Units	MAX Heat Rate mmbtu/hr	NOx Rate (lbs/mmbtu)	Daily Tons
Brandon1	8000	0.09	6.72
Brandon2	8000	0.09	6.72
Wagner 2	2013	0.09	1.69
Wagner3	2740	0.09	2.30
Crane 1	2500	0.09	2.10
Crane2	2500	0.09	2.10
Total	25753	**Raven 24 hr tons**	**27.81**

Daily Caps - If SCR Based - Low End

- Assumes all units within each system controlled with SCRs
  - Very high performing SCRs at 0.07 lbs/mmbtu
- Full operation
- NRG system would be at 20.27 tons/day
- Raven system would be at 21.63 tons/day

NRG Units	MAX Heat Rate mmbtu/hr	NOx Rate (lbs/mmbtu)	Daily tons
Chalk Point 1	3130	0.07	2.63
Chalk Point	3130	0.07	2.63
Dickerson 1	1646	0.07	1.38
Dickerson 2	1646	0.07	1.38
Dickerson 3	1646	0.07	1.38
Morgantown 1	6465	0.07	5.43
Morgantown 2	6465	0.07	5.43
Total	24128	**NRG 24 hr tons**	**20.27**

Raven Units	MAX Heat Rate mmbtu/hr	NOx Rate (lbs/mmbtu)	Daily Tons
Brandon1	8000	0.07	6.72
Brandon2	8000	0.07	6.72
Wagner 2	2013	0.07	1.69
Wagner3	2740	0.07	2.30
Crane 1	2500	0.07	2.10
Crane2	2500	0.07	2.10
Total	25753	**Raven 24 hr tons**	**21.63**

Daily Caps - If Natural Gas Based - High End

- Assumes all non-SCR units within each system convert to natural gas
  - Consistent with .04B(3)
  - Better performing retrofit level … 0.15 lbs/mmbtu
- Full operation
- SCR units at 0.09 lbs/mmbtu
- NRG system would be at 31.87 tons/day
- Raven system would be at 32.86 tons/day

HRG Units	**MAX Heat Rate mmbtu/hr**	**NOx Rate (lbs/mmbtu)**	**Daily tons**
Chalk Point 1	3130	0.09	3.38
Chalk Point 2	3130	0.15	5.63
Dickerson 1	1646	0.15	2.96
Dickerson 2	1646	0.15	2.96
Dickerson 3	1646	0.15	2.96
Morgantown 1	6465	0.09	6.98
Morgantown 2	6465	0.09	6.98
Total	24128	**NRG 24 hr tons**	**31.87**

Raven Units	**MAX Heat Rate mmbtu/hr**	**NOx Rate (lbs/mmbtu)**	**Daily tons**
Brandon1	8000	0.09	8.64
Brandon2	8000	0.09	8.64
Wagner 2	2013	0.15	3.62
Wagner3	2740	0.09	2.96
Crane 1	2500	0.15	4.50
Crane2	2500	0.15	4.50
Total	25753	**Raven 24 hr tons**	**32.86**

Daily Caps - If Natural Gas Based - Low End

- Assumes all non-SCR units within each system convert to natural gas
  - Better performing retrofit level … 0.15 lbs/mmbtu
  - NG units operate at 75%
- SCR units at 0.09 lbs/mmbtu (100% capacity)
- NRG system would be at 28.24 tons/day
- Raven system would be at 29.71

NRG Units	MAX Heat Rate mmbtu/hr	Daily NOx Rate (lbs/mmbtu)	Capacity Factor	Daily tons
Chalk Point 1	3130	0.09	1.00	3.38
Chalk Point 2*	3130	0.15	0.75	4.23
Dickerson 1	1646	0.15	0.75	2.22
Dickerson 2	1646	0.15	0.75	2.22
Dickerson 3	1646	0.15	0.75	2.22
Morgantown 1	6465	0.09	1.00	6.98
Morgantown 2	6465	0.09	1.00	6.98
Total	24128	**NRG 24 hr tons**		**28.24**

Raven Units	MAX Heat Rate mmbtu/hr	Daily NOx Rate (lbs/mmbtu)	Capacity Factor	Daily tons
Brandon1	8000	0.09	1.00	8.64
Brandon2	8000	0.09	1.00	8.64
Wagner 2	2013	0.15	0.75	2.72
Wagner3	2740	0.09	1.00	2.96
Crane 1	2500	0.15	0.75	3.38
Crane2	2500	0.15	0.75	3.38
Total	25753	**Raven 24 hr tons**		**29.71**

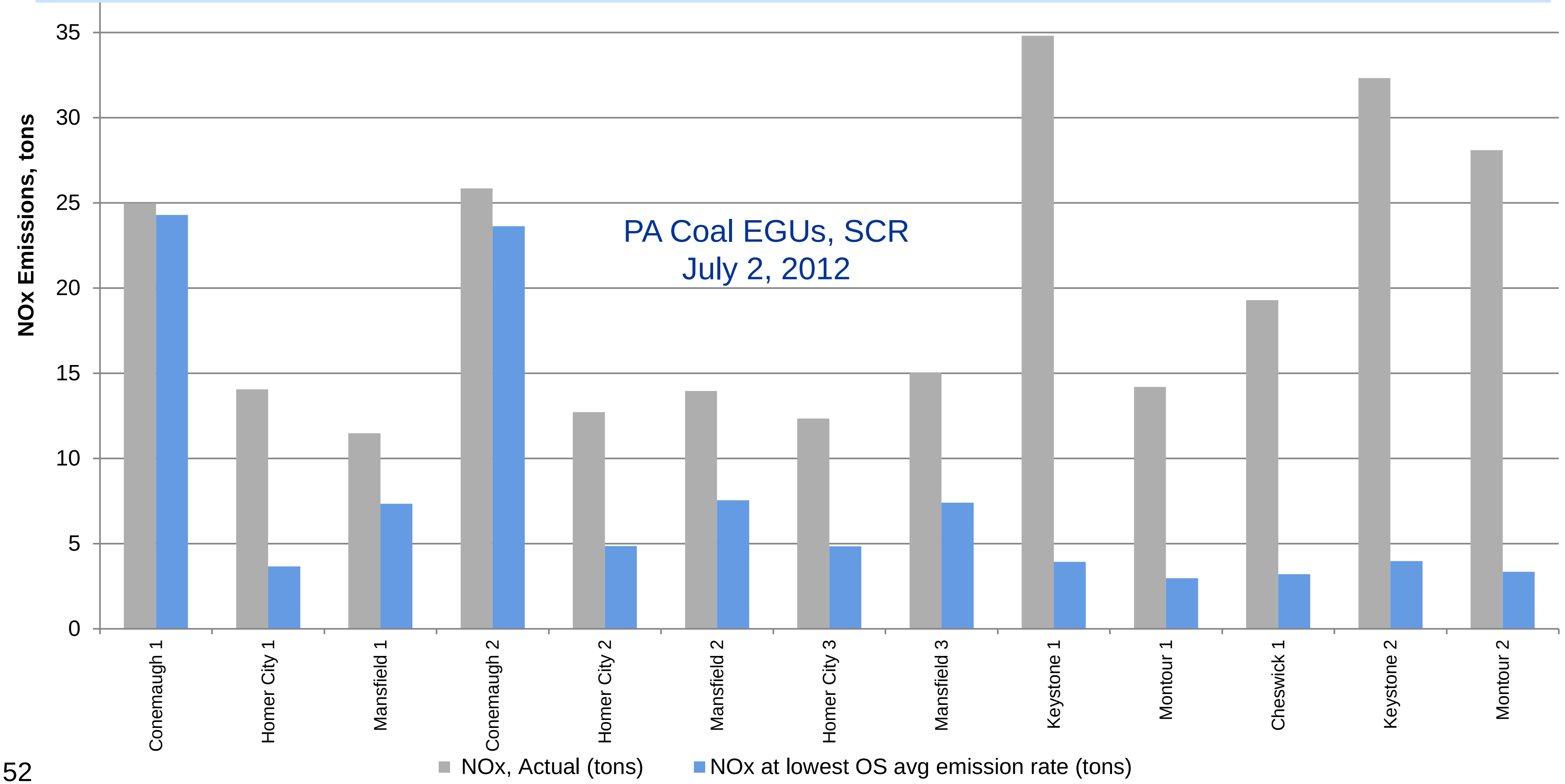
Daily Caps - Summary

Daily Caps	NRG	Raven
SCR - High	26.06	27.81
SCR - Low	20.27	21.63
NG - High	31.87	32.86
NG - Low	28.24	29.71

The proposed regulation sets 21 tons per day as the maximum daily emissions of NOx allowed from either companies “system”

Is 21 Tons per Day a Tough Cap?

- It is a very tough cap
- There are numerous individual units in PA that by themselves routinely emit more than 21 tons of NOx in a single day
- Our researchers tell us that because of winds and ozone chemistry, reductions in PA may be as … or more important … to solving Maryland's ozone problem than "in-State" reductions

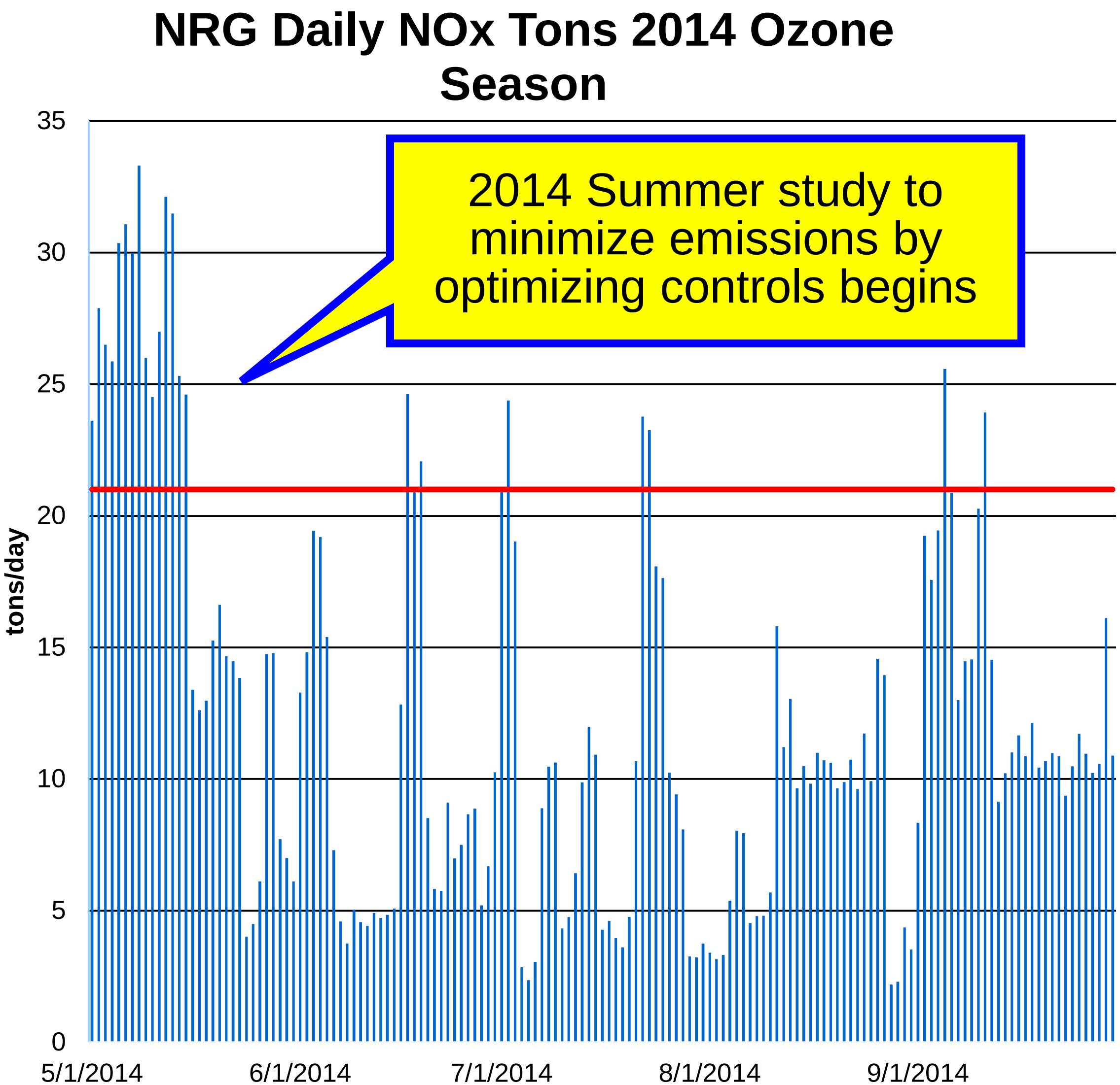


Caps and Historical Data

What does measured data tell us?

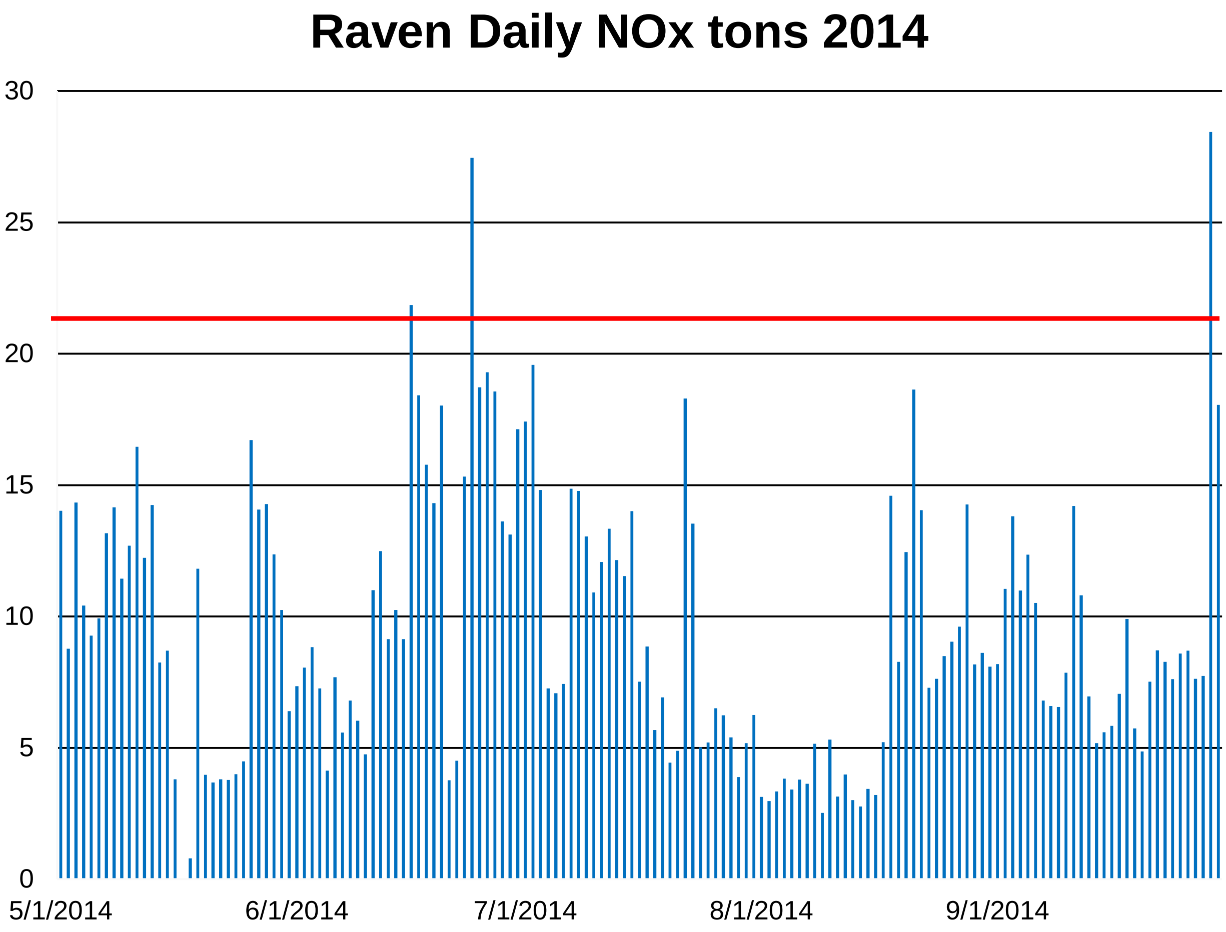
- The caps must have meaning …
  - Must be lower than high peak day emissions in the past
- We’ve looked at measured data in 2011, 2012, 2013 and 2014
  - 2012 was a hotter than normal summer
  - 2014 was cooler
  - 2014 was the first year where both companies minimized daily emissions by optimizing the use of existing control technology
    - The 2014 summer study

NRG Daily Emission 2014 Ozone Season



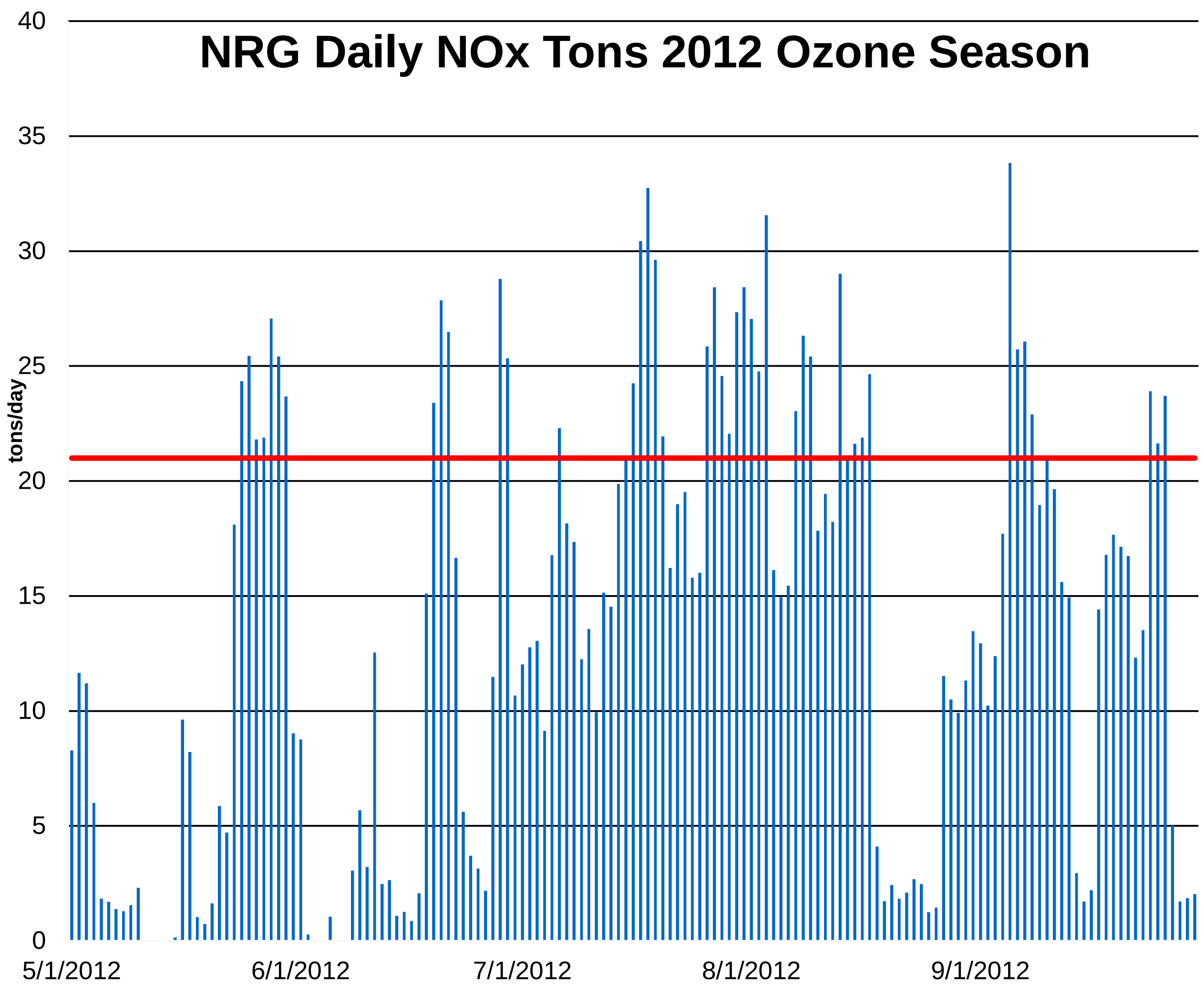
- 153 days total
- 23 days(15%) over 21 tons
- 130 days (85%) under 21 tons
- Max 33.30 tons

Raven Daily Emission 2014 Ozone Season



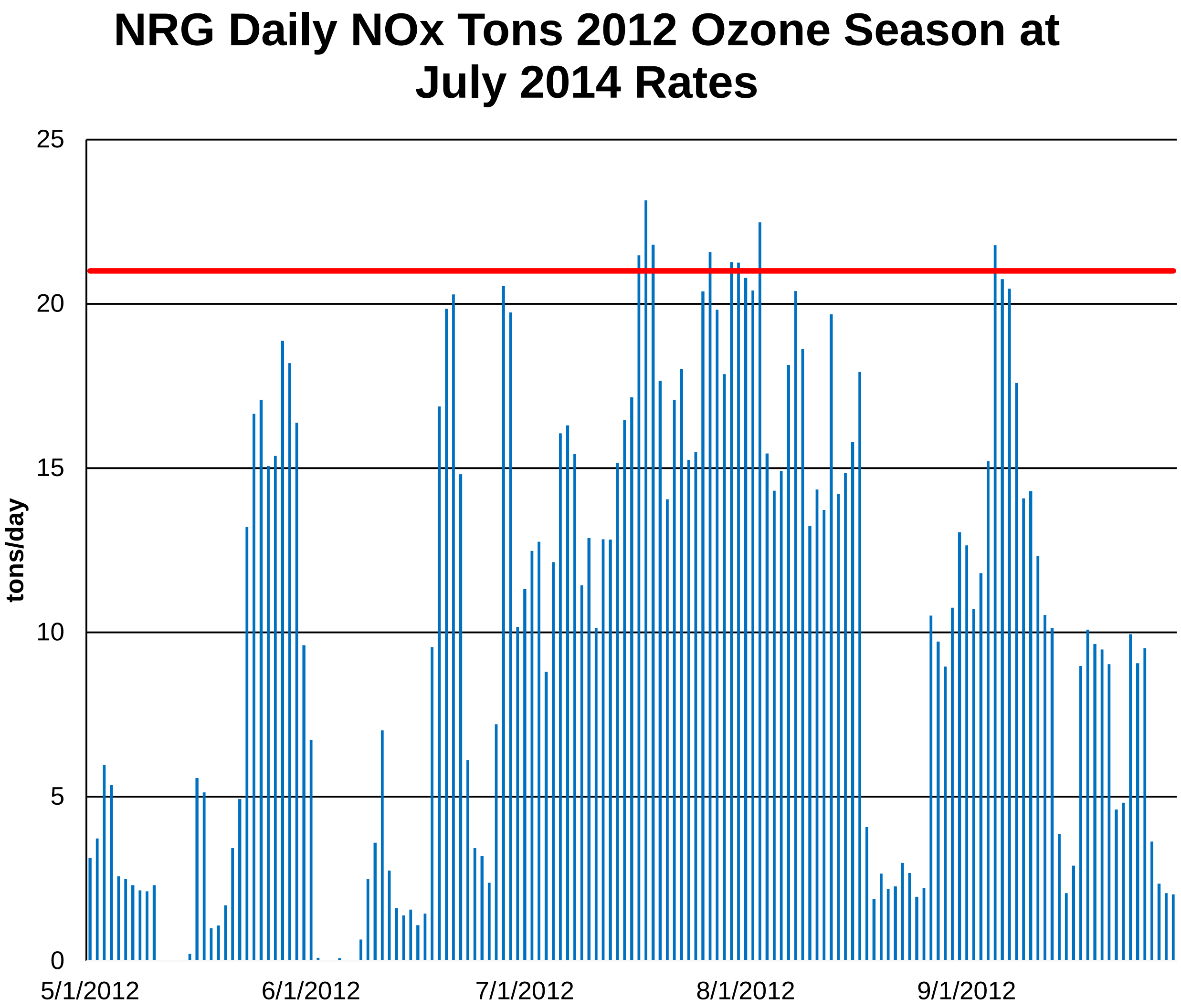
- 153 days total
- 2 days (1%) over 21 tons
- 151 days (99%) under 21 tons
- Highest day 27 tons June 24th 2014

