September 10, 2009

OTC CAIR Replacement Rule Recommendation Technical Support Document

The OTC is providing technical information in support of the recommendations to EPA on a CAIR replacement rule included in the September 2, 2009 joint letter from OTC and LADCO and the additional recommendations in the September 10, 2009 letter from OTC. The supporting materials provided below are organized as follows:

- Assessments and Rationale for Electricity Generating Units (EGUs)
  - EGU Emission Rates
  - Timing
  - Cost of Controls
  - Air Quality Benefits

- Assessments and Rationale for Other Sectors
  - Other Stationary Source Measures
  - Mobile Source Measures

- Appendix I – EGU Rates
- Appendix II – Timing
- Appendix III – Cost of Controls
- Appendix IV – Air Quality Benefits
- Appendix V – Other Sectors

The technical information included in this support document is based on studies and analyses conducted recently by the OTC, and where noted, by LADCO.

Assessments and Rationale for Electricity Generating Units (EGUs)

In its earliest response to EPA's proposed transport rule - first the Interstate Air Quality Rule (IAQR), and later, the Clean Air Interstate Rule (CAIR) - OTC provided comments and analyses showing that additional NOx and SO_2 reductions beyond those the rule provided would be needed for areas in the OTR to come into attainment with the ozone and $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). In response to the IAQR and CAIR, the OTC states developed a multi-pollutant position in 2004, using several different analyses of potential EGU control rates as a basis for developing national caps for NOx and SO_2 that were more stringent and earlier than those provided in CAIR.

The analysis used in OTC's recent review of the 2004 multi-pollutant position, along with evaluations of the current state of controls on EGUs and rate information extracted from recent American Electric Power Service Corp. (AEP) settlements and consent decrees was provided to the state collaborative process. Additional support for the timeframes and flexibility provisions in the OTC additional recommendations are provided in a short case study on the experiences of the Maryland Department of Environment (MDE) with its Healthy Air Act (HAA), as well as experiences in other states with their own state rules and additional information contained in the AEP settlements/consent decrees. Recent evaluations of control cost data that OTC has conducted for potential control strategies, including analyses for industrial, commercial and institutional boilers and boilers serving EGUs, provide data for relative cost/ton comparison between EGU and other sector NOx and SO_2 controls. An additional sensitivity analysis using OTC's latest SIP modeling runs, in tandem with the results from the State

Collaborative modeling runs, demonstrate the need for the air quality benefits that can be achieved from the rates and structure of the OTC recommendations.

EGU Emission Rates

In developing its 2004 position, OTC relied heavily on an analysis conducted by the National Association of Clean Air Agencies (NACAA) to support of its 2002 Principles for a Multi-Pollutant Strategy for Power Plants. The NACAA analysis demonstrated that reductions in the range of 82-88% by 2013 for SO_2 and 73-81% for NOx from a 2001 baseline were technologically feasible. Reductions within this range would yield emission rates as follows:

- NOx: 0.07 for new source BACT; 0.10 for retrofit BACT; and
- SO_2: 0.10 for new source BACT; 0.15 for retrofit BACT.

In comparison, the average emission rates for 2001 as reported by EPA were 0.37 lb/mmBtu for NOx and 0.84 lb/mmBtu for SO_2 (the 2001 baseline would not have included the NOx SIP Call).

OTC continued to work on and refine its position on EGU rates, based on additional analyses. In a 2007 review, the OTC Multi-P Workgroup performed an analysis to determine revised NOx and SO_2 cap levels.

Assessment 1. In the 2007 review of the OTC multi-pollutant position for EGUs, the OTC Multi-P Workgroup performed an analysis using the EPA Acid Rain database and information from the Department of Energy's Energy Information Agency (EIA) to examine reasonably cost-effective post-combustion EGU control technologies and determine fleet-wide average NOx and SO_2 emission rates for the fossil fuel-fired EGUs in the lower 48 states. The OTC Multi-P Workgroup concluded that for NOx, a 0.08 lbs/mmBtu fleet wide average emission rate would be achievable by 2018, along with an interim hard cap in 2012 based on a 0.125 lbs/mmBtu fleet-wide average. For SO_2 the OTC Multi-P Workgroup concluded that a 0.15 lb/mmBtu fleet wide average emission rate was achievable by 2018, along with an interim hard cap in 2012 based on a 0.25 lb/mmBtu fleet-wide average. The methodology applied by the OTC Multi-P Workgroup included the assumptions in Table I-1 below (also shown in Appendix I):

Table I-1. Control Assumptions for the Methodology Applied by the OTC Multi-P Workgroup

	EGU Size				Emission reduction assumed	
	25MW-<100MW	100MW-<200MW <50% input capacity	100MW-<200MW >50% input capacity	200MW or greater	For EGUs with existing "assumed" add-on controls	For EGUs applying "new" add-on controls
NOx	SNCR	SNCR	SCR	SCR	Remains same as 2008 controlled level	90% SCR 355 SNCR 55% SNCR to SCR increment
SO2	DSI	DSI	FGD	FGD	Remains same as 2008 controlled level	95% FGD 60% DSI

Control Technologies: DSI (Duct Sorbent Injection); FGD (Flue Gas Desulfurization); SCR (Selective Catalytic Reduction); SNCR (Selective Non-Catalytic Reduction)
* For EGUs identified as already incorporating the technology applied in the OTC Multi-P Workgroup's methodology their NOx emission rates were assumed to remain the same as their 2008 Ozone Season controlled

emission rates and their SO_2 emission rates were assumed to remain the same as their annual 2008 controlled emission rates.
**For each NOx and SO_2 control technology a 0.06 lb/MMBTU "basement" level (i.e., maximum control level) was assumed.

When these assumptions are applied to coal units (all coal and coal>100 MW) on a statewide average ozone season basis in the Ozone Transport Region (OTR), the result is a range of rates for NOx between 0.06 and 0.23 lb/mmBtu. A similar application in the LADCO states on a statewide average ozone season basis yields NOx rates in the range of 0.06 and 0.14 lb/mmBtu. Similarly, when the SO_2 assumptions are applied in the OTR on a statewide annual basis, the result is a range of rates for SO_2 between 0.06 and 0.32 lb/mmBtu. Following suit in the LADCO states on a statewide annual basis yields SO_2 rates in the range of 0.06 and 0.31 lb/mmBtu. Statewide rates for each state based on this analysis are outlined in Tables I-2 through I-5 in Appendix I.

This analysis does not include emissions from units in the states that use other fuels, such as natural gas, that would lower the overall statewide average emission rate. It also shows that some states with higher percentages of coal in their overall fuel mix will need flexibility in the regulatory structure and timing to achieve those rates.

Assessment 2. In a second assessment of potential EGU rates, OTC compiled information for each of the states in the eastern U.S. to show the average NOx and SO_2 emission rates from EPA's 2008 Clean Air Market Division (CAMD) database, based on units 25 MW and above for all fuels. Then the incremental NOx and SO_2 rates within the ranges discussed by the State Collaborative were calculated for each state, from 0.07 - 0.125 lb/mmBtu for NOx and from 0.15 - 0.30 lb/mmBtu for SO_2. The tons reduced at each control level increment and the percent reduction from 2008 levels is calculated for each state. The results are shown in Tables I-6 and I-7 in Appendix I, along with Tables I-8 and I-9 showing LADCO's data on achievable average annual emission rates based on their plant-level, unit-level analysis of coal fired units greater than 100 MW, and the timing of projected post-combustion controls installations. Comparing the OTC tables based on the CAMD data with the LADCO table, the 2008 rates are very close, despite the fact that the CAMD data includes all fuels and the LADCO data is for coal units only.

Assessment 3. Using a third data set to assess potential EGU emission rates, the OTC examined the recent consent decree signed by American Electric Service Corp. (AEP) which requires the installation of SCR and FGD controls on EGUs in a number of states including Indiana, Kentucky, Ohio, Virginia and West Virginia. The consent decree requires several of these units to meet a federally-enforceable 30-day rolling average emission rate of 0.100 lb/mmBtu for NOx and a 30-day rolling average emission rate of 0.100 lb/mmBtu for SO_2. Furthermore, repowering requirements as stipulated in the consent decree state that the technology achieve "equivalent environmental performance that at a minimum achieves and maintains a 30-day rolling average emission rate of 0.100lb/mmBtu or a 30-day rolling average removal efficiency of at least 95% for SO_2 and a 30-day rolling average emission rate of 0.070 lb/mmBtu for NOx.

The limits specified in the AEP consent decree provide additional support for the technical feasibility and cost effectiveness of the NOx and SO_2 emission rates "observed by" the State Collaborative EGU Technical Workgroup presented at the State Collaborative meetings held on October 7, 2008 and April 27-28, 2009. AEP would not have signed this consent decree if it was not certain that it could comply with all of its terms. Note that the NOx and SO_2 emission rates in the consent decree are more stringent than the NOx and SO_2 emission rates in the OTC recommendations because they are based on unit specific, 30-day rolling average emission rates rather than statewide average emission rates. If EGU retrofits can achieve the NOx and SO_2 rates specified in the AEP consent decree on a unit specific basis, then it should be feasible for other EGUs to achieve these emission rates on a statewide average basis.

Timing

Timing flexibility is a key issue in developing an EGU control strategy. If the regulatory structure is designed correctly, it will provide incentives to get controls installed quickly. One example of this is provided by the Maryland Department of Environment's (MDE) experience with their Healthy Air Act (HAA), which was passed in 2006, with final rules issued in January 2007 (see MDE case study in Appendix II). MDE's experience with the HAA demonstrates that it is possible to achieve simultaneous, rather than sequential, installation of controls in less than 3 years after promulgation of the rules requiring those controls.

- In Maryland, 3 SCRs and 6 SNCRs on coal units ranging in size from 125 - 600 MW, and 6 FGD on 9 coal-fired units ranging in size from 200 -700 MW are installed or will have completed installation by the end of 2009, or less than 3 years after the HAA rules were promulgated. Four SCRs had been installed on coal-fired power plants in Maryland prior to the HAA.
- MDE included a waiver for units that could not meet the control levels by the date required, providing additional time for them to install controls. The waiver was not utilized by any EGU.
- The installations responding to the HAA rules occurred at the same time that controls were being required for CAIR and a number of consent decrees on EGUs. Despite these competing interests, there were no delays in construction or installation due to labor or equipment constraints.

More specific information can be found in Appendix II, Example 1 on the MDE HAA case study, including a schematic of the timeline of installations on specific EGUs in response to the rule.

