APPENDIX K

March 30, 2017
From: MANE-VU Technical Support Committee
To: MANE-VU Air Directors

Re: Four-Factor Data Collection

Introduction

In order to submit a Long Term Strategy (LTS) every state that reasonably contributes to a Class I area must assess whether it would be reasonable to control sources or groups of sources in the next planning period by considering the following, which gets termed the Four-Factor Analysis:

(1) costs of compliance,
(2) time necessary for compliance,
(3) energy and non-air quality environmental impacts of compliance, and
(4) remaining useful life of any potentially affected sources. (40 CFR 51.308(f)(2)(i))

It is also important for Class I states to have information that will be considered by contributing states so that during the interstate consultation process they can make reasonable asks for controls to be implemented. To achieve these two ends the MANE-VU Four-Factor/Contribution Assessment Workgroup, a subset of the Technical Support Committee, worked to collect the information.

During the first regional haze planning cycle, MANE-VU through MARAMA through the contractor MACTEC documented six sectors that had emissions that were reasonable anticipated to contribute to visibility degradation in MANE-VU: Electric Generating Units (EGUs), Industrial/Commercial/Institutional Boilers (ICI Boilers), Cement Kilns, Heating Oil, Residential Wood Combustion, and Outdoor Wood Boilers.[1] For the former three sectors, information on individual point sources was also collected in additional to sector level data.

Due to resource constraints a contractor could not be hired to update the original report in its entirety nor expand upon it, but through a combination of contractor work and data collection by state staff the information needed by states for their SIP planning for the second regional haze planning period was collected. The remainder of the memorandum explains what was collected for each of the six sectors and where information is located.

Sectors that Reasonably Contribute to Visibility Impairment

EGUs

Sector level information needed to assess the four factors for EGUs were updated through a contract with SRA and has been posted to MARAMA's website for download.[2] As part of the contract

[1] MACTEC Federal Programs, Inc., *Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*, July 9, 2007, http://www.marama.org/publications_folder/visibility/RPG/FinalReport/RPGFinalReport_070907.pdf.
[2] Ed Sabo, *2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*, January 31, 2016,

information on the cost of controls was reviewed and some controls were updated in MARAMA's EMF system to allow for states to have access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas." It should be noted that a bug was found in the EMF code during this review that as of writing had not been fixed by EPA and would need to be accounted for.

Information was also collated on the 444 EGUs that were determined following an initial round of CALPUFF modeling to warrant further scrutiny based on their emissions of SO_2 and NO_X.[3] Several sources of data were available to rely on for information on the capacity and installed controls on individual units. Information from NEEDS v5.15[4], ERTAC EGU v2.5L2[5], data collection on NOX controls conducted by Maryland Department of Environment, and MANE-VU's "167 Stack Retrospective."[6] The individual facility information is in the spreadsheet title "EGU Data for Four-factor Analyses (Only CALPUFF Units)."[7] You can view the locations of the facilities in Figure 1. MANE-VU States were given the opportunity to review the data in early November of 2016.

ICI Boilers

Sector level information needed to assess the four factors for ICI boilers were updated through a contract with SRA and has been posted to MARAMA's website for download. [8] As part of the contract information on the cost of controls was updated in MARAMA's EMF system to allow for states to have access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas."

Information was also collected on the 50 facilities that according to 2011 Q/d contributed the must to visibility impact in each Class I area from sulfate.[9] Since many of these facilities were duplicates the number of sites data was collected for totaled 82. Later in the data collection process the number of sources was limited to only sources that cumulatively contributed to 50% of the impairment. The

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http://www.marama.org/images/stories/documents/publications/FINAL_Updates_to_4Factor_Reasonable_Progress_Report_2016_01_31.pdf.

[3] MANE-VU Technical Support Committee, "EGU Data for Four-Factor Analyses (Only CALPUFF Units)," January 10, 2017.

[4] US EPA, "NEEDS v.5.15 User Guide," August 2015.

[5] ERTAC Workgroup, "Documentation of ERTAC EGU CONUS Versions 2.5 and 2.5L2," December 12, 2016, http://www.marama.org/images/stories/documents/events/Documentation_of_ERTAC_EGU_CONUS_2_5L_2017_12_10_FINAL_TO_POST_resized.pdf.

[6] MANE-VU Technical Support Committee, *Status of the Top 167 Electric Generating Units (EGUs) That Contributed to Visibility Impairment at MANE-VU Class I Areas during the 2008 Regional Haze Planning Period*, July 25, 2016, http://otcair.org/MANEVU/Upload/Publication/Reports/Status%20of%20the%20Top%20167%20Stacks%20from%20the%202008%20MANE-VU%20Ask.pdf.

[7] MANE-VU Technical Support Committee, "EGU Data for Four-Factor Analyses (Only CALPUFF Units)."

[8] Sabo, *2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*.

[9] MANE-VU Technical Support Committee, *MANE-VU Updated Q/d*C Contribution Assessment*, April 6, 2016, http://otcair.org/MANEVU/Upload/Publication/Reports/MANE-VU%20TSC%20-%20Updated%20QC%20over%20d%20Contribution%20Assessment%20-%20Final.pdf.

facilities are listed in Table 1 with information on 2011 SO2 emissions, number of Class I sites affected. The individual facility information is in the spreadsheet title "Industrial Source Data for Four-factor Analyses" along with data needed for base year modeling.[10] The data was provided for stakeholder review, including to states in upwind Regional Planning Organizations, OTC/MANE-VU Spring Committee Meeting in Washington, DC on April 12, 2016 and then again at the OTC/MANE-VU Fall Committee Meeting in Washington, DC on September 20, 2016. You can view the locations of the facilities in Figure 1.

Table 1: 82 Industrial Sources that Impact Class I Areas

State	*Facility ID*	*Facility Name*	*2011 SO_2 Tons*	*#Sites Top 50*	*#Sites >= 50%*
IL	**7793311**	Tate & Lyle Ingredients Americas, LLC	102.90	5	3
IL	**8065311**	Aventine Renewable Energy Inc.	21.51	5	5
IN	**3986511**	Indiana Harbor East	1,332.52	5	0
IN	**4553211**	Indiana University	2,467.99	1	0
IN	**4873211**	Ball State University	1,045.58	4	0
IN	**4885311**	Citizens Thermal	124.94	5	4
IN	**5552011**	University of Notre Dame Du Lac	4,291.94	2	0
IN	**7364611**	Sabic Innovative Plastics Mt. Vernon, LLC	9,570.03	5	4
IN	**7376411**	Tate & Lyle, Lafayette South	908.83	4	0
IN	**7376511**	ArcelorMittal Burns Harbor Inc.	309.55	5	5
IN	**8181811**	Alcoa Inc., Warrick Operations	1,495.20	5	2
IN	**8192011**	US Steel, Gary Works	1,063.30	5	3
IN	**8198511**	ESSROC Cement Corp	1,516.32	1	0
IN	**8223611**	Eli Lilly & Co., Clinton Labs	4,434.03	2	0
KY	**6096411**	E I DuPont, Inc.	2,045.96	1	0
KY	**7352311**	Century Aluminum Sebree, LLC	1,917.99	5	2
KY	**7365311**	Isp Chemicals Inc.	2,207.50	1	0
MA	**7236411**	Solutia, Inc.	19,696.90	2	0
MD	**6117011**	Naval Support Facility, Indian Head	1,728.88	1	0
MD	**7763811**	Luke Paper Company	2,133.08	5	5
MD	**8239711**	Sparrows Point, LLC	2,033.07	1	1
ME	**5253911**	Madison Paper	1,444.64	2	0
ME	**5691611**	Huhtamaki Inc., Waterville	1,420.05	1	0
ME	**5692011**	FMC Biopolymer	992.04	2	0
ME	**5974211**	Woodland Pulp, LLC	680.87	2	0
ME	**7764711**	Verso Paper, Androscoggin Mill	1,018.69	2	0
ME	**7945211**	The Jackson Laboratory	1,754.70	1	0
ME	**8200111**	Sappi, Somerset	983.53	2	0
MI	**8126511**	Escanaba Paper Company	297.11	2	0
MI	**8160611**	St. Mary's Cement, Inc. (U.S.)	1,279.00	2	0
MI	**8483611**	US Steel, Great Lake Works	1,046.43	5	5
NC	**7920511**	Blue Ridge Paper Products, Canton Mill	2,043.68	5	5
NC	**8048011**	KapStone Kraft Paper Corporation	1,467.51	1	0
NC	**8122511**	DAK Americas, LLC	2,181.00	1	0
NH	**7199811**	Dartmouth College	22,024.21	1	0
NH	**7866711**	Gorham Paper & Tissue, LLC	2,400.59	1	0
NJ	**12804611**	Gerresheimer Moulded Glass	3,007.04	1	0
NJ	**8093211**	Atlantic County Utilities Authority Landfill	907.88	1	0
NY	**7814711**	Morton Salt Division	1,143.29	4	1
NY	**7968211**	Alcoa, Massena Operations (West Plant)	805.13	4	2
NY	**7991711**	International Paper Ticonderoga Mill	1,917.74	4	3
NY	**8090911**	Norlite Corporation	2,887.99	1	0
NY	**8091511**	Kodak Park Division	681.06	5	5
NY	**8105211**	Lafarge Building Materials, Inc.	2,102.47	5	5
NY	**8176611**	CARGILL SALT CO- WATKINS GLEN PLANT	1,280.09	3	0
NY	**8325211**	Finch Paper LLC	2,265.36	1	1
OH	**15485811**	Fluor-B&W Portsmouth LLC	102.90	1	0
OH	**7219511**	Youngstown Thermal	21.51	1	0

[10] MANE-VU Technical Support Committee, "Industrial Source Data for Four-Factor Analyses," March 30, 2017.