NRG Daily Emission 2012 Ozone Season



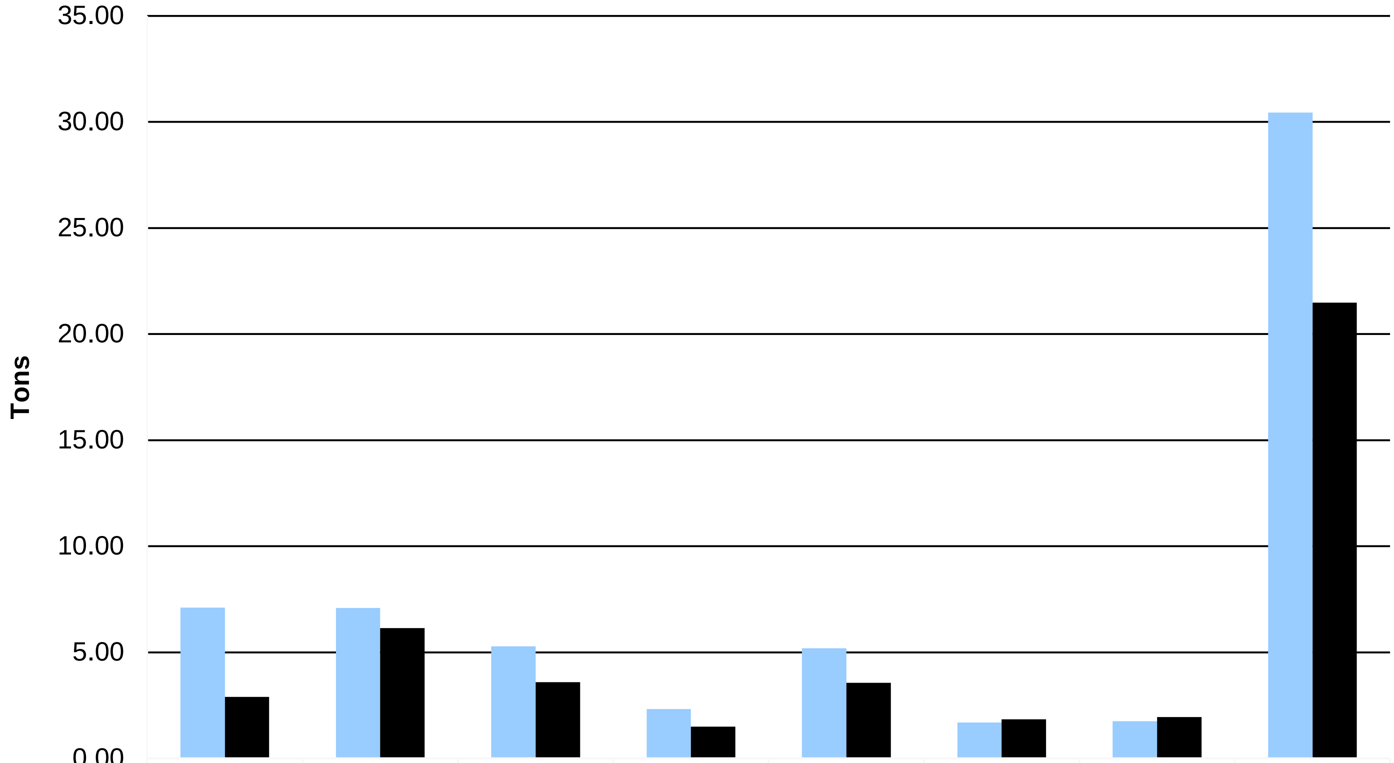
- 153 days total
- 42 days (27%) over 21 tons
- 111 days (73%) under 21 tons
- Highest day 33.8

NRG - 2012 - Optimization Assumed



- 153 days total
- 8 days (5%) over 21 tons
- 145 days (95%) under 21 tons
- Highest days
  - July 17 - 21.47 tons
  - July 18 - 23.15 tons

July 17, 2012 at July 2014 Rates



	Chalk Point 1 NOx Tons	Chalk Point 2 NOx Tons	Dickerson 1 NOx Tons	Dickerson 2 NOx Tons	Dickerson 3 NOx tons	Morgantown 1 NOx tons	Morgantown 2 NOx Tons	NRG Daily Total NOx tons
Actual tons	7.11	7.09	5.28	2.32	5.20	1.69	1.75	30.43
Tons at July 14 rates	2.90	6.14	3.60	1.49	3.56	1.84	1.95	21.48

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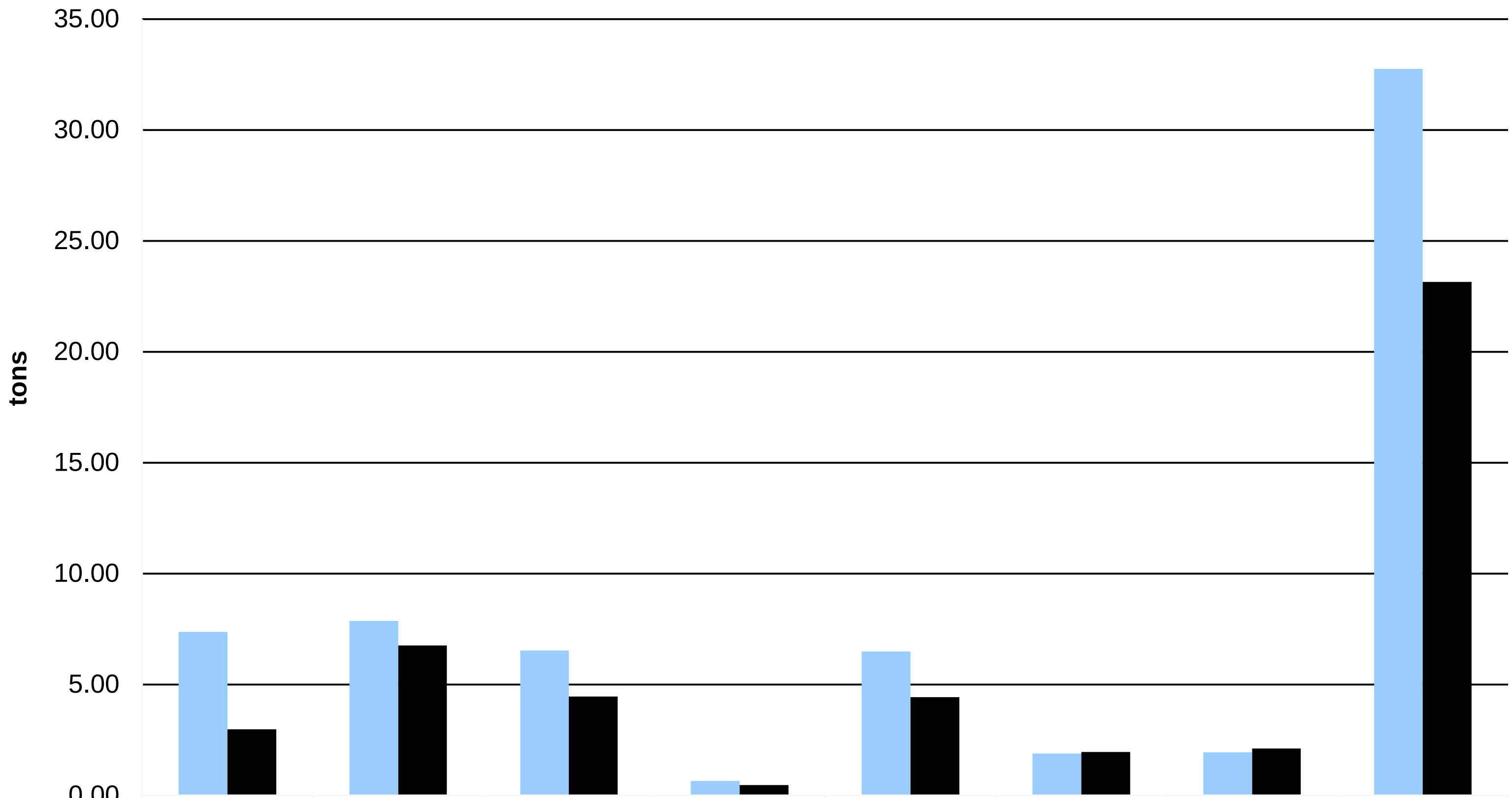
July 18, 2012 at July 2014 Rates



	Chalk Point 1 NOx Tons	Chalk Point 2 NOx Tons	Dickerson 1 NOx Tons	Dickerson 2 NOx Tons	Dickerson 3 NOx tons	Morgantown 1 NOx tons	Morgantown 2 NOx Tons	NRG Daily Total NOx tons
Actual tons	7.37	7.87	6.54	0.66	6.49	1.88	1.94	32.75
Tons at July 14 rates	2.98	6.76	4.46	0.46	4.43	1.95	2.11	23.15

Earlier Public Health Protection

… and benefits to the Bay, when new option 4 is chosen

.04 Additional NO_x Emission Control Requirements.

A. This regulation applies to C.P. Crane units 1 and 2, Chalk Point unit 2, Dickerson units 1, 2, and 3 and H.A. Wagner unit 2.

B. General Requirements. The owner or operator of the affected electric generating units subject to this regulation shall choose from the following:

(1) Not later than June 1, 2020:

(a) Install and operate a selective catalytic reduction (SCR) control system; and

(b) Meet a NO_x emission rate of 0.09 lbs/MMBtu, as determined on a 30-day rolling average during the ozon season;

(2) Not later than June 1, 2020, permanently retire the unit;

(3) Not later than June 1, 2020, permanently switch fuel from coal to natural gas for the unit;

(4) Not later than June 1, 2020, meet either a NO_x emission rate of 0.13 lbs/MMBtu as determined on a 24-hour systemwide block average or a systemwide NO_x tonnage cap of 21 tons per day during the ozone season.

C. When option B(4)of this regulation is selected:

(1) Not later than May 1, 2016, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.13 lbs/MMBtu during the ozone season.

(2) Not later than May 1, 2018, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.11 lbs/MMBtu during the ozone season.

(3) Not later than May 1, 2020, the owner or operator of an affected electric generating unit shall not exceed a NO_x 30-day systemwide rolling average emission rate of 0.09 lbs/MMBtu during the ozone season.

Highlighted Regulation - Pages 2 and 3

Choosing Option 4 …

… also requires phased in deeper reductions in 2016, 2018 and 2020

- Opting into option 4 also requires system-wide, phased in, additional NOx reductions:
  - 0.13 lb/mmbtu in 2016
  - 0.11 lb/mmbtu in 2018
  - 0.09 lb/mmbtu in 2020
  - All 30-day rolling averages

Other New Regulatory Language

Reliability Safety Valve Linked to New Option 4

New regulation .07 - Pages 4 and 5

.07 Electric System Reliability During Ozone Seasons.

A. In the event of emergency operations, a maximum of 12 hours of operations per system per ozone season may be removed from the calculation of the NO_x limitations in Regulation .04B(4) of this chapter from the unit(s) responding to the emergency operations provided that:

(1) Within one business day following the emergency operation, the owner or operator of the affected electric generating unit(s) notifies the Manager of the Air Quality Compliance Program of the emergency operations taken by PJM Interconnection; and

(2) Within five business days following the emergency operation, the owner or operator of the affected electric generating unit(s) provides the Department with the following information:

(a) PJM documentation of the emergency event called and the unit(s) requested to operate;

(b) Unit(s) dispatched for the emergency operation;

(c) Number of hours that the unit(s) responded to the emergency operation and the consecutive hours that will be used towards the calculation of the NO_x limitations in §.04B(4) of this chapter; and

(d) Other information regarding efforts the owner or operator took to minimize NO_x emissions in accordance with Regulation .03A(1) of this chapter on the day that the emergency operation was called.

B. Any partial hour in which a unit operated in response to emergency operations under §A of this regulation shall constitute a full hour of operations.

Supporting definition in regulation .01 - Page 1

(2) "Emergency operations" means an event called when PJM Interconnection, LLC or a successor independent system operator, acts to invoke one or more of the Warning or Action procedures in accordance with PJM Manual 13, Revision 57, as amended, to avoid potential interruption in electric service and maintain electric system reliability.

PJM Warnings and Actions

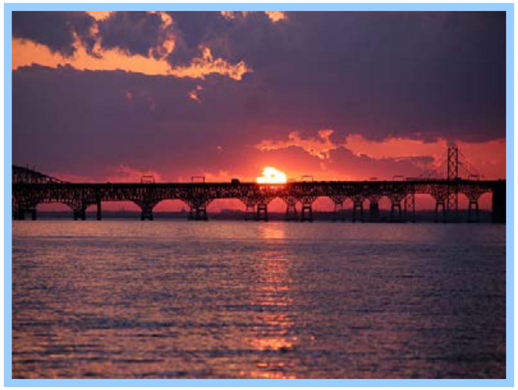
- The electricity grid in Maryland is well supported and includes adequate backup generation for high energy demand days
- In rare instances, PJM needs more reserves and issues emergency warnings and actions needed for reliability
- The regulation would allow for half a day or 12 hours of emissions to be excluded only from the calculation of daily limits

Year	Summer Events	Event Details					
		Date	Hrs	Units	Date	Hrs	Units
2015	0		0			0	
2014	0		0			0	
2013	2	7/18	4	CP1&2, D1,2&3, M1&2	9/11	5	CP1&2, D1,2&3, M1&2
2012	2	7/17	5	CP1&2, D1,2&3, M1&2, BS1&2, W2&3, C1&2	7/18	4	CP1&2, D1&3, M1&2
2011	2	6/9	4	CP2, M1&2, W2&3, BS1&2,C1&2	7/22	7	CP1&2, D1,2&3, M1&2, BS1&2, W2&3, C1&2

The Ozone Standard and Excursions

- When EPA finalizes a standard it is designed to insure public health and environmental protection with an adequate margin of safety

- EPA weighs both elements of the standard when determining protection with an adequate margin of safety
  - The level of the standard … and
  - The form of the standard



- So … the ozone standard is …
  - The fourth highest level measured at individual monitors averaged for three consecutive years
- The standard allows an occasional excursion above 75 ppb and still protects public health and the environment with an adequate margin of safety

Reliability in 2020

- The reliability safety valve does not come in to play until 2020
- MDE and the Maryland Public Service Commission (PSC) expect many fewer issues with reliability in 2020
- Four new natural gas units scheduled for construction and operation before 2020
- New systems being put into place by PJM also appear to set the stage for a very stable, reliable energy system in the 2020 time frame

Other New Language

… needed to implement option 4

- In definitions - page 1 … highlighted regulation

(10) "24-hour systemwide block average emission rate" means a value in lbs/MMBtu calculated by:

(a) Summing the total pounds of pollutant emitted from the system during 24 hours between midnight of one day and ending the following midnight;

(b) Summing the total heat input to the system 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 system hours between midnight of one day and ending the following midnight by the total heat input during 24 system hours between midnight of one day and ending the following midnight.

MARYLAND

Other New Language - Continued

… linked to option 4

- Clarifying natural gas and ownership issues
- Page 3 … highlighted regulation

D. In order to calculate the 24-hour systemwide block average emission rate and systemwide NO_x tonnage cap under §B(4) of this regulation and the systemwide rolling average emission rates under §C of this regulation:

(1) The owner or operator shall use all affected electric generating units within their system as those terms are defined in Regulation .01B of this chapter; and

(2) The unit(s) NOx emissions from all operations during the entire operating day shall be used where the unit(s) burn coal at any time during that operating day.

E. Beginning June 1, 2020, if the unit(s) included in a system, as that system existed on May 1, 2015, is no longer directly or indirectly owned, operated, or controlled by the owner, operator, or controller of the system:

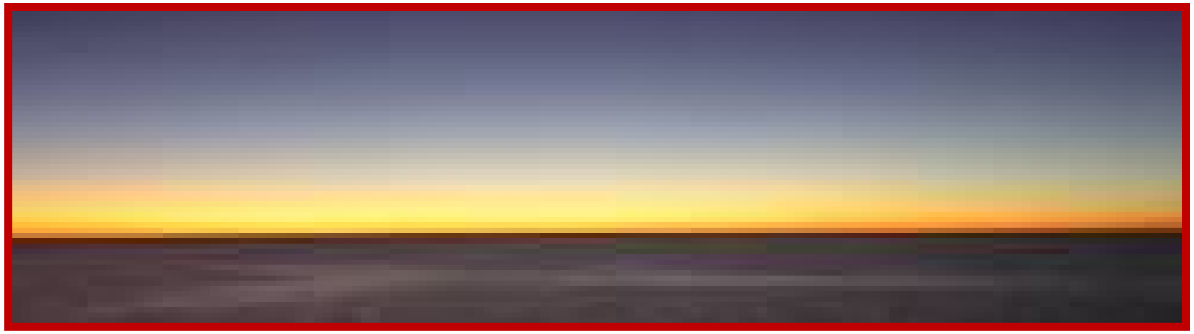
(1) The remaining units within the system shall meet either:

(a) The requirements of §B(1)—(3) of this regulation; or

(b) A NOx emission rate of 0.13 lbs/MMBtu as determined on a 24-hour systemwide block average and the requirements of §C(3) of this regulation.

(2) The unit(s) no longer included in the system shall meet requirements of §B(1)—(3) of this regulation.

F. For the purposes of this regulation, the owner includes parent companies, affiliates, and subsidiaries of the owner.



Other New Language - Continued

… driven by the need to implement option 4

- Building option 4 into reporting and compliance requirements
- Page 4 … highlighted regulation

(5) For an affected electric generating unit which has selected the compliance option of Regulation .04B(4) of this chapter, beginning June 1, 2016, the 30-day rolling average emission rate and 30-day systemwide rolling average emission rate calculated in lbs/MMBtu;

(6) For an affected electric generating unit which has selected the compliance option of Regulation .04B(4) of this chapter, beginning June 1, 2020, data, information, and calculations which demonstrate the systemwide NO_x emission rate as determined on a 24-hour block average or the actual systemwide daily NO_x emissions in tons for each day during the month; and

(7) For an affected electric generating unit which has selected the compliance option of Regulation .04E(2) of this chapter, beginning June 1, 2020, data, information, and calculations which demonstrate the systemwide NO_x emission rate as determined on a 24-hour block average for each day during the month.

MARYLAND


Ozone, Public Health and
Environmental Benefits From
the New Regulations

How Much Will the New Regulation

… help Maryland with it's ozone problem?

- Maryland has historically had one of the toughest ozone problems in the Country
  - Recent progress in reducing ozone has been remarkable
  - 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 in 2015
    - This SIP must be supported by photochemical modeling and an "Attainment Demonstration"
  - We believe we have enough modeling completed to have a very clear picture of what Maryland needs in it's plan to bring the State into attainment

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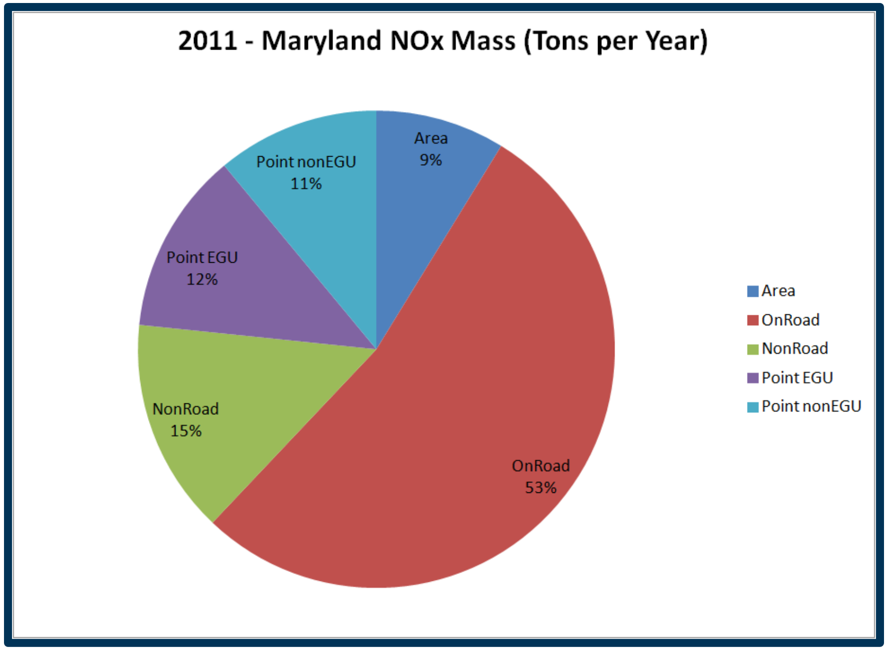
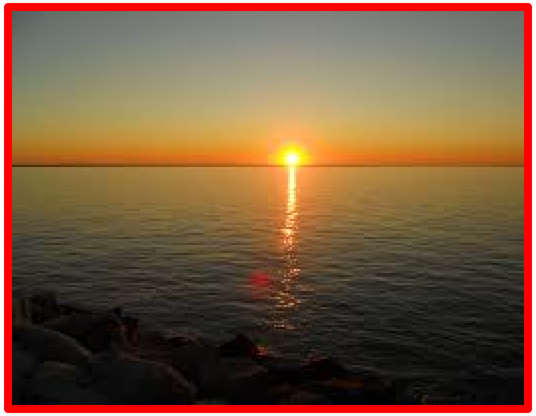
The New Regulation - How Much Help?

- It is a small, but very important part of the "Maryland Plan"
- The Maryland Plan looks at Power plants, cars, many other source categories
- We know the States ozone problem is dominated by ozone pollution floating in from upwind states (called ozone transport)
- But we also know that on many days between 30% and 50% of the States problem is home grown



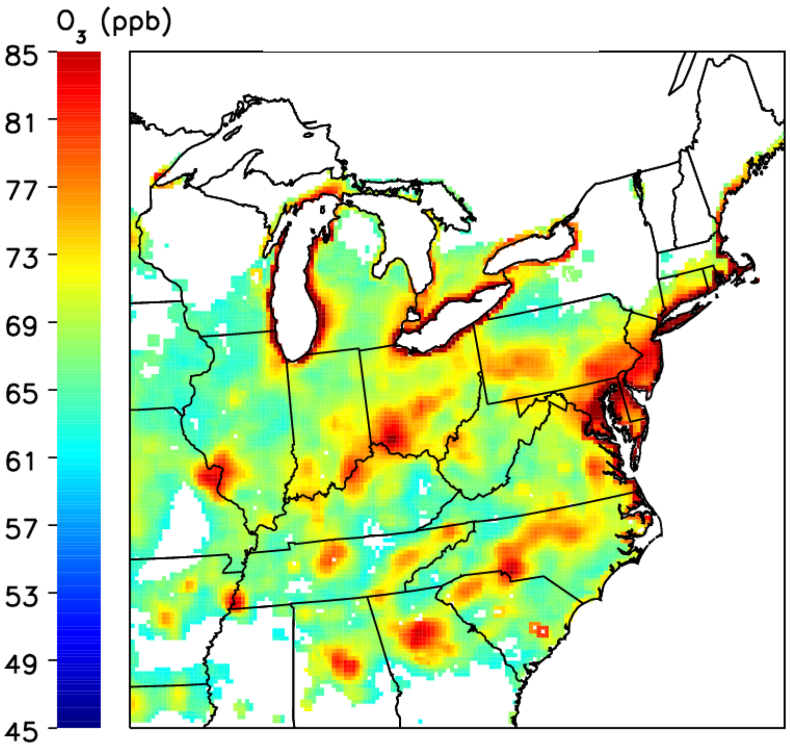
Control Measures in the MD Plan

- The Maryland Plan focuses on 3 basic packages of new control measures
- Widespread regional emission reduction programs that are "on the books" or "on the way" (OTB/OTW):
- Reductions in upwind states to reduce ozone transport
  - On some days, our research balloons and airplanes measure incoming ozone already above the 75 ppb standard
  - Power plants, cars and trucks and multiple other sources
- New reduction measures in Maryland
  - This regulatory effort on power plants
  - Other efforts on mobile and smaller "area" source

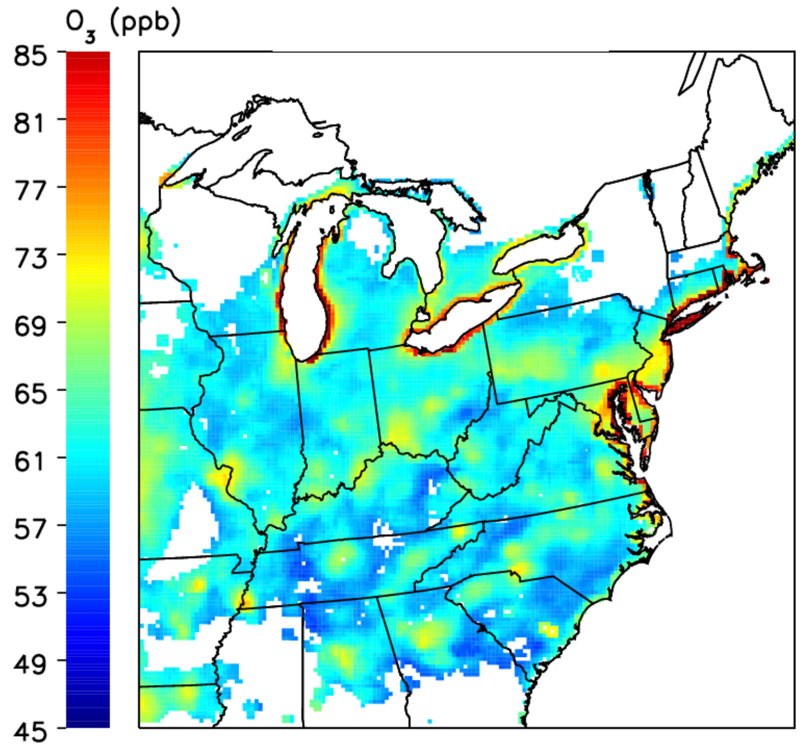


The Bottom Line

… Projected ozone improvements 2011 to 2018 from the Maryland Plan



2011 Measured Ozone

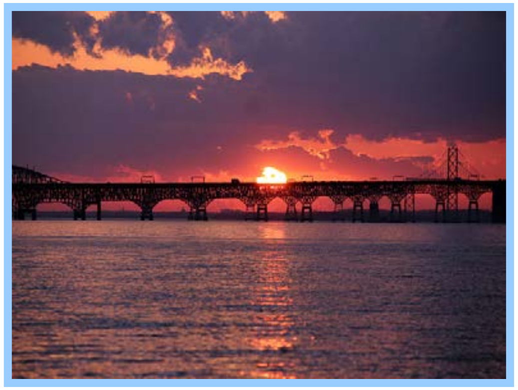


2018 - After the Maryland Plan

More later …

OTB/OTW Reductions - Some Background

- There are over 40 control programs in this piece of our Plan
  - Generally older control programs that continue to generate deeper reductions as they are phased in or as fleets turn over
- By far, the largest contributors to NOx reductions in the OTB/OTW category are mobile sources
  - Tier 2 Vehicle Standards
  - Federal fuel economy (CAFÉ) standards
  - Heavy Duty Diesel Standards
  - Marine Diesel Engine Standards
  - Emission Control Area (ECA) requirements
  - Many more …
- VOC reductions from the OTB/OTW category come from programs like
  - Federal consumer product and paint regulations
  - Tier 2 Vehicle Standards
  - VOC RACT … Many more …



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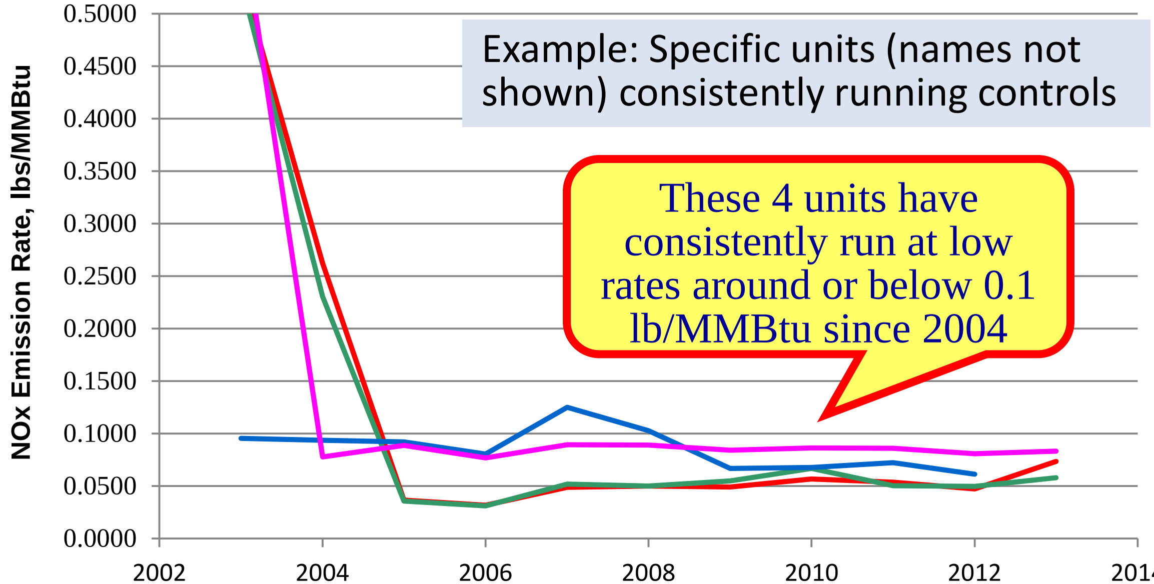
New Reductions in Transport Included?