In another example from Delaware, the state established phased NOx and SO_2 limits in Regulation 1146, promulgated in December 2006, with the first phase of controls required to be operational in May 2009. This provided a 2.5-year window from promulgation of the rule to installation and operation of controls for the first phase of NOx and SO_2 controls. The emission rates and timing for the reductions required by Delaware's Regulation 1146 is applicable to coal-fired and residual oil-fired units 25 MW and above are as follows:

- NOx = 0.15 lb/mmBtu on all units beginning May 1, 2009 through December 2011, with a second, more stringent limit on the same units of 0.125 lb/mmBtu for the period January 1, 2012 and beyond (limits are on a rolling 24-hour basis);
- SO_2 = 0.37 lb/mmBtu on all units beginning May 1, 2009 through December 2011, with a second, more stringent limit on coal-fired units of 0.26 lb/mmBtu for the period January 1, 2012 and beyond (limits are on a rolling 24-hour basis); and
- Residual oil-fired units may not accept residual fuel oil for combustion that has a sulfur content in excess of 0.5% by weight from January 1, 2009 and beyond.

More information on Delaware's Regulation 1146 can be found at:
http://regulations.delaware.gov/AdminCode/title7/1000/1100/1146.shtml

Finally, data collected on controls resulting from EPA's NOx SIP Call show that a over 75 percent of the SCR units installed occurred within a 4-year window, between 2003 to 2007, with more than 50 percent of the installations occurring in the 2003-2004 timeframe. More information on the installation of SCR controls in response to EPA's NOx SIP Call can be found in Appendix II, Example 2.

Cost of Controls

EPA needs to perform a comprehensive cost analysis for the CAIR replacement rule; however, in the interim the data show that aggressive controls on EGUs continues to be the most cost-effective option available to the states in meeting the ozone and $PM_{2.5}$ standards.

Table III-1 in Appendix III provides recently developed cost estimates for various NOx and SO_2 controls in 2008 dollars, including selective non-catalytic reduction (SCR), selective catalytic reduction (SCR), flue gas desulfurization, low NOx burners (LNB)and combinations of these controls on coal-fired, residual oil-fired, distillate oil-fired and natural gas-fired boilers. The data shows that the cost for controls caps out at $4,900 per ton of NOx removed for an SCR and $3,600 per ton of SO_2 removed for a dry FGD system (dry scrubber) installed on a 250 mmBtu/hr (approximately 73 MW) coal-fired boiler operating at 66 percent capacity. The NOx control costs for 250 mmBtu/hr fossil fuel-fired boilers serving EGUs range from $1,100 to $8,700 per ton of NOx removed and the SO_2 control costs for 250 mmBtu/hr coal-fired boilers serving EGUs range from $1,400 to $3,600 per ton of SO_2 removed.

OTC is conducting an extensive examination of potential control measures to consider as additional strategies in their ozone and $PM_{2.5}$ SIPs. The costs of several of these controls on a $/ton basis far exceed the cost of EGU controls, as shown in Tables III-2 and III-3 in Appendix III.

Air Quality Benefits

The State Collaborative effort has produced modeling analyses to examine the impact that a CAIR replacement rule might have on air quality in the Eastern United States. These regional modeling results show that an EGU based strategy would have a positive impact on $PM_{2.5}$ and ozone air quality in the region and that while nearby sources have by far the greatest impact, significant contribution to levels of ozone and $PM_{2.5}$ can come from states several hundred miles away. This effort also shows that with an EGU strategy that approximates CAIR and other currently adopted measures many areas are still above the current ozone (0.075 ppm) and $PM_{2.5}$ NAAQS.

Furthermore, the State Collaborative modeling also show that even with the most stringent NOx (0.07 lb/mmBtu) and SO_2 (0.10 lb/mmBtu) emission control rates applied on a unit-by-unit basis, a number of areas remain in non-attainment . Under these emission limits the modeling shows 23 counties in non-attainment for the 75 ppb ozone standard, 10 counties not meeting the $PM_{2.5}$ daily standard, and 3 counties in non-attainment for the $PM_{2.5}$ annual standard. The State Collaborative modeling is not "SIP quality," so it was conducted to provide, at best, ballpark estimates that are only meant to be directionally correct. Even with the substantial improvement in air quality shown in the 2018 modeling results, however, approximately 37 million people will still be exposed to unhealthy levels of air pollution. Results from the State Collaborative air quality modeling are summarized in the charts and maps on pages 1-2 of Appendix IV.

To ascertain the level of reductions that might be necessary to meet the current ozone NAAQS, the OTC performed sensitivity modeling. This sensitivity modeling employed across-the-board reduction in NOx emissions (point, area and mobile sources). This sensitivity modeling indicates that by reducing NOx emissions by 40 % from all sectors attainment with the current ozone NAAQS is possible. While it is likely impossible to reduce NOx emissions by 40 % from all sectors, this provides a pathway to determine the level of emissions reductions needed for planning purposes. The ultimate decision on the measures chosen will be based on feasibility (both technical and cost) and effectiveness. Results from the OTC sensitivity modeling are summarized in the maps and charts on pages 3-5 of Appendix IV.

Assessments and Rationale for Other Sectors

The states in the eastern U.S. have affirmed that emission reductions beyond what is achievable from EGU sources alone will be necessary to comply with the ozone and $PM_{2.5}$ standards, and to address transport and regional haze. Both the joint OTC-LADCO recommendation of September 2, 2009 and the additional recommendations provided by OTC in the September 20, 2009 letter put forward potential EGU emission rates for consideration by EPA that go beyond the original CAIR levels. It is important that significant reductions are also obtained from sources in the area and mobile source sectors to bring areas into attainment with air quality standards and mitigate transport of air pollutants and their precursors from one part of the country into another.

<u>Other Stationary and Area Source Measures</u>

The OTC states have taken actions beyond the EGU sector during the past 10 years to reduce NOx and VOC emissions from non-EGU stationary and area sources including consumer products, architectural and industrial maintenance coatings, adhesives and sealants, solvents, portable fuel containers, asphalt paving, distributed generators, cement kilns, glass furnaces and industrial, commercial and institutional (ICI) boilers. The model rules developed in 2001 and 2006 for these source categories have been developed and implemented by many of the OTC states as outlined in Tables V-1 through V-4 in Appendix V.

The OTC has long advocated to EPA that these rules be applied nationally, and EPA has taken national action in some areas, e.g., consumer products. The ICI boiler model rule was used in last year's State Collaborative discussions with LADCO to help develop a joint set of recommendations for a national ICI boiler strategy to EPA. Further, in the current planning work occurring in the OTR for the new ozone and $PM_{2.5}$ SIPs, the OTC is continuing to drill down into other non-EGU stationary and area source categories to find additional reductions, as outlined in the potential measures illustrated in Tables III-2 and III-3 in Appendix III.

<u>Mobile Source Control Measures</u>

The OTC states have also implemented numerous programs to reduce ozone precursor emissions from mobile sources. The majority of the states have adopted California Low Emission Vehicle standards applicable to new vehicles, which are more stringent than federal standards. To address emissions from in-use vehicles, the states have implemented Inspection and Maintenance Programs and aggressive diesel retrofit programs.

States have also exercised their option to opt-in to federal reformulated gasoline as part of their State Implementation Plans (SIPs). To counter growth in vehicle miles traveled, states in the region have included transportation control measure in their SIPs (e.g., improved public transit) and have implemented many air quality improvement projects through the conformity review process to ensure mobile source emission budgets are met.

The OTC Mobile Source Committee is currently working on additional mobile measures as part of the 2008 ozone standard regional attainment planning process. It is supporting the adoption of national measures in areas where the states are pre-empted from taking action. For example, it has submitted a letter of support for the ocean going vessels Emission Control Areas (ECA) designation to reduce emissions from port areas. And it has encouraged EPA to issue guidance from EPA on its Aftermarket Catalyst Replacement Standards policy. The OTC is also advocating for EPA to address backsliding with regard to the Renewable Fuel Standard (RFS), to ensure that phase 2 of the program does not further exacerbate criteria pollutant impacts that have occurred in Phase 1 of the program.

Other mobile measures that are under review in the OTC and NESCAUM states are:

- Offshore lightering for ships (VOC reductions)
- Seaports strategy (PM strategy primarily)
- Adoption and enforcement of non-road idling requirements (VOC, NOx and GHG reductions)
- Regional fuel for OTC states/areas that have not yet adopted RFG (i.e. large parts of PA and NY))
- Heavy duty diesel strategies such as Inspection and Maintenance Programs for Diesels and expansion of diesel retrofit programs
- Additional VMT-reduction strategies that will result in ozone precursor and GHG reductions

In the context of Greenhouse Gas Emissions, the OTC states have been involved in numerous actions that will result in the overall reduction of ozone precursors as well as GHG emissions. The litigation of Mass v. EPA, joined by many OTC states, and the active support of OTC-member states for the integration of motor vehicle efficiency standards and GHG emission standards into a new federal policy endorsed by President Obama are examples. The RGGI States, with PA, are also working on the development of a low carbon fuel standard (LCFS), including the potential to improve the infrastructure for electric vehicles that may be part of that strategy, and smart growth/VMT and land use measures to reduce mobile emissions.

Appendix I – EGU Rates

Assessment 1

The methodology applied by the OTC Multi-P Workgroup and used for this assessment is included the assumptions in Table 1-1 below:

Table I-1. Control Assumptions for the Methodology Applied by the OTC Multi-P Workgroup

	EGU Size				Emission reduction assumed	
	25MW-<100MW	100MW-<200MW <50% input capacity	100MW-<200MW >50% input capacity	200MW or greater	For EGUs with existing "assumed" add-on controls	For EGUs applying "new" add-on controls
NOx	SNCR	SNCR	SCR	SCR	Remains same as 2008 controlled level	90% SCR 355 SNCR 55% SNCR to SCR increment
SO2	DSI	DSI	FGD	FGD	Remains same as 2008 controlled level	95% FGD 60% DSI

Control Technologies: DSI (Duct Sorbent Injection); FGD (Flue Gas Desulfurization); SCR (Selective Catalytic Reduction); SNCR (Selective Non-Catalytic Reduction)

* For EGUs identified as already incorporating the technology applied in the OTC Multi-P Workgroup's methodology their NOx emission rates were assumed to remain the same as their 2008 Ozone Season controlled emission rates and their SO_2 emission rates were assumed to remain the same as their annual 2008 controlled emission rates.