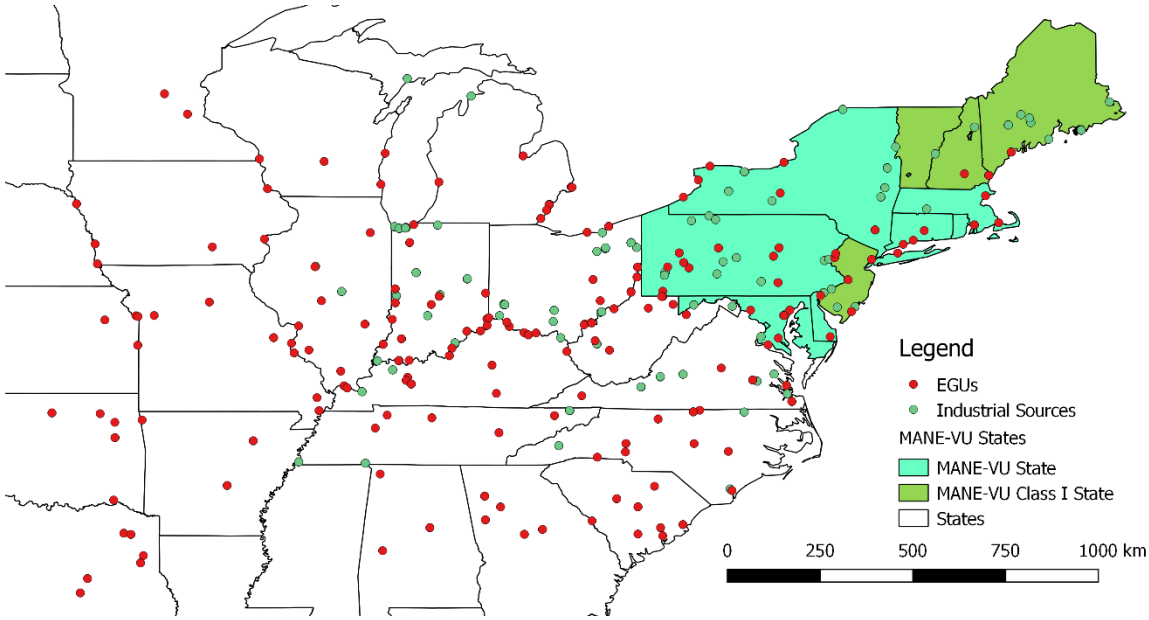
State	Facility ID	Facility Name	2011 SO_2 Tons	#Sites Top 50	#Sites >= 50%
OH	**7416411**	Cargill, Inc., Salt Division, Akron	1,332.52	4	0
OH	**7997111**	Morton Salt, Inc.	2,467.99	5	5
OH	**8008811**	AK Steel Corporation	1,045.58	4	0
OH	**8063611**	BDM Warren Steel Operations, LLC	124.94	5	0
OH	**8130511**	Kraton Polymers U.S. LLC	4,291.94	5	1
OH	**8131111**	P. H. Glatfelter Company, Chillicothe Facility	9,570.03	5	5
OH	**8170411**	City of Akron Steam Generating	908.83	5	0
OH	**8252111**	The Medical Center Company	309.55	5	2
OH	**9301711**	DTE St. Bernard, LLC	1,495.20	3	0
PA	**3186811**	Penn State Univ	1,063.30	5	0
PA	**3881611**	Hercules Cement Co. LP, Stockertown	1,516.32	5	1
PA	**4966711**	United Refining Co., Warren Plant	4,434.03	2	0
PA	**6463511**	PPG IND, Inc., Works No. 6	2,045.96	1	0
PA	**6532511**	AMER REF Group, Bradford	1,917.99	3	0
PA	**6582111**	International Waxes, Inc., Farmers Valley	2,207.50	5	3
PA	**6582211**	Keystone Portland Cement, East Allen	19,696.90	3	0
PA	**6652211**	Philadelphia Energy SOL REF/ PES	1,728.88	1	0
PA	**7409311**	USS CORP, Edgar Thomson Works	2,133.08	4	0
PA	**7872711**	Appleton Papers, Spring Mill	2,033.07	2	0
PA	**7873611**	Sunoco Inc. (R&M), Marcus Hook Refinery	1,444.64	5	2
PA	**8204511**	USS, Clairton Works	1,420.05	4	0
PA	**9248211**	Team Ten, Tyrone Paper Mill	992.04	5	1
TN	**3982311**	Eastman Chemical Company	680.87	5	5
TN	**4963011**	Packaging Corporation of America	1,018.69	1	0
TN	**5723011**	Cargill Corn Milling	1,754.70	2	0
VA	**4182011**	Smurfit Stone Container Corporation, West Point	983.53	1	0
VA	**4183311**	GP Big Island LLC	297.11	1	0
VA	**4938811**	Huntington Ingalls, Inc., NN Shipbldg Div	1,279.00	1	0
VA	**5039811**	Roanoke Cement Company	1,046.43	4	1
VA	**5748611**	Radford Army Ammunition Plant	2,043.68	5	1
VA	**5795511**	Philip Morris USA, Inc., Park 500	1,467.51	1	0
WV	**4878911**	DuPont, Washington Works	2,181.00	5	1
WV	**4987611**	Capitol Cement, Essroc Martinsburg	22,024.21	3	1
WV	**5782411**	Bayer Cropscience	2,400.59	5	1

Cement Kilns

Sector level information needed to assess the four factors for cement kilns. Control factors are in MARAMA's EMF system but are those that came installed with the system and represent control costs found in EPA's CoST Manual.[11] Concerning data for individual point sources, cement kilns were included in the work to use Q/d to determine the industrial sources with the most impact on Class I areas. As a result data was collected on individual cement kilns and the cement kilns that were in the list of the 82 industrial sources with the most impact and individual facility information is in the spreadsheet title "Industrial Source Data for Four-factor Analyses" along with data needed for base year modeling.[12]

[11] US EPA, *Control Strategy Tool (CoST) Development Documentation*, June 9, 2010.
[12] MANE-VU Technical Support Committee, "Industrial Source Data for Four-Factor Analyses."

Figure 1: EGUs and Industrial Sources for which Data Collection Occurred



Heating Oil

Sector level information needed to assess the four factors for heating oil were updated through a contract with SRA and has been posted to MARAMA's website for download.[13] As part of the contract information on the cost of controls was updated in MARAMA's EMF system to allow for states to have access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas." Since heating oil is an area source no specific point source data was collected.

Residential Wood Stoves (RWS)

Sector level information needed to assess the four factors for RWSs were updated through a contract with SRA and has been posted to MARAMA's website for download.[14] As part of the contract information on the cost of controls was updated in MARAMA's EMF system to allow for states to have access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas." Since RWS is an area source no specific point source data was collected.

Outdoor Wood-fired Boilers (OWB)

Sector level information needed to assess the four factors for OWBs were updated through a contract with SRA and has been posted to MARAMA's website for download.[15] As part of the contract information on the cost of controls was updated in MARAMA's EMF system to allow for states to have

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[13] Sabo, *2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*.
[14] Ibid.
[15] Ibid.

access to more recent information if they opt to use EMF and the full list of control factors updated are included as an Appendix to "2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas." Since OWB is an area source no specific point source data was collected.

Summary

Sector	Sector Level Data		Source Level Data		CoST Data
	Update?	Location	Update?	Location	Update?
EGUs	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas	Yes	EGU Data for Four-Factor Analyses	Yes
ICI Boilers	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas	Yes	Industrial Source Data for Four-Factor Analyses	Yes
Cement Kilns	No	Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas	Yes	Industrial Source Data for Four-Factor Analyses	No
Heating Oil	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas		n/a	Yes
RWS	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas		n/a	Yes
OWB	Yes	2016 Updates to the Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas		n/a	Yes

APPENDIX L

2016 UPDATES TO THE ASSESSMENT OF REASONABLE PROGRESS FOR REGIONAL HAZE IN MANE-VU CLASS I AREAS

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EXECUTIVE SUMMARY

In 2007, the Mid-Atlantic Regional Air Management Air Association, Inc. (MARAMA) sponsored an analysis of the costs of potential measures to improve visibility in Class I areas in and near the Mid-Atlantic and Northeast region. The effort resulted in a report prepared for MANE-VU by MACTEC Engineering and Consulting Inc. entitled *Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas*[1]. The report considered four factors to help MANE-VU members determine which emission control measures may be needed to make reasonable progress in improving visibility:

- costs of compliance,
- time necessary for compliance,
- energy and non-air quality environmental impacts of compliance, and
- remaining useful life of any existing source subject to such requirements.

In 2015, MARAMA issued a contract for SRA International, Inc. to conduct appropriate analysis to update the cost information in the following chapters of the 2007 Report:

- Chapter 2 - Source Category Analysis: EGUs;
- Chapter 4 - Source Category Analysis: Industrial, Commercial, and Institutional Boilers;
- Chapter 8 - Heating Oil;
- Chapter 9 - Residential Wood Combustion;
- Chapter 10 - Outdoor Wood Fired Boilers.

In addition, the Chapters regarding EGUs and ICI boilers were expanded to describe NO_x emissions control options and costs.

MARAMA has developed the capability to run EPA's Control Strategy Tool (CoST) model. CoST allows users to estimate the emission reductions and costs associated with future-year emission control strategies, and then to generate emission inventories that reflect the effects of applying the control strategies. Some of the underlying control and cost information in CoST tool is dated, and EPA's project to update this data has been delayed due to resource constraints. As part of SRA's contract, updates to the CoST Control Measures Database were prepared to reflect the updated cost information for the source categories addressed in this project.

This document presents the updated analyses of the economic and environmental impacts of potential control scenarios that could be implemented by MANE-VU States to reduce emissions from the above source categories in order to make reasonable progress toward meeting visibility improvement goals. This document also includes a memorandum documenting the efforts to update CoST with information from the analyses of the costs of potential measures to improve visibility in Class I areas in and near the Mid-Atlantic and Northeast region.

This report does not draw conclusions about which control measures are reasonable in any given state. The information presented in this report may be used by states as they develop policies and implementation plans to address reasonable progress goals.

[1] See: http://www.marama.org/technical-center/regional-haze-planning/reasonable-progress-analysis

CHAPTER 2

SOURCE CATEGORY ANALYSIS: ELECTRIC GENERATING UNITS

SOURCE CATEGORY DESCRIPTION

The MANE-VU contribution assessment demonstrated that sulfur dioxide (SO_2) emissions from electric generating units (EGUs) are the principal contributor to visibility impairment in Class I MANE-VU areas (NESCAUM, 2006). Emissions of oxides of nitrogen (NO_x) may also contribute to visibility impairment and EGUs are important sources of NO_x emissions. MANE-VU previously developed an assessment (MACTEC, 2007) of SO_2 control technologies to achieve reasonable progress goals with respect to the four factors listed in Section 169A of the Clean Air Act. The information presented in this Chapter is an update to some parts of the MACTEC report and now includes NO_x control technologies.

Types of EGUs

Electricity is generated at most power plants by using mechanical energy to rotate the shaft of electromechanical generators. The energy needed to rotate the generator shaft can be produced by burning fossil fuels; from nuclear fission; from the conversion of kinetic energy from flowing water, wind, or tides; or from the conversion of thermal energy from geothermal wells or concentrated solar energy. Electricity also can be produced directly from sunlight using photovoltaic cells or by using a fuel cell to electrochemically convert chemical energy into an electric current. The focus of this Chapter is on EGUs that burn fossil fuels.

Key characteristics of fossil fuel-fired EGUs include (based on LADCO, 2005):

- **Fuel type and quality**. Fossil fuels include (coal, natural gas, and petroleum liquids). Historically, more than half of the electricity generated in the U.S. was from burning of coal. Coal is broadly classified into one of four types (anthracite, bituminous, subbituminous, or lignite) based on differences in heating values and amounts of fixed carbon, volatile matter, ash, sulfur, and moisture. Recent changes in energy markets have increased the role of natural gas in power generation. Petroleum liquids – residual oil and distillate oil – are used to a much lesser extent for generating electricity.
- **Combustion type**. The combustion of a fossil fuel to generate electricity can be either in: 1) a steam generating unit (also referred to as a "boiler") to feed a steam turbine that, in turn, spins an electric generator: or 2) a combustion turbine or a reciprocating internal combustion engine that directly drives the generator. Some modern power plants use a "combined cycle" electric power generation process, in which a gaseous or liquid fuel is burned in a combustion turbine that both drives electrical generators and provides heat to produce steam in a heat recovery steam generator (HRSG). The steam produced by the HRSG is then fed to a steam turbine that drives a second electric generator.
- **Unit size**. The electric-generating capacity of units ranges from approximately 15 to 1,300 MW. Given a typical efficiency of about 33 percent for steam generating units, this corresponds to a heat input range of 150 to 13,400 MMBTU/hr.
- **Unit age**. New boilers tend to be more efficient than older ones. Many boilers over 40 years old are still in service. Newer combined cycle plants that drive both a combustion

turbine generator set and a stream turbine generator significantly increases the overall efficiency of the electric power generation process.