- Three significant new transport strategies are included in the Maryland Plan
- The Federal Tier 3 Vehicle and Fuel Standards may be the most significant new transport strategy
- New OTC Regional Measures
- “Good Neighbor “ controls that address coal-fired power plants in 10 states upwind of MD are also included in the modeling
    - Focuses primarily on the large potential reductions from insuring that currently installed technologies are run well
        - Also includes significant reductions from units scheduled for retirement (or other major changes) by 2018

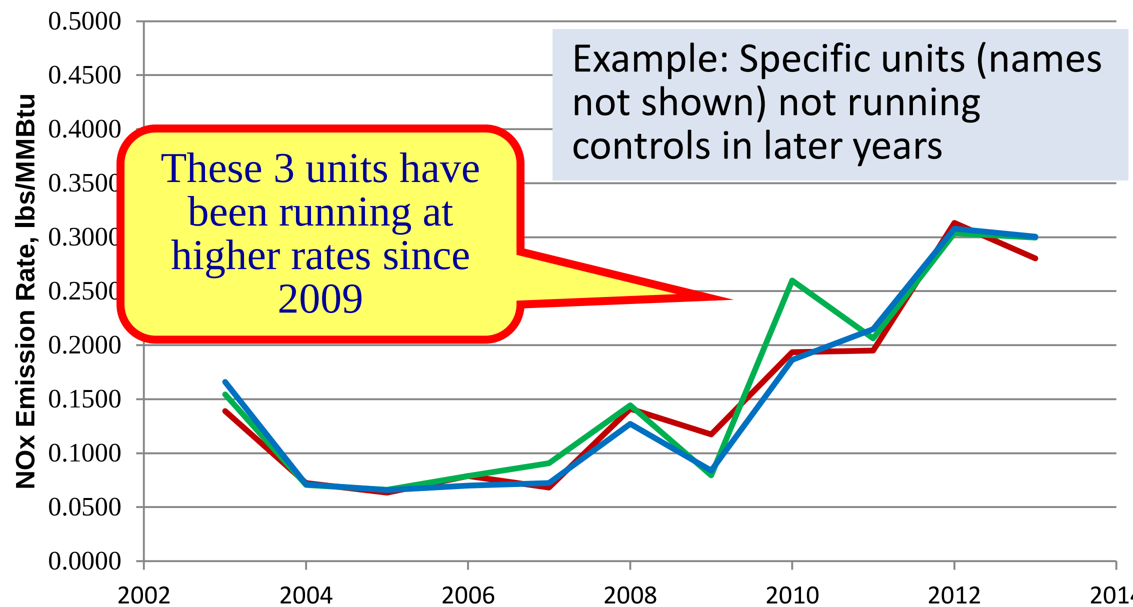
Running Power Plant Controls Well?

Average Ozone Season Emission Rates at Specific Units by Year

Many Sources Run Controls Well →

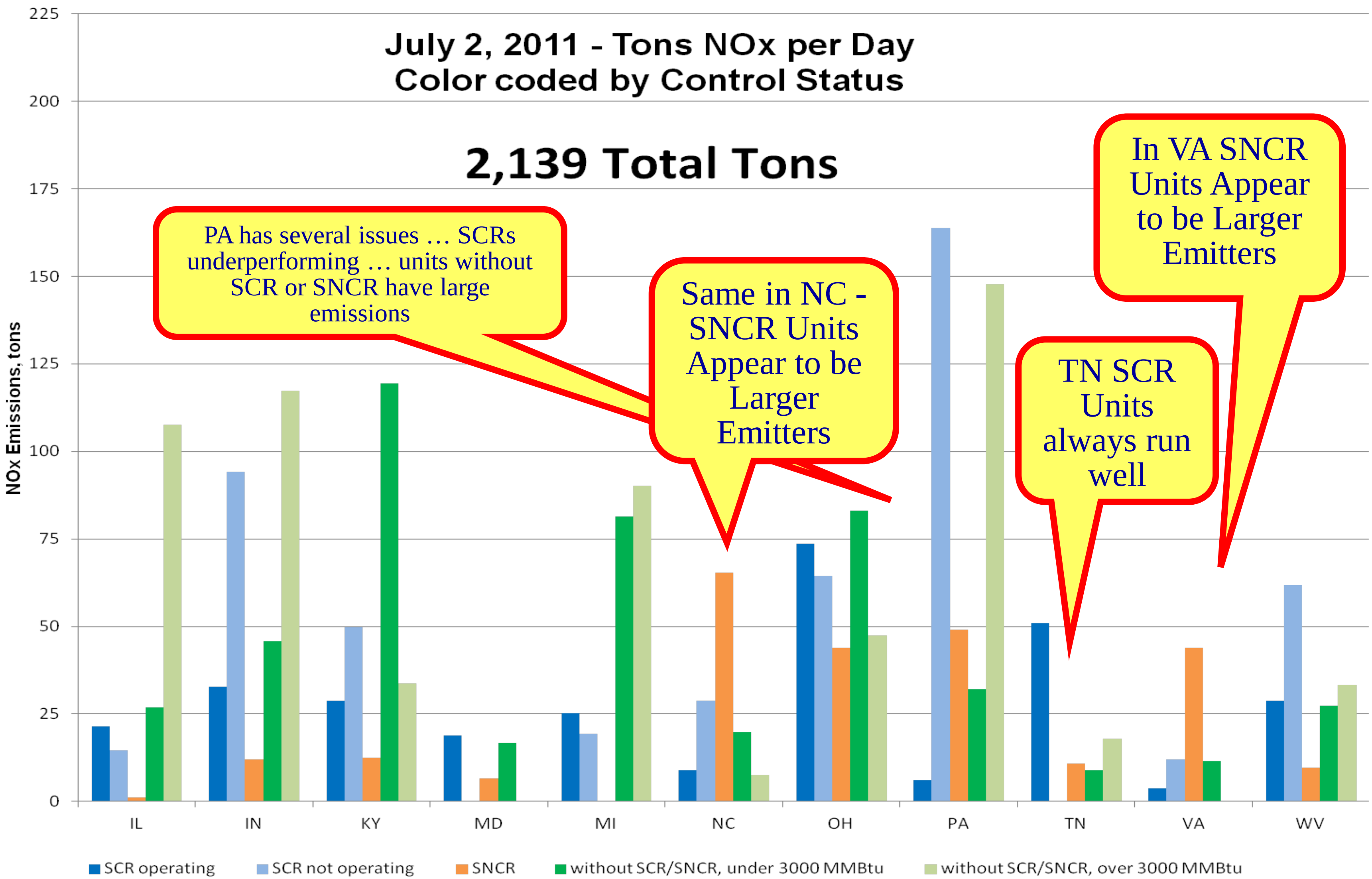


Some Units Are Not Running Controls as Well →



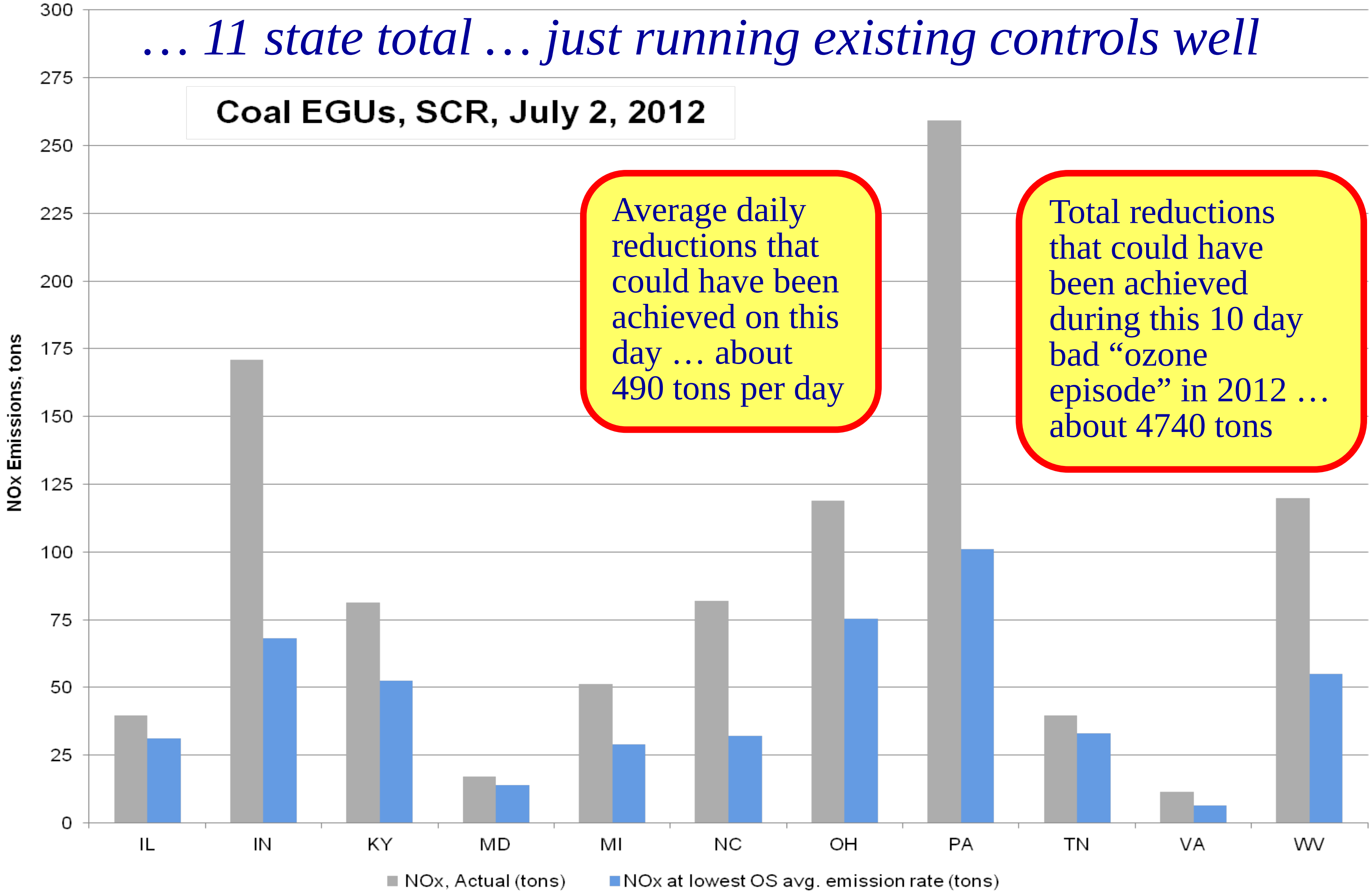
MDE has conducted this kind of analysis for every coal-fired unit in states that contribute to Maryland's ozone problem

So What Has MDE Found?



The MDE research has shown that many, many sources across the East are not using their control technologies the way they were designed to be used

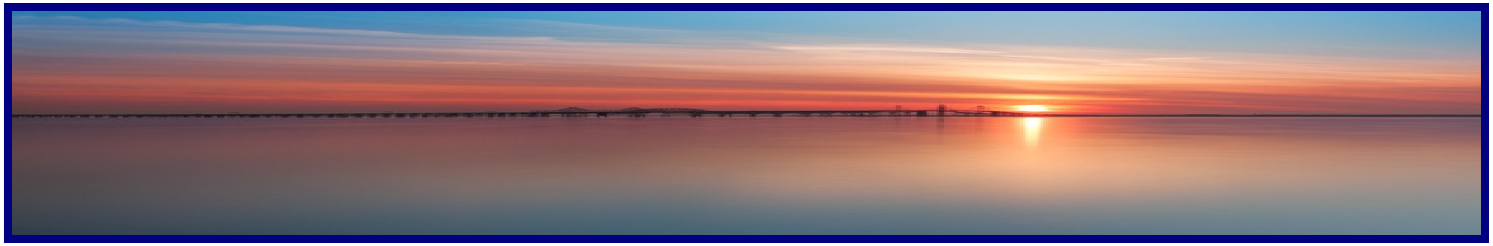
Reductions Could be Very Large



What Inside the OTC Measures are Included?

- Mobile Source Initiatives
  - Aftermarket Catalyst effort
  - ZEV/CALEV state programs
  - Onroad and offroad idling
  - Heavy Duty I&M
  - Smartways
- NOx and VOC reductions
- New potential initiatives like Ports are not included

- Stationary and Area Source Efforts
  - Third Generation OTC/SAS Initiatives
    - Consumer products
    - Architectural and Industrial Maintenance (AIM) Coatings
    - Auto coatings
    - Ultra Low NOx burners
- NOx and VOC reductions



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Reductions from OTC Measures

OTC Model Control Measures	Regional Reductions (tons per year)	Regional Reductions (tons per day)
Aftermarket Catalysts	14,983 (NOx) 3,390 (VOC)	41 (NOx) 9 (VOC)
On-Road Idling	19,716 (NOx) 4,067 (VOC)	54 (NOx) 11 (VOC)
Nonroad Idling	16,892 (NOx) 2,460 (VOC)	46 (NOx) 7 (VOC)
Heavy Duty I & M	9,326 (NOx)	25 (NOx)
Enhanced SMARTWAY	2.5%	
Ultra Low NOx Burners	3.669 (NOx)	10 (NOx)
Consumer Products	9,729 (VOC)	26 (VOC)
AIM	26,506 (VOC)	72 (VOC)
Auto Coatings	7,711 (VOC)	21 (VOC)

- Just in the OTC states
- Thanks to OTC Stationary and Area Source … and Mobile Source Committees
- Reductions from newest OTC initiatives not yet included in this chart

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What "Inside MD" Reductions are Included?

- New OTC measures
- New EGU regulation for NOx
  - Required for RACT and Attainment
- Maryland efforts on mobile sources
  - Electric vehicle initiatives
  - CALEV/ZEV efforts
  - "Beyond Conformity" partnerships
- Primarily NOx reductions from EGU regulation

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MDE Ozone Modeling

- MDE works with the University of Maryland, the OTC Modeling Committee, EPA and other states to conduct significant amounts of photochemical modeling
  - One of the premiere modeling centers in U.S.
- Current MDE/UMD/OTC Modeling Platform
  - CMAQv5.0.2 (Community Multiscale Air Quality Model)
    - Complemented by CAMX v6.10 (Comprehensive Air Quality Model with Extensions)
  - 2011 WRF (Weather Research & Forecasting) meteorological data.
  - 2011, 2017 and 2018 MARAMA/OTC/EPA inventories
  - Constantly working to improve the model
- Model performance is generally very good
- Modeling being shown today is not final …
  - But it is very high quality and future improvements will not alter the basic information presented today

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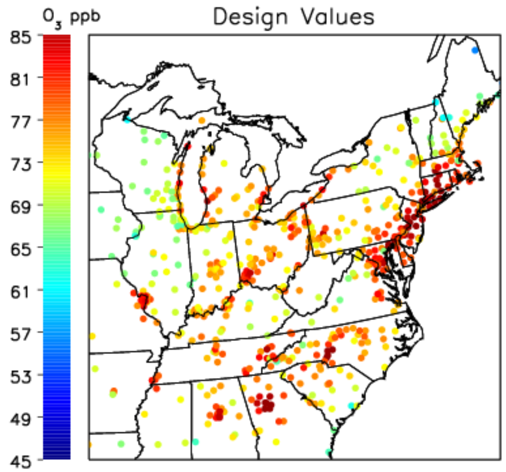
Who Contributes to MDs Ozone?

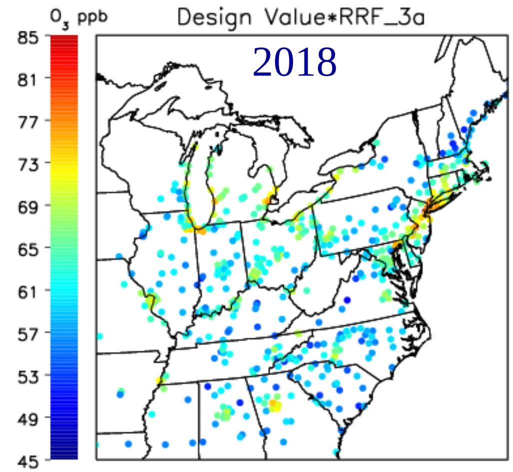
- The CAMX model has a source apportionment tool called OSAT (Ozone Source Apportionment Tool) that allows the model to work backwards and ask questions like “what states” or “what source sectors” sent the ozone to Edgewood MD – or Sheboygan WI – or Atlanta GA?
- The following samples of OSAT runs from the University of Maryland (UMCP) and the Lake Michigan Air Directors (LADCO) provide a quick snapshot of which states and which sources contribute most to Maryland’s ozone problem

Building the Maryland Plan

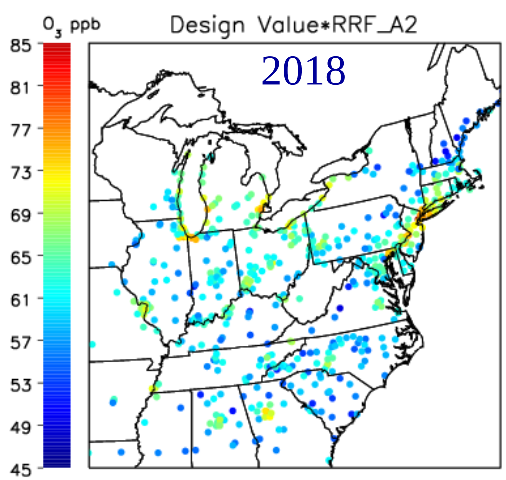
The 2011 Base



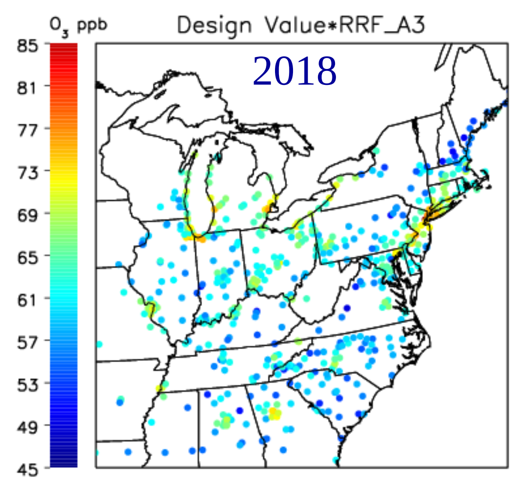
Add regional controls across the East (OTB/OTW, Tier 3, regional EGU controls)



Add the "OTR" controls along I-95 corridor



Add new controls just in MD

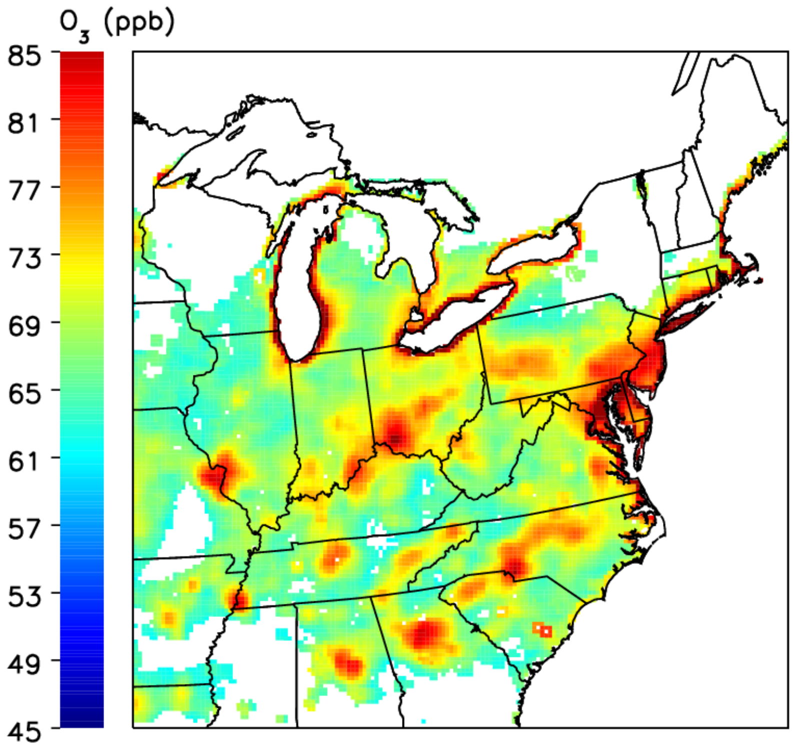


Acronym Reminder

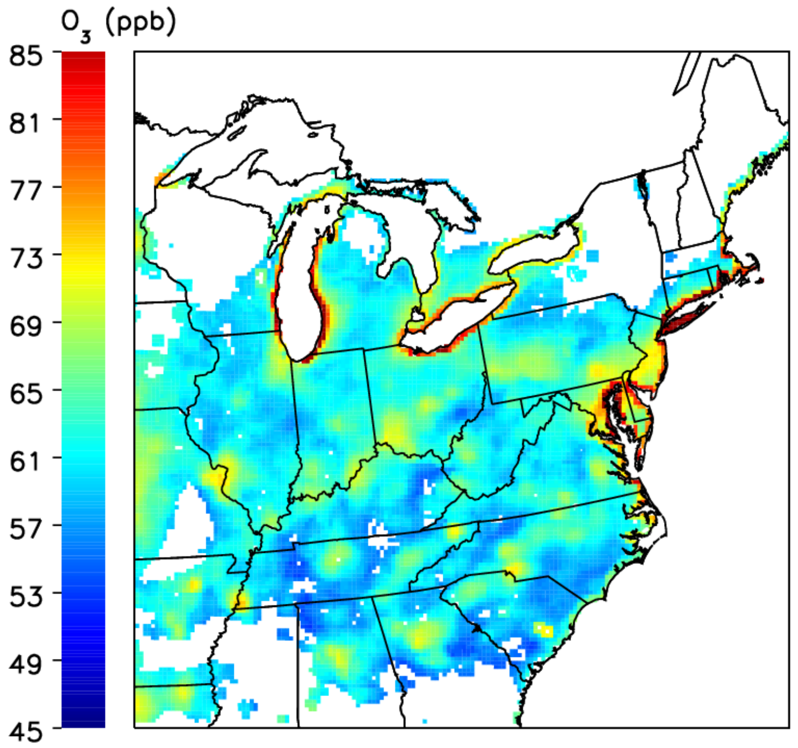
- OTB/OTW stands for emission reductions that are "on-the-books" or "on-the-way"
- Tier 3 is the new federal tailpipe and fuel standards that achieve large NOx reductions
- EGUs are "electric generating units" or power plants
- The OTR is the Ozone Transport Region which includes 13 states from VA to ME along the I-95 corridor