**For each NOx and SO_2 control technology a 0.06 lb/MMBTU "basement" level (i.e., maximum control level) was assumed.

Based on the above assumptions, the "predicted" statewide average ozone season NOx emission rates are shown below:

Table I-2. All Coal

State	Predicted NOx Mass	2008 O.S. Heat Input	Predicted Avg NOx Rate	State	Predicted NOx Mass	2008 O.S. Heat Input	Predicted Avg NOx Rate
CT	395	13,163,750	0.0600	IL	13,297	443,240,475	0.0600
DE	1,863	20,145,049	0.1850	IN	12,814	427,135,645	0.0600
MA	1,569	40,324,189	0.0778	MI	12,645	208,348,933	0.1214
MD	5,345	112,279,215	0.0952	OH	19,156	274,909,447	0.1394
NH	1,754	15,347,558	0.2286	WI	34,845	627,665,733	0.1110
NJ	2,438	30,586,717	0.1594				
NY	4,321	76,120,595	0.1135				
PA	25,880	446,215,793	0.1160				
VA	6,070	119,264,709	0.1018				

If only coal-fired units with a nameplate rating of 100MW or greater are to be considered, the "predicted" statewide average ozone season NOx emission rates are shown below:

Table I-3. >100 MW Coal

State	Predicted NOx Mass	2008 O.S. Heat Input	Predicted Avg NOx Rate	State	Predicted NOx Mass	2008 O.S. Heat Input	Predicted Avg NOx Rate
CT	395	13,163,750	0.0600	IL	12,817	417,656,155	0.0614
DE	1,863	20,145,049	0.1850	IN	23,368	492,447,671	0.0949
MA	1,298	35,899,623	0.0723	MI	13,082	278,933,070	0.0938
MD	5,127	110,241,907	0.0930	OH	26,348	519,802,282	0.1014
NH	1,362	11,735,819	0.2321	WI	7,293	185,704,212	0.0785
NJ	2,284	29,350,532	0.1556				
NY	3,828	68,614,070	0.1116				
PA	24,430	430,902,559	0.1134				
VA	4,918	107,929,830	0.0911				

Based on the above assumptions, the "predicted" statewide average annual SO2 emission rates for all coal-fired EGUs are shown below:

Table I-4. All Coal

State	SO_2 Mass	Heat Input	SO_2 Rate	State	SO_2 Mass	Heat Input	SO_2 Rate
CT	915	30,494,774	0.0600	IL	52,260	1,032,913,414	0.1012
DE	6,877	53,729,573	0.2560	IN	184,979	1,183,751,273	0.3125
MA	15,976	101,700,315	0.3142	MI	30,911	714,421,520	0.0865
MD	12,891	255,974,177	0.1007	OH	149,190	1,291,957,283	0.2310
NH	3,560	38,335,281	0.1857	WI	21,100	453,687,252	0.0930
NJ	4,226	62,812,030	0.1346				
NY	20,848	181,042,512	0.2303				
PA	133,087	1,068,514,484	0.2491				
VA	18,790	279,184,954	0.1346				

If only coal-fired units with a nameplate rating of 100MW or greater are to be considered, the "predicted" statewide average annual SO2 emission rates are shown below:

Table I-5. >100 MW Coal

State	SO_2 Mass	Heat Input	SO_2 Rate	State	SO_2 Mass	Heat Input	SO_2 Rate
CT	915	30,494,774	0.0600	IL	42,489	991,323,073	0.0857
DE	6,877	53,729,573	0.2560	IN	159,449	1,149,099,381	0.2775
MA	14,861	93,738,547	0.3171	MI	21,018	653,861,186	0.0643
MD	11,412	250,831,639	0.0910	OH	130,335	1,241,187,821	0.2100
NH	1,565	30,332,534	0.1032	WI	15,199	432,619,948	0.0703
NJ	3,582	59,793,990	0.1198				
NY	15,695	160,893,978	0.1951				
PA	119,772	1,034,993,798	0.2314				
VA	15,312	250,443,277	0.1223				

Assessment 2

Table I-6. NOx Table

State	NOx Tons	NOx Rate	0.125	Red. 0.125	% Red. 0.125	0.1	Red. 0.10	% Red. 0.10	0.07	Red. 0.07	% Red. 0.07	Heat Input
IL	119967	0.226	66295	53672	45	53036	66931	56	37125	82842	69	1060713465
IN	196135	0.306	80199	115935	59	64159	131975	67	44912	151223	77	1283188639
MI	103474	0.275	46998	56476	55	37598	65875	64	26319	77155	75	751966181
OH	235126	0.355	82817	152309	65	66254	168872	72	46378	188749	80	1325072026
WI	47343	0.190	31099	16244	34	24879	22464	47	17415	29927	63	497577808
LADCO TOTAL	702043	0.285	307407	394636	56	245926	456117	65	172148	529895	75	4918518119
PA	175218	0.286	76626	98592	56	61301	113917	65	42911	132308	76	1226016925
NY	30871	0.109	30871	0	0	28384	2487	8	19869	11002	36	567686169
NJ	9143	0.096	9143	0	0	9143	0	0	6659	2483	27	190267033
MD	35922	0.263	17048	18875	53	13638	22284	62	9547	26376	73	272761427
VA	43017	0.237	22652	20365	47	18122	24895	58	12685	30332	71	362431406
MA	9353	0.068	9353	0	0	9353	0	0	9353	0	0	274620434
NH	4641	0.096	4641	0	0	4641	0	0	3373	1268	27	96364833
CT	3116	0.067	3116	0	0	3116	0	0	3116	0	0	92717786
DE	8936	0.279	4003	4934	55	3202	5734	64	2241	6695	75	64042015
ME	680	0.022	680	0	0	680	0	0	680	0	0	61863689
DC	94	0.280	42	52	55	33	60	64	23	70	75	668330
RI	462	0.017	462	0	0	462	0	0	462	0	0	55392442
VT	296	0.140	263	32	11	211	85	29	147	148	50	4214041
OTC TOTAL	321749	0.197	204315	117434	36	163452	158297	49	114417	207333	64	3269046530
AL	112614	0.240	58697	53917	48	46958	65656	58	32870	79744	71	939155771
FL	155451	0.197	98770	56681	36	79016	76435	49	55311	100140	64	1580319063
GA	105894	0.221	59900	45994	43	47920	57974	55	33544	72350	68	958401269
KY	157847	0.319	61918	95929	61	49535	108312	69	34674	123173	78	990691497
MS	41917	0.237	22110	19807	47	17688	24229	58	12381	29535	70	353752142
NC	54652	0.144	47283	7369	13	37826	16826	31	26478	28174	52	756524591
SC	42045	0.190	27615	14430	34	22092	19953	47	15465	26581	63	441843531
TN	85543	0.294	36392	49151	57	29114	56430	66	20380	65164	76	582275154
WV	97331	0.228	53329	44002	45	42663	54668	56	29864	67467	69	853266499
Other State Total	853294	0.229	466014	387280	45	372811	480483	56	260968	592326	69	7456229518
TOTAL	1877087	0.240	977737	899350	48	782190	1094897	58	547533	1329554	71	15643794167

Table I-7. SO2 Table

State	SO2 tons	SO2 Rate	0.3	Red. 0.3	% Red.0.3	0.23	Red. 0.23	% Red. 0.23	0.2	Red. 0.20	% Red. 0.20	0.15	Red. 0.15	% Red. 0.15	Heat Input
IL	257431	0.485	159107	98324	38	121982	135449	53	106071	151360	59	79554	177877	69	1060713465
IN	593154	0.925	192478	400676	68	147567	445587	75	128319	464835	78	96239	496915	84	1283188639
MI	326501	0.868	112795	213706	65	86476	240024	74	75197	251304	77	56397	270103	83	751966181
OH	709995	1.072	198761	511234	72	152383	557611	79	132507	577487	81	99380	610614	86	1325072026
WI	129695	0.521	74637	55058	42	57221	72473	56	49758	79937	62	37318	92376	71	497577808
LADCO TOTAL	2016775	0.820	737778	1278997	63	565630	1451145	72	491852	1524923	76	368889	1647886	82	4918518119
PA	831915	1.357	183903	648012	78	140992	690923	83	122602	709313	85	91951	739964	89	1226016925
NY	65427	0.231	65427	0	0	65284	143	0	56769	8658	13	42576	22850	35	567686169
NJ	21204	0.223	21204	0	0	21204	0	0	19027	2177	10	14270	6934	33	190267033
MD	227198	1.666	40914	186283	82	31368	195830	86	27276	199921	88	20457	206740	91	272761427
VA	125985	0.695	54365	71620	57	41680	84306	67	36243	89742	71	27182	98803	78	362431406
MA	46347	0.338	41193	5154	11	31581	14766	32	27462	18885	41	20597	25751	56	274620434
NH	36895	0.766	14455	22440	61	11082	25813	70	9636	27259	74	7227	29668	80	96364833
CT	3955	0.085	3955	0	0	3955	0	0	3955	0	0	3955	0	0	92717786
DE	31808	0.993	9606	22202	70	7365	24444	77	6404	25404	80	4803	27005	85	64042015
ME	1041	0.034	1041	0	0	1041	0	0	1041	0	0	1041	0	0	61863689
DC	212	0.634	100	111	53	77	135	64	67	145	68	50	162	76	668330
RI	18	0.001	18	0	0	18	0	0	18	0	0	18	0	0	55392442
VT	2	0.001	2	0	0	2	0	0	2	0	0	2	0	0	4214041
OTC TOTAL	1392007	0.852	436183	955825	69	355648	1036359	74	326905	1065102	77	245178	1146829	82	3269046530
AL	357547	0.761	140873	216673	61	108003	249544	70	93916	263631	74	70437	287110	80	939155771
FL	263745	0.334	237048	26697	10	181737	82008	31	158032	105713	40	118524	145221	55	1580319063
GA	514539	1.074	143760	370779	72	110216	404323	79	95840	418699	81	71880	442659	86	958401269
KY	344356	0.695	148604	195753	57	113930	230427	67	99069	245287	71	74302	270055	78	990691497
MS	65317	0.369	53063	12254	19	40681	24635	38	35375	29941	46	26531	38785	59	353752142
NC	227030	0.600	113479	113551	50	87000	140030	62	75652	151378	67	56739	170291	75	756524591
SC	157190	0.712	66277	90914	58	50812	106378	68	44184	113006	72	33138	124052	79	441843531
TN	208069	0.715	87341	120728	58	66962	141107	68	58228	149842	72	43671	164398	79	582275154
WV	301574	0.707	127990	173584	58	98126	203449	67	85327	216248	72	63995	237579	79	853266499
Other State Total	2439368	0.654	1118434	1320933	54	857466	1581901	65	745623	1693745	69	559217	1880150	77	7456229518
TOTAL	5848149	0.748	2292395	3555755	61	1778744	4069405	70	1564379	4283770	73	1173285	4674865	80	15643794167

LADCO Analysis

Based on this plant-level, unit-level analysis of coal-fired units, the LADCO States identified the following achievable annual average emission rates:

Table I-8. NOx and SO_2 Analysis

NOx					
Year	**Illinois**	**Indiana**	**Michigan**	**Ohio**	**Wisconsin**
2008	0.23	0.305	0.29	0.36	0.21
2013	0.11 – 0.12	0.297	0.18	0.24	0.13
2014	0.11 – 0.12	0.171	0.15	0.18	0.12
2015	0.11 – 0.12	0.165	0.13	0.17	0.10
2017	0.11 – 0.12	0.114	0.11	0.12	0.09
SO2					
Year					
2008	0.50	0.93	0.91	1.09	0.57
2013	0.24 – 0.44	0.67	0.58	0.75	0.39
2014	0.20 -0.43	0.66	0.45	0.65	0.39
2015	0.19 – 0.28	0.66	0.37	0.65	0.25
2017	0.15 – 0.23	0.25	0.25	0.256	0.16

It should be noted that the analysis is based on coal-fired units. Consideration of all units (coal, oil, gas, and biomass) will result in emission rates slightly below those indicated above.