- **Load**. Depending on utility needs, units may be operated somewhat differently. Baseload units are run continuously at a constant, high fraction of maximum rated load. Cycling units are run at a load that varies with demand. Peaking units run only during periods of high demand, which in some cases may be limited to the few hottest days of the summer or coldest days of the winter.
- **Type of control technologies employed**. Nearly all EGUs already employ some level of air pollution control technology to meet regulatory requirements. Some facilities have switched coal supply regions to use low sulfur coal to meet regulatory requirements, or have switched from coal to natural gas for economic or environmental reasons.

All of these factors affect the rate of emissions for a specific EGU.

Clean Air Act Regulations Controlling EGUs

EGUs are currently governed by multiple State and federal regulations under Titles I, III, and IV of the Clean Air Act. Each of these programs is discussed in the following paragraphs.

Title I imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. The NSPS apply to brand new sources or to an existing unit that meets certain, specific conditions described in the Clean Air Act and implementing regulations for being “modified” or “reconstructed.” The original NSPS applied to coal-fired units that were constructed or modified after 1971. EPA periodically revises the NSPS to reflect improvements in control methods for the reduction of emissions. The latest revision to the NSPS occurred in 2015 and established carbon pollution standards for new or modified power plants. Previously, the NSPS only applied to SO_2, NO_x and particulate matter emissions.

Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements (known as New Source Review, or NSR). NSR requires evaluation of control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in nonattainment areas. Control strategies that constitute BACT and LAER evolve over time and are reviewed on a case by case basis in State permitting proceedings. Since 1999, EPA and some states have pursued a coordinated, integrated compliance and enforcement strategy to address NSR compliance issues at the nation's coal-fired power plants. Many of these cases have resulted in settlements requiring facilities to install state-of-the-art air pollution controls.

Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements include Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on the locale's degree of non-attainment with ambient air quality standards.

Title I addresses the regional haze issue. In 1999, EPA published a final rule to address a type of visibility impairment known as regional haze. The regional haze rule required States to submit

implementation plans to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas. As required by the CAA, EPA included in the final regional haze rule a requirement for best available retrofit technology (BART) for certain large stationary sources, including EGUs, that were built between 1962 and 1977.

Title I addresses the interstate transport of air pollution. Various allowance trading programs came into effect to address transport. The Ozone Transport Commission (OTC) NO_x Budget Program began in 1999 in the northeastern U.S. to reduce summertime NO_x emissions that contributed to ozone nonattainment. It was effectively replaced by the NO_x Budget Trading Program under the NO_x SIP Call in 2003, which was designed to reduce the transport of ground-level ozone in the larger eastern region of the U.S. The NO_x Budget Trading Program was effectively replaced by the Clean Air Interstate Rule (CAIR) in 2009 and capped emissions of SO_2 and NO_x in the eastern U.S. This program ended January 1, 2015. The current program is known as the Cross-State Air Pollution Rule (CSAPR) that requires 28 states to reduce power plant emissions that contribute to ozone and/or fine particle pollution in other states.

Title I establishes a mechanism for controlling air pollution from existing stationary sources that emit pollutants other than criteria or hazardous air pollutants. In 2015, EPA used its authority under Section 111(d) to address CO_2 emissions from power plants. This program is a state-based program for existing sources, where EPA establishes guidelines and the states then design programs that fit in those guidelines and get the needed reductions. While Section 111(d) does not directly address SO_2 and NO_x emissions, the state plans to address CO_2 emissions from power plants will likely impact the future emission of those pollutants.

Title III requires EPA to regulate emissions of hazardous air pollutants. The Mercury and Air Toxics (MATS) rule for power plants has a long history. In 2011, EPA finalized national standards to reduce mercury and other toxic air pollution from coal and oil-fired power plants. EPA estimates that 40% of older power plants do not have advanced air pollution control equipment to control emissions of air toxics. While the MATS rule does not directly address SO_2 and NO_x emissions, it will likely impact the future emission of those pollutants.

Title IV established the Acid Rain Program (ARP) in 1995 and required reductions in emissions of SO_2 and NO_x (the primary causes of acid rain) from power plants using market-based mechanisms. The SO_2 program set a permanent cap on the total amount of SO_2 that may be emitted by EGUs, with the final 2010 SO_2 cap set at 8.95 million tons, a level of one-half of the emissions from the power sector in 1980. NO_x reductions under the ARP are achieved through a program that applies to a subset of coal-fired EGUs. Since the program began in 1995, the ARP has achieved significant emission reductions.

The regulation of EGUs by various CAA programs has resulted in a variety of unit level emission limits that vary greatly and depend on boiler age, size, fuel type and location.

Emission and Fuel Consumption Trends

Unit level emissions, generation, primary fuel type and primary control information were obtained from EPA's Air Market Program Data tool (EPA, 2015). The primary fuel type was

grouped into four bins (coal, oil, gas and wood). Primary control information was grouped into logical bins based on the pollutant. The EPA data do not explicitly list the use of low-sulfur coal as a SO_2 control, so some of the units listed as "no control" may actually use low-sulfur coal as a compliance strategy.

Tables 2.1 to 2.6 show trends in EGU SO_2 and NO_x emissions and electric generation in MANE-VU, the Midwest Regional Planning Organization (MRPO), and the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) states. In general, emissions have declined significantly while generation has remained relatively constant. The following trends were observed in each RPO:

- **SO_2 Emissions in MANE-VU States**. Emissions in 2014 were 80% less than in 2002, while generation was only 8% less. Generation from coal-fired units decreased by 44%, while generation from gas-fired units increased by 106%. Generation from gas-fired units now exceeds generation of coal-fired units. Generation from coal-fired units with no add-on control devices decreased by 88% from 2002 to 2014. Only 14% of coal-fired generation was from units with no add-on control devices.
- **SO_2 Emissions in MRPO States**. Emissions in 2014 were 68% less than in 2002, while generation was only 4% less. Generation from gas-fired units increased significantly, but coal-fired generation still accounts for 87% of total generation. Generation from coal-fired units with no add-on control devices decreased by 66% from 2002 to 2014. But 32% of coal-fired generation in 2014 was from units with no add-on control devices.
- **SO_2 Emissions in VISTAS States**. Emissions in 2014 were 78% less than in 2002, while generation was 5% more. Generation from gas-fired units increased significantly, and now accounts for 40% of total generation with coal-fired generation accounting for 60%. Generation from coal-fired units with no add-on control devices decreased by 85% from 2002 to 2014. Only 14% of coal-fired generation in 2014 was from units with no add-on control devices.
- **NO_x Emissions in MANE-VU States**. Emissions in 2014 were 62% less than in 2002. Generation from coal-fired units equipped with SCR increased by 83% over that timeframe, and 67% of coal-fired generation in 2014 was from units equipped with SCR. Generation from gas-fired units equipped with SCR increased by 200% over that timeframe, and 79% of gas-fired generation in 2014 was from units equipped with SCR.
- **NO_x Emissions in MRPO States**. Emissions in 2014 were 69% less than in 2002. Generation from coal- and gas-fired units equipped with SCR increased dramatically. However, only 58% of coal-fired generation in 2014 was from units equipped with SCR.
- **NO_x Emission in VISTAS States**. Emissions in 2014 were 70% less than in 2002. Generation from coal- and gas-fired units equipped with SCR increased dramatically. However, only 74% of coal-fired generation in 2014 was from units equipped with SCR.

There are many other state- or facility-specific reasons that would also help explain the decrease in SO_2 and NO_x emissions and the shift in generation from coal to gas. It is beyond the scope of this project to identify all possible reasons.

Emission projections for future years are currently being developed ERTAC Electric Generation Unit (EGU) Forecasting Tool. Please check the MARAMA website (www.marama.org) for the latest emission projection results.

Table 2.1 Trends in SO_2 Emissions (tons/year) from EGUs in the MANE-VU Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	1,413,962	137,592	1,436,809	143,160	1,131,578	120,381	227,534	23,684	182,739	16,004
COAL	Dry FGD	0	946	0	2,921	19,177	5,536	22,667	6,814	8,559	6,559
COAL	Wet Lime FGD	36,848	21,122	37,853	23,553	57,262	32,608	137,381	60,472	75,876	52,142
COAL	Wet Limestone FGD	30,497	25,369	27,086	28,616	16,597	25,287	47,622	48,396	27,060	32,488
COAL	Other	9,181	10,718	18,411	8,267	17,959	7,464	25,031	4,691	19,134	3,278
		1,490,488	**195,747**	**1,520,159**	**206,517**	**1,242,573**	**191,276**	**460,234**	**144,056**	**313,366**	**110,471**
OIL	No Control	110,132	37,955	144,898	44,804	20,890	16,415	6,336	9,489	7,356	9,881
OIL	Dry FGD	0	0	0	0	0	0	0	0	0	0
OIL	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
OIL	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
OIL	Other	0	0	0	0	0	0	0	0	0	0
		110,132	**37,955**	**144,898**	**44,804**	**20,890**	**16,415**	**6,336**	**9,489**	**7,356**	**9,881**
GAS	No Control	5,605	82,963	9,710	102,069	1,681	114,998	830	159,814	2,700	171,093
GAS	Dry FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
GAS	Other	0	0	0	0	0	0	0	0	0	0
		5,605	**82,963**	**9,710**	**102,069**	**1,681**	**114,998**	**830**	**159,814**	**2,700**	**171,093**
WOOD	No Control	6	201	10	264	2	284	1	259	260	326
WOOD	Dry FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Other	0	0	0	0	927	692	2	332	23	615
		6	**201**	**10**	**264**	**929**	**976**	**4**	**591**	**283**	**941**
		1,606,230	**316,865**	**1,674,776**	**353,655**	**1,266,072**	**323,666**	**467,404**	**313,950**	**323,704**	**292,386**

Source: EPA, 2015a

Table 2.2 Trends in SO_2 Emissions (tons/year) from EGUs in the MRPO Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	2,575,134	370,970	2,575,616	388,520	1,670,614	315,565	1,175,633	224,716	576,289	124,755
COAL	Dry FGD	1,798	517	1,478	496	4,578	1,920	16,960	14,855	19,631	27,472
COAL	Wet Lime FGD	64,672	32,047	63,543	37,478	150,972	63,122	162,533	72,627	118,736	87,587
COAL	Wet Limestone FGD	134,943	40,804	133,317	42,175	168,253	90,460	96,799	103,573	148,596	129,585
COAL	Other	10,108	3,317	21,618	5,044	20,252	4,749	13,556	3,711	31,241	19,259
		2,786,655	**447,654**	**2,795,573**	**473,713**	**2,014,668**	**475,816**	**1,465,481**	**419,483**	**894,493**	**388,658**
OIL	No Control	4,756	1,047	3,103	755	679	167	17	125	136	66
OIL	Dry FGD	2,790	0	2,686	0	0	0	0	0	0	0
OIL	Wet Lime FGD	57	0	3	0	0	0	0	0	0	0
OIL	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
OIL	Other	0	0	0	0	0	0	0	0	0	0
		7,603	**1,047**	**5,792**	**755**	**679**	**167**	**17**	**125**	**136**	**66**
GAS	No Control	3,495	15,026	2,323	43,400	3,009	21,009	590	42,538	601	54,280
GAS	Dry FGD	0	0	0	0	0	0	0	0	0	57
GAS	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
GAS	Other	999	0	380	0	414	0	267	62	386	1,320
		4,493	**15,026**	**2,703**	**43,400**	**3,424**	**21,009**	**856**	**42,599**	**988**	**55,657**
WOOD	No Control	139	181	554	214	191	571	716	751	501	778
WOOD	Dry FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Other	0	0	0	0	0	0	0	0	0	0
		139	**181**	**554**	**214**	**191**	**571**	**716**	**751**	**501**	**778**
		2,798,891	**463,909**	**2,804,622**	**518,082**	**2,018,963**	**497,563**	**1,467,070**	**462,958**	**896,117**	**445,159**