Total Ozone Improvement 2011 to 2018

… the Maryland Plan without MD NOx regulation



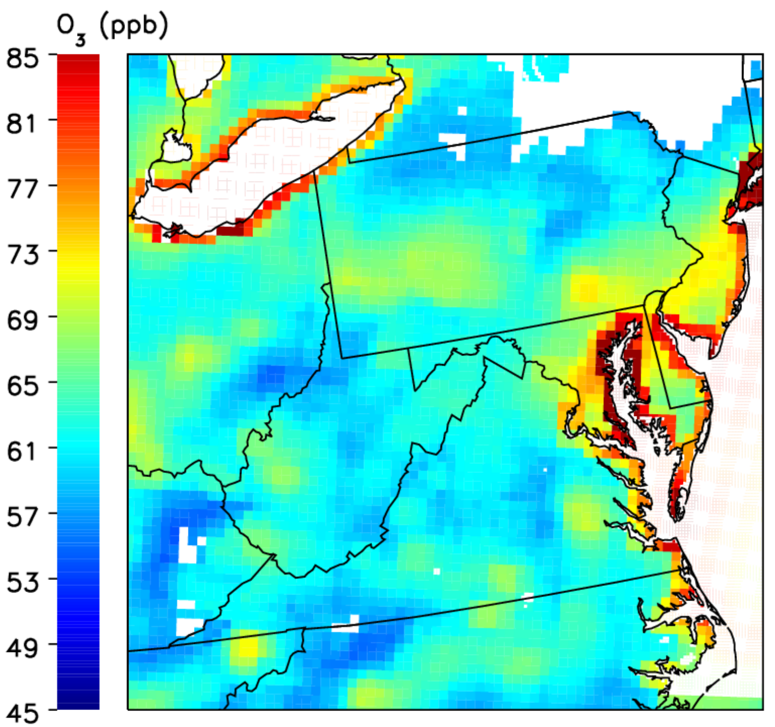
2011 Measured Ozone



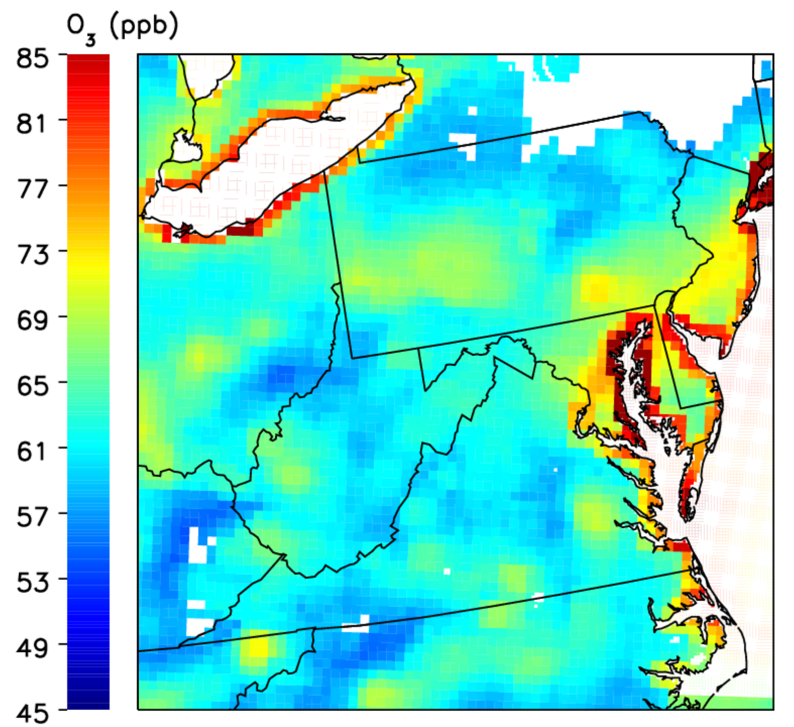
2018 - MD Plan Without NOx Reg

Ozone in 2018 - New NOx Reg

… Adding the maximum reductions from the 2020 requirements from the new regulation



2018 - MD Plan
Without NOx Reg

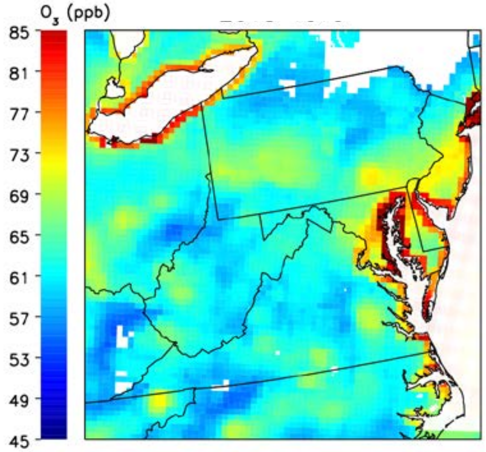


2018 - MD Plan
With NOx Reg

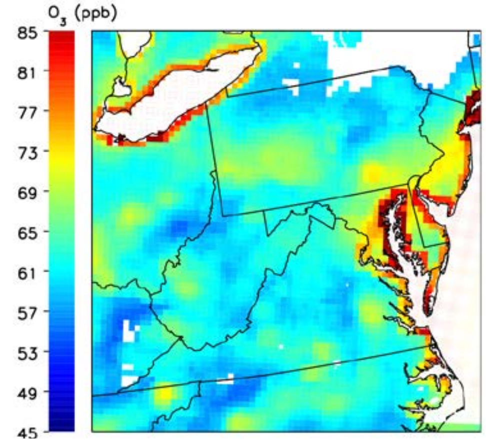
Comparing Ozone Benefits

… 2018 ozone levels after the new regulation

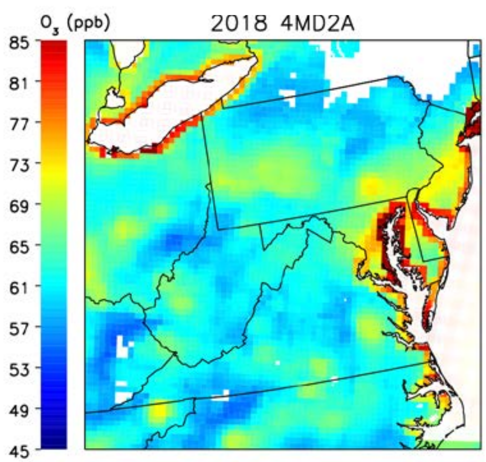
2018 - MD Plan Without NOx Reg



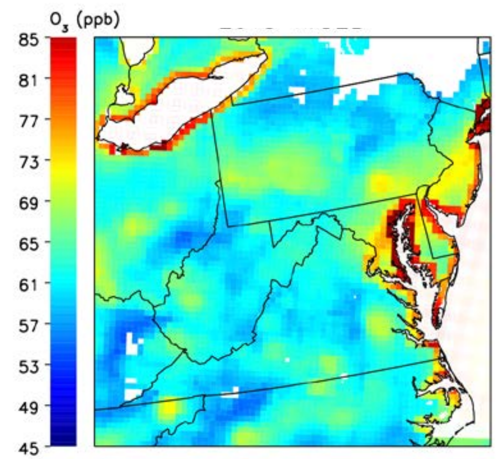
2018 - MD Reg Phase 1



2020 - MD Reg - Old Phase 2

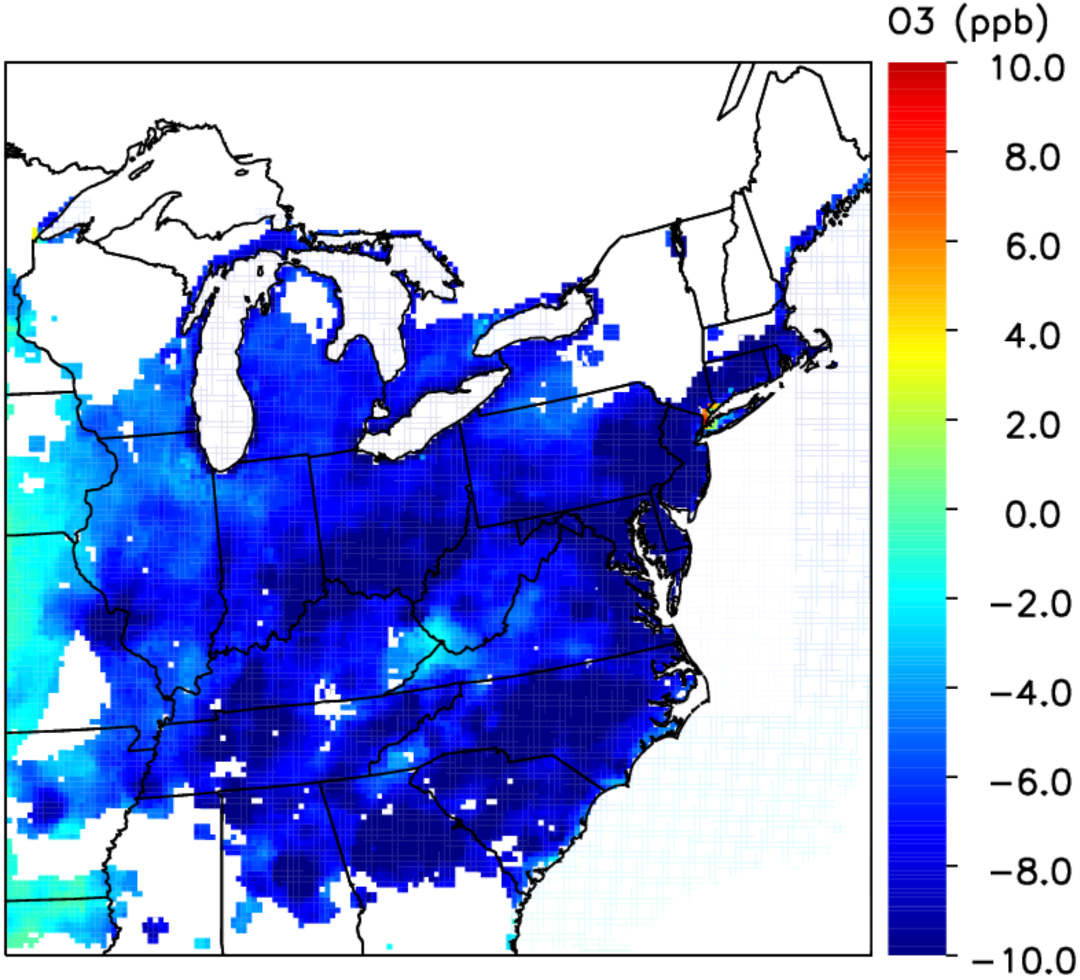


2020 - MD Reg - New Phase 2



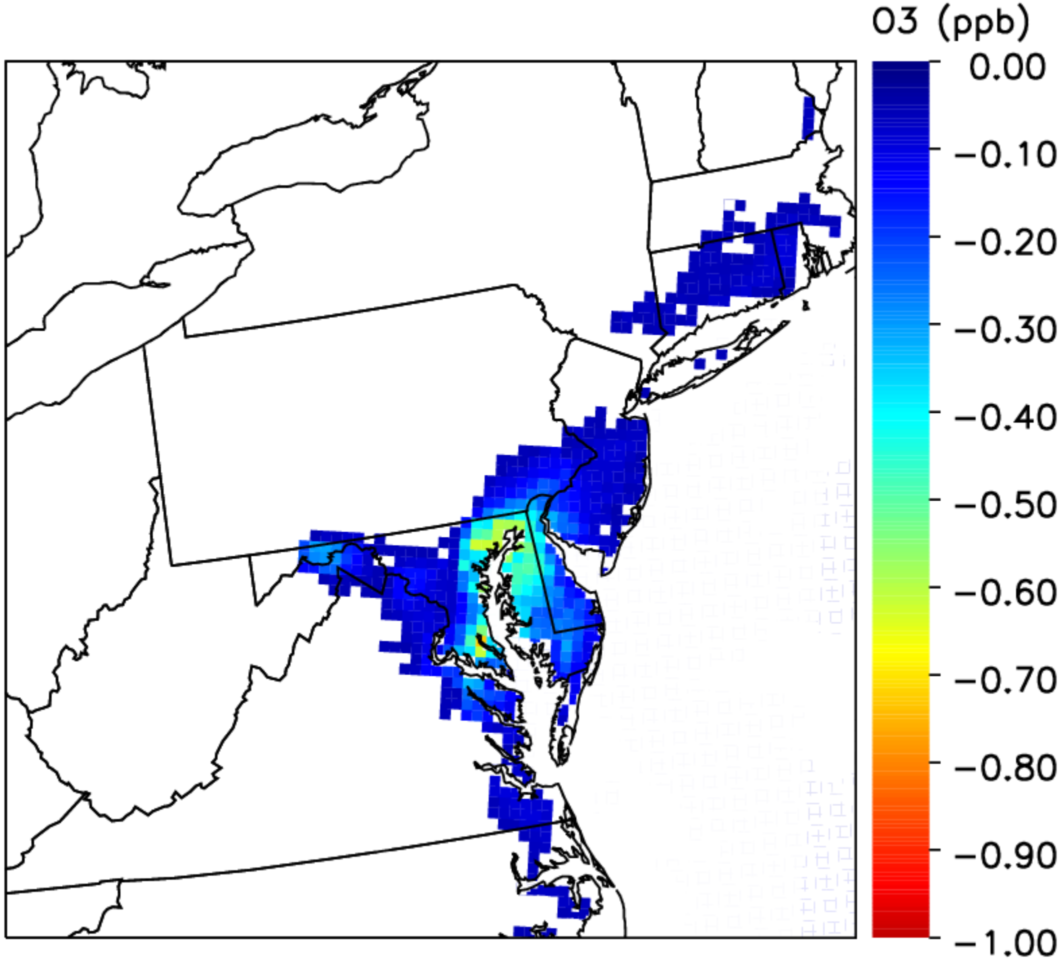
Total Ozone Benefits

… Total ozone reductions from the Maryland Plan including the new Phase 2 (2020) NOx reductions



Ozone Benefits from the NOx Reg

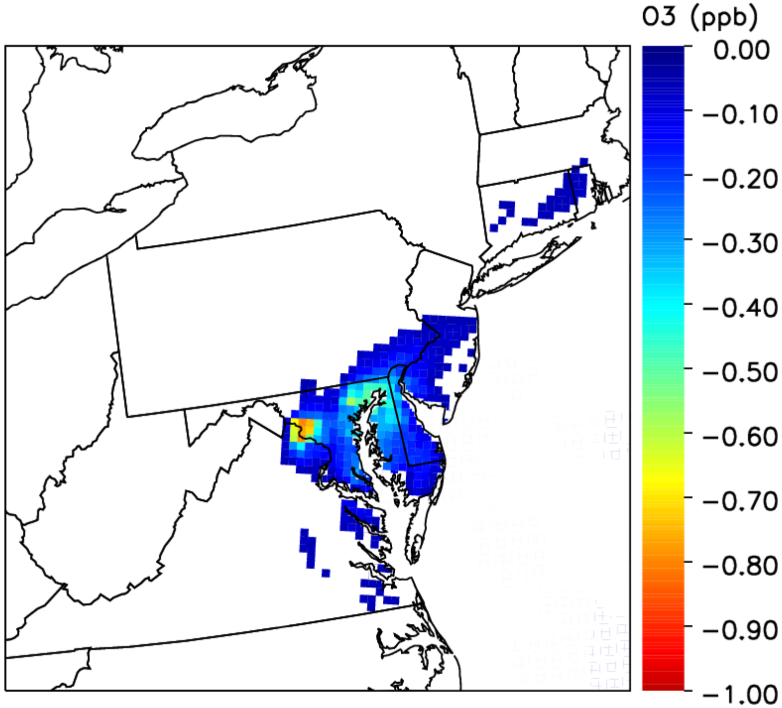
… Reduced ozone from the 2015 requirements of the new regulation



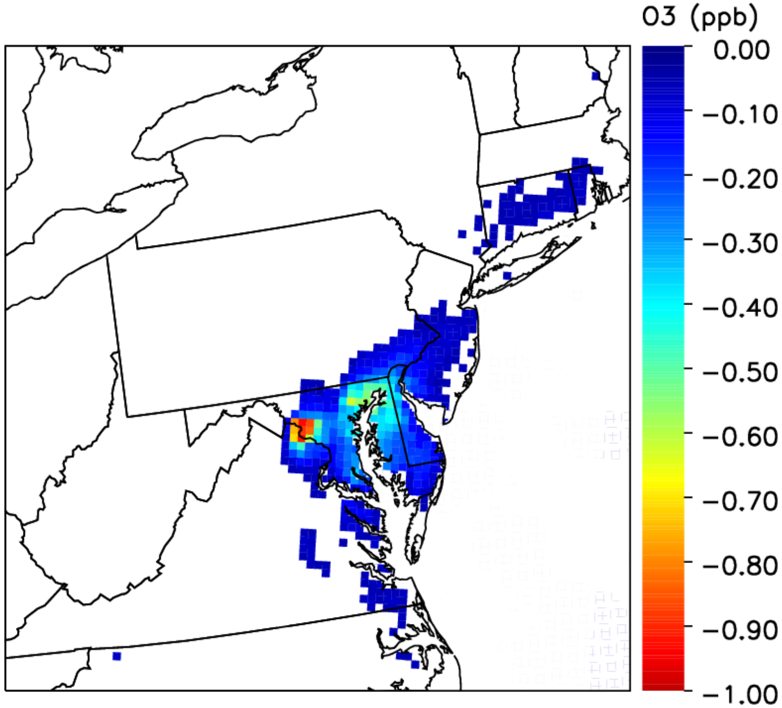
Note scale change

Ozone Reductions in 2020

… From the earlier regulation and the new option 4 requirements in 2020



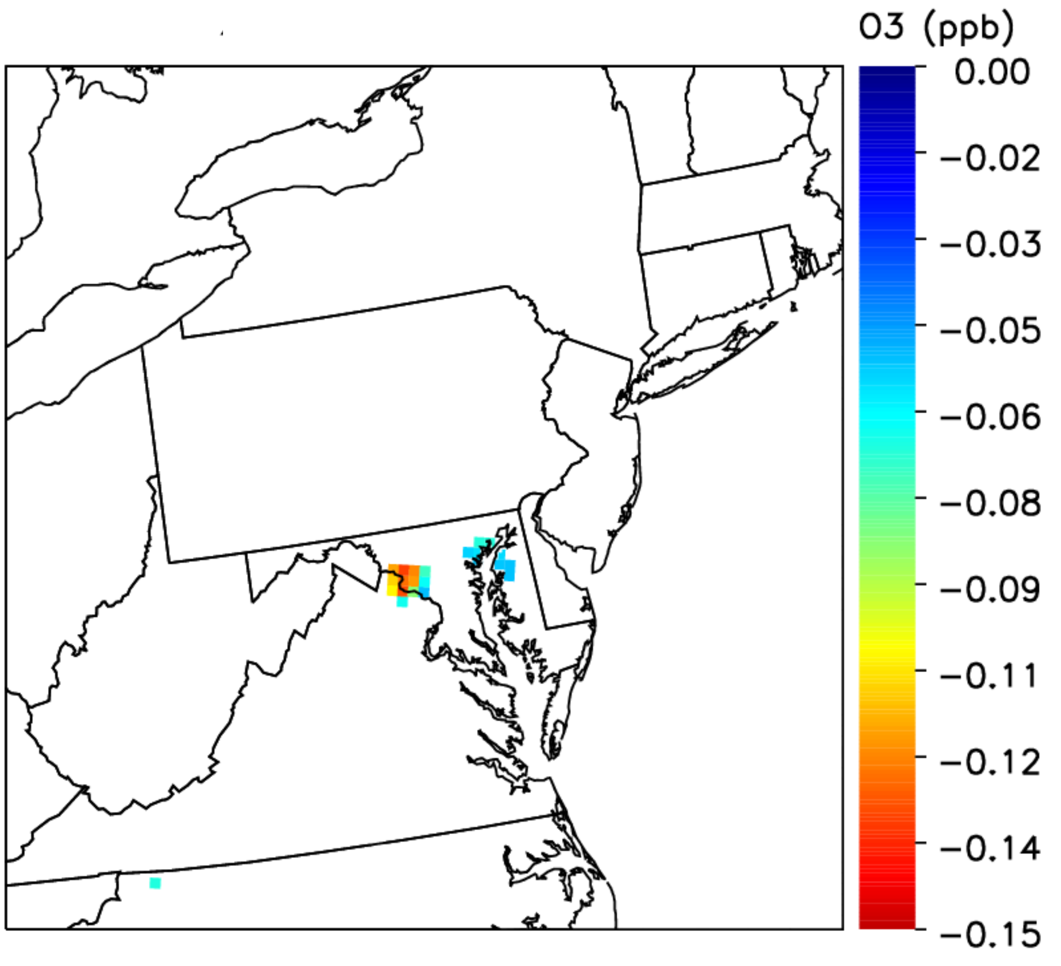
Additional 2020 reductions from 2020 requirements in the earlier proposal



Additional 2020 reductions from 2020 requirements in the new regulation - Option 4 -

Small Additional Benefits …

… from the new option 4 requirements for 2020 reductions

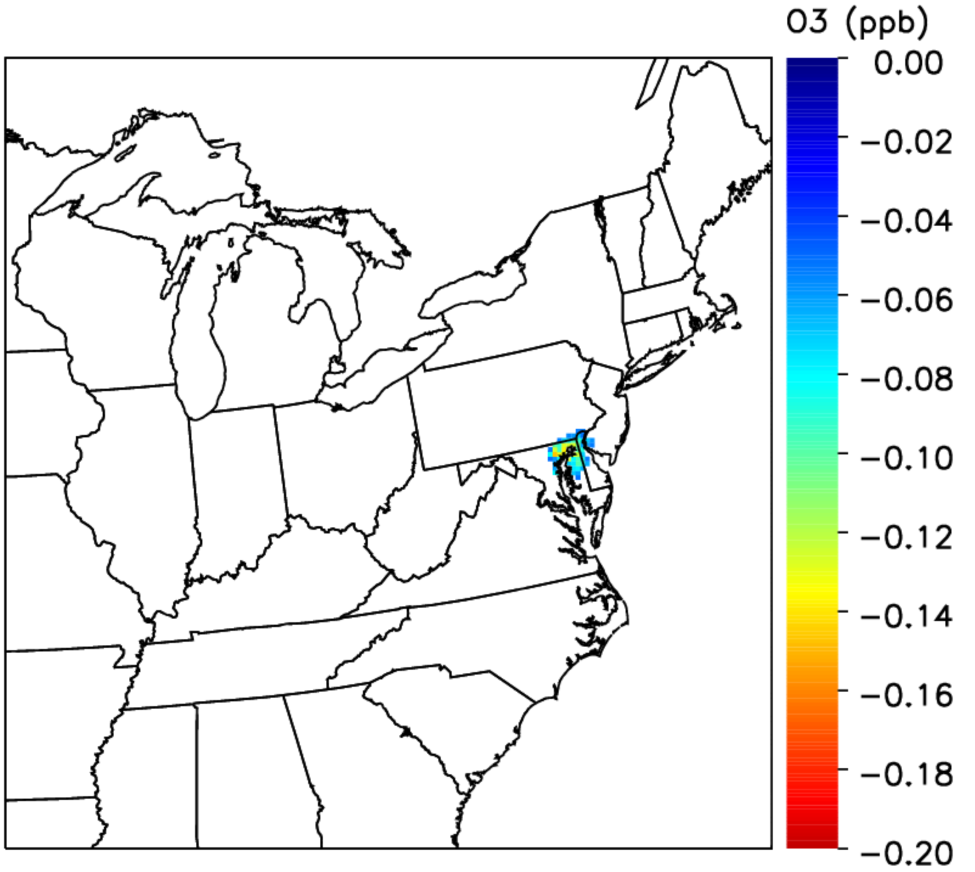


Note scale change

Additional Benefits in 2018

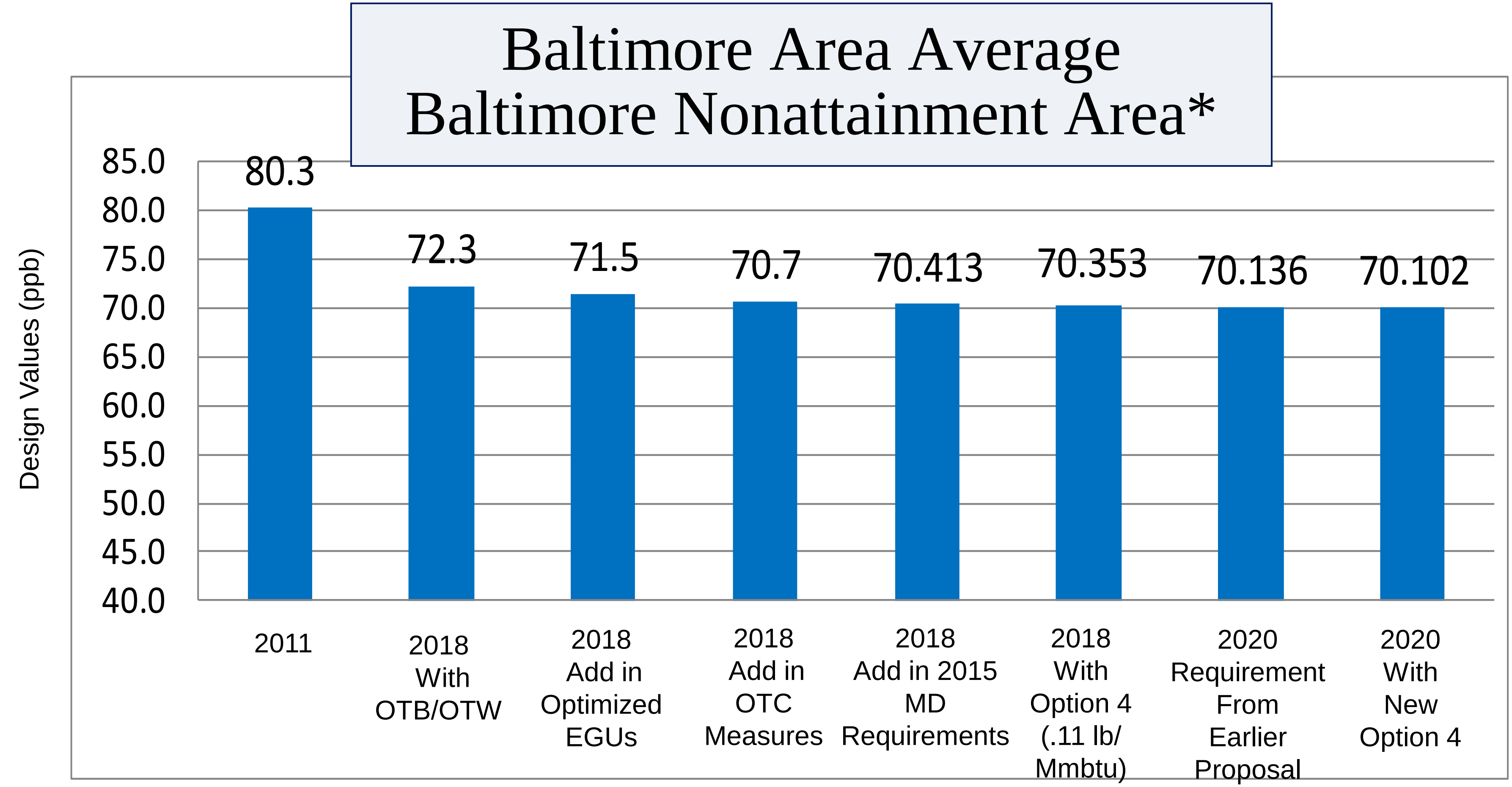
… Earlier reduced ozone with Option 4

Small additional reductions from the 0.11 lb/MMBTU limit required in 2018 when Option 4 is selected