The number of post-combustion controls assumed in this analysis is provided below. The total amount of mega-wattage controlled in each state is on the order of 80-90%.

Table I-9. Analysis of Post-combustion Controls by Year

	NOx																**SO2**				
	SCR					**SNCR**					**ALL**						**FGD**				
	IL	IN	MI	OH	WI	IL	IN	MI	OH	WI	IL	IN	MI	OH	WI		IL	IN	MI	OH	WI
2008		23	3	19	1		4	0	15	1	17	27	3	34	2		6	23	2	16	1
2013		23	7	25	5		7	0	11	8	32	30	7	36	13		20	29	7	25	6
2014		23	12	26	5		7	0	11	8	34	30	12	37	13		29	29	12	33	6
2015		23	17	27	5		17	0	11	15	36	40	17	38	20		35	29	17	33	6
2017		32	25	34	8		17	0	14	15	36	49	27	48	23		37	48	27	41	13

Note: IL and OH numbers reflect number of units controlled, and IN and WI numbers reflect number of installations (which may cover several units).

APPENDIX II – Timing

Example 1: Case Study

Maryland Healthy Air Act
Deadlines and the Installation of Control Equipment

BACKGROUND

In April of 2006, the Maryland General Assembly adopted the Maryland Healthy Air Act. The bill was signed into law on April 6, 2006. In general, the law required significant reductions in Nitrogen Oxides (NOx), Sulfur Dioxide (SO2) and Mercury (HG) from electricity generating units (EGUs) in Maryland. It also required Maryland to join the Regional Greenhouse Gas Initiatve (RGGI), the first cap-and-trade program to tackle CO2 in the Country.

Portions of Maryland are nonattainment for the federal Ozone and PM2.5 Standards. NOx reductions were a critical part of Maryland's plan to reduce ground level ozone. Reductions in SO2 and NOx are both important to the States plans to lower fine particle levels. Maryland also had multiple issues with mercury and the Chesapeake Bay.

The Healthy Air Act was driven by the concept that the emission reductions from the Healthy Air Act would be important to the States own efforts to solve its air quality problems. It did, however, recognize that Maryland had a responsibility under the Clean Air Act to reduce pollution to also help downwind neighbors.

The implementing regulations were put on a fast track and were adopted on January 18^{th}, 2007.

The Healthy Air Act includes two phases of reductions: 2009 and 2012 for NOx and 2010 and 2012 for SO2 and mercury. Table 1 below summarizes the additional NOx and SO2 reductions required in 2009, 2010, 2012 and 2013.

Table 1
Maryland Healthy Air Act Emission Reductions

	2009	2010	2012	2013
NOx	70%		75%	
SO2		80%		85%
Mercury		80%		90%

Because of pre-2006 control programs like the OTC NOx Budget Rule, total NOx reductions from Maryland EGUs between 1990 and 2012 are estimated to be over 85%.

THE DEADLINES

While the Healthy Air Act was being debated, there was considerable concern raised over the issue of timing. In general, Maryland's two major power generators argued that the 2 years to install NOx controls and the 2 ½ to 3 years to install SO2 and Mercury controls were a huge and perhaps impossible challenge. Over 60% of Maryland's electricity comes from coal.

Maryland's largest generator (3 plants – 9 units) argued that the only feasible way to install the controls required by the Healthy Air Act was to go in series (plant-by-plant) and that a plant-by-plant approach could take over 6 years.

As a result of this debate, the law included several waiver provisions to allow affected sources more time, without penalty, if such delays could be justified. For Phase 1 (2009 for NOx and 2010 for SO2 and HG) there have been no requests for waivers. Both of Maryland's major generators have installed their controls in parallel, not in series (plant-by-plant).

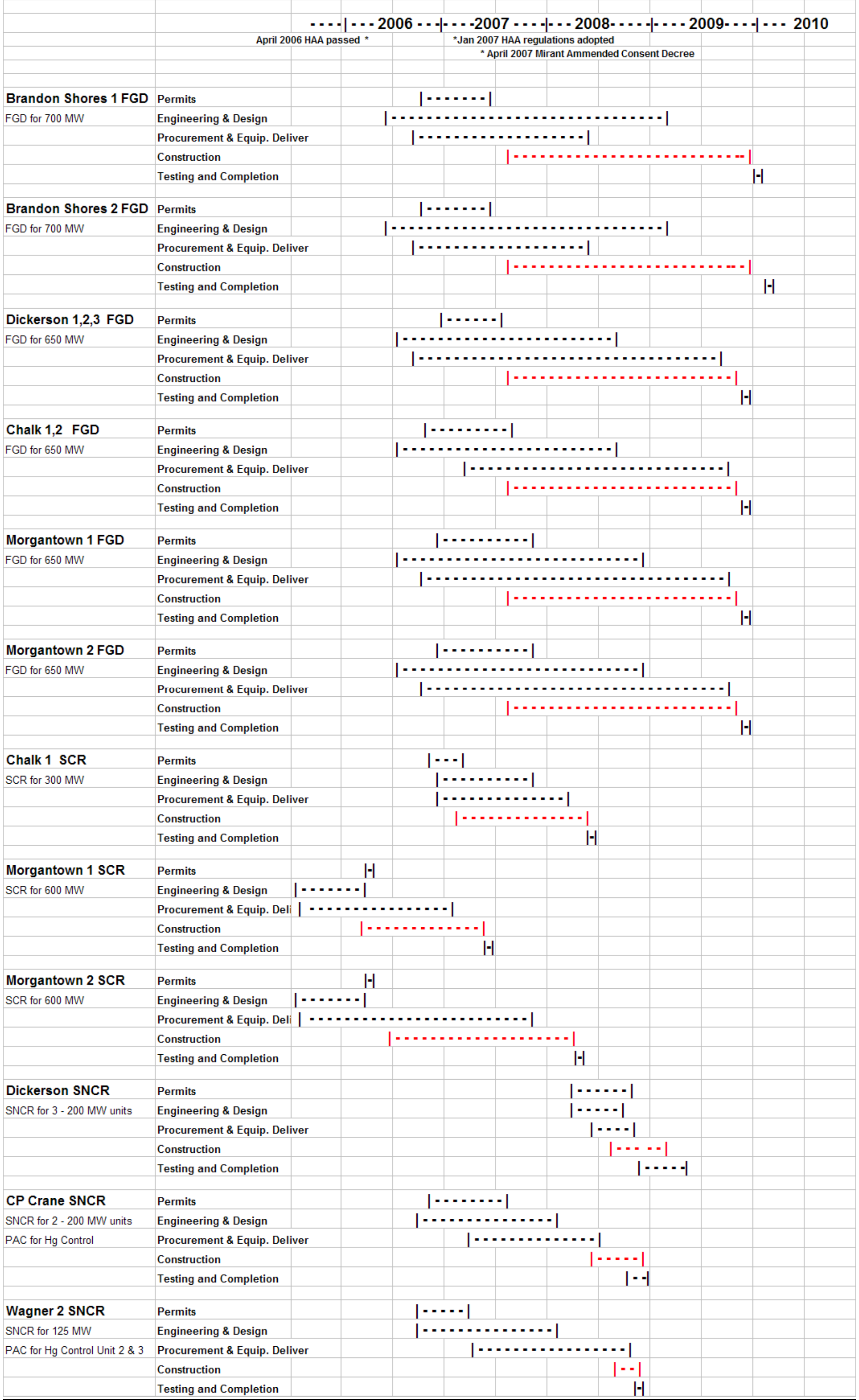
Because of the Healthy Air Act, by 2010, over $2 Billion will have been invested in new control equipment (6 scrubbers, 3 SCRs, 6 SNCRs). Four SCRs and numerous combustion modifications had been installed on coal fired power plants in the Maryland prior to the Healthy Air Act.

Table 2 below summarizes the planning and installation schedules for the six largest plants in the State.

Construction schedules for the FGD ran approximately 28 months each. Engineering economies were realized by using the same size FGD for the four Mirant installations. While the number of units served by each FGD in the three plants in the Mirant system varied, the total MW of capacity feeding each FGD was approximately the same at about 600 MW. This allowed the same engineering design to be used for each FGD. The two FGD at Brandon Shores are also identical to each other.

While the use of two FGD designs assisted with the timely completion of the six projects, material handling design and ductwork to and from the FGDs were different at each site. Three of the FGD projects had to deal with SCR construction occurring simultaneous to the FGD construction, and accommodations for crane availability had to be carefully scheduled. All of the FGD's required new stacks with fiber glass liners. The liners were constructed on site and the equipment installed to fabricate the liners the required permits to construct from MDE.

Table 2 Healthy Air Act Project Time Line in Maryland



OTHER MID-ATLANTIC STATES

Between 2006 and 2009 there were other very significant efforts taking place in the Mid-Atlantic area to add scrubbers, SCRs and SNCRs. Because of state programs and the Clean Air Interstate Rule (CAIR), Virginia, New Jersey, Delaware, West Virginia and North Carolina all had significant control technology installation efforts taking place between 2006 and 2009.