Source: EPA, 2015a

Table 2.3 Trends in SO_2 Emissions (tons/year) from EGUs in the VISTAS Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	3,147,982	453,588	3,114,055	461,624	2,032,556	328,550	786,147	122,318	477,290	66,549
COAL	Dry FGD	6,090	4,945	7,586	9,235	12,130	10,804	14,638	11,000	14,341	13,421
COAL	Wet Lime FGD	107,245	45,056	166,351	53,362	186,923	97,734	129,185	124,425	104,130	137,626
COAL	Wet Limestone FGD	235,104	109,318	207,285	116,905	256,628	189,316	213,505	253,569	196,775	238,378
COAL	Other	26,321	10,909	33,620	11,427	14,823	11,144	22,553	8,818	26,646	11,759
		3,522,743	**623,816**	**3,528,898**	**652,553**	**2,503,060**	**637,547**	**1,166,027**	**520,130**	**819,181**	**467,733**
OIL	No Control	145,925	31,700	137,052	26,328	42,461	14,258	5,516	8,879	2,633	3,582
OIL	Dry FGD	0	0	0	0	0	0	0	0	0	0
OIL	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
OIL	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
OIL	Other	1	64	0	6	0	14	0	14	0	43
		145,926	**31,764**	**137,052**	**26,334**	**42,461**	**14,272**	**5,516**	**8,893**	**2,633**	**3,626**
GAS	No Control	44,593	91,018	59,246	119,781	20,826	149,178	3,781	251,643	3,335	307,965
GAS	Dry FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
GAS	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
GAS	Other	0	32	0	5	0	5	0	7	0	46
		44,594	**91,050**	**59,246**	**119,786**	**20,826**	**149,183**	**3,781**	**251,650**	**3,336**	**308,010**
WOOD	No Control	0	0	0	0	77	403	3,436	325	5,820	389
WOOD	Dry FGD	0	0	0	0	0	0	0	0	82	151
WOOD	Wet Lime FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Wet Limestone FGD	0	0	0	0	0	0	0	0	0	0
WOOD	Other	0	0	0	0	0	0	0	0	17	649
		0	**0**	**0**	**0**	**77**	**403**	**3,436**	**325**	**5,919**	**1,189**
		3,713,263	**746,629**	**3,725,196**	**798,673**	**2,566,424**	**801,405**	**1,178,760**	**780,998**	**831,069**	**780,558**

Source: EPA, 2015a

Table 2.4 Trends in NO_x Emissions (tons/year) from EGUs in the MANE-VU Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	15,059	6,643	9,696	4,600	4,911	1,286	2,188	978	1,917	939
COAL	OFA	512	298	1,252	0	189	0	211	0	222	0
COAL	Comb Mod	15,689	2,942	12,605	2,265	8,931	2,420	4,876	1,410	2,854	534
COAL	Low NO_x	235,422	122,236	138,601	87,984	107,623	74,831	76,126	55,147	22,587	23,823
COAL	SNCR	54,883	20,781	67,128	32,659	54,786	27,606	35,142	16,625	19,606	9,132
COAL	SCR	65,776	40,469	90,330	76,845	102,531	82,667	74,283	67,395	101,710	74,115
COAL	Other	2,961	2,377	7,697	2,164	7,091	2,466	7,244	2,500	2,176	1,928
		390,303	**195,747**	**327,308**	**206,517**	**286,062**	**191,276**	**200,070**	**144,056**	**151,073**	**110,471**
OIL	No Control	20,392	10,231	19,761	11,631	5,397	3,512	3,496	1,395	4,434	2,550
OIL	OFA	11,359	12,017	14,346	13,620	4,195	6,358	1,352	1,952	444	554
OIL	Comb Mod	980	349	1,117	667	692	141	493	72	258	228
OIL	Low NO_x	14,234	11,468	12,574	11,940	3,672	4,651	2,076	3,821	2,538	4,411
OIL	SNCR	993	758	1,357	1,102	501	406	151	139	31	11
OIL	SCR	832	504	580	584	105	514	120	1,445	121	1,332
OIL	Other	4,286	2,627	5,892	5,261	856	833	664	664	1,012	796
		53,076	**37,955**	**55,628**	**44,804**	**15,418**	**16,415**	**8,352**	**9,489**	**8,838**	**9,881**
GAS	No Control	9,183	9,969	10,775	7,518	7,352	4,996	4,787	8,352	5,040	8,460
GAS	OFA	1,985	4,501	2,721	4,050	834	2,107	741	2,120	1,002	2,786
GAS	Comb Mod	1,403	1,086	980	907	831	891	283	274	474	263
GAS	Low NO_x	5,482	7,706	3,987	11,020	3,293	12,272	2,341	12,332	3,621	14,212
GAS	SNCR	2	0	1	0	2	0	116	276	538	366
GAS	SCR	6,354	45,429	4,913	69,465	4,761	88,365	5,810	129,292	6,167	135,909
GAS	Other	9,177	14,272	5,202	9,110	3,378	6,367	3,559	7,168	4,344	9,097
		33,586	**82,963**	**28,579**	**102,069**	**20,450**	**114,998**	**17,638**	**159,814**	**21,186**	**171,093**
WOOD	SNCR	0	0	0	0	515	692	149	332	167	349
WOOD	SCR	0	0	0	0	0	0	0	0	202	266
WOOD	Other	230	201	297	264	296	284	117	259	161	326
		230	**201**	**297**	**264**	**810**	**976**	**266**	**591**	**807**	**941**
		477,195	**316,865**	**411,812**	**353,655**	**322,740**	**323,666**	**226,327**	**313,950**	**181,904**	**292,386**

Source: EPA, 2015a

Table 2.5 Trends in NO_x Emissions (tons/year) from EGUs in the MRPO Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
MRPO											
COAL	No Control	254,978	80,185	75,593	31,920	46,090	20,840	21,882	11,602	12,089	5,825
COAL	OFA	149,978	46,354	72,854	27,471	75,307	28,744	34,925	21,349	6,546	4,382
COAL	Comb Mod	4,002	1,901	7,153	2,578	5,709	2,610	2,982	1,939	97	0
COAL	Low NO_x	501,333	264,896	274,250	203,233	233,119	188,340	180,163	161,181	138,523	120,527
COAL	SNCR	11,854	4,898	32,416	16,415	37,962	23,413	23,107	15,761	25,237	30,794
COAL	SCR	104,930	46,079	307,201	191,868	306,820	211,869	126,852	207,651	131,761	227,130
COAL	Other	9,740	3,341	4,198	229	2,116	0	2,338	0	3,001	0
		1,036,815	**447,654**	**773,665**	**473,713**	**707,123**	**475,816**	**392,250**	**419,483**	**317,253**	**388,658**
OIL	No Control	95	1	538	25	244	19	70	7	378	20
OIL	OFA	741	0	681	0	17	0	6	0	0	0
OIL	Comb Mod	0	0	0	0	0	0	0	0	0	0
OIL	Low NO_x	1,513	1,023	899	697	205	147	15	118	43	46
OIL	SNCR	63	0	1	0	0	0	0	0	0	0
OIL	SCR	0	0	0	0	0	0	0	0	0	0
OIL	Other	37	23	59	33	3	2	0	0	0	0
		2,448	**1,047**	**2,178**	**755**	**468**	**167**	**91**	**125**	**421**	**66**
GAS	No Control	2,135	1,924	3,492	20,960	2,190	1,801	1,707	546	1,923	834
GAS	OFA	170	205	219	135	30	16	0	0	5	0
GAS	Comb Mod	0	0	253	121	290	152	0	0	0	0
GAS	Low NO_x	3,403	7,530	1,941	7,089	1,720	4,164	1,959	6,238	1,767	6,126
GAS	SNCR	0	0	0	0	0	0	0	0	0	0
GAS	SCR	349	2,990	903	10,366	889	10,416	1,561	31,651	2,058	43,814
GAS	Other	1,631	2,378	2,995	4,729	3,209	4,459	2,940	4,165	2,570	4,883
		7,688	**15,026**	**9,804**	**43,400**	**8,328**	**21,009**	**8,168**	**42,599**	**8,323**	**55,657**
WOOD	SNCR	0	0	0	0	759	372	1,315	751	1,429	778
WOOD	Other	532	181	730	214	496	199	0	0	0	0
		532	**181**	**730**	**214**	**1,256**	**571**	**1,315**	**751**	**1,429**	**778**
		1,047,484	**463,909**	**786,377**	**518,082**	**717,175**	**497,563**	**401,824**	**462,958**	**327,426**	**445,159**

Source: EPA, 2015a

Table 2.6 Trends in NO_x Emissions (tons/year) from EGUs in the VISTAS Region

Primary Fuel	Primary Control	2002		2005		2008		2011		2014	
		Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)	Emissions (tpy)	Generation (10^9 BTU)
COAL	No Control	206,027	74,111	88,672	39,548	58,630	22,811	20,486	8,602	21,905	8,808
COAL	OFA	67,409	19,581	42,925	14,102	29,665	9,107	16,747	4,544	8,392	1,925
COAL	Comb Mod	9,170	3,610	3,725	1,441	771	360	0	0	0	0
COAL	Low NO_x	861,782	394,564	409,563	215,660	309,081	173,303	165,960	102,160	110,156	69,744
COAL	SNCR	8,357	5,222	43,893	29,272	70,722	54,941	56,294	43,341	40,379	31,132
COAL	SCR	155,382	81,961	423,522	313,602	350,958	337,900	165,153	333,690	212,978	345,228
COAL	Other	82,085	44,768	60,270	38,927	54,025	39,125	26,059	27,794	9,823	10,896
		1,390,213	**623,816**	**1,072,570**	**652,553**	**873,852**	**637,547**	**450,700**	**520,130**	**403,634**	**467,733**
OIL	No Control	33,174	16,258	24,349	11,503	10,435	6,522	2,415	2,911	1,636	1,070
OIL	OFA	1,096	1,017	1,771	1,763	409	362	77	80	235	213
OIL	Comb Mod	4,164	1,794	4,094	1,143	2,663	1,197	2,690	1,482	23	37
OIL	Low NO_x	12,672	9,002	13,585	9,122	4,909	5,169	2,136	3,577	680	1,595
OIL	SNCR	0	0	0	0	0	0	0	0	0	0
OIL	SCR	0	0	0	0	0	0	0	0	0	0
OIL	Other	4,690	3,693	3,766	2,804	999	1,023	663	842	640	712
		55,795	**31,764**	**47,565**	**26,334**	**19,414**	**14,272**	**7,980**	**8,893**	**3,213**	**3,626**
GAS	No Control	14,581	9,423	9,198	4,965	5,495	4,879	7,739	4,721	5,233	5,135
GAS	OFA	599	655	756	683	2,771	1,292	1,599	1,561	77	63
GAS	Comb Mod	27	98	6	30	9	55	5	27	81	197
GAS	Low NO_x	29,219	44,495	27,973	48,994	16,030	41,598	10,564	48,485	8,356	44,974
GAS	SNCR	0	0	0	0	0	0	0	0	0	0
GAS	SCR	3,053	28,554	5,372	57,141	6,030	91,355	8,827	183,987	12,026	245,419
GAS	Other	4,696	7,826	4,984	7,972	5,786	10,004	6,303	12,870	6,257	12,223
		52,175	**91,050**	**48,290**	**119,786**	**36,120**	**149,183**	**35,036**	**251,650**	**32,030**	**308,010**
WOOD	No Control	0	0	0	0	574	403	947	325	755	389
WOOD	OFA	0	0	306	0	0	0	1,592	0	1,655	0
WOOD	SCR	0	0	0	0	0	0	0	0	465	800
		0	**0**	**306**	**0**	**574**	**403**	**2,539**	**325**	**3,521**	**1,189**
		1,498,183	**746,629**	**1,168,731**	**798,673**	**929,961**	**801,405**	**496,254**	**780,998**	**442,399**	**780,558**

Source: EPA, 2015a

FACTOR 1 – COST OF COMPLIANCE

Air pollution control technologies for EGUs have advanced substantially over the last several decades. As described in the previous section, state and federal clean air rules to address acid rain and ground-level smog led to power plant owners successfully deploying a range of advanced pollution control systems at hundreds of facilities across the country, providing valuable experience with the installation and operation of these technologies. This has provided regulators and industry with a working knowledge of a suite of cost-effective air pollution control options.