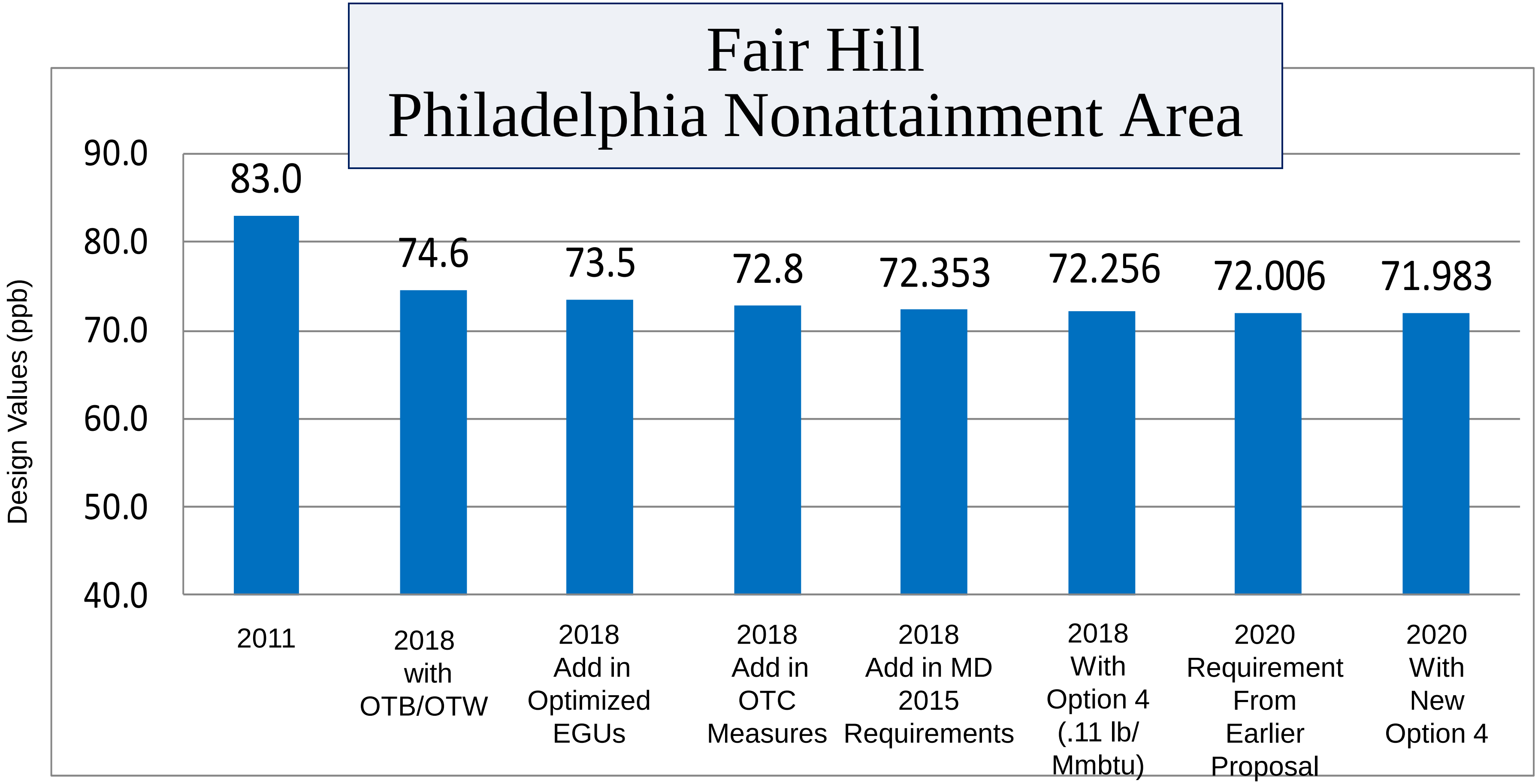
Note scale change

A Snapshot of Ozone Reductions

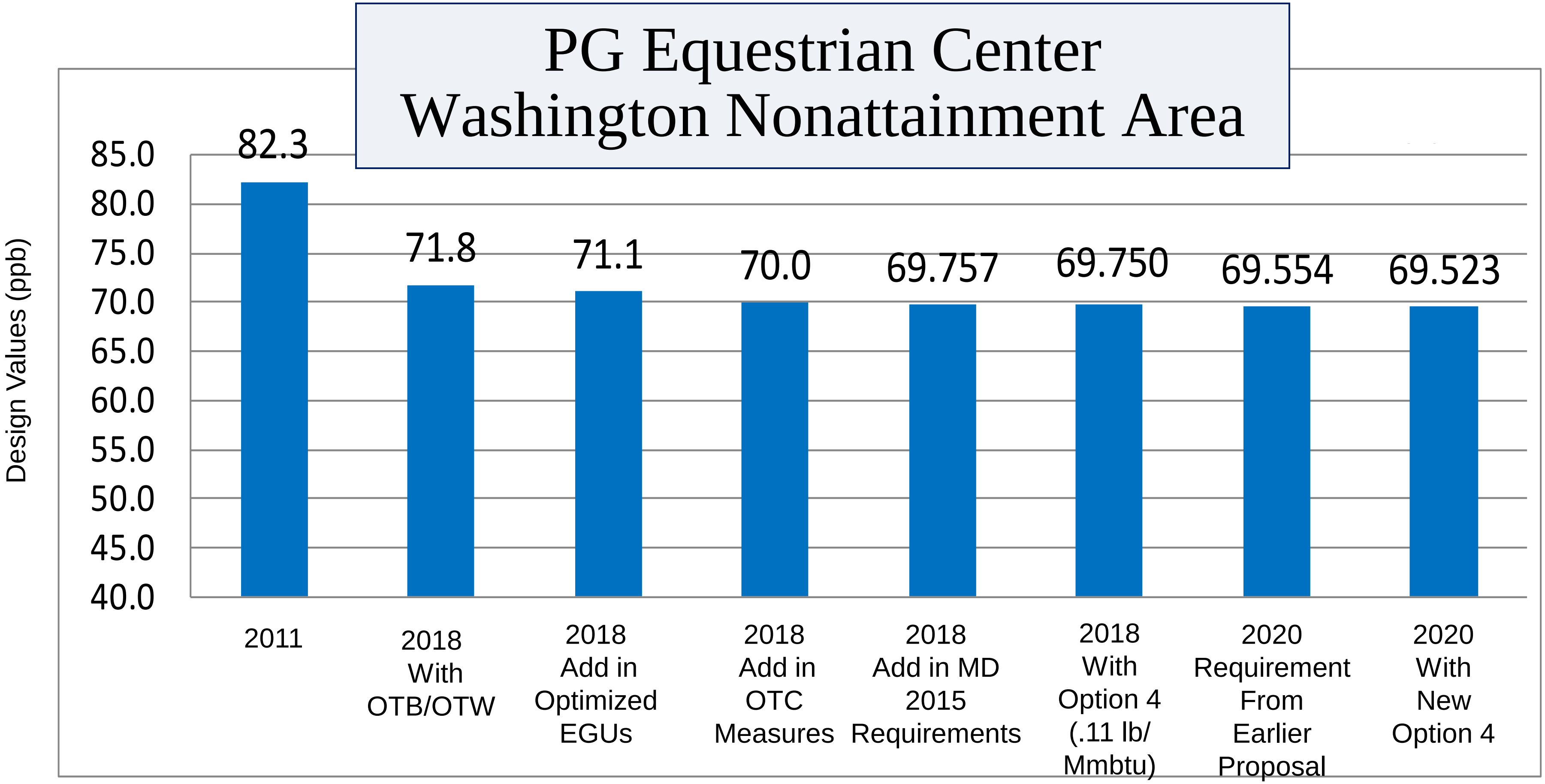


* The Baltimore nonattainment area is currently measuring attainment for the 75 ppb ozone standard at all monitors

A Snapshot - Current Worst Monitor



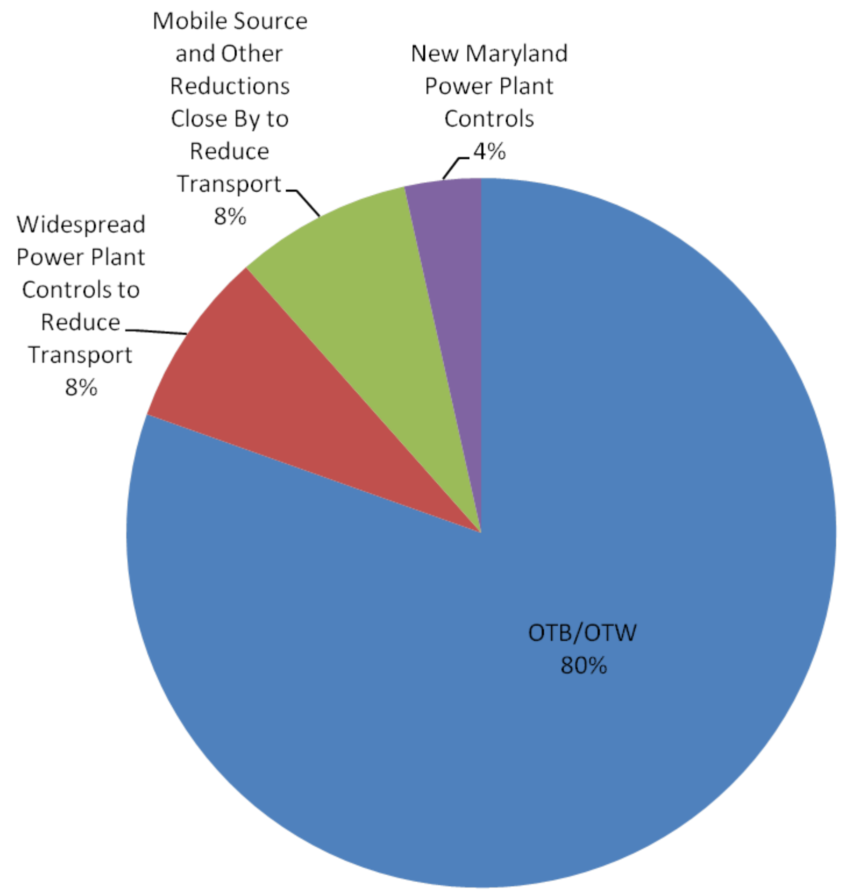
A Snapshot - Current Second Worst



Getting to Clean Air

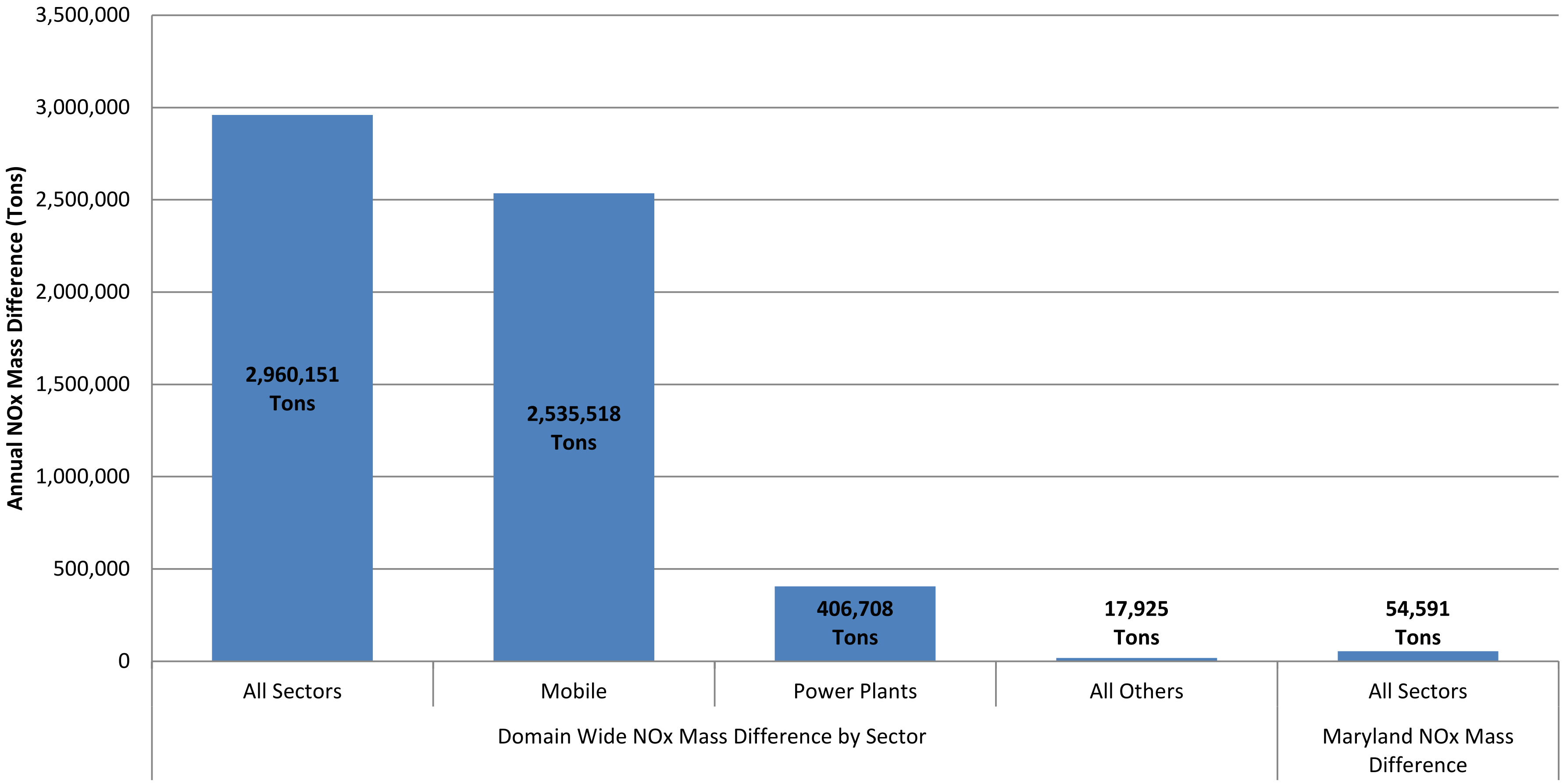
- The MDE modeling shows that Maryland has a plan that will bring the State into permanent attainment with the 75 ppb ozone standard …
  - Even when the weather is much hotter and more likely to create high ozone
- Current data in Baltimore already shows attainment
- The new NOx regulations provide small, but important ozone benefits
- The vast majority of the ozone benefits in Maryland come from OTB/OTW measures and other measures to reduce transport into Maryland

2011 to 2018 Reduction in Ozone- Baltimore



An Emissions Reductions Snapshot

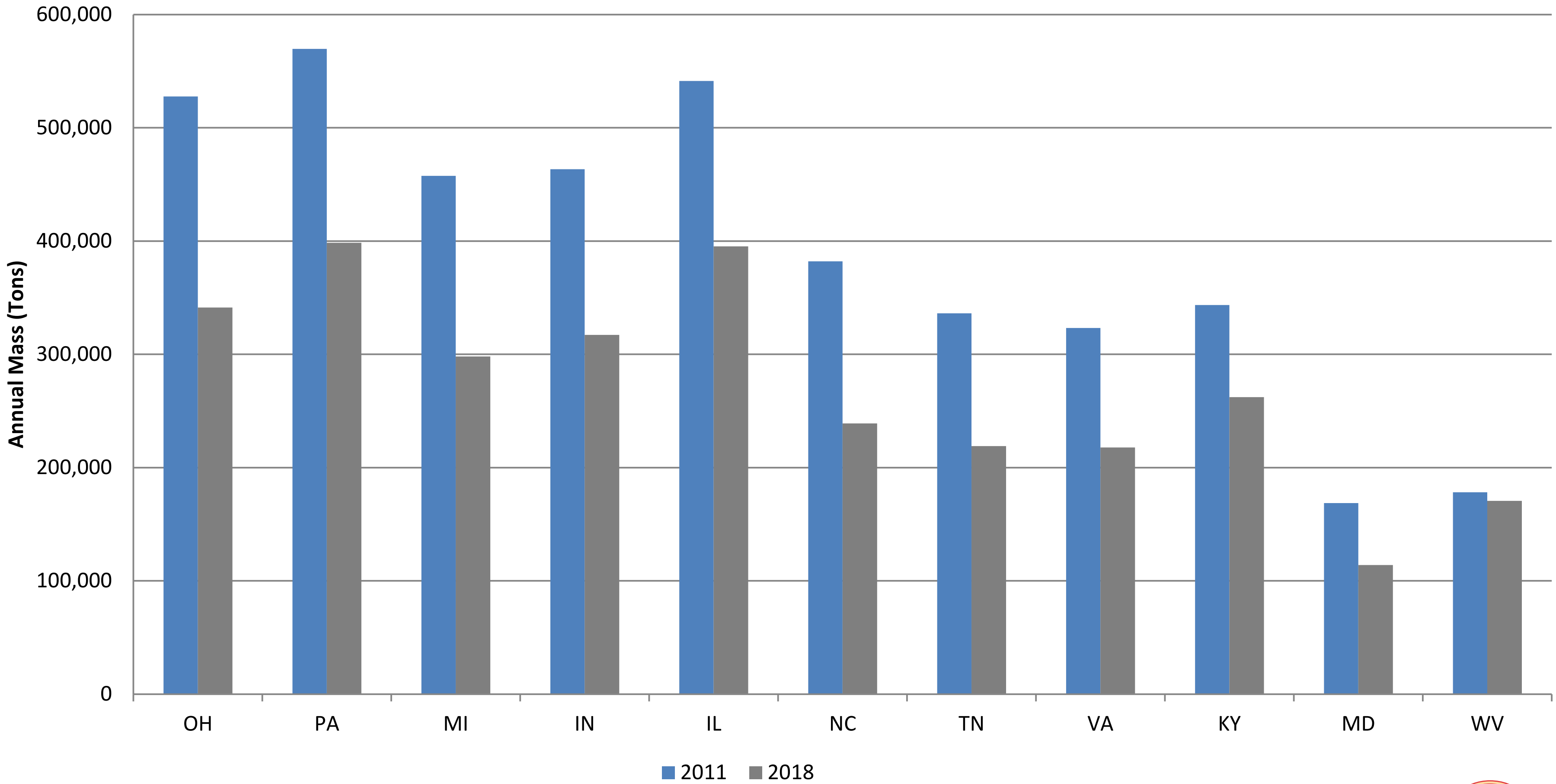
… NOx emission reductions across the East Maryland Plan - 2011 to 2018