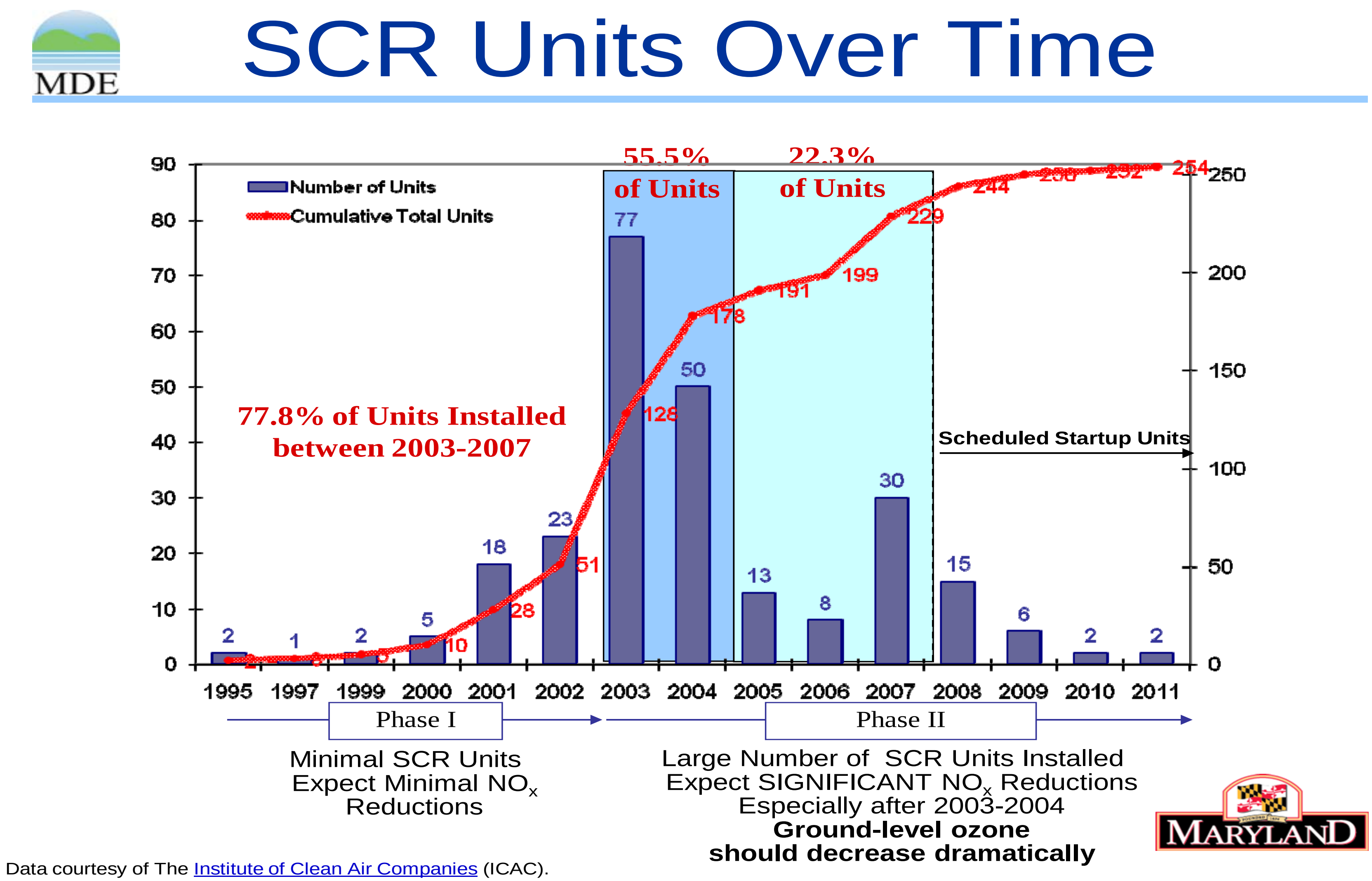
CONCLUSION

With the appropriate regulatory structure, very significant pollution control systems, including FGDs, SCRs and SNCRs, can be installed in multiple plants owned by the same company, in parallel, in a relatively short timeframe.

Supplemental Information:

- Law: http://mlis.state.md.us/2006rs/bills/sb/sb0154e.pdf
- Regulation: http://www.mde.state.md.us/assets/document/26-11-27_MD_Healthy_Air_Act.pdf

Example 2: Installation of SCR Units from EPA's NOx SIP Call



Appendix III – Cost of Controls

Table III-1. Available Emission Control Devices, Emission Reductions and Estimated Costs[1]

Fuel Type	Pollutant	Available Control Device	Expected Emission Reduction (%)	Control Cost Estimate[a] ($/ton removed)
Coal-Fired	NOx	Selective Non-Catalytic Reduction (SNCR) Selective Catalytic Reduction (SCR)	45% 85%	$2,500 - $3,000 $1,600 - $4,900
	SO_2	Flue Gas Desulfurization (FGD) system (dry scrubber) Wet FGD system (wet scrubber)	95% 95%	$1,500 - $3,600 $1,400 - $3,400
Residual Oil-Fired	NOx	Low NOx Burners (LNB) LNB plus Flue Gas Recirculation (FGR) Selective Non-Catalytic Reduction (SNCR) LNB plus SNCR Selective Catalytic Reduction (SCR)	50% 60% 50% 65% 85%	$1,100 - $4,400 $2,600 - $5,400 $3,100 - $4,000 $3,500 - $6,400 $2,600 - $8,300
Distillate Oil-Fired	NOx	Low NOx Burners (LNB)	50%	$2,200 - $8,700
Gas-Fired	NOx	Low NOx Burners (LNB)	50%	$2,200 - $8,700

Note: [a]Cost estimates shown are in 2008 dollars for a **250 MMBtu/hr boiler (≈ 73 MW)** operating at 66 percent capacity and operating 8,760 hours per year

[1] New Hampshire Department of Environmental Services (October 2008) Draft ICI Boiler NOx and SO_2 Control Cost Estimates [PowerPoint slides]. (Andy Bodnarik, 2009)

Table III-2 Stationary and Area Source Measures

NOx Measure	State Rules	National Measure	Emissions Reduction	Cost
Boilers serving EGUs	DE, NJ,MA, MD	*	413 TPD OTR	$1,100 - 8,700 per ton
New Small Gas Boilers	CA, TX	*	53 TPD OTR	$3,300 to $16,000 per ton
Municipal waste incinerators	NJ, MD	*	14 TPD OTR	$2,140 per ton (SNCR)
HEDD EGUs	NJ	*	TBD	$45,000 to $300,000 per unit
Stationary Generator Regulation (DG)	DE, MA, MD, NJ	*	TBD	$39,700 to $79,700 per TPD
Minor New Source Review	DE, CT, MD, MA, NJ, RI	*	TBD	$600 to $18,000 per ton
Energy security / Energy efficiency	TBD	*	TBD	TBD

Table III-3 Stationary and Area Source VOC Measures

VOC Measure	State Rules	National Measure	Emissions Reduction	Cost
AIM rule	CA	*	50 TPD OTR	$2,240 per ton
Auto Refinishing	CA	*	21 TPD OTR	$2,860 per ton
Consumer Products 2006	CA	*	19 TPD OTR	$7,700 per ton
Lower VOC Solvent Degreaser	MD, CA	*	13 TPD OTR	$1,400 per ton
Gas Stations	TBD	*	TBD	TBD
Large VOC Storage Tanks	MD, NJ	*	TBD	$2,288 to $29,000 per ton
Minor New Source Review	DE, CT, MD, MA, NJ, RI	*	TBD	TBD

Appendix IV – Air Quality Benefits

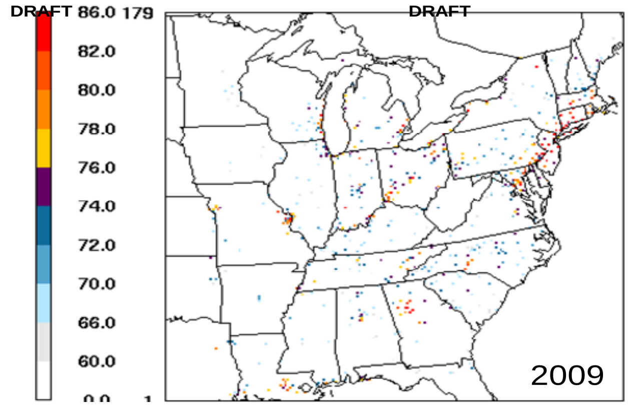
State Collaborative Modeling Results

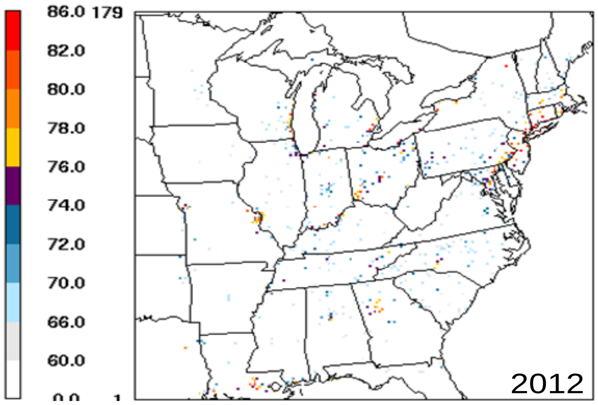
DRAFT

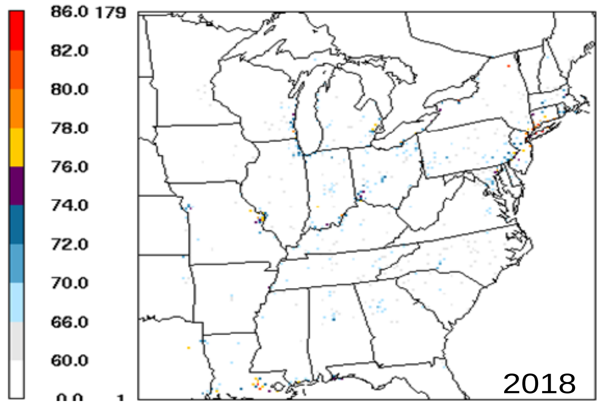
Ozone 8-Hour Concentrations

8-Hour - 0.08 ppm NAAQS (No. of Counties > NAAQS)				
	Midwest	Southeast	Northeast	Total
2009	1	1	8	10
2012	0	0	3	3
2018	0	0	0	0

8-Hour - 0.075 ppm NAAQS (No. of Counties > NAAQS)				
	Midwest	Southeast	Northeast	Total
2009	50	31	66	147
2012	30	14	45	89
2018	8	2	13	23