Pollutant emission controls are generally divided into three major types, as follows:

- Pre-combustion controls, in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- Combustion controls, in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- Post-combustion controls, in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

The following sections provide a brief summary of SO_2 and NO_x control options and costs, drawing heavily on recent work sponsored by EPA and regional planning organizations. More detailed descriptions of the options can be found in the literature cited in the list of references.

Identification of Available SO_2 Control Options

SO_2 is an undesirable by-product of the combustion of sulfur-bearing fossil fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8% or more. Untreated distillate oils typically have sulfur contents less than 0.5% while residual oil can have 1-2% sulfur by weight. Pipeline quality natural gas contains virtually no sulfur. Essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to SO_3 depending on fuel and boiler characteristics).

Since the relationship between sulfur content in the fuel and SO_2 emissions is essentially linear, the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal, or from coal/oil to natural gas) are directly proportional to the difference in sulfur contents of fuels. Therefore, changing fuels is the principal means of reducing sulfur emissions without adding flue gas treatment methods. Major issues associated with fuel substitution include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

Over the past decade, some EGUs have reduced the amount of SO_2 created through changes in fuel; however, in many cases such changes may be uneconomical or impractical. For this reason, gas treatment methods that capture the SO_2 that is formed from these industrial sources may be the most effective form of controlling SO_2 emissions. Post-combustion controls reduce SO_2 emissions by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based)

and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. Post-combustion SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers", broadly grouped into wet FGD, dry FGD, and dry sorbent injection (DSI) technologies.

A summary of available SO_2 control technology options are shown in Table 2.7. The method of SO_2 control appropriate for any individual EGU is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost effective emissions reduction technologies for SO_2 are available and have proven effective in reducing emissions from the exhaust gas stream of EGU boilers.

Table 2.7 SO_2 Control Options for Coal-fired EGU Boilers

Technology	Description	Applicability	Performance
Switch to Low Sulfur Coal (generally <1% Sulfur)	Replace high sulfur bituminous coal with lower sulfur coal	Potential control measure for all coal-fired EGUs using coal with a high sulfur content	50-80% reduction in SO_2 emissions
Switch to natural gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-fired EGUs	Virtually eliminate SO_2 emissions by switching to natural gas
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired EGUs	20-25% reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) - Wet	SO_2 is removed from flue gas by dissolving it in a lime or limestone slurry. (Other alkaline chemicals are sometimes used)	Applicable to all coal-fired EGUs	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Spray Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) –Dry Sorbent Injection	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

Table references: MACTEC, 2007; STAPPA-ALAPCO, 2006; NESCAUM, 2011; EPA, 2013.

Cost of Compliance – SO_2 Control Options

To compare the various control options, information has been compiled on the cost-effectiveness of fuel switching and retrofitting controls. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases.

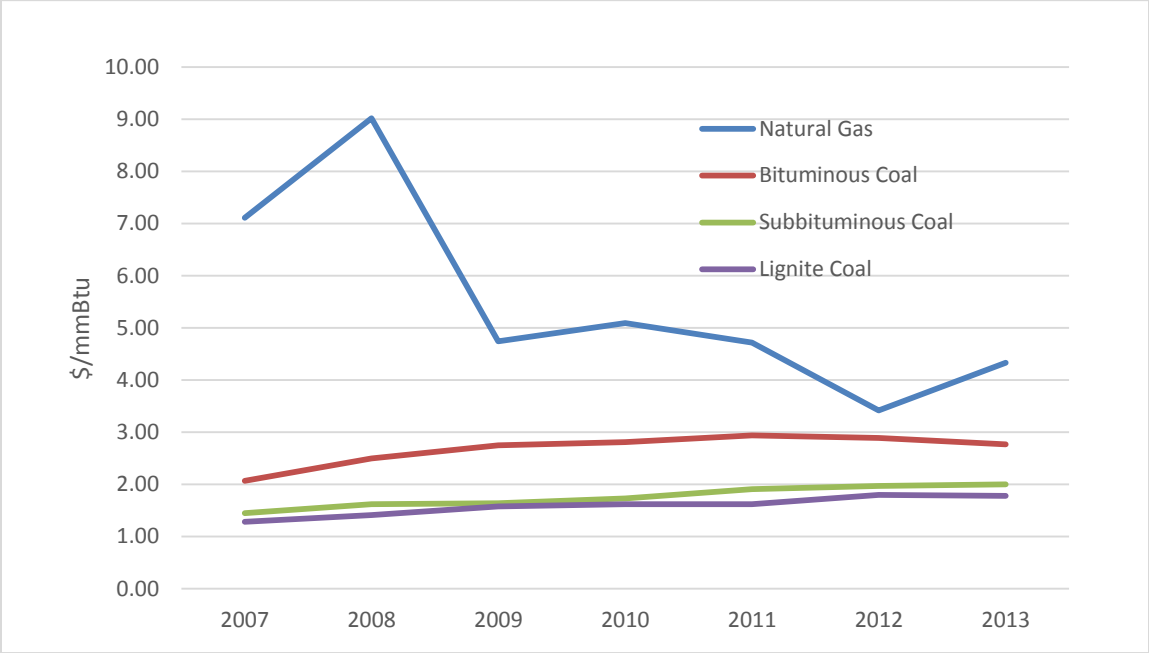
Cost of Switching from Coal to Natural Gas

In many cases, switching to lower sulfur fuels is one of the most straightforward and technologically feasible strategies for reducing emissions, but it is not a trivial undertaking (NACAA, 2015). For any existing EGU, there are reasons the current fuels are used and other

fuels are not used. Similarly, there are reasons the primary fuel is primary and the backup fuels are backups. These decisions are influenced by many different factors, such as delivered fuel costs, fuel handling system design, boiler design, availability of natural gas pipeline capacity, and so forth. Switching fuels will be most feasible from a technological perspective where a boiler is already designed to combust more than one type of fuel.

The original Four Factors Analysis (MACTEC, 2007) found that coal to natural gas conversion was uneconomical at the time due to the fuel price disparity between the two fuels. The price of natural gas was approximately four times higher than coal according to average monthly costs of fuel delivered to electricity producers (January 2007 data from EIA). Therefore there was no additional cost analysis in the report. The price of natural gas has decreased considerably since then, conversion to natural gas is viable economically, and a large number of coal-fired EGUs have converted or are in the process of converting. Information collected by EPA through October 2014 indicates that 70 coal fired units with a capacity of 12,400 MWs will have converted to natural gas between 2011 through 2015 (EPA, 2015a).

Figure 2.1 U.S. Delivered Coal and Natural Gas Prices for Electric Generation Average Cost by Fuel $/MMBTU



Source: Table 7.4; EIA, 2015.

EPA developed conversion cost and performance assumptions for use with the IPM® model (EPA, 2013). Capital cost components include the costs of boiler modifications and the cost of extending natural gas lateral pipeline spurs to a natural gas main pipeline. Operating and maintenance costs, fixed and variable, are less after the conversion due to lower costs of operating a gas boiler versus a coal boiler (e.g., fewer maintenance materials and less waste disposal). There is a heat rate penalty due to lower stack temperature and higher moisture loss.

Table 2.8 IPM v5.13 Cost and Performance Assumptions for Coal to Gas Conversions

Factor	Assumption	Description
Heat Rate Penalty	+5%	Lower stack temperature and higher moisture loss reduces efficiency
Incremental Capital Cost	PC Unit: $/kW = 267*(75/MW)^0.35 Cyclone Unit: : $/kW = 374*(75/MW)^0.35	New gas burners, piping, air heater upgrade, gas recirculating fans, and control system modifications.
Incremental Fixed O&M	-33% of the FOM cost of the existing coal unit	Reduced need for maintenance materials and labor.
Incremental Variable O&M	-25% of the VOM cost of the existing coal unit	Reduced waste disposal and other miscellaneous costs.

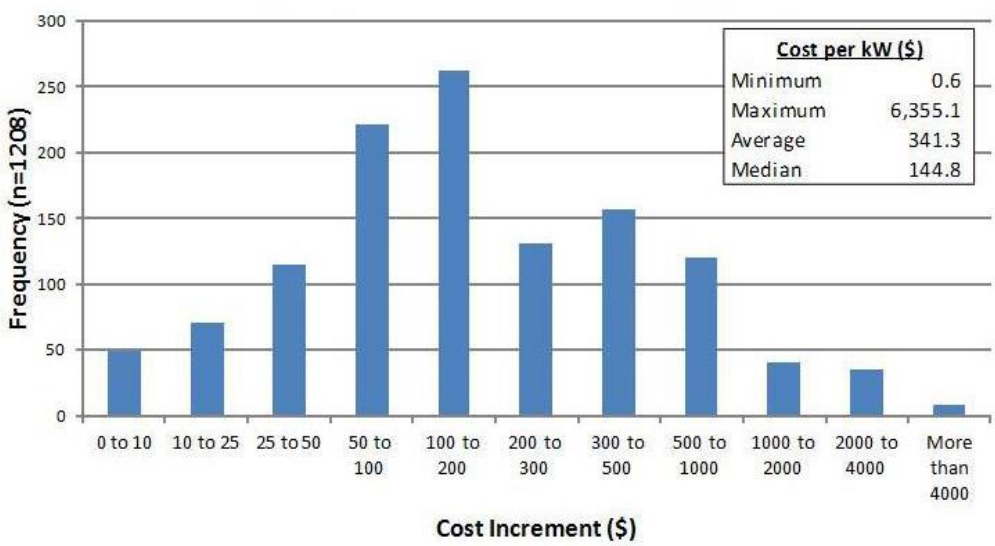
Table reference: Table 5-21, EPA, 2013.

EPA also developed estimates of the cost of extending pipeline laterals from each coal-fired boiler to the interstate national gas pipeline system. Their analysis included a number of factors including:

- Mainline pipeline flow capacity
- Required lateral capacity based on heat rate and boiler capacity
- Diameter of each lateral (calculated using the Weymouth equation)
- Cost per lateral ($90,000 per inch-mile based on recently completed projects)

Based on data for 1,208 coal-fired units EPA calculated an average cost per boiler of $341/kW of capacity. The distribution of lateral costs is shown in Figure 2.2.