MARYLAND DEPARTMENT OF THE ENVIRONMENT

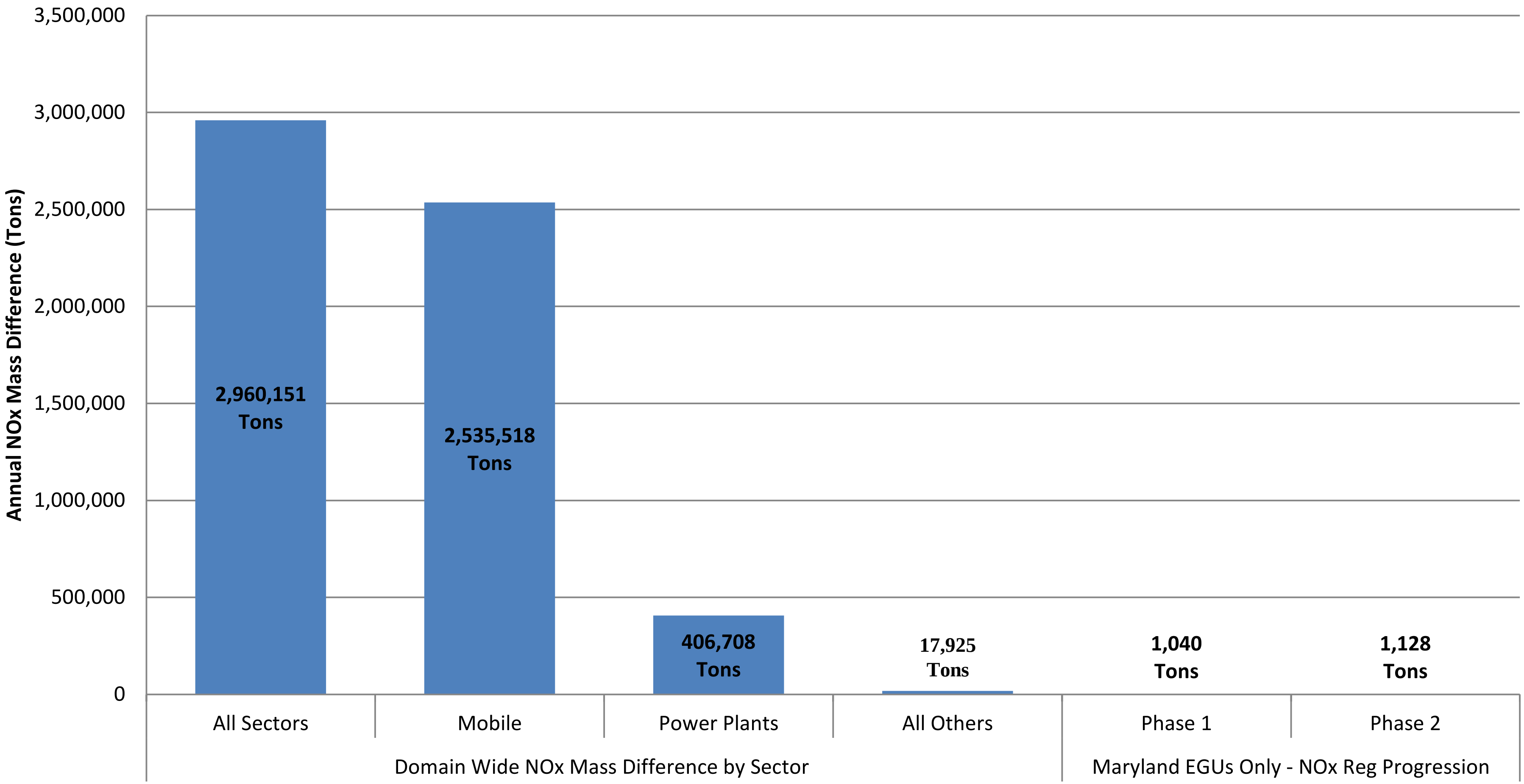
NOx Reductions by State

… states contributing to ozone in Maryland
Maryland Plan - 2011 to 2018



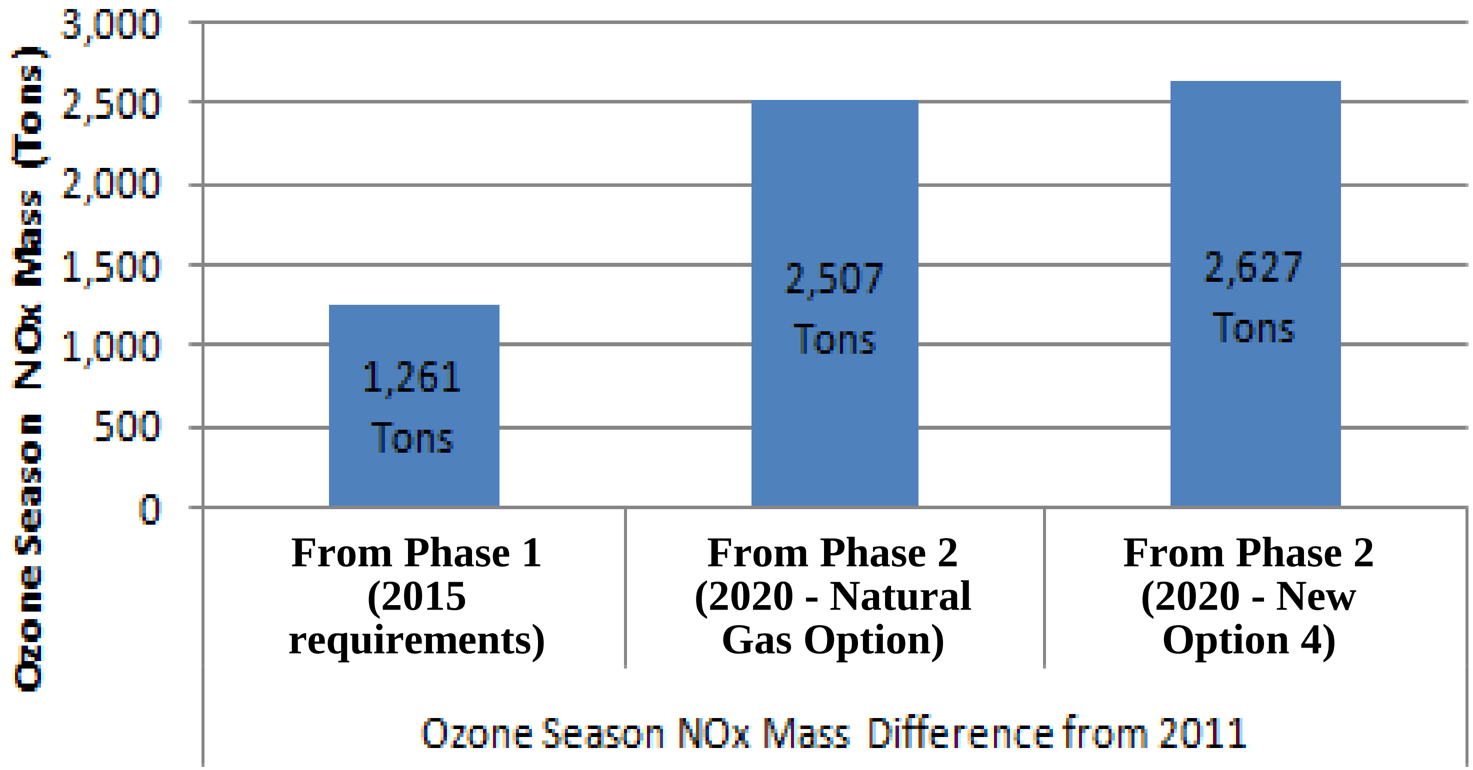
NOx Tons From New Regulation

… 2011 to 2018 annual reductions



NOx Reductions - New Regulation

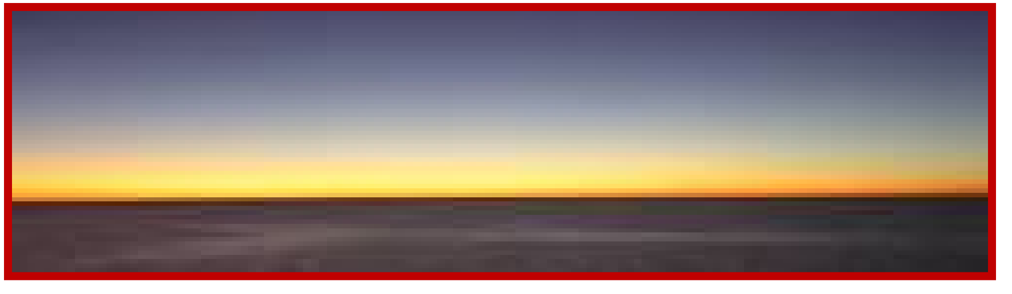
… additional ozone season NOx reductions from the new regulation



Wrap-Up

The Maryland Ozone Plan

- Maryland has a comprehensive strategy to address ozone based upon two decades of research and progress
- The regulation being discussed today is part of that strategy
  - The new regulation protects public health and promotes a healthy and sustainable economy
- The new regulation provides equal or greater public health protection compared to the earlier proposal
  - The first three options for compliance are identical to the earlier proposal
  - Choosing the new Option 4 comes with increased responsibility for earlier pollution reductions
  - Choosing Option 4 also insures lower ozone in 2020
    - An additional 120 tons of NOx reductions in the ozone season



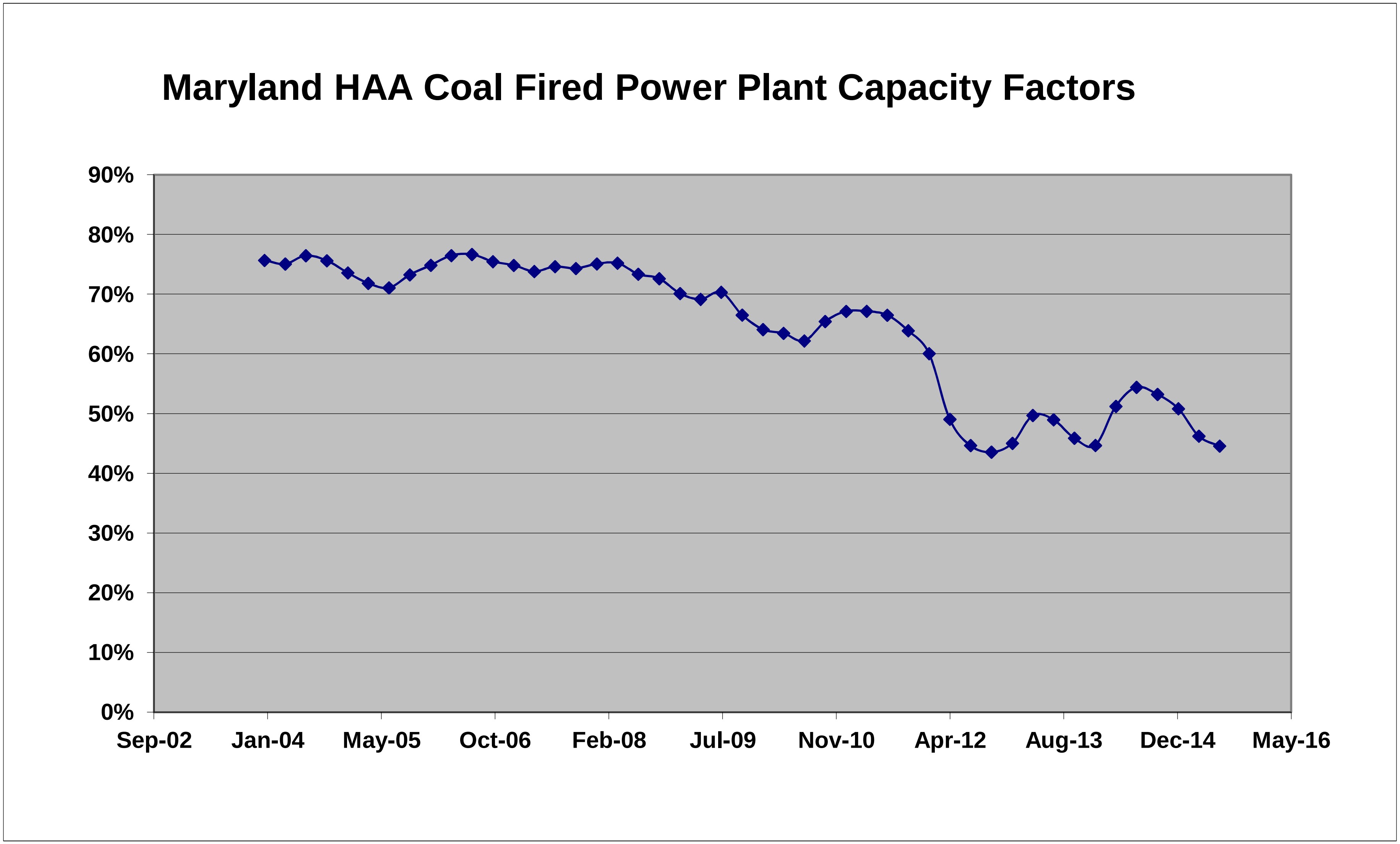
MDE

Questions?

MARYLAND
DEPARTMENT OF THE ENVIRONMENT

Appendix B

MARYLAND COAL-FIRED POWER PLANT CAPACITY FACTORS



Maryland HAA Coal Fired Power Plant Capacity Factors
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Sep-02
Jan-04
May-05
Oct-06
Feb-08
Jul-09
Nov-10
Apr-12
Aug-13
Dec-14
May-16

Appendix C

Maryland Coal-Fired EGUs

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

July 2012 Ozone Season NOx 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:

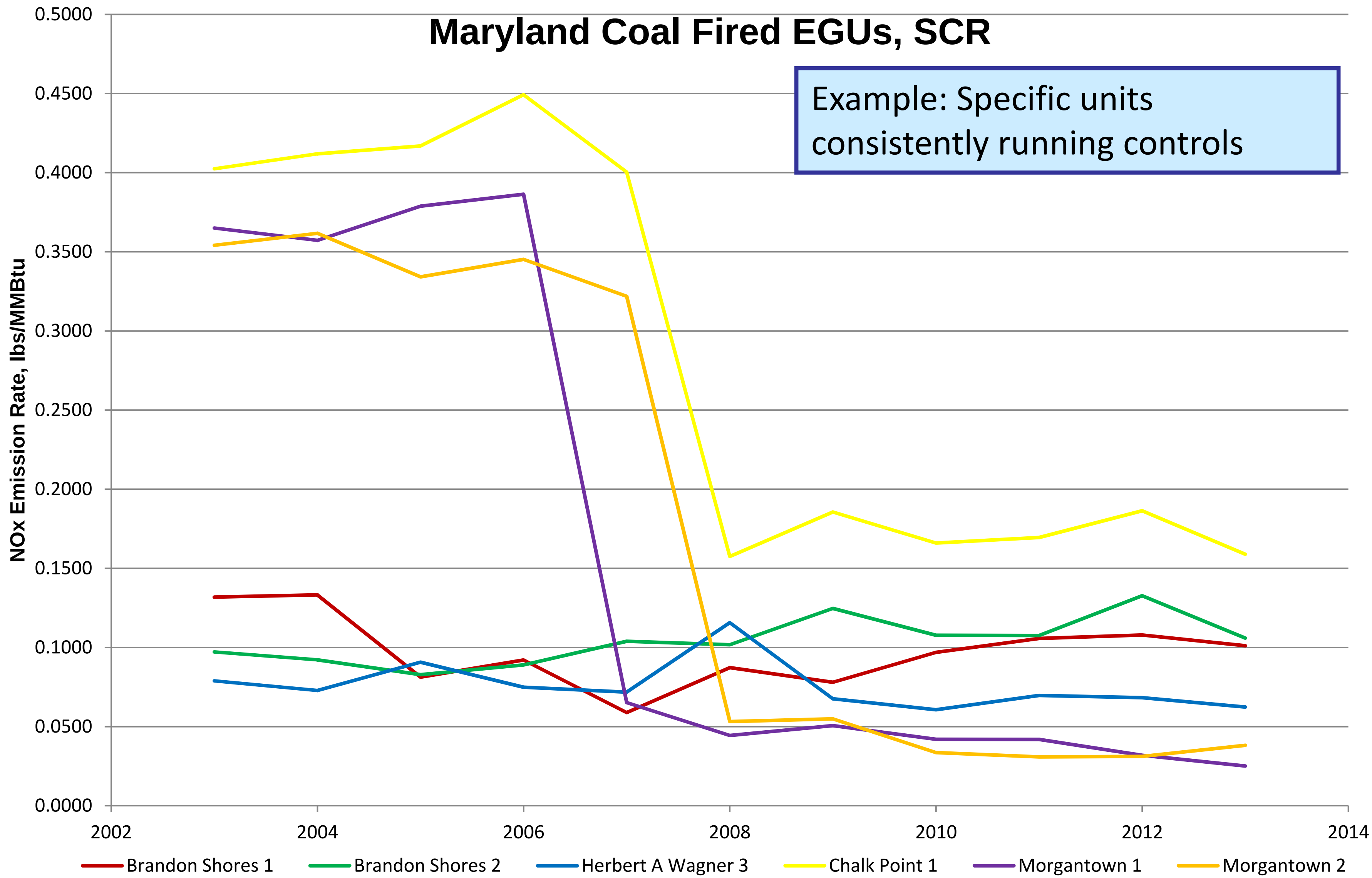
- CEMS data, downloaded from CAMD
- Emissions and projection data from ERTAC

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.

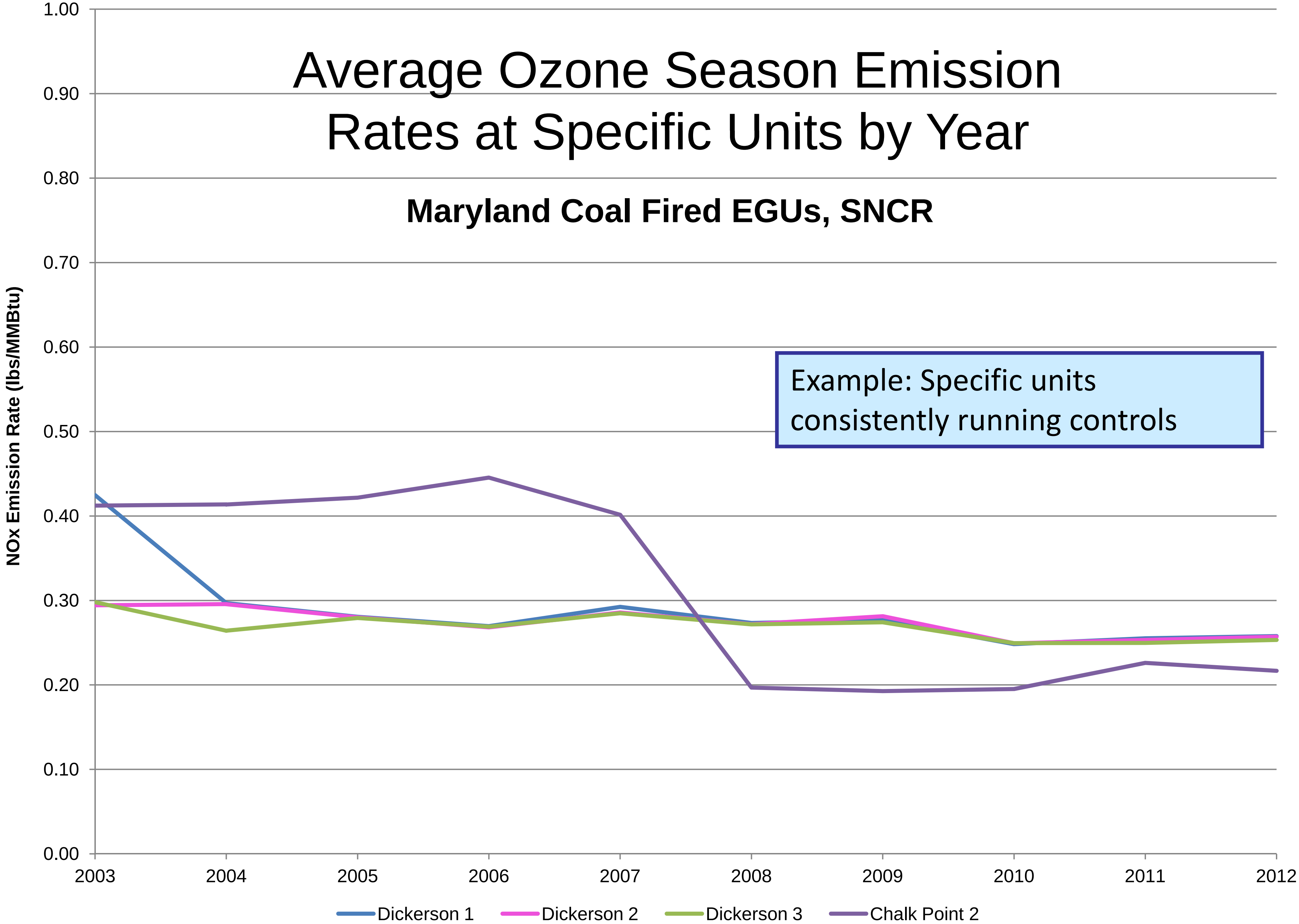
The same data analysis was performed for 10 other States with ozone transport contributions to Maryland. These results are available upon request.

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.



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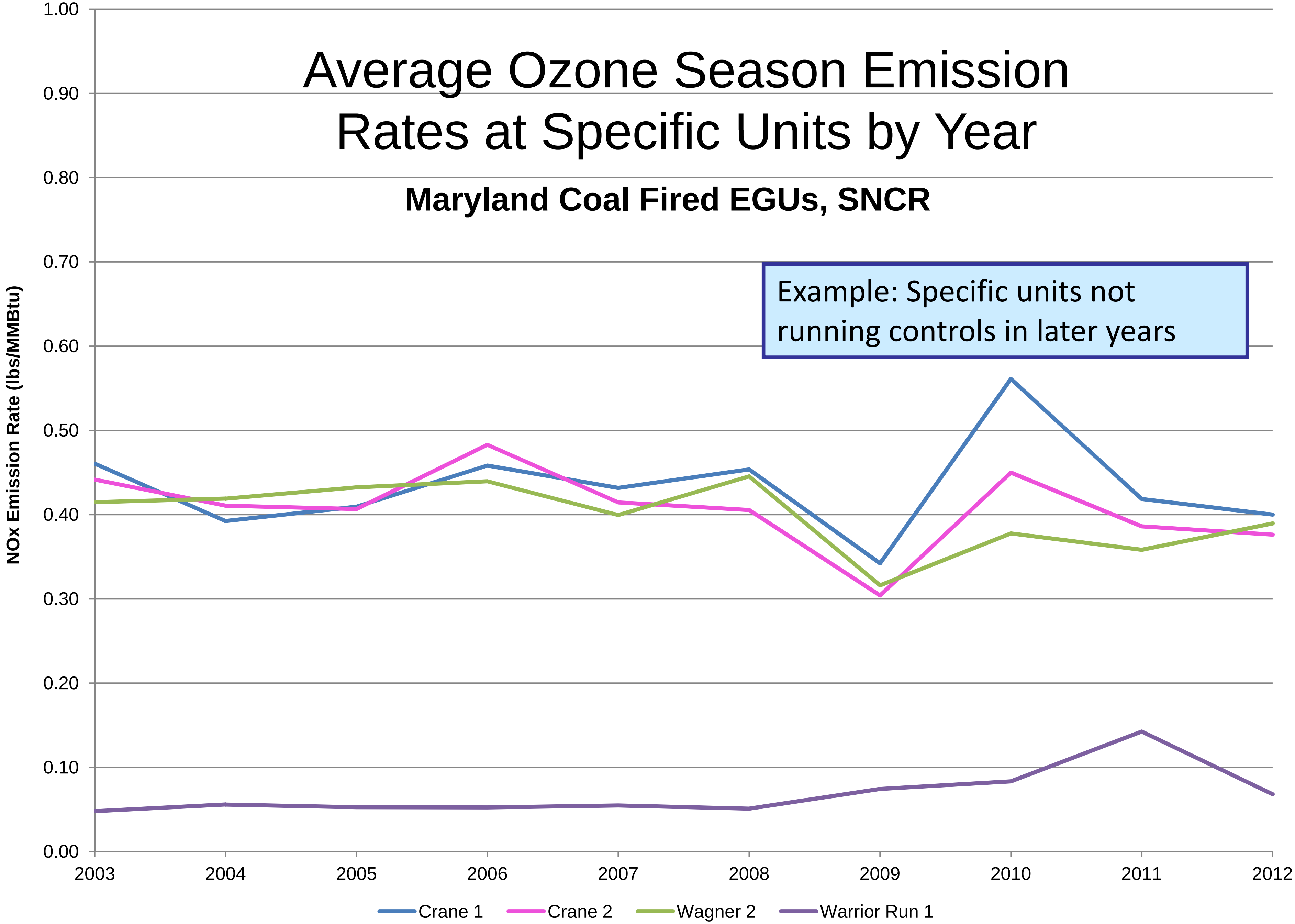

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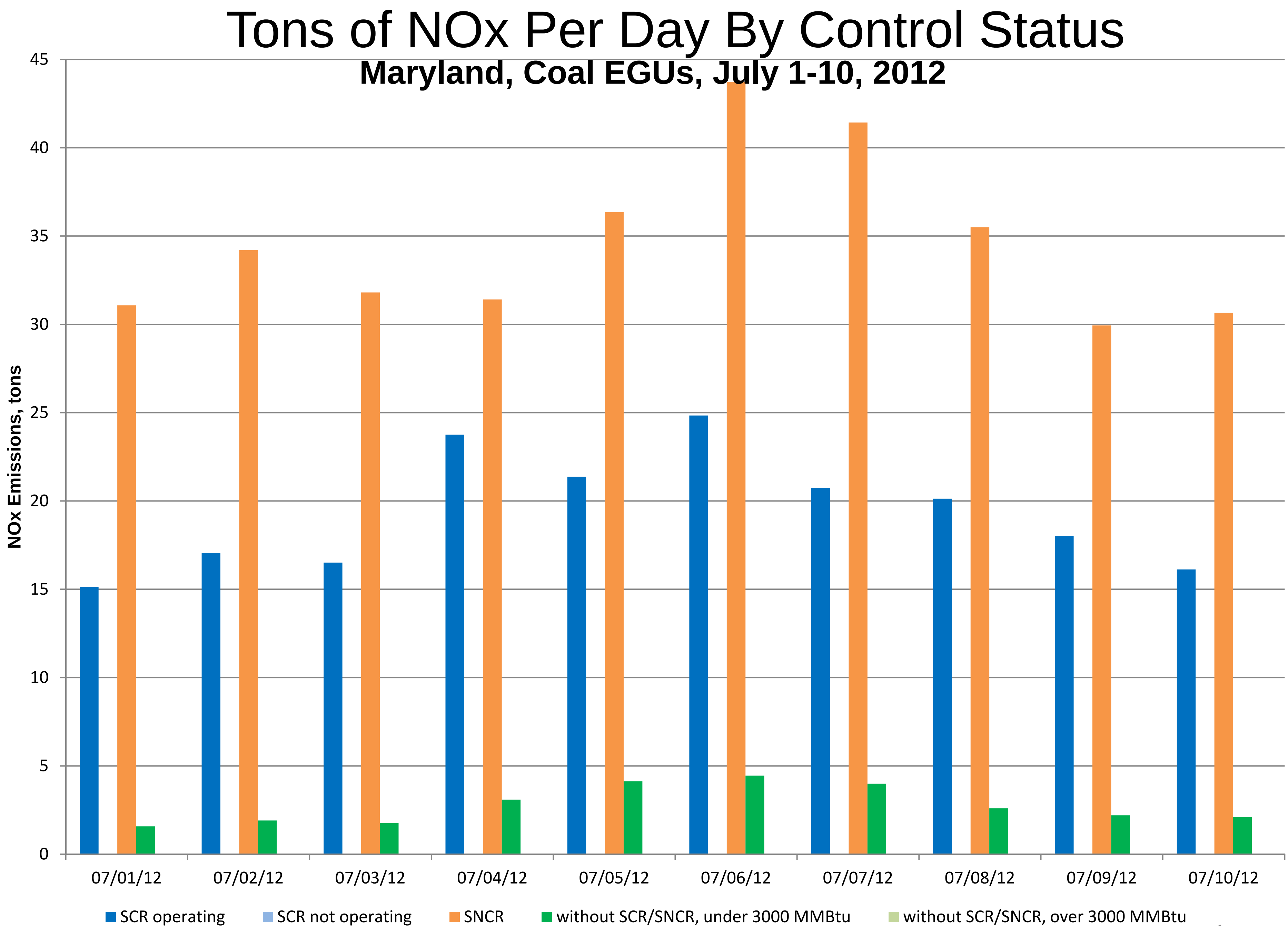
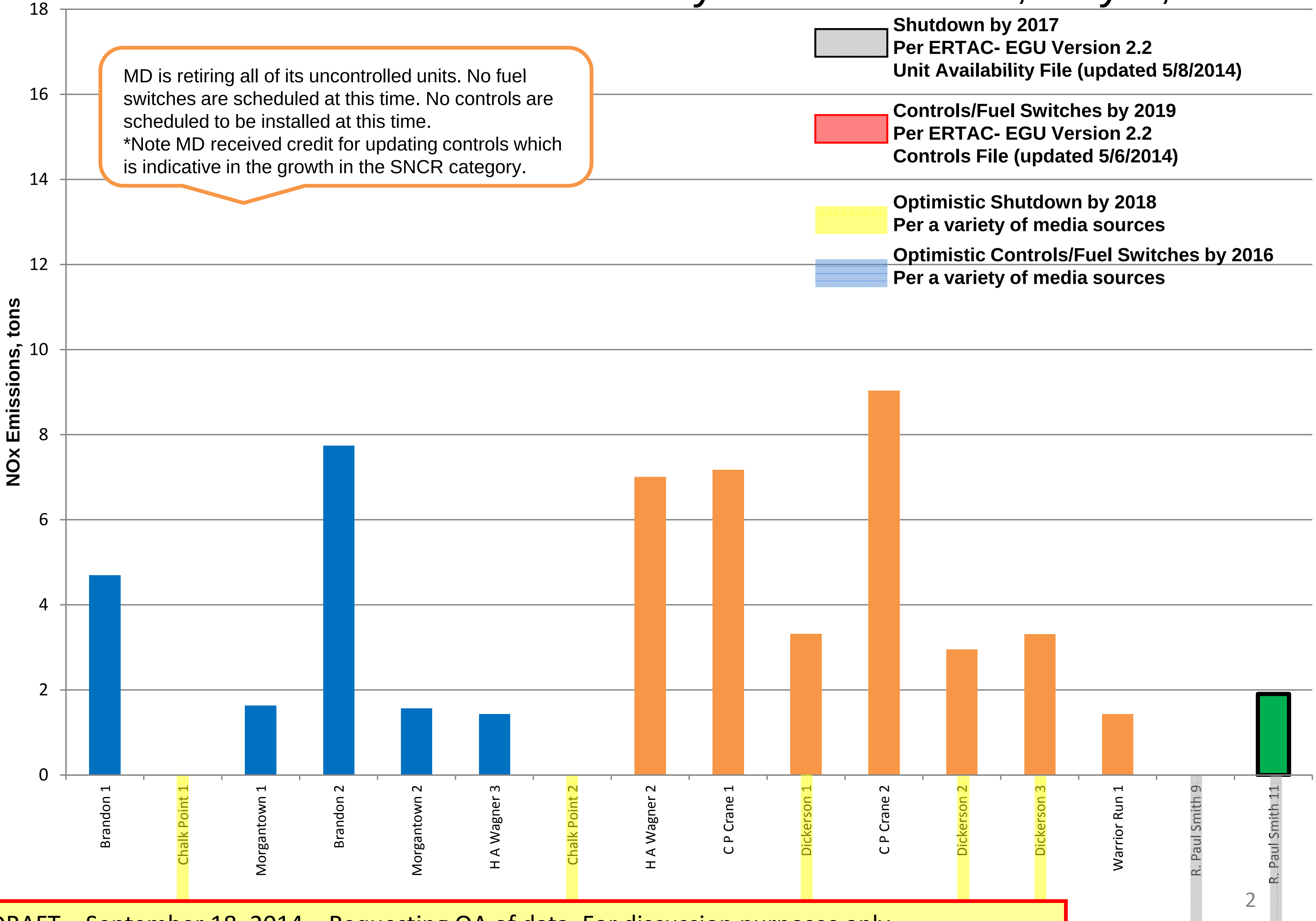


DRAFT – September 18, 2014 – Requesting QA of data. For discussion purposes only.