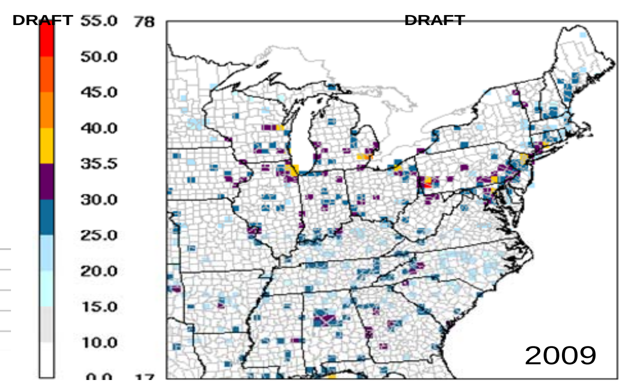


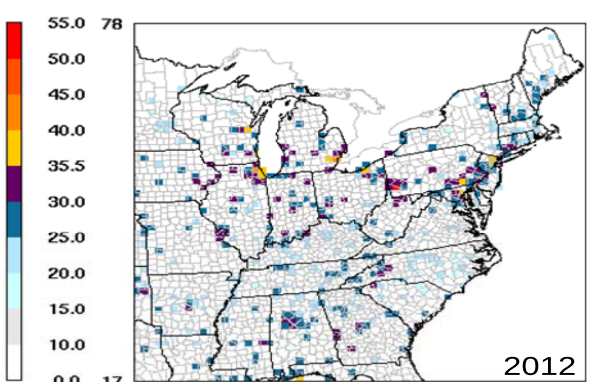
Based on 2005 meteorology

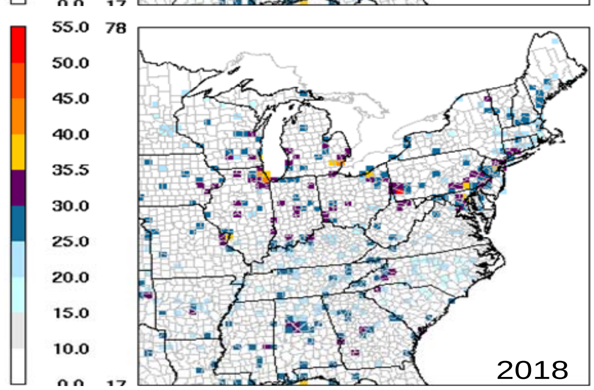
DRAFT

$PM_{2.5}$ Daily Concentrations

Daily (No. of Counties > NAAQS)				
	Midwest	Southeast	Northeast	Total
2009	6	0	6	12
2012	6	0	5	11
2018	6	0	4	10





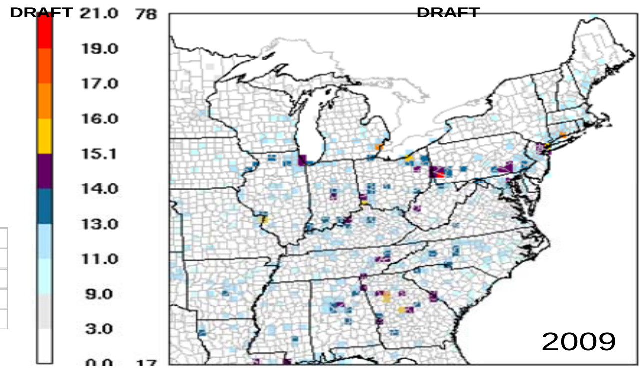


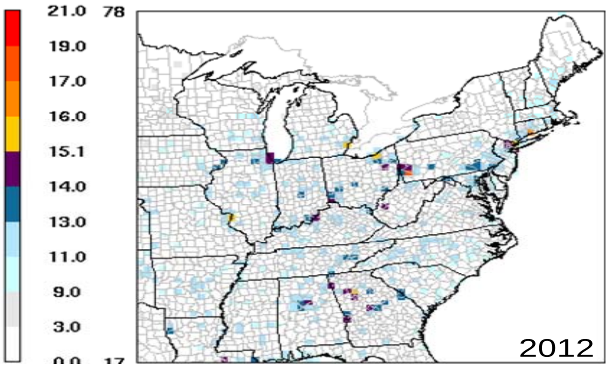
Based on 2005 meteorology

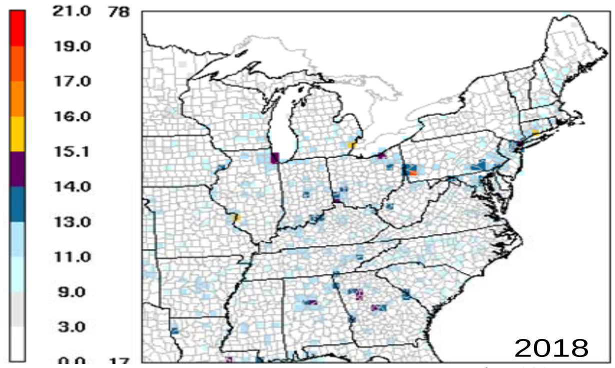
DRAFT

$PM_{2.5}$ Annual Concentrations

Annual (No. of Counties > NAAQS)				
	Midwest	Southeast	Northeast	Total
2009	4	3	2	9
2012	3	1	2	6
2018	2	0	1	3



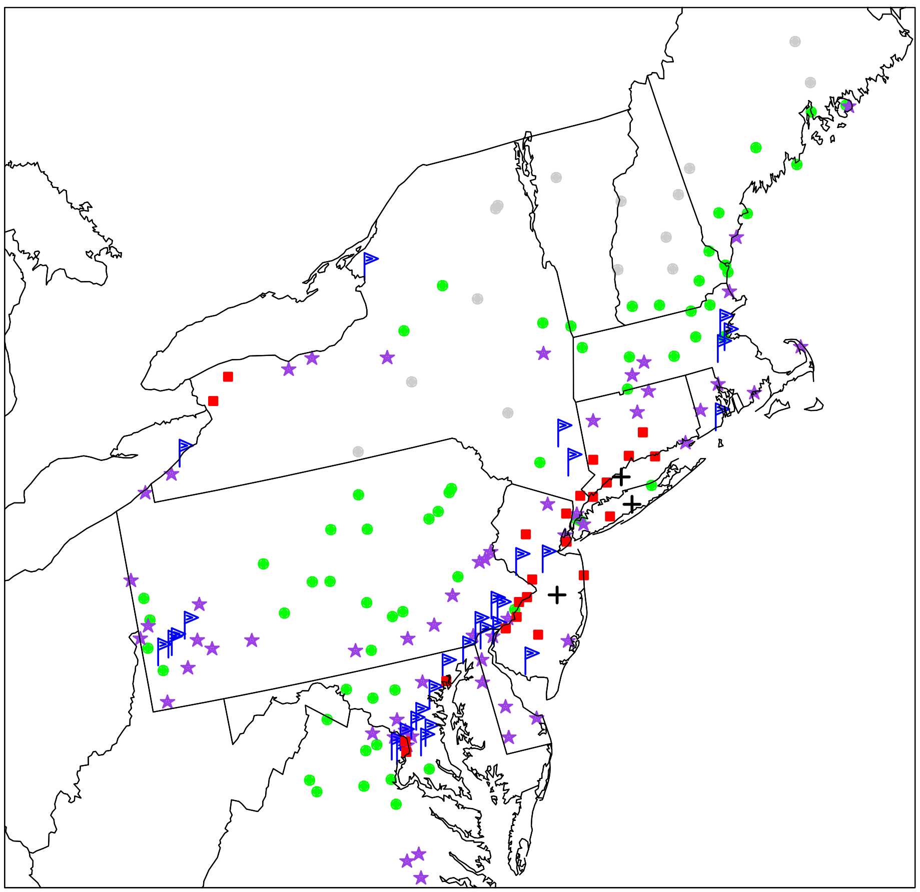




Based on 2005 meteorology

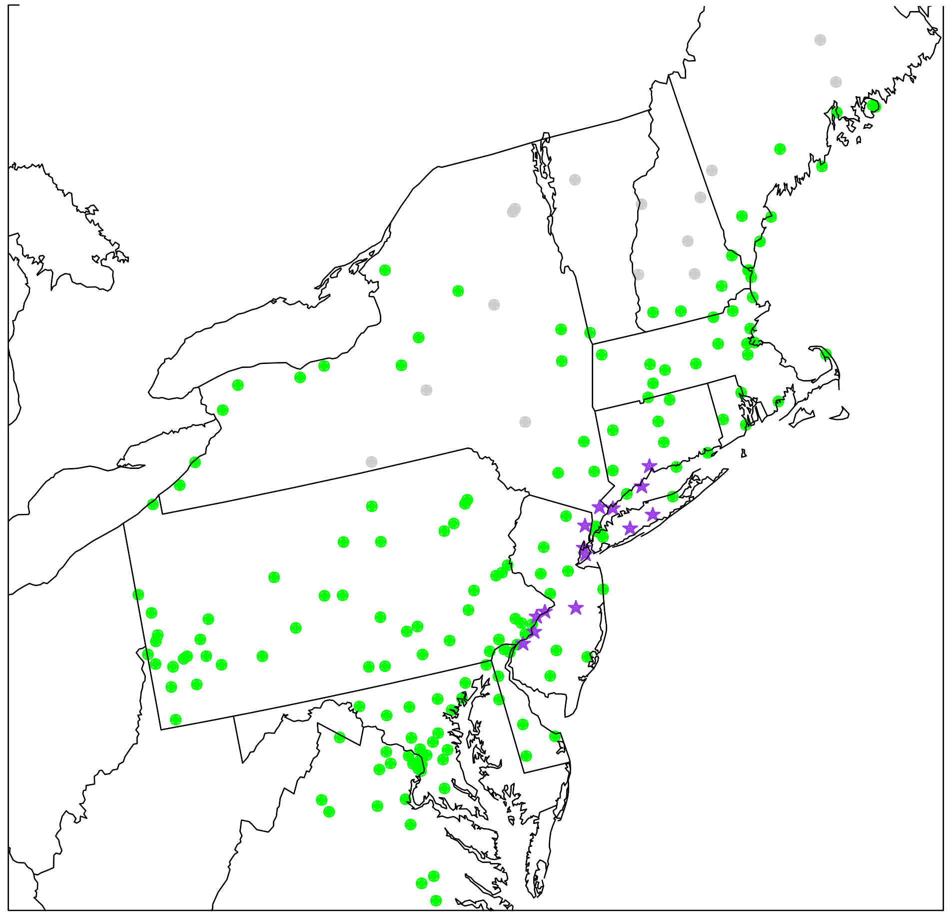
OTC Sensitivity Modeling Runs: 40% NOx Emission Reduction, All Sectors