Figure 2.2 Lateral Pipeline Costs per kW of Boiler Capacity



Source: Figure 5-7; EPA, 2013.

Cost of Switching from High to Low Sulfur Coal

Switching to a low-sulfur coal or blending a lower sulfur coal can impact cost due to the following main reasons:

- The cost of low-sulfur coal compared to higher sulfur coal
- The cost of transporting low-sulfur coal from the west to the east
- The cost of necessary boiler or coal handling equipment modifications
- The lower heating value of most low-sulfur coal requires more coal to be consumed to produce an equivalent amount of electricity.

Recent data from the Energy Information Administration show the average price of coals from various locations together with estimated heating values and sulfur content. The prices of coal indicated in Tables 2.4 and 2.5 do not include the cost of delivery.

The sulfur content, heating values and prices of coals mined in various regions of the country vary considerably (See Table 2.9). Central Appalachian coals, which are lower in sulfur than Illinois Basin or Northern Appalachian coals, generally have high heating value and are more accessible than low-sulfur western coal.

Table 2.9 Average Weekly Coal Commodity Spot Priced ($2014 per ton)

Week Ended	Central Appalachia 12,500 BTU, 1.2 lbs SO_2 / MMBTU	Northern Appalachia 13,000 BTU, <3.0 lbs SO_2 / MMBTU	Illinois Basin 11,800 BTU, 5.0 lbs SO_2 / MMBTU	Powder River Basin 8,800 BTU, 0.8 lbs SO_2 / MMBTU	Uinta Basin 11,700 BTU, 0.8 lbs SO_2 / MMBTU
23-Oct-15	$49.00	$52.00	$32.75	$11.55	$40.55
30-Oct-15	$49.00	$52.00	$32.75	$11.55	$40.55
6-Nov-15	$49.00	$52.00	$32.75	$11.55	$40.55
13-Nov-15	$43.50	$48.95	$32.60	$11.55	$40.65
20-Nov-15	$43.50	$48.95	$32.60	$11.55	$40.65

Source: http://www.eia.gov/coal/news_markets/

Note: The historical data file of spot prices is proprietary and cannot be released by EIA

Powder River Basin coal has a significantly lower heating value than the other four varieties of coal, but on an energy basis, it is still approximately one third the cost of the other coals listed. Since Powder River Basin coal contains significantly less sulfur, it would seem that this coal would be the best fuel for boilers trying to incorporate a lower sulfur coal. Unfortunately, due to the lower heating value of the coal, boilers that are configured to burn coal with a higher heating value can only use a small percentage of this low-sulfur coal (no higher than 15% Powder River Basin coal). The only way to burn higher percentages of the Powder River Basin coal would be to extensively retrofit the boilers or suffer from poor boiler performance and other operating difficulties (MACTEC, 2007). Such retrofits should be reviewed in light of current Prevention of Significant Deterioration (PSD) permitting regulations to ensure that all such requirements are met and that emissions do not increase. The coal prices included in Table 2.9 do not reflect the cost of boiler retrofits required to combust low sulfur coal.

Once coal is mined, it must be transported to where it will be consumed. Transportation costs add to the delivered price of coal. In some cases, like in long-distance shipments of Powder River Basin coal to power plants in the East, transportation costs can be more than the price of coal at the mine. Most coal is transported by train, barge, truck, or a combination of these modes. All of these transportation modes use diesel fuel. Increases in oil prices can significantly affect the cost of transportation and thereby affect the final delivered price of coal. In 2013, the average sales price of coal at the mine was $37.24 per ton, and the average delivered price to the electric power sector was $45.21 per ton, resulting in an average transportation cost of $7.97 per ton, or 18% of the total delivered price (EIA, .

Cost of Coal Cleaning

Coal cleaning may be an economically viable approach for reducing coal sulfur compared to the purchase of lower sulfur coals from western states (Staudt, 2012). Sulfur may be removed from the coal through cleaning measures that remove rock and pyrite (including pyritic sulfur). Most coals experience some form of cleaning prior to shipment in order to remove impurities and increase the heating value of the delivered coal. To the extent that sulfur may be in these impurities, such as in pyrites, sulfur can be removed as well; however, some sulfur is organically bound to the coal and cannot be removed, at least through physical separation. Physical cleaning measures rely on the difference in density between the impurities and the coal. Chemical cleaning measures chemically remove impurities.

Up to 60% sulfur (on a heating value basis) is removed through physical cleaning methods from uncleaned coal depending upon the coal and the practice used (Staudt, 2012). However, 60% represents the best potential technology while common commercial practice reduces coal sulfur by about 40%. Higher sulfur reductions are possible if chemical cleaning methods are considered. Current data was unavailable for the cost of coal cleaning. However, because it has been used in practice, it is certainly an approach that is available and feasible, and is likely to be economically viable for many industrial facilities.

Cost of Post-Combustion Gas Treatment Technologies

While many EGUs can accommodate fuel changes to reduce the amount of SO_2 emitted, such changes may be uneconomical or impractical for other units. For this reason, gas treatment methods that capture and control the SO_2 that is formed may be the most effective form of control. Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use depending on the technology used. More detailed descriptions of these technologies can be found in recent literature (NESCAUM, 2011; EPA, 2013.)

The estimates previously used in the 2007 Assessment (MACTEC, 2007) were not used in this analysis because the EPA publications that served as the basis for those cost estimates are dated, and more recent cost factors are available. Instead, cost models developed by the engineering firm Sargent and Lundy LLC (S&L) were used to update SO_2 post-combustion control cost. Under a contract with EPA, SRA issued a subcontract to S&L to update and add to the retrofit emission control models previously developed for EPA and used in the Integrated Planning

Model (IPM®). The detailed reports and example calculation worksheets for S&L retrofit emission control models used by EPA are available in Attachments 5-1 through 5-7 of the IPM documentation for EPA Base Case v5.13 (EPA, 2013). Sargent & Lundy relied on several published sources for their cost models, which were significantly augmented by the S&L in-house database of recent FGD projects.

The two critical factors common across most all of the control device cost estimates are the volume of air treated (unit size) and the amount of pollutant to be removed. The exception is the Dry Sorbent Injection control for SO_2 where the prime cost is for the sorbent, and therefore unit size is not as important as the amount of pollutant removed. The S&L models also include a retrofit factor that can be changed based on the size of the site. Retrofits at smaller older plants can be more expensive on plant sites that have little room for the control equipment. Applicability, performance and cost factors for each control device are discussed briefly below.

- Limestone Forced Oxidation (LSFO): Typically not used on applications smaller than 100 MW. SO_2 emission control above 95%. The lowest manufacturer SO_2 emission guarantee is 0.04 lb/MMBTU. Base capital cost estimates include minor physical and chemical wastewater treatment.
- Lime Spray Dryer (LSD): This device is also called a Spray Dryer Absorber (SDA). Typically not used on applications smaller than 50 MW, and limited to coals with sulfur content less than 3.0 lbs SO_2/MMBTU. Can meet 95% SO_2 mission control. The lowest manufacturer emission guarantee is 0. 06 lb/MMBTU.
- Dry Sorbent Injection (DSI): Should not be used when coal sulfur content is greater than 2.0 lbs/MMBTU. SO_2 emission control dependent on the downstream particulate control device and amount of sorbent injected (Normalized Stoichiometric Ratio). Trona injection followed by an electrostatic precipitator can achieve 40 to 50% SO_2 reduction, and 70 to 75% reduction when injection is followed by a fabric filter. Cost estimates do not include particulate control device costs.

Tables 2.10 to 2.12 show SO_2 add-on control cost estimates for a number of boiler and control scenarios from the IPM documentation. These examples were used to calculate a cost effectiveness in $/ton using the same methodology as in the *2007 Assessment* which used a capital recovery factor of 0.15 and capacity factor of 0.85. The IPM documentation did not provide SO_2 control cost estimates for DSI. Table 2.13 provides a cost effectiveness estimate for DSI based on a 500 MW example from the S&L report.

Table 2.10 Examples of SO_2 Add-On Control Costs from EPA Base Case v5.13 (2011$)

FGD Type	Heat Rate (BTU/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M ($/MWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
LSFO	9,000	-1.5	1.53	2.203	819	23.7	600	11.2	519	8.3	471	7.7	426	6.4
	10,000	-1.67	1.7	2.26	860	24.2	629	11.5	544	8.6	495	8	447	6.6
	11,000	-1.84	1.87	2.49	899	24.6	658	11.8	569	8.9	517	8.2	467	6.8
LSD	9,000	-1.18	1.2	2.51	701	17.3	513	8.6	444	6.5	422	5.7	422	5.3
	10,000	-1.32	1.33	2.79	734	17.7	538	8.9	465	6.8	442	5.9	442	5.5
	11,000	-1.45	1.47	3.07	766	18	561	9.1	485	7	461	6.1	461	5.7

Notes:

1. The LSFO estimates are based on 3.0 lbs SO_2/MMBTU coal, and 96% removal. LSD estimates are based on 2.0 lbs SO_2/MMBTU coal and 92% removal.
2. The capacity penalty and heat rate penalty are not used in calculating cost effectiveness in $/ton removed. The penalties represent the electricity demand of the FGD. The capacity penalty equals the percent of unit generation required for the control device. The heat rate penalty is based on the capacity penalty and is a modeling procedure to capture the effect of the control device on fuel use and generation. It does not represent an actual increase in the unit heat rate.
3. Table Reference: Table 5-3, Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model. U.S. EPA #450R13002, November 2013.

Table 2.11 SO_2 LSFO Control Cost Effectiveness for EPA Base Case v5.13 Examples (2011$)

FGD Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Coal Sulfur lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	SO_2 Reduction (tons/kW-yr)	2011$/ton Reduction
LSFO	100	9,000	0.15	0.85	3	96%	163.0	0.097	1,689
LSFO	100	10,000	0.15	0.85	3	96%	170.0	0.107	1,586
LSFO	100	11,000	0.15	0.85	3	96%	178.0	0.118	1,509
LSFO	300	9,000	0.15	0.85	3	96%	117.6	0.097	1,219
LSFO	300	10,000	0.15	0.85	3	96%	122.7	0.107	1,144
LSFO	300	11,000	0.15	0.85	3	96%	129.0	0.118	1,094
LSFO	500	9,000	0.15	0.85	3	96%	102.6	0.097	1,063
LSFO	500	10,000	0.15	0.85	3	96%	107.0	0.107	998
LSFO	500	11,000	0.15	0.85	3	96%	112.8	0.118	956
LSFO	700	9,000	0.15	0.85	3	96%	94.8	0.097	982
LSFO	700	10,000	0.15	0.85	3	96%	99.1	0.107	924
LSFO	700	11,000	0.15	0.85	3	96%	104.3	0.118	884
LSFO	1000	9,000	0.15	0.85	3	96%	86.7	0.097	898
LSFO	1000	10,000	0.15	0.85	3	96%	90.5	0.107	844
LSFO	1000	11,000	0.15	0.85	3	96%	95.4	0.118	809

Notes:

The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007)

Table 2.12 SO_2 LSD Control Cost Effectiveness for EPA Base Case v5.13 Examples (2011$)

FGD Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Coal Sulfur lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	SO_2 Reduction (tons/kW-yr)	2011$/ton Reduction
LSD	100	9,000	0.15	0.85	2	92%	141.1	0.062	2,289
LSD	100	10,000	0.15	0.85	2	92%	148.6	0.069	2,169
LSD	100	11,000	0.15	0.85	2	92%	155.8	0.075	2,067
LSD	300	9,000	0.15	0.85	2	92%	104.2	0.062	1,691
LSD	300	10,000	0.15	0.85	2	92%	110.4	0.069	1,611
LSD	300	11,000	0.15	0.85	2	92%	116.1	0.075	1,541
LSD	500	9,000	0.15	0.85	2	92%	91.8	0.062	1,489
LSD	500	10,000	0.15	0.85	2	92%	97.3	0.069	1,421
LSD	500	11,000	0.15	0.85	2	92%	102.6	0.075	1,362
LSD	700	9,000	0.15	0.85	2	92%	87.7	0.062	1,422
LSD	700	10,000	0.15	0.85	2	92%	93.0	0.069	1,357
LSD	700	11,000	0.15	0.85	2	92%	98.1	0.075	1,302
LSD	1000	9,000	0.15	0.85	2	92%	87.3	0.062	1,416
LSD	1000	10,000	0.15	0.85	2	92%	92.6	0.069	1,351
LSD	1000	11,000	0.15	0.85	2	92%	97.7	0.075	1,297

Notes:
The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the 2*007 Assessment* (MACTEC, 2007).