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



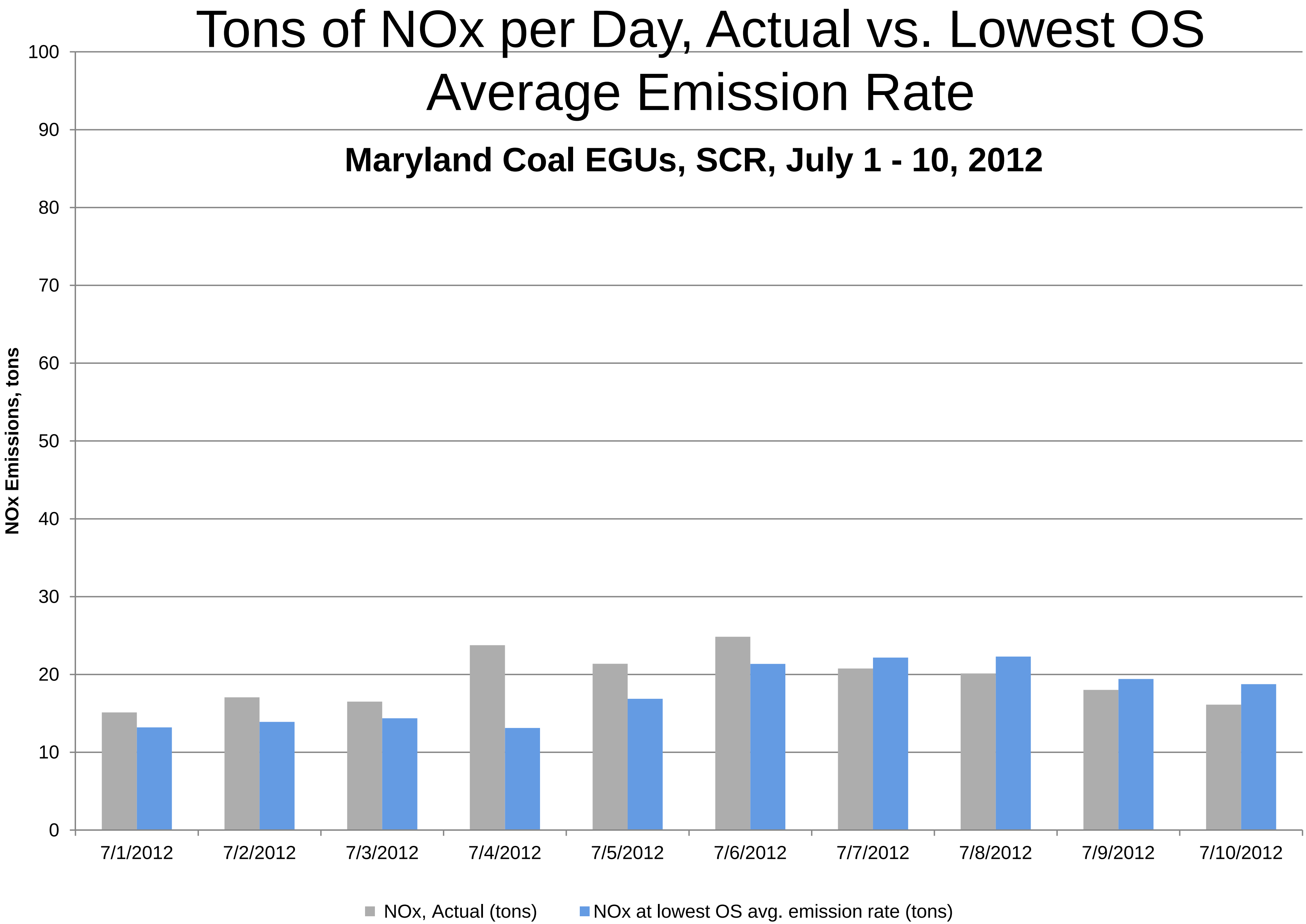
DRAFT – September 18, 2014 – Requesting QA of data. For discussion purposes only.

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								

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

MD: Small (< 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	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

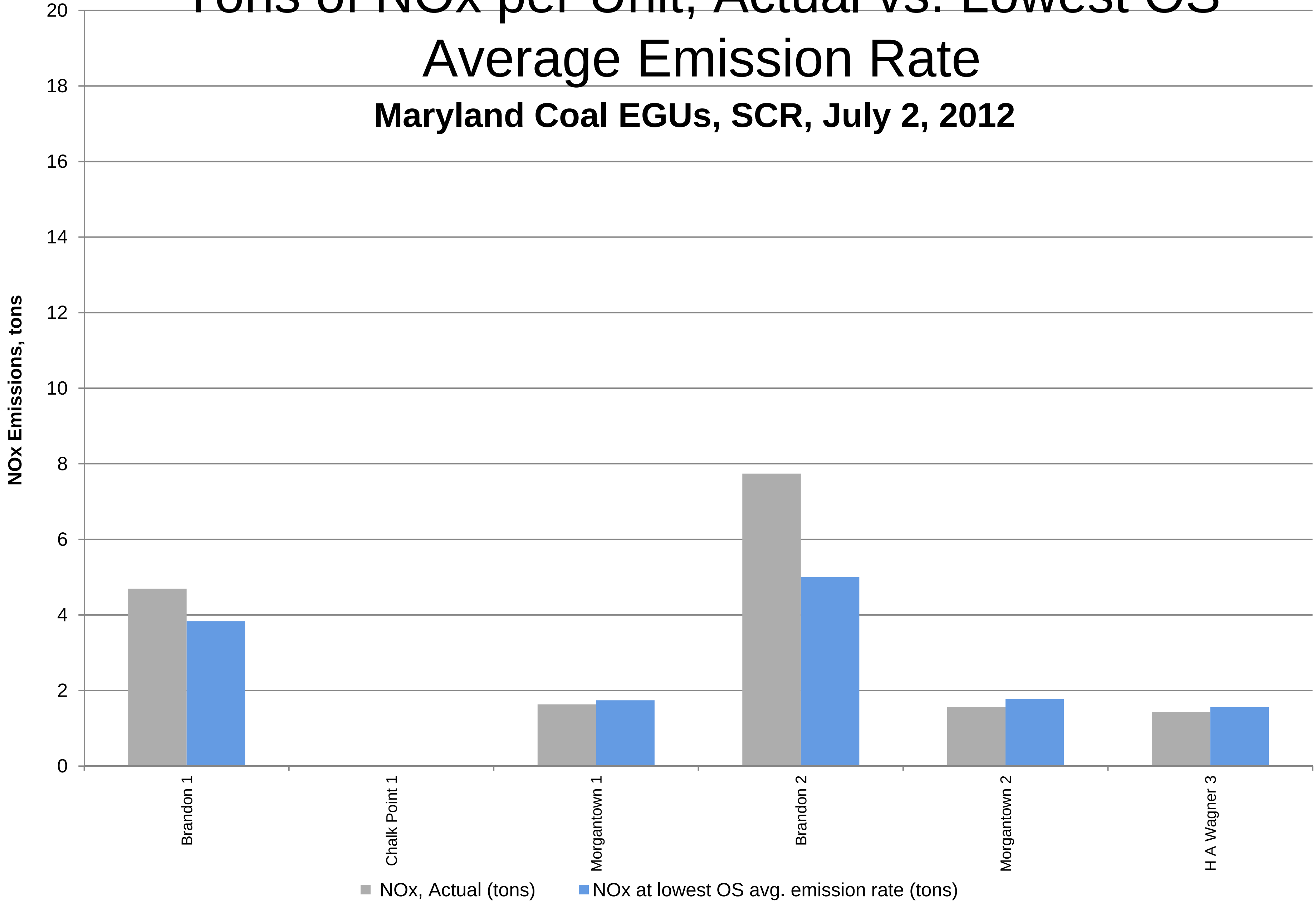
DRAFT – September 18, 2014 – Requesting QA of data. For discussion purposes only.



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

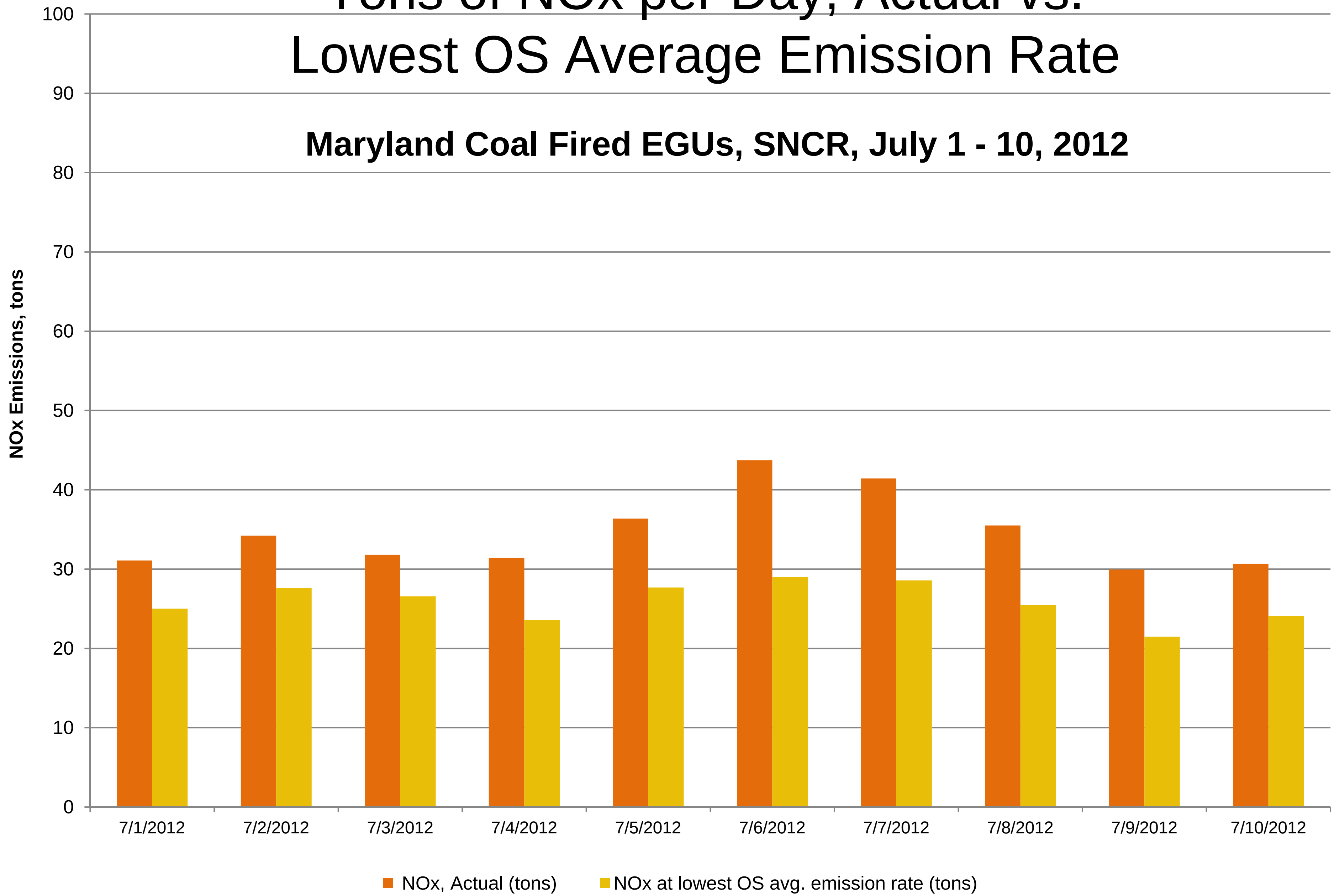
Tons of NOx per Unit, Actual vs. Lowest OS Average Emission Rate

Maryland Coal EGUs, SCR, July 2, 2012



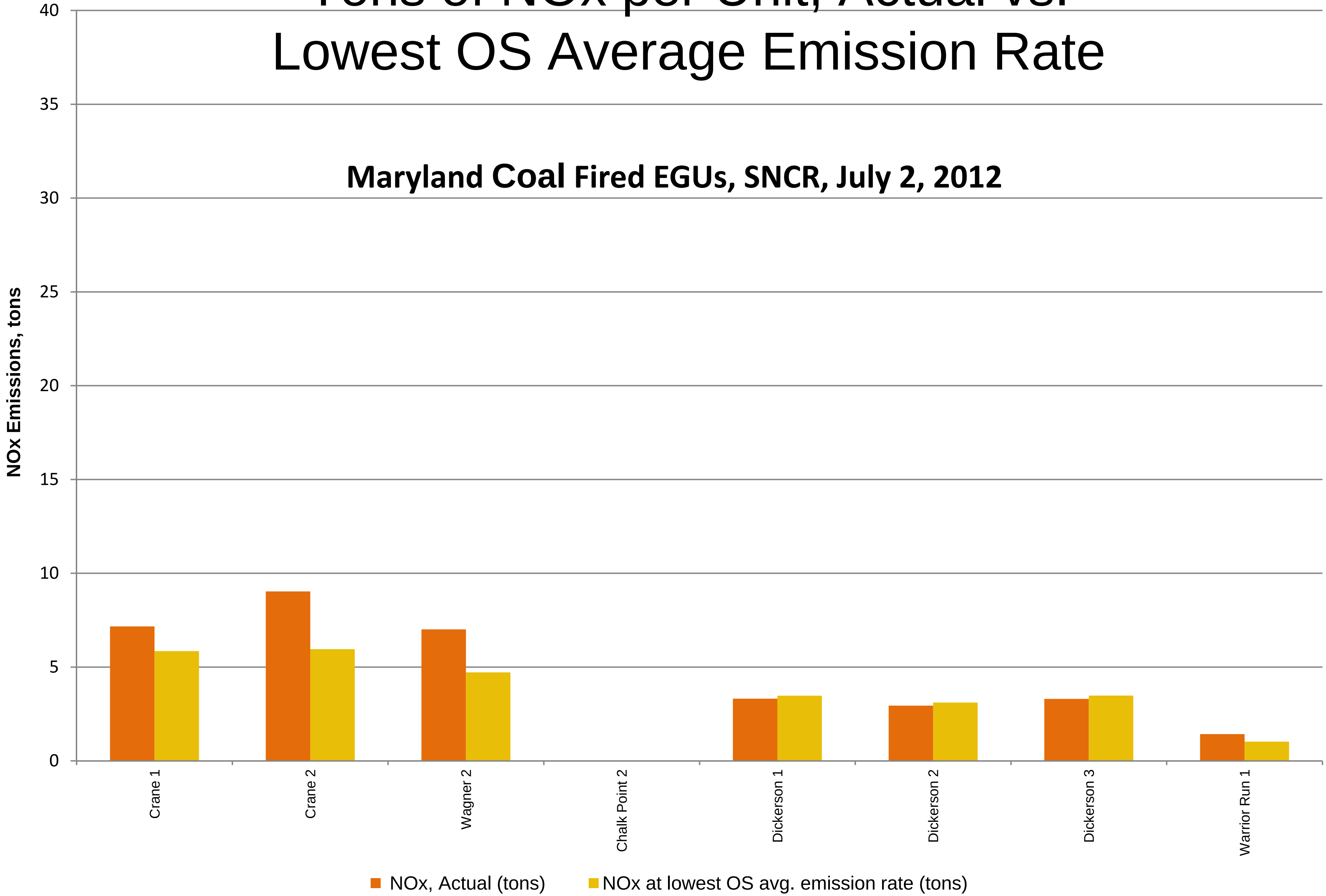
DRAFT – September 18, 2014 – Requesting QA of data. For discussion purposes only.

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



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

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



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 (ORISPL)	Unit ID	Year	Associated Stacks	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
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 Com
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 Coo
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 Coo
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 (Primary)	Representative (Secondary)	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	ARP : Morrison, Q	ARP : Trace	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boile	Coal		Wet Lime FGD	Low NOx Burner Technology w/ Overfire Air Sel	Cyclone Baghouse
Brandon Shores	TRNOX : Haught, [	TRNOX : M	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boile	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 boile	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 boile	Coal			Low NOx Burner Technology w/ Overfire Air Sel	Electrostatic Precipitator
R. Paul Smith Power St	ARP : Cannon, Dav	ARP : Cain,	Phase 2	Phase 1 Gr	Operating	Dry bottom wall-fired boile	Coal			Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitator
R. Paul Smith Power St	ARP : Cannon, Dav	ARP : Cain,	Phase 2	Phase 1 Gr	Operating	Tangentially-fired	Coal			Low NOx Burner Technology w/ Closed-coupled/Se	Electrostatic Precipitator<b
Chalk Point	RGGI : Garlick, Jan	RGGI : Gau	Table 1	Phase 1 Gr	Operating	Dry bottom wall-fired boile	Coal	Pipeline Na	Wet Limestone	Low NOx Burner Technology (Dry Bottom only) 	Electrostatic Precipitator
Chalk Point	ARP : Garlick, Jam	ARP : Gaud	Table 1	Phase 1 Gr	Operating	Dry bottom wall-fired boile	Coal	Pipeline Na	Wet Limestone	Low NOx Burner Technology (Dry Bottom only) 	Electrostatic Precipitator
Dickerson	TRSO2G1 : Gouvei	TRSO2G1 :	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Separated OFA 	Baghouse Electrostatic
Dickerson	TRNOXOS : Gouve	TRNOXOS :	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Separated OFA 	Baghouse Electrostatic
Dickerson	TRNOXOS : Gouve	TRNOXOS :	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Separated OFA 	Baghouse Electrostatic
Morgantown	ARP : Garlick, Jam	ARP : Gaud	Table 1	Phase 1 Gr	Operating	Tangentially-fired	Coal	Residual Oi	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Se	Electrostatic Precipitator
Morgantown	ARP : Garlick, Jam	ARP : Gaud	Table 1	Phase 1 Gr	Operating	Tangentially-fired	Coal	Residual Oi	Wet Limestone	Low NOx Burner Technology w/ Closed-coupled/Se	Electrostatic Precipitator
AES Warrior Run	RGGI : Leaf, Jeff ((	RGGI : Braun, Wilma L (3185),CAIR			Operating	Circulating fluidized bed bo	Coal	Diesel Oil	Fluidized Bed Limes	Ammonia Injection Selective Non-catalytic Redu	Baghouse
Perryman	ARP : Blair, Scott I	ARP : Tracey, Edward F (2683) (En			Operating	Combustion turbine	Diesel Oil				
Perryman	ARP : Blair, Scott I	ARP : Tracey, Edward F (2683) (En			Operating	Combustion turbine	Diesel Oil				
Perryman	CAIRNOX : Blair, S	CAIRNOX : Tracey, Edward F (2683			Operating	Combustion turbine	Diesel Oil				
Perryman	ARP : Blair, Scott I	ARP : Tracey, Edward F (2683) (En			Operating	Combustion turbine	Diesel Oil				
Chalk Point	CAIROS : Garlick, J	CAIROS : Gaudette, Robert (60548			Operating	Combustion turbine	Diesel Oil				
Morgantown	ARP : Garlick, Jam	ARP : Gaudette, Robert (605481)			Operating	Combustion turbine	Diesel Oil				
Morgantown	ARP : Garlick, Jam	ARP : Gaudette, Robert (605481)			Operating	Combustion turbine	Diesel Oil				
Morgantown	ARP : Garlick, Jam	ARP : Gaudette, Robert (605481)			Operating	Combustion turbine	Diesel Oil				
Morgantown	ARP : Garlick, Jam	ARP : Gaudette, Robert (605481)			Operating	Combustion turbine	Diesel Oil				
Herbert A Wagner	TRNOX : Haught, [	TRNOX : M	Phase 2		Operating	Dry bottom wall-fired boile	Other Oil	Pipeline Natural Gas			Electrostatic Precipitator
Herbert A Wagner	RGGI : Morrison, (	RGGI : Trac	Phase 2		Operating	Dry bottom wall-fired boile	Other Oil	Pipeline Natural Gas			Electrostatic Precipitator
Gould Street	ARP : Blair, Scott I	ARP : Trace	Phase 2		Operating	Dry bottom wall-fired boile	Pipeline Natural Gas				
Perryman	ARP : Blair, Scott I	ARP : Trace	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Riverside	ARP : Blair, Scott I	ARP : Trace	Phase 2		Operating	Dry bottom wall-fired boile	Pipeline Natural Gas				
Riverside	ARP : Blair, Scott I	ARP : Tracey, Edward F (2683) (En			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil			
Westport	CAIROS : Blair, Scc	CAIROS : Tracey, Edward F (2683)			Operating	Combustion turbine	Pipeline Natural Gas				
Chalk Point	CAIRNOX : Garlick	CAIRNOX :	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	ARP : Garlick, Jam	ARP : Gaud	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	ARP : Garlick, Jam	ARP : Gaud	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	ARP : Garlick, Jam	ARP : Gaud	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	ARP : Garlick, Jam	ARP : Gaudette, Robert (605481)			Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Dickerson	CAIRNOX : Garlick	CAIRNOX :	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Dickerson	CAIRSO2 : Garlick,	CAIRSO2 : (	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Rock Springs Generatir	ARP : Peach, Jame	ARP : Doug	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generatir	ARP : Peach, Jame	ARP : Doug	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generatir	ARP : Peach, Jame	ARP : Doug	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generatir	ARP : Peach, Jame	ARP : Doug	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Brandywine Power Fac	ARP : Martin, Johr	ARP : Brigg	Phase 2		Operating	Combined cycle	Pipeline Natural Gas	Diesel Oil		Water Injection Other	
Brandywine Power Fac	ARP : Martin, Johr	ARP : Brigg	Phase 2		Operating	Combined cycle	Pipeline Natural Gas	Diesel Oil		Water Injection Other	
Vienna	ARP : Grant, Jack	ARP : Sulliv	Phase 2		Operating	Tangentially-fired	Residual Oil				
Chalk Point	ARP : Garlick, Jam	ARP : Gaud	Phase 2		Operating	Tangentially-fired	Residual Oil	Pipeline Natural Gas		Overfire Air	
Chalk Point	CAIRSO2 : Garlick,	CAIRSO2 : (	Phase 2		Operating	Tangentially-fired	Residual Oil	Pipeline Natural Gas		Overfire Air	