DVF 2012 BOTB/BOTW "NoCAIR"

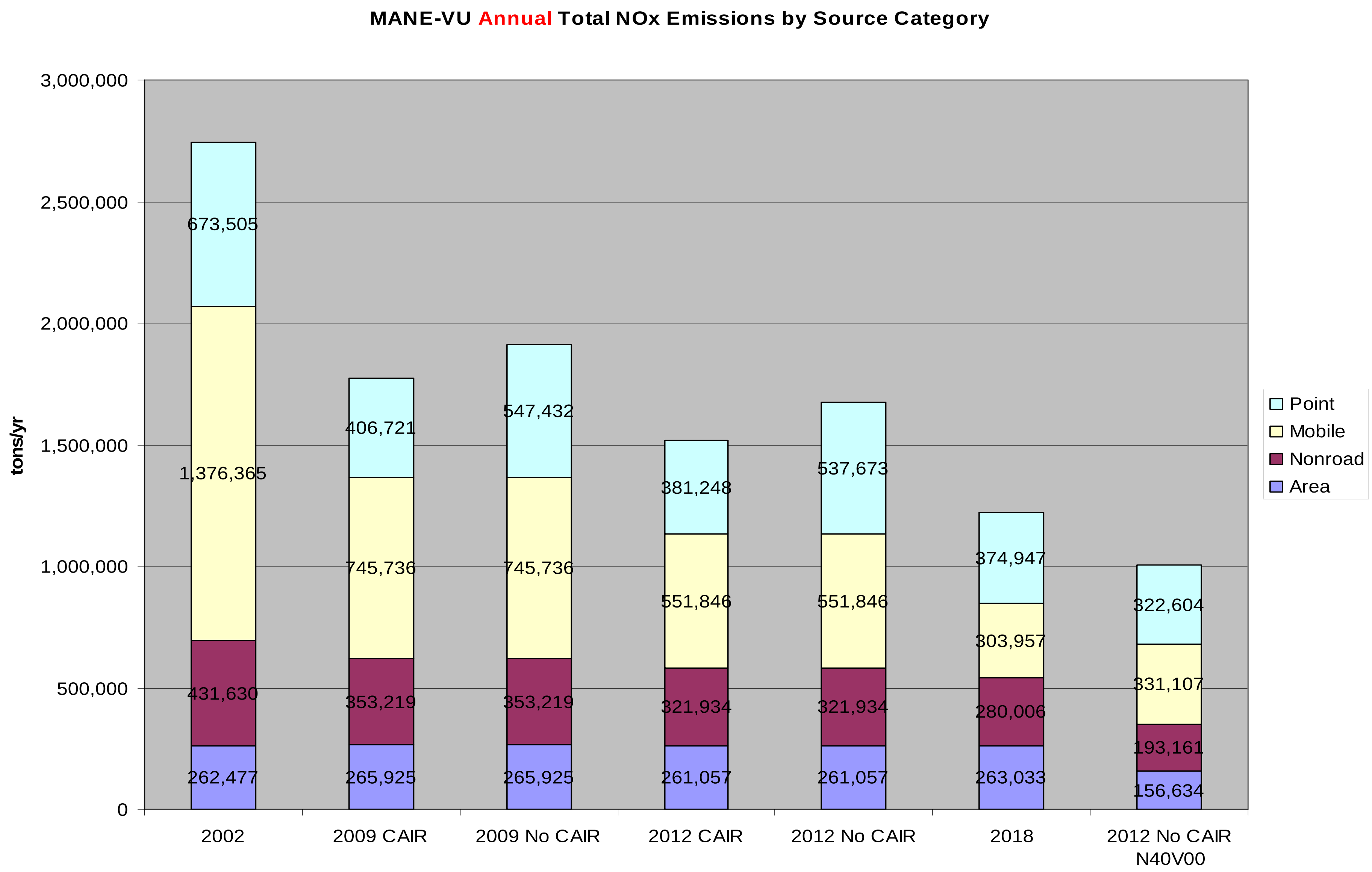


- <71 ppb
- 71 – 75 ppb
- 76 – 79 ppb
- 80 – 84 ppb
- >84 ppb
- No RRF Available

DVF 2012 BOTB/BOTW "NOCAIR" Minus 40% Across-the-Board Anthropogenic NOx

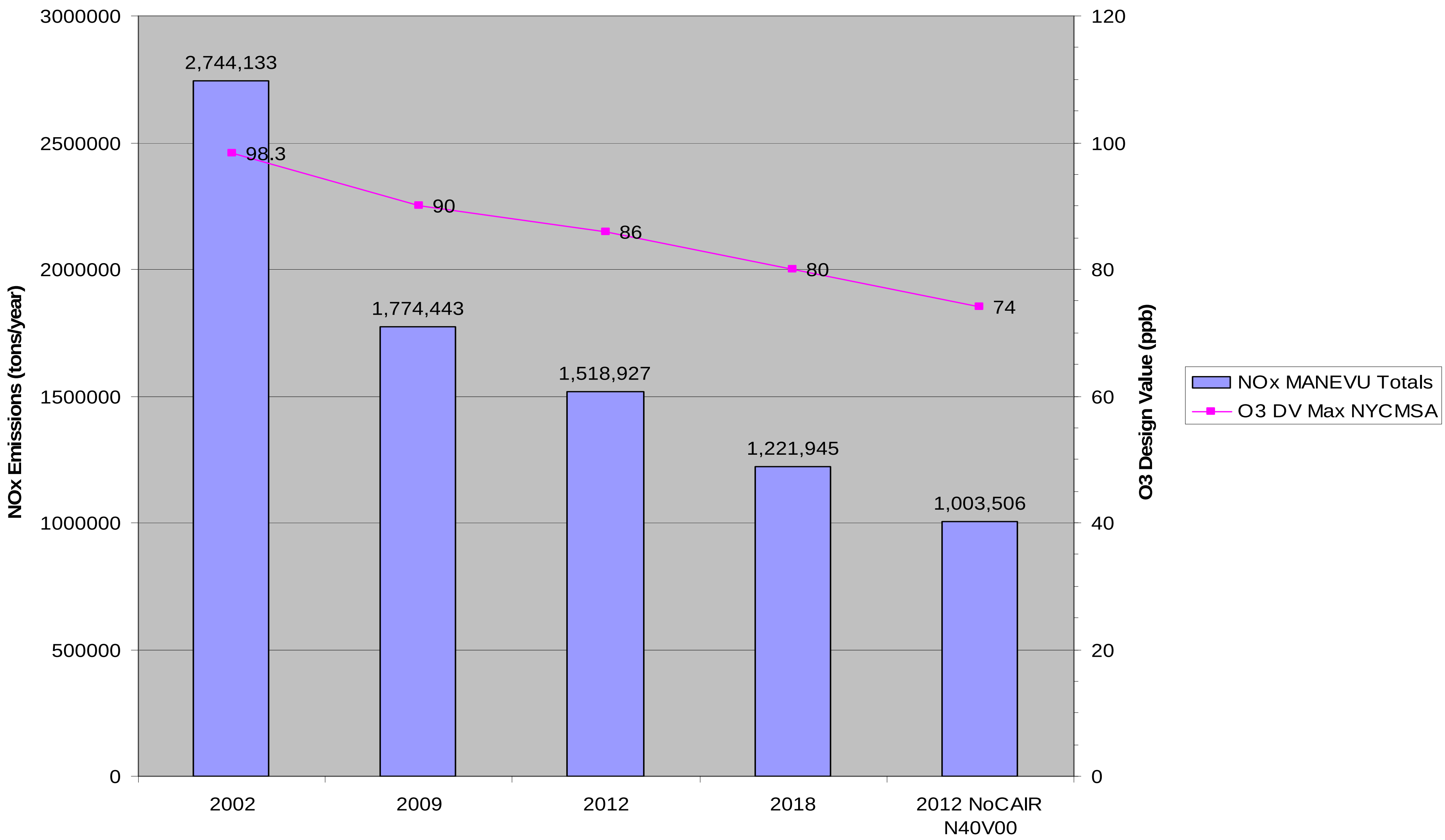


- <71 ppb
- 71 – 75 ppb
- 76 – 79 ppb
- 80 – 84 ppb
- >84 ppb
- No RRF Available



MANE-VU Annual Total NOx Emissions by Source Category
tons/yr
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
673,505
1,376,365
431,630
262,477
406,721
745,736
353,219
265,925
547,432
745,736
353,219
265,925
381,248
551,846
321,934
261,057
537,673
551,846
321,934
261,057
374,947
303,957
280,006
263,033
322,604
331,107
193,161
156,634
2002
2009 CAIR
2009 No CAIR
2012 CAIR
2012 No CAIR
2018
2012 No CAIR N40V00
Point
Mobile
Nonroad
Area

MANE-VU Annual Total NOx Emissions (All Categories) and Highest O3 8-hr Design Value in the NYCMSA



Appendix V – Other Sectors

Table V-1. Status Report on OTC State Efforts to Promulgate Regulations Based on OTC 2001 Model Rules (as of May 19, 2009)

	Consumer Products	Architectural and Industrial Maintenance Coatings	Portable Fuel Containers	Mobile Equipment Repair and Refinishing	Solvent Cleaning	Additional NOx Controls	Distributed Generation Standards	State Contacts and Links to Rules
CT	Effective	Effective	Effective	Effective (similar rule)	Effective	Alternative requirements in effect	Effective	Contact: Susan Amarello 860-424-3442 http://www.ct.gov/dep/cwp/view.asp?a=2684&q=331196&depNav_GID=1619
DE	Effective See 2006 rule	Effective	See 2006 rule	Effective	Effective	Effective	Effective 1/11/06	Contact: Gene Pettingill 302-323-4542 Reg. 24, 41, 42, and 1144 http://www.dnrec.state.de.us/air/aqm_page/regs.htm http://www.dnrec.state.de.us/air/aqm_page/pro_regs.htm
DC	Effective	Effective	See 2006 rule	Effective	Effective	NOx RACT Already in place	In progress	(202) 535
ME	Effective	Effective	See 2006 rule	Effective	Effective		Effective	Contact: Jeff Crawford 207-287-2437 http://www.maine.gov/dep/air/regulations/index.htm
MD	Effective (COMAR 26.11.32)	Effective (COMAR 26.11.33)	See 2006 rule	Effective (similar rule)	Effective (similar rule)	In progress	In progress	Contact: Gene Higa 410-631-3353 PFC: Eddie Durant Consumer Products: Husain Waheed 410-537-3240 http://www.dsd.state.md.us/comar/subtitle_chapters/26_Chapters.htm
MA	Adopted CP rule (Phase II) 10/19/2007; new standards effective 1/1/2009	Rule adopted 10/19/2007; new standards effective 1/1/2009	See 2006 rule	Effective (similar rule)	Rule adopted 3/06/2009; new standards effective 9/06/2009.	Effective (similar rule)	Rule finalized 9/2005	Contacts: Consumer products; AIM Coatings; solvents: Azin Kavian azin.kavian@state.ma.us Distributed Generation: Robert.donaldson@state.ma.us Proposed regulations: http://www.mass.gov/dep/public/publiche.htm Final regulations: http://www.mass.gov/dep/air/laws/regulati.htm
NH	Adopted (Effective January 1, 2007)	Adopted (7/27/06)	See 2006 rule	Not considering	Adopted	Under review	Effective (not based on OTC model rule)	Contact: Mike Fitzgerald 603-271-6390 Solvents: http://www.des.state.nh.us/rules/env-a1200.pdf DG: http://www.des.state.nh.us/rules/env-a3700.pdf