Table 2.13 SO_2 DSI Control Costs and Cost Effectiveness Based on Sargent and Lundy Model Example ($2012)

FGD Type	Capacity (MW)	Heat Rate (BTU/kWh)	Variable O&M ($/MWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Coal Sulfur lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	SO_2 Reduction (tons/kW-yr)	2012$/ton Reduction
DSI	500	9,500	9.18	44	0.89	0.15	0.85	2	50%	75.8	0.035	2,144

Notes:

1. The DSI generation based cost estimates assume 2.0 lbs SO_2/MMBTU coal and 50% removal. Downstream particulate control by an Electrostatic Precipitator.
2. The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007).
3. Table Reference: Attachment 5-3 of the IPM documentation for EPA Base Case v5.13

Identification of NO_x Control Options

The formation of NO_x is a byproduct of the combustion of fossil fuels. Most of the NO_x formed during the combustion process is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NO_x; and (2) oxidation of nitrogen that is chemically bound in the fuel, referred to as fuel NO_x. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NO_x emissions.

A variety of approaches to minimize or reduce NO_x emissions into the atmosphere have been and continue to be developed (NESCAUM, 2011). A relatively simple way of understanding the many technologies available for NO_x emission control is to divide them into two major categories: (1) those that minimize the formation of NO_x itself during the combustion process (e.g., smaller quantities of NO_x are formed during combustion); and (2) those that reduce the amount of NO_x after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach as combustion modifications, whereas technologies in the second category are termed post-combustion controls. Combinations of some of these technologies are not only possible, but also often desirable as they may produce more effective NO_x control than the application of a stand-alone technology.

A summary of available NO_x control technology options is shown in Table 2.14. Combustion modifications can vary from simple "tuning" or optimization efforts to the deployment of dedicated technologies such as Low NO_x Burners (LNB), Overfire Air (OFA) or Flue Gas Recirculation~~s~~ (FGR). Conventional, commercial post-combustion NO_x controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NO_x produced in the boiler to convert the NO_x to harmless nitrogen and water. SNCR accomplishes this at higher temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NO_x.

Table 2.14 NO_x Control Options for Coal-fired EGU Boilers

Technology	Description	Applicability	Performance
Switch to natural gas	Replace coal combustion with natural gas. Natural gas contains low fuel-bound nitrogen content and requires lower excess air for combustion than coal, resulting in lower uncontrolled NO_x emissions.	Potential control measure for all coal-fired EGUs	50 to 80% reduction in NO_x emissions. Will still require NO_x combustion and or post-combustion controls.
Combustion Controls	Modifications to the boiler furnace burners and combustion air systems to lower flame temperatures and oxygen concentrations to reduce thermal NO_x formation.	Potential control measure for most types of coal-fired EGU boilers. Dependent on boiler and coal type.	10 to 60% reduction in NO_x emissions.

Technology	Description	Applicability	Performance
Selective Noncatalytic Reduction (SNCR)	Ammonia or urea reagent is injected into the flue gas stream and reduces NO_x in to N_2 and H_2O without a catalyst.	Potential control measure for all coal-fired EGUs. Costs per ton of NO_x controlled for retrofitting a plant smaller than 100 MW increase rapidly due to the lack of economy of size. Also, older power plants in the 50 MW range tend to have compact plant sites with limited room for retrofit equipment.	25% reduction in NO_x emissions from pulverized coal boilers. 50% reduction from fluidized bed boilers.
Selective Catalytic Reduction (SCR)	Ammonia vapor injected into the flue gas stream upstream of a catalyst that assists the reduction reaction of NO_x to nitrogen gas (N_2) and water (H_2O)	Potential control measure for all coal-fired EGUs (≥ 25MW). Costs per ton of NO_x reduced for retrofitting a plant smaller than 100 MW increase rapidly due to the lack of economy of size.	90% reduction in NO_x emissions
Return Partially Operating SCR and SNCR Systems to Full Operation	Depressed NO_x allowance costs have resulted in some units to be able to comply by purchasing allowances rather than running existing emission control systems	Potential control measures for units that do not continuously run existing emission control systems	Highly variable based on fluctuations in allowance costs

Table references: NESCAUM, 2011; EPA, 2013; EPA, 2015b; EPA, 2015c; EPA, 2015d.

Cost of Compliance – NO_x Control Options

Cost of Combustion Controls

Information on NO_x combustion control costs emission reduction rates and for coal-fired EGUs are also available in the EPA's IPM v5.13 documentation (EPA 2013). Control cost and performance vary by boiler and coal types. Table 2.15 shows the NO_x combustion control costs used in IPM v5.13. The costs shown are for a 300 MW coal-fired boiler of different common types. EPA uses scaling factors to estimate the capital and fixed O&M costs of combustion controls for boilers smaller and larger than 300 MW. Variable O&M costs were assumed constant.

Table 2.16 shows the range of NO_x emission rates for boilers with combustion controls by boiler and coal types used by the model. The low rate in the range is the floor rate for reduction, and the high rate is a cut-off rate that indicates the use of combustion controls. Table 2.17 shows the fractional reduction for different combustion control configurations when adding new combustion controls.

Table 2.15 NO_x Combustion Control Cost Factors for Coal Fired Boilers (2011$)

Boiler Type	Technology	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Dry Bottom Wall-fired	Low NO_x Burner without Overfire Air (LNB without OFA)	48	0.3	0.07
	Low NO_x Burner with Overfire Air (LNB with OFA)	65	0.5	0.09
Tangentially-fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	26	0.2	0
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	35	0.2	0.03
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	41	0.3	0.03
Vertically-Fired	NO_x Combustion Control	31	0.2	0.06

Scaling Factors:

- LNB without OFA and LNB with OFA = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$
- LNC1, LNC2, and LNC3 = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$
- Vertically –Fired ($/kW for 300 MW Unit) x $(300/X)^{0.553}$
  Where ($kW for 300 MW Unit) is from the above Capital Costs or Fixed O&M Costs, and X is the capacity in MW of the unit.

Table Reference: EPA, 2013

Table 2.16 Range of NO_x Emission Rates for Coal-fired EGUs with Combustion Controls

Boiler Type	NO_x Rate lb/MMBTU		
	Bituminous	Subbituminous	Lignite
Dry Bottom Wall-fired	0.43-0.32	0.33-0.18	0.29-0.18
Tangentially-fired	0.34-0.24	0.24-0.12	0.22-0.17
Cell Burners	0.43-0.32	0.24-0.12	0.22-0.17
Cyclones	0.62-0.47	0.67-0.49	0.67-0.49
Vertically-Fired	0.57-0.49	0.44-0.25	0.44-0.25

Table Reference: EPA, 2013

Table 2.17 Fractional NO_x Reduction for Different Combustion Control Configurations

Boiler Type	Coal Type	Combustion Control	Fraction of Removal	Default Removal
Dry Bottom Wall-fired	Bituminous	LNB	0.163 + 0.272*Base NO_x	0.568
		LNB and OFA	0.313 + 0.272*Base NO_x	0.718
	Subbituminous/Lignite	LNB	0.135 + 541*Base NO_x	0.574
		LNB and OFA	0.285 + 541*Base NO_x	0.724
Tangentially-fired	Bituminous	LNC1	0.162 + 336*Base NO_x	0.42
		LNC2	0.212 + 336*Base NO_x	0.47
		LNC3	0.362 + 336*Base NO_x	0.62
	Subbituminous/Lignite	LNC1	0.20 + 717*Base NO_x	0.563
		LNC2	0.25 + 717*Base NO_x	0.613
		LNC3	0.35 + 717*Base NO_x	0.713

Table Reference: EPA, 2013

Most operating coal-fired EGUs already have NO_x combustion controls. Only about 10% of the EGUs in the current version of the IPM modeling inventory (National Electric Energy Data System v5.15) show no combustion controls or add-on controls. Of these only 20 have a capacity greater than 25 MW (EPA, 2013). Table 2.18 provides an example cost effectiveness for combustion control installations on four of the uncontrolled EGUs from the modeling inventory.

Cost of Post-Combustion Gas Treatment Technologies

Cost models developed by S&L were used to update NO_x post-combustion control costs (EPA, 2013). S&L updated and added to the retrofit emission control models previously developed for EPA and used in earlier versions of the IPM.

- Selective Catalytic Reduction (SCR): Removal efficiency is affected by the type of coal and costs for SCR catalyst, reagent and steam. SCR can achieve NO_x rate floor of 0.07 lbs NO_x/MMBTU for bituminous coal and 0.05 lbs NO_x /MMBTU for subbituminous and lignite. The fuel type (sulfur content) also affects the air pre-heater costs if ammonium bisulfate or sulfuric acid deposition poses a problem (coal sulfur content greater than 3.0 lbs SO_2/MMBTU).
- Selective Non-Catalytic Reduction (SNCR): NO_x removal efficiencies range from 25 to 50% based on boiler type. Like SCRs, the fuel type affects cost with air preheater modifications required for coals with sulfur content greater than 3.0 lbs SO_2/MMBTU.

Tables 2.19 to 2.22 show NO_x add-on control cost estimates for coal plants for a number of boiler and control scenarios from the IPM documentation. These examples were used to calculate a cost effectiveness in $/ton using the same methodology as in the *2007 Assessment* (MACTEC, 2007) which used a capital recovery factor of 0.15 and capacity factor of 0.85.

Table 2.18 Combustion Control Cost Effectiveness Examples for Uncontrolled EGUs in EPA Base Case v5.13 (2011$)

NOx Control Type	Boiler Type	Coal Type	Capacity MW	Heat Rate BTU/kWh	Variable O&M $/MWh	Capital Cost $/kW	Assumed NO_x Rate lb/MMBTU	Assumed Percent Reduction	Total Annual Cost $/kW-yr	NO_x Reduction tons/kW-yr	2011$/ton Reduction
LNC2	Tangential	Bituminous	40	12,000	0.03	72	0.465	47%	11.4	0.010	1,170
LNC1	Tangential	Subbituminous	77	10,900	0.03	42	0.332	58%	6.8	0.008	873
LNC1	Tangential	Subbituminous	138	10,800	0.03	34	0.321	58%	5.6	0.007	751
LNB	Wall Dry	Subbituminous	36	9,900	0.03	103	0.535	57%	16.3	0.011	1,448

Notes:

The cost effectiveness calculation methodology, capital recovery factor (0.15), and capacity factor (0.85) are the same as used in the 2*007 Assessment* (MACTEC, 2013).