State	Facility Name	Facility ID (ORISPL)	Unit ID	Year	Associated Stacks	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
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, CS	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, CS	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 Sou
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 Sou
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 Sou
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 Sou
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 Sou
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 Sou
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 Sou
MD	Riverside	1559	CT6	2014		CAIROS	0	2							3	Baltimore	Electric Utility	Constellation Power Sou
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
		46							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 boile	Coal		Wet Lime FGD	Low NOx Burner Technology w/ O	Cyclone Baghouse
Brandon Shores	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boile	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 Modi	Baghouse
C P Crane	Table 1	Group 2	Operating	Cyclone boiler	Coal			Overfire Air Combustion Modi	Baghouse
Herbert A Wagner	Phase 2	Phase II Gr	Operating	Dry bottom wall-fired boile	Coal			Low NOx Burner Technology (Dry E	Electrostatic Precipitator
Herbert A Wagner	Phase 2	Phase 2	Operating	Dry bottom wall-fired boile	Coal			Low NOx Burner Technology w/ O	Electrostatic Precipitator
Chalk Point	Table 1	Phase 1 Gr	Operating	Dry bottom wall-fired boile	Coal	Pipeline Natura	Wet Limestone	Low NOx Burner Technology (Dry E	Electrostatic Precipitator
Chalk Point	Table 1	Phase 1 Gr	Operating	Dry bottom wall-fired boile	Coal	Pipeline Natura	Wet Limestone	Low NOx Burner Technology (Dry E	Electrostatic Precipitator
Dickerson	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Se	Baghouse Electrostatic Pr
Dickerson	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Se	Baghouse Electrostatic Pr
Dickerson	Phase 2	Phase II Gr	Operating	Tangentially-fired	Coal		Wet Limestone	Low NOx Burner Technology w/ Se	Baghouse Electrostatic Pr
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 bo	Coal	Diesel Oil	Fluidized Bed Li	Ammonia Injection Selective N	Baghouse
Perryman	rce Generation Inc.		Operating	Combustion turbine	Diesel Oil				
Perryman	rce Generation Inc.		Operating	Combustion turbine	Diesel Oil				
Perryman	rce Generation Inc.		Operating	Combustion turbine	Diesel Oil				
Perryman	rce Generation Inc.		Operating	Combustion turbine	Diesel Oil				
Chalk Point			Operating	Combustion turbine	Diesel Oil				
Morgantown			Operating	Combustion turbine	Diesel Oil				
Morgantown			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 boile	Other Oil	Pipeline Natural Gas			Electrostatic Precipitator
Herbert A Wagner	Phase 2		Operating	Dry bottom wall-fired boile	Other Oil	Pipeline Natural Gas			Electrostatic Precipitator
Gould Street	Phase 2		Operating	Dry bottom wall-fired boile	Pipeline Natural Gas				
Perryman	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Riverside	Phase 2		Operating	Dry bottom wall-fired boile	Pipeline Natural Gas				
Riverside	rce Generation Inc.		Operating (Ret	Combustion turbine	Pipeline Natural Gas	Diesel Oil			
Westport	nmodities Group, Inc.		Operating	Combustion turbine	Pipeline Natural Gas				
Chalk Point	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas	Diesel Oil		Water Injection	
Chalk Point	Cooperative		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 Generati	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generati	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generati	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Rock Springs Generati	Phase 2		Operating	Combustion turbine	Pipeline Natural Gas			Dry Low NOx Burners	
Brandywine Power Fa	Phase 2		Operating	Combined cycle	Pipeline Natural Gas	Diesel Oil, Liquified Petroleum G		Water Injection Other	
Brandywine Power Fa	Phase 2		Operating	Combined cycle	Pipeline Natural Gas	Diesel Oil, Liquified Petroleum G		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 D

REFERENCE LINKS FOR NATURAL GAS REPORTS

1.

http://www.sourcewatch.org/index.php?title=Coal_plant_conversion_projects

Natural gas conversions

Although some coal-fired power plants are reported to have been converted from coal to natural gas, a 2010 study by the Aspen Environmental Group for the American Public Power Association reports that such "conversions," when examined, are replacements rather than retrofits:[12]

> The electricity industry can theoretically switch to natural gas either by retrofitting existing coal-fired units to burn natural gas or by closing the coal plants and building new gas-fired plants. Aspen's research uncovers no instances of coal plant retrofits to natural gas and, in fact, virtually all of the public references to conversion of coal to natural gas or repowering turn out instead to be replacements. The reason is economics. Even the U.S. Government Accountability Office (GAO), when it looked at this issue switching the Capitol Building power plant to natural gas, noted that not only was switching all U.S. coal-fired generation infeasible due the gas supply and infrastructure required, but that it would be more cost-effective to construct new gas-fired units than to retrofit existing coal-fired units to burn natural gas. Combined-cycle gas-fired generation costs roughly $1 million per MW, installed.

The environmental impacts of natural gas are better understood than those of biomass. Natural gas combustion produces almost 45 percent fewer carbon dioxide emissions than coal, emits lower levels of nitrogen oxides and particulates, and produces virtually no sulfur dioxide and mercury emissions. The lower levels of these emissions mean that the use of natural gas does not contribute significantly to smog or acid rain formation. In addition, because natural gas boilers do not need the scrubbers required by coal-fired power plants to reduce SO_2 emissions, natural gas plants create much less toxic sludge. [13]

2.

http://file.wikileaks.org/file/crs/RL34746.pdf

CRS Report for Congress
Power Plants: Characteristics and Costs

Stan Kaplan
Specialist in Energy and Environmental Policy
Resources, Science, and Industry Division

November 13, 2008

3.

http://fpc.state.gov/documents/organization/135929.pdf

Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants

Stan Mark Kaplan
Specialist in Energy and Environmental Policy
January 19, 2010

APPENDIX E

AIR QUALITY MODELING RESULTS

Table of Contents

I. Overview

The Maryland Department of the Environment (MDE) contracted with the University of Maryland at College Park (UMD) Department of Atmospheric & Oceanic Science to perform photochemical modeling to demonstrate the effect the proposed NOx regulation (proposed COMAR 26.11.38 – Control of NOx Emissions from Coal Fired Electric Generating Units) will have on Maryland's air quality. This document will describe the emissions and meteorological data used as input to the photochemical model, as well as the results in ozone concentrations based on the photochemical modeling completed.

II. Modeling Emissions

This section will describe the type of model used to prepare the pollutant emissions.

A. Emissions Model Selection and Configuration

The Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System was selected for the proposed regulation modeling analysis. The SMOKE model was originally developed at the Microelectronics Center of North Carolina (MCNC) to integrate emissions data processing with high-performance computing (HPC) sparse – matrix algorithms. The SMOKE model is now under active development at the Institute for Environment and is partially supported by the Community Modeling and Analysis Systems (CMAS).

The SMOKE model is principally an emissions-processing system and not a true emissions inventory preparation system in which emissions are simulated from 'first principles'. This means that, with the exception of mobile and biogenic sources, its purpose is to provide an efficient, modern tool for converting emissions inventory data into the formatted gridded, speciated, hourly emissions files required by an air quality simulation model. For mobile emissions, the on-road emissions model MOVES2014 was used. For biogenic emissions modeling, SMOKE uses whatever biogenic emissions it is given. In this particular case, BEIS emissions were integrated into model ready format.

SMOKE is the fastest emissions processing tool currently available to the air quality modeling community. The sparse matrix approach used throughout SMOKE permits rapid and flexible processing of emissions data. The rapid processing is possible because SMOKE uses a series of matrix calculations rather than a less-efficient sequential approach used by previous systems. The process is flexible because the processing steps of temporal projection, controls, chemical speciation, temporal allocation, and spatial allocation have been separated into independent operations wherever possible. The results from these steps are merged together at a final stage of processing using vector-matrix multiplication. This means that individual steps (such as adding a new control strategy, or processing for a different grid) can be performed and merged without having to redo all of the other processing steps.

The SMOKE model supports area, mobile, fire, point, and biogenic sources emissions processing. For biogenic emissions, SMOKE supports both gridded land use and county total land use data.

SMOKE (Version 3.5.1) was used for the proposed NOx regulation's modeling demonstration. EPA provided a draft NEI2011v2 emissions (USEPA, August 2015) files to the Mid-Atlantic Regional Air Management Association (MARAMA). The stationary sources emissions were then grown using MARAMA created growth factors based on states' inputs and EPA's 2018/2028 Modeling Platform for mobile source emission projections. EPA released the NEI2018v1 on January 14, 2015. The EPA IPM 5.13 EGU emissions were replaced with the Eastern Region Technical Advisory Committee (ERTAC) 2.3 EGU emissions (http://marama.org/2013-ertac-egu-forecasting-tool-documentation) in an effort to use the best emissions data available to model this proposed NOx regulation.

III. Meteorological Model

This section will describe the type of meteorological model selected to obtain the meteorological parameters needed to perform the air quality simulations for the proposed NOx regulation.

Meteorological inputs for the CMAQ modeling were developed by EPA for the 2011 modeling platform using version 3.4 of the Weather Research and Forecasting (WRFv3.4) numerical weather prediction model (Skamarock et al., 2008). The meteorological outputs from WRF include hourly varying winds, temperature, moisture, vertical diffusion rates, clouds, and rainfall rates. Additional details about this WRF simulation and its performance evaluation can be found in U.S. EPA (2014b).

IV. Air Quality Model

This section will describe the photochemical modeling system selected to perform the air quality simulations for the proposed regulation.

The EPA's Models-3/Community Multi-scale Air Quality (CMAQ) model version 5.0.2 was the model used for this analysis of the proposed regulation. The modeling system is a 'One-Atmosphere' photochemical grid model capable of simulating ozone and PM2.5 at a regional scale and is considered one of the preferred models for regulatory modeling applications. CMAQ is generally considered by the scientific community to meet the following prerequisites for photochemical modeling applications:

1. It has been received and been revised in response to scientific peer review.
2. It is appropriate for the specific application on a theoretical basis.

3. It shall be used with a database that is adequate to support its application.
4. It has been shown to perform well in past ozone modeling applications.
5. It will be applied consistently with a protocol on methods and procedures.

Furthermore, several factors were considered as criteria for choosing CMAQ as a qualifying air quality model to support the proposed regulation and these factors are:

1. Documentation and past track record in similar applications;
2. Advanced science and technical features available in the modeling system;
3. Experience of staff; and
4. Required time and resources versus available time and resources.

For further documentation on the CMAQ model, see http://www.epa.gov/asmdnerl/CMAQ/CMAQscienceDoc.html.

V. Modeling Scenarios

This section will describe the modeling scenarios used to simulate the effect the proposed regulation will have on air quality in Maryland. For all scenarios the meteorological period of July 1 – July 31, 2011 was simulated. This particular month was an appropriate period to model since there were a high number of ozone exceedance days. During July 2011 Maryland experienced 17 ozone exceedance days. In addition, 2011 National Emissions Inventory (NEI) was selected by EPA to be the base year for their modeling platform that will be used to support the development of the revised ozone NAAQS (US EPA, 2015).

Descriptions of the modeling scenarios are as follows:

Base Case Scenario

The Base Case Scenario consists of 2011 NEI v2 from EPA, ERTAC EGU emissions (replaced EPA's IPM EGU emissions) and EPA MOVES 2014 mobile sources. The base case model ready emissions were provided by the New York State Department of Environmental Conservation (NYSDEC) as part of an ongoing modeling effort of the Ozone Transport Commission (OTC) of which Maryland is a member.

Future Base Case Scenario

The Future Base Case Scenario consists of the 2011 Base Case Scenario being grown by MARAMA to a future year of 2018 for the OTC. EGU 2018 projected emissions were developed from the ERTAC tool. The controls applied to the inventory were the following: On The Books (OTB)/On The Way (OTW) and Tier 3 mobile controls plus optimized EGUs and OTC measures.

Phase 1 Scenario
This scenario consisted of the Future Base Case Scenario plus 2018 optimized Maryland EGUs.

Phase 2 Scenario
This scenario consisted of the Phase 1 Scenario plus a 0.11 lb/mmBtu as is required should they select a 21 ton/day or 0.11 lb/mmBtu daily rate cap compliance in 2020.

Phase 2 Fuel Switch Scenario
This scenario consisted of the Phase 1 Scenario plus a fuel switch from coal to natural gas and meets a NOx emission rate of 0.15 lb/mmBtu.

Phase 2 Option 4 Scenario
This scenario consisted of the Phase 1 Scenario plus Raven and NRG systems meeting a 21 ton per day NOx mass cap and meeting a system wide 30-day rolling average of 0.09 lb/mmBtu.

VI. Modeling Results

This section will describe the modeling results of the various scenarios.

Figure 1 shows the average of the top six days when ozone was above the 8-hour ozone standard and areas that have no colors associated with them did not have six days above the 8-hour ozone standard for the month of July for the 2011 Base Case Scenario. All the orange and red areas represent ozone concentrations the exceeded the NAAQS.

It should be noted, that EPA Draft Modeling Guidance (USEPA, December, 2014) suggests that the top ten days should be used for the modeled attainment test, but after discussions with EPA it was decided that the top six days would be suitable for a single month.

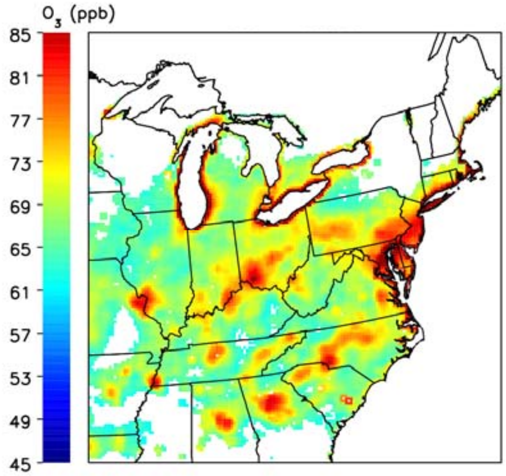


Figure 1. 2011 Base Case

Figure 2 shows the average of the top six days when ozone was above the 8-hour standard and areas that have no colors associated with them did not have six days above the 8-hour ozone standard for the month of July for the 2018 Future Base Case Scenario. This particular scenario represents what the ozone levels would be in 2018 without the proposed NOx regulation. The orange red color in central Maryland shows that area would exceed the ozone NAAQS.

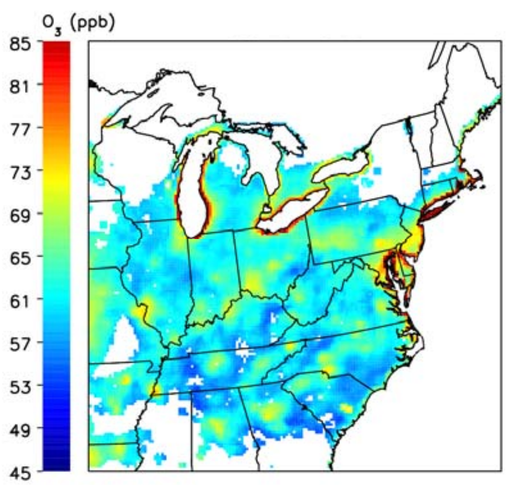


Figure 2. 2018 Future Base Case without the Maryland Proposed Regulation

Figure 3 shows the average of the top six days when ozone was above the 8-hour ozone standard and areas that have no colors associated with them did not have six days above the 8-hour ozone standard for the month of July for the 2018 Future Base Case Scenario. This particular scenario represents what the ozone levels would be in 2018 with the proposed NOx regulation. Again there's some orange and red colors in central Maryland which means that not all areas in Maryland would be attaining the ozone NAAQS.

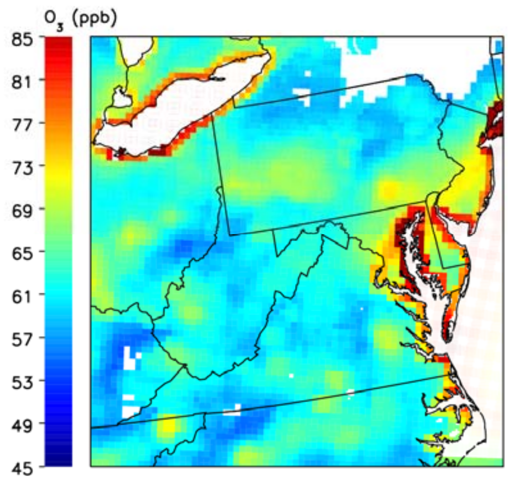


Figure 3. 2018 Future Base Case with the Maryland Proposed Regulation

Figure 4 shows the total ozone reductions based on the new Phase 2 (2020) of the proposed regulation when compared to the air quality in 2011. The dark blue color over Maryland represents an ozone decrease of approximately 8-10 ppb.

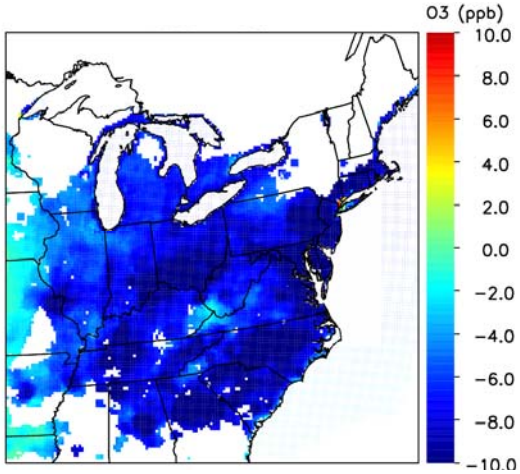


Figure 4. Total Ozone Reductions from the Maryland Proposed Regulation Including the New Phase 2 (2020) NOX Reductions

Figure 5 shows the total ozone reductions for the Phase 1 Scenario, which consisted of 2018 optimized Maryland EGUs. The reduction in Maryland ozone concentrations was approximately 0.70 ppb.

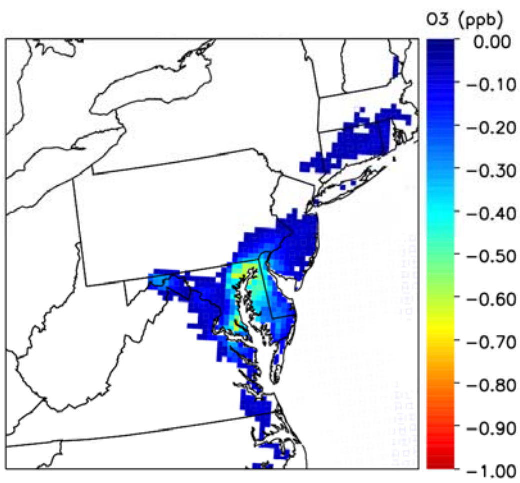


Figure 5. Total Ozone Reductions from Phase 1 of the Proposed Regulation

Figure 6 shows the additional reductions from the 2020 requirements of the proposed NOx regulation (Phase 2 Option 4 Scenario). The ozone reduction in Maryland would be approximately 0.65 ppb.

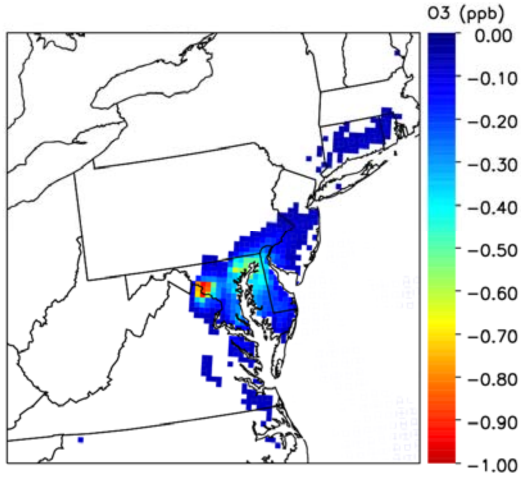


Figure 6. Additional Reductions from 2020 requirements of the Proposed Regulation (Phase 2 Option 4)

Figure 7 shows the additional ozone reductions based on the Phase 2 Option 4 Scenario when compared to the old proposed NOx regulation. The ozone reduction in Maryland could be as much as approximately 0.15 ppb.

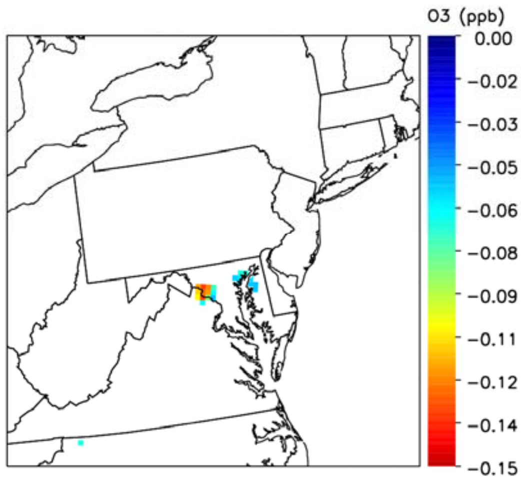


Figure 7. Additional Benefit of Phase 2 New Option 4 Scenario

Figure 8 shows the additional ozone reductions in 2018 from the Phase 2 Scenario when the Phase 2 Option 4 is selected. The reduction in Maryland could be approimately 0.20 ppb.

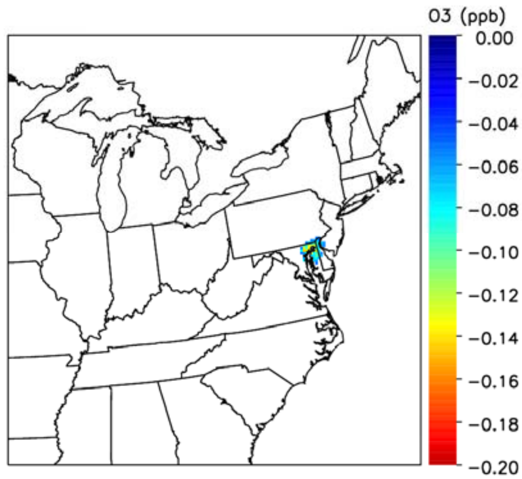


Figure 8. Additional Reductions in 2018 When Phase 2 Option 4 is Selected

VII. Conclusions

The photochemical modeling results demonstrate that the proposed NOx regulation will result in Maryland ozone reductions that will be needed to help attain the current 8-hour ozone NAAQS of 75 ppb. Figure 9 shows the modeled average 8-hour ozone concentrations for the Baltimore Nonattainment Area.

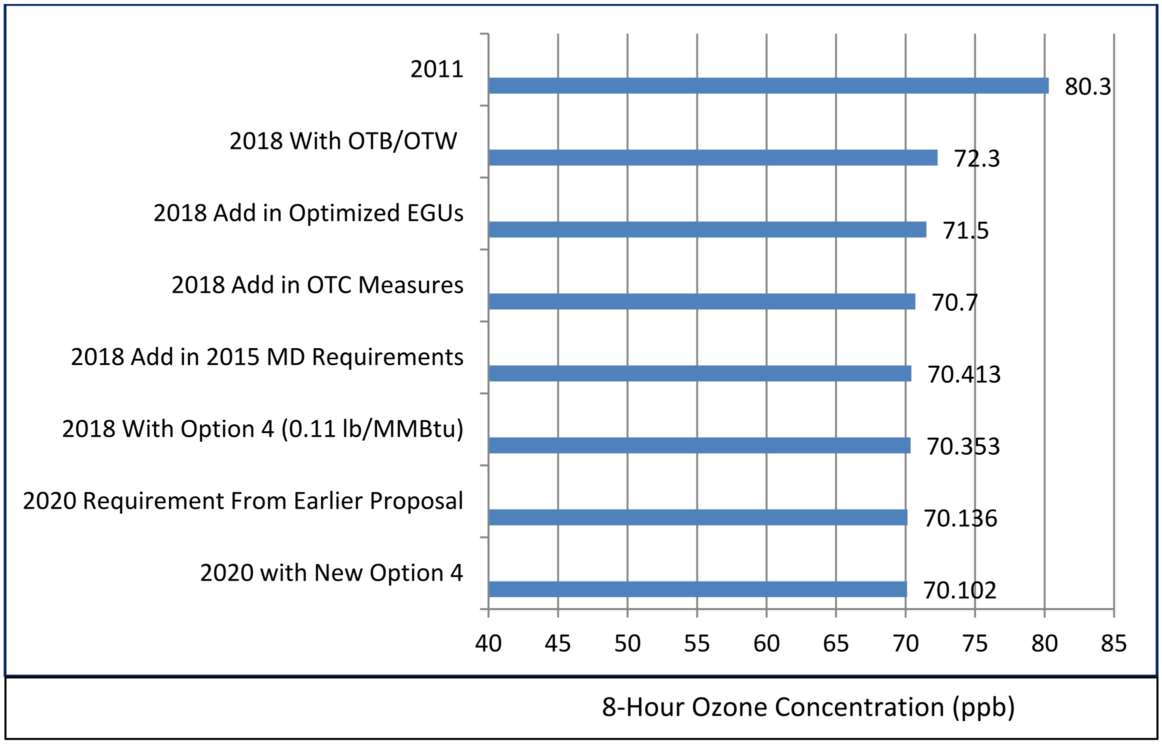


Figure 9. Average Ozone Concentrations for the Baltimore Nonattainment Area

(Note: Baltimore Nonattainment Area is currently measuring attainment for the 75 ppb ozone standard at all monitors.)

References

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Skamarock W.C., Klemp J.B., Dudhia J., Gill D.O., Baker D.M, Duda M.G., Huang X.-Y., Wang W., and Powers J.G (2008) A description of the Advanced Research WRF Version 3. NCAR Technical Note NCAR/TH465+STR, June

U.S. Environmental Protection Agency (2014b) Meteorological model performance for annual 2011 WRF v3.4 simulation. Technical support document prepared by the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, November. Available at http://www.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf

U.S. Environmental Protection Agency (2015) Air quality modeling technical support document for the 2008 ozone NAAQS transport assessment. Technical support document prepared by the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, January. Available at http://www.epa.gov/airtransport/O3TransportAQModelingTSD.pdf

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