Table V-2. Status Report on OTC State Efforts to Promulgate Regulations Based on OTC 2001 Model Rules (as of May 19, 2009)

	Consumer Products	Architectural and Industrial Maintenance Coatings	Portable Fuel Containers	Mobile Equipment Repair and Refinishing	Solvent Cleaning	Additional NOx Controls	Distributed Generation Standards	State Contacts and Links to Rules
NJ	Effective	Effective	Effective	Effective	Effective	Effective	Effective	Contacts: CP, PFCs: Judy Rand 609-984-1950 Additional NOx Controls, DG: Allan Willinger 609-633-1120
NY	Effective	Effective	See 2006 rule	Effective	Effective	Effective	In progress (Target effective date 07/01/10)	Contact: Ron Stannard 518-402-8396 CP: http://www.dec.state.ny.us/website/regs/ch3.htm (Part 235) AIM: http://www.dec.state.ny.us/website/regs/part205_new.html PFC: http://www.dec.state.ny.us/website/regs/239.htm MERR: ftp://www.dec.state.ny.us/dar/library/text228.pdf SC: http://www.dec.state.ny.us/website/regs/part226.html ANC: ftp://www.dec.state.ny.us/dar/library/xpt227.pdf
PA	Effective	Effective	See 2006 status report; Will rely on Fed PFC rule adopted by EPA on February 26, 2007. 72 FR 8427	Similar rule is already in place	Effective	Effective	Will consider	Contact: Susan Hoyle, shoyle@state.pa.us; 717-772-2329 Additional NOx Controls http://www.pabulletin.com/secure/data/vol34/34-50/2176.html MERR: http://www.pacode.com/secure/data/025/chapter129/s129.75.html SC: http://www.pacode.com/secure/data/025/chapter129/s129.63.html PFC: http://www.pacode.com/secure/data/025/chapter130/subchapAtoc.html CP: http://www.pacode.com/secure/data/025/chapter130/subchapBtoc.html AIM: http://www.pacode.com/secure/data/025/chapter130/subchapCtoc.html
RI	Effective 7/09,	Effective 7/09	See 2006 rule	Effective (similar rule)	Effective (similar rule) Updated 10.08	Will consider	Effective (similar rule)	Contact: Barbara Morin 401-222-2808
VT	Will consider	RACT**	See 2006 rule	RACT**	RACT**	RACT**	In progress	
VA	Effective	Effective	See 2006 rule	Effective	Effective			Contact: Gary Graham (804) 698-4103 gegraham@deq.virginia.gov AIM: http://www.deq.virginia.gov/air/pdf/airregs/449.pdf PFC: http://www.deq.virginia.gov/air/pdf/airregs/442.pdf MERR: http://www.deq.virginia.gov/air/pdf/airregs/448.pdf SC: http://www.deq.virginia.gov/air/pdf/airregs/447.pdf CP: http://www.deq.virginia.gov/air/pdf/airregs/450.pdf CP Info: http://www.deq.virginia.gov/air/consumerprod.html

** RACT determination required at the time of renewal of operating permit by state law

Table V-3. Status Report on OTC State Efforts to Promulgate Regulations Based on OTC 2006 Model Rules (as of May 19, 2009)

	Consumer Products (Phase II)	*Adhesives and Sealants*	*Portable Fuel Containers (w/ Kerosene)*	*Diesel Chip Reflash*	*Asphalt Paving*	*Regional Fuel*	*Additional NOx Controls*	*State Contacts and Links to Rules*
CT	*Effective*	*Effective*	*Effective*	*Developing an integrated heavy-duty diesel truck strategy*	*Rule adoption proceeding.*	*Effective statewide*	*Under evaluation as part of a multi-pollutant planning effort*	*Contact:* *Susan Amarello 860-424-3442* *http://www.ct.gov/dep/cwp/view.asp?a=2684&q=331196&depNav_GID=1619*
DE	*Effective April 11, 2009*	*Effective April 11, 2009*	*Relying on federal rule*	*Developing strategy*	*Similar rule already in effect*	*Already in effect statewide*	*Effective on July 11, 2007*	*Adhesives, PFC, Asphalt, Consumer Products: Gene Pettingill 302-323-4542* *Regional Fuel, Chip Reflash: Phil Wheeler (302) 739-9402* *Additional NOx Controls: Frank Gao (302)0323-4542* *http://regulations.delaware.gov/AdminCode/title7/1000/1100/1141.shtml#TopOfPage*
DC	*Proposed May 2007; addressing public comments*	*Proposed May 2007; addressing public comments*	*Proposed May 2007*	*No Action*	*No Action*	*No Action*	*No Action*	*Contact: Cecily Beall (202) 535-2626*
ME	*Rule adopted, Standards effective Jan 1, 2009*	*Scheduled for adoption 5/21/09*	*Draft rule under development*	*No action*	*Scheduled for public hearing 6/18/09*	*No Action*	*No Action*	*Contact: Jeff Crawford 207-287-2437* *http://www.maine.gov/dep/air/regulations/index.htm*
MD	*Proposal publication 03/31/07; Hearing 5/1/07; Final Reg Pub 06/08/07; Effective 06/18/07*	*Rule adopted February 5, 2008; new standards effective April 7, 2008.* *Single Ply Roof Amendment: Adopted 04/29/09; Published 05/22/09; Effective 06/01/09*	*Proposal publication 03/31/07; Hearing 5/1/07; Final Reg Pub 06/08/07; Effective 06/18/07*	*No action*	*Under review*	*Presently in nonattainment areas, will consider regional fuel for attainment areas*	*Distributed Generation regulation: Proposal publication 10/24/08; Hearing 11/25/08; Final Reg Pub 05/08/09; Effective 05/18/09 Partial HEDD consent order 2008.*	*Contacts:* *PFC: Eddie Durant* *Consumer Products, Adhesives: Husain Waheed* *DG: Randy Mosier* *410-537-3240*
MA	*Rule adopted 10/19/2007; new standards effective 1/1/2009*	*Rule under development.*	*Will rely on 2007 Federal PFC rule (72 FR 8427) .*	*No action*	*Rule under development.*	*Already have RFG statewide*	*Under review*	*Contacts:* *Consumer products; Adhesives and Sealants; Asphalt Paving: Azin Kavian azin.kavian@state.ma.us* *Proposed regulations: http://www.mass.gov/dep/public/publiche.htm* *Final regulations: http://www.mass.gov/dep/air/laws/regulati.htm*

Table V-4. Status Report on OTC State Efforts to Promulgate Regulations Based on OTC 2006 Model Rules (as of May 19, 2009)

	Consumer Products (phase II)	Adhesives and Sealants	Portable Fuel Containers (w/ Kerosene)	Diesel Chip Reflash	Asphalt Paving	Regional Fuel	Additional NOx Controls	State Contacts and Links to Rules
NH	Draft rule under development (on hold)	Draft rule under development (on hold)	Adopted	No action	Under review	Under consideration	Under review	Contact: Mike Fitzgerald 603-271-6390 Solvents: http://www.des.state.nh.us/rules/env-a1200.pdf DG: http://www.des.state.nh.us/rules/env-a3700.pdf Send annual date code update information to: airfiles@des.nh.gov
NJ	Adopted 10/30/08	Adopted 10/30/08	Adopted 10/30/08	No action	Adopted 3/20/09	RFG in place state wide	Adopted 3/20/09	http://www.state.nj.us/dep/aqm/ Contacts: CP, PFCs, Adhesives: Judy Rand 609-984-1950. Asphalt Paving: Stella Oluwaseun-Apo 609-777-0430 Diesel Chip Reflash: John Gorgol 609-292-1413 Additional NOx Controls: Allan Willinger 609-633-1120
NY	Proposed Hearings 7/09	In progress	Adopted 06/30/09	Evaluating court decision	In progress	Under consideration	In progress	Contact: Ron Stannard 518-402-8396
PA	Final rulemaking scheduled for Environmental Quality Board consideration June 16, 2008; Anticipated effective date for new categories is Jan 1, 2009	Proposed Rulemaking schedule for Environmental Quality Board consideration August 17, 2008; Anticipated effective date is May 1, 2009	Will rely on Fed PFC rule adopted by EPA on February 26, 2007. 72 FR 8427	No plans to pursue at this time.	Under consideration	Under consideration	Cement Kiln and Glass Furnace regulations' public comment periods close June 23, 2008; Anticipated effective date is May 1, 2009	Contact: Susan Hoyle 717-772-2329 **shoyle@state.pa.us** www.depweb.state.pa.us/pubpartcenter/site/default.asp www.pacode.com/ www.pabulletin.com/
RI	Rule Adopted May 2009, limits effective 7/1/09	Rule Adopted May 2009, limits effective 7/1/09	Will rely on federal rule.	No plans to pursue	Hearing on rule 2/09, limits will be effective 5/10	RFG in place state wide	No plans at this time to implement this measure.	Contact: Barbara Morin 401-222-2808 barbara.morin@dem.ri.gov
VT	No plan to adopt	Plan to pursue	Plan to pursue	Plan to pursue depending on legal basis	Considering	Under consideration, would adopt if truly regional	No plans at this time to implement this measure.	
VA	Notice of intended regulatory action	Notice of intended regulatory action	Notice of intended regulatory action	No current plans to pursue.	No current plans to pursue.	No current plans to pursue.	No current plans to pursue.	Contact: Gary Graham (804) 698-4103 gegraham@deq.virginia.gov