Table 2.19 Examples of NO_x Add-On Control Costs for Coal Plants from EPA Base Case v5.13

Scrubber Type	Heat Rate (BTU/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M ($/MWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
SCR	9,000	-0.54	0.54	1.23	321	1.76	263	0.76	243	0.64	232	0.58	222	0.53
	10,000	-0.56	0.56	1.32	349	1.86	287	0.81	266	0.69	255	0.63	244	0.57
	11,000	-0.58	0.59	1.41	377	1.96	311	0.87	289	0.73	277	0.67	265	0.62
SNCR Tangential	9,000	-0.05	0.78	1.04	55	0.48	30	0.26	22	0.2	18	0.16	15	0.13
	10,000	-0.05	0.78	1.15	56	0.5	30	0.27	23	0.2	19	0.17	15	0.14
	11,000	-0.05	0.78	1.27	57	0.51	31	0.27	23	0.21	19	0.17	16	0.14
SNCR Fluidized Bed	9,000	-0.05	0.78	1.04	41	0.36	22	0.2	17	0.15	14	0.12	11	0.1
	10,000	-0.05	0.78	1.15	42	0.37	23	0.2	17	0.15	14	0.12	12	0.1
	11,000	-0.05	0.78	1.27	43	0.38	23	0.21	17	0.15	14	0.13	12	0.1

Notes:

1. The estimates are based on a boiler burning bituminous coal with NO_x inlet rate of 0.5 lb NO_x/MMBTU.
2. The SCR removal efficiency is assumed to be 90%. SNCR removal efficiency for tangential fired unit is assumed to be 25%, and 50% for a fluidized bed unit.
3. The capacity penalty and heat rate penalty are not used in calculating cost effectiveness in $/ton removed. The penalties represent the electricity demand of the FGD. The capacity penalty equals the percent of unit generation required for the control device. The heat rate penalty is based on the capacity penalty and is a modeling procedure to capture the effect of the control device on fuel use and generation. It does not represent an actual increase in the unit heat rate.
4. Table Reference: Table 5-6, Documentation for EPA Base Case v.5.13, Using the Integrated Planning Model. U.S. EPA #450R13002, November 2013.

Table 2.20 NO_x SCR Control Cost Effectiveness for Coal Plants for EPA Base Case v5.13 Examples (2011$)

NOx Control Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Inlet NO_x Rate lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	NO_x Reduction (tons/kW-yr)	2011$/ton Reduction
SCR	100	9,000	0.15	0.85	0.5	90%	59.1	0.015	3,917
SCR	100	10,000	0.15	0.85	0.5	90%	64.0	0.017	3,822
SCR	100	11,000	0.15	0.85	0.5	90%	69.0	0.018	3,745
SCR	300	9,000	0.15	0.85	0.5	90%	49.4	0.015	3,274
SCR	300	10,000	0.15	0.85	0.5	90%	53.7	0.017	3,205
SCR	300	11,000	0.15	0.85	0.5	90%	58.0	0.018	3,148
SCR	500	9,000	0.15	0.85	0.5	90%	46.2	0.015	3,067
SCR	500	10,000	0.15	0.85	0.5	90%	50.4	0.017	3,009
SCR	500	11,000	0.15	0.85	0.5	90%	54.6	0.018	2,962
SCR	700	9,000	0.15	0.85	0.5	90%	44.5	0.015	2,954
SCR	700	10,000	0.15	0.85	0.5	90%	48.7	0.017	2,907
SCR	700	11,000	0.15	0.85	0.5	90%	52.7	0.018	2,861
SCR	1000	9,000	0.15	0.85	0.5	90%	43.0	0.015	2,851
SCR	1000	10,000	0.15	0.85	0.5	90%	47.0	0.017	2,805
SCR	1000	11,000	0.15	0.85	0.5	90%	50.9	0.018	2,760

Notes:

The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007).

Table 2.21 NO_x SNCR (Tangential Boiler) Control Cost Effectiveness for Coal Plants for EPA Base Case v5.13 Examples (2011$)

NOx Control Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Inlet NO_x Rate lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	NO_x Reduction (tons/kW-yr)	2011$/ton Reduction
SNCR	100	9,000	0.15	0.85	0.5	25%	16.5	0.004	3,933
SNCR	100	10,000	0.15	0.85	0.5	25%	17.5	0.005	3,752
SNCR	100	11,000	0.15	0.85	0.5	25%	18.5	0.005	3,617
SNCR	300	9,000	0.15	0.85	0.5	25%	12.5	0.004	2,985
SNCR	300	10,000	0.15	0.85	0.5	25%	13.3	0.005	2,865
SNCR	300	11,000	0.15	0.85	0.5	25%	14.4	0.005	2,808
SNCR	500	9,000	0.15	0.85	0.5	25%	11.2	0.004	2,685
SNCR	500	10,000	0.15	0.85	0.5	25%	12.2	0.005	2,624
SNCR	500	11,000	0.15	0.85	0.5	25%	13.1	0.005	2,562
SNCR	700	9,000	0.15	0.85	0.5	25%	10.6	0.004	2,532
SNCR	700	10,000	0.15	0.85	0.5	25%	11.6	0.005	2,489
SNCR	700	11,000	0.15	0.85	0.5	25%	12.5	0.005	2,437
SNCR	1000	9,000	0.15	0.85	0.5	25%	10.1	0.004	2,417
SNCR	1000	10,000	0.15	0.85	0.5	25%	11.0	0.005	2,354
SNCR	1000	11,000	0.15	0.85	0.5	25%	12.0	0.005	2,343

Notes:

The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the *2007 Assessment* (MACTEC, 2007).

Table 2.22 NO_x SNCR (Fluidized Bed Boiler) Control Cost Effectiveness for Coal Plants for EPA Base Case v5.13 Examples (2011$)

NOx Control Type	Capacity (MW)	Heat Rate (BTU/kWh)	Assumed Capital Recovery Factor	Assumed Capacity Factor	Assumed Inlet NO_x Rate lb/MMBTU	Assumed Percent Reduction	Total Annual Cost ($/kW-yr)	NO_x Reduction (tons/kW-yr)	2011$/ton Reduction
SNCR	100	9,000	0.15	0.85	0.5	50%	14.3	0.008	1,702
SNCR	100	10,000	0.15	0.85	0.5	50%	15.2	0.009	1,637
SNCR	100	11,000	0.15	0.85	0.5	50%	16.3	0.010	1,591
SNCR	300	9,000	0.15	0.85	0.5	50%	11.2	0.008	1,342
SNCR	300	10,000	0.15	0.85	0.5	50%	12.2	0.009	1,312
SNCR	300	11,000	0.15	0.85	0.5	50%	13.1	0.010	1,281
SNCR	500	9,000	0.15	0.85	0.5	50%	10.4	0.008	1,247
SNCR	500	10,000	0.15	0.85	0.5	50%	11.3	0.009	1,210
SNCR	500	11,000	0.15	0.85	0.5	50%	12.2	0.010	1,187
SNCR	700	9,000	0.15	0.85	0.5	50%	10.0	0.008	1,189
SNCR	700	10,000	0.15	0.85	0.5	50%	10.8	0.009	1,159
SNCR	700	11,000	0.15	0.85	0.5	50%	11.7	0.010	1,141
SNCR	1000	9,000	0.15	0.85	0.5	50%	9.5	0.008	1,133
SNCR	1000	10,000	0.15	0.85	0.5	50%	10.5	0.009	1,124
SNCR	1000	11,000	0.15	0.85	0.5	50%	11.5	0.010	1,114

Notes:

The cost effectiveness calculation methodology, capital recovery factor, and capacity factor are the same as used in the 2*007 Assessment* (MACTEC, 2007).

The cost calculations for SCR discussed above apply to coal units. For SCR on oil/gas steam units, S&L developed the following cost parameters (EPA, 2013):

- Capital costs - $80/kW (2011$)
- Fixed O&M – $1.16/kW-hr
- Variable O&M – $0.13/MWh
- Percent removal – 80%

S&L also developed scaling factors for capital and fixed O&M costs to determine costs for various sized units using the above parameters.

Cost of Switching from Coal to Natural Gas

Switching from coal to natural gas may be a cost-effective strategy for reducing both SO_2 and NO_x emissions. The per BTU NO_x emissions for coal are about double those of natural gas (e.g., uncontrolled NO_x emissions for coal are generally 0.4 - 0.8 lbs/MMBTU, and 0.1 - 0.2 lbs/MMBTU for distillate oil and natural gas). Thus, a switch from coal to natural gas will a NO_x reduction co-benefit in addition to reducing SO_2 emissions. Fuel switching costs were discussed previously in the SO_2 section.

Cost of Returning Partially Operating SCRs and SNCRs to Full Operation

Since units that are partially running their SCR or SNCR system have already incurred the fixed operating costs (which are associated with having the controls functioning at any level), the remaining cost to achieve full design capability is the cost of additional reagent (EPA, 2015d). Changing NO_x removal rates following commencement of operations does not affect fixed operation and maintenance costs; likewise, the variable operation and maintenance components of catalyst replacement and auxiliary power are indifferent to reagent consumption or NO_x removal. In short, for SCRs and SNCRs, the marginal cost to increase from partial operation to full operation reflects the cost of additional reagent.

EPA estimated the reagent portion of operations costs $503 per ton NO_x removed (EPA, 2015d). This represents a reasonable estimate of the cost for operating these post combustion controls based on current market ammonia prices. The OTC also completed an analysis of the cost of full-time operation of SCRs versus the price of NO_x allowances (OTC, 2015). OTC estimated the costs to be in the range of $439 to $2,188 per ton of NO_x removed.

FACTOR 2 – COMPLIANCE TIME FRAME

Generally, sources are given a 2-4 year phase-in period to comply with new rules. Under the previous Phase I of the NOx SIP Call, EPA provided a compliance date of about 3½ years from the SIP submittal date. Most MACT standards allow a 3-year compliance period. Under Phase I of the NOx SIP Call, EPA provided a 2-year period after the SIP submittal date for compliance. States generally provided a 2-year period for compliance with RACT rules. For the purposes of this review, we have assumed that a maximum of 2 years after SIP submittal is adequate for pre-combustion controls (fuel switching) and a maximum of 3 years is adequate for the installation of post combustion controls.

For post-combustion controls, site-specific information must be supplied to vendors in order to determine the actual time needed for installation of a given control. Large scale implementation of control devices within the EGU sector, particularly in a short time period, may require consideration of impacts on regional electricity demands. Integrated Planning Model (IPM®) has allowed for these and other impacts in determining the least cost approach to emission reductions, however, there is a great deal of uncertainty associated with modeled results in comparison to real-world applications of control strategies.

For BART control measures, the proposed BART guidelines require States to establish enforceable limits and require compliance with the BART emission limitations no later than 5 years after EPA approves the regional haze SIP.

FACTOR 3 - ENERGY AND NON-AIR QUALITY IMPACTS

Fuel switching from coal to natural gas will have a small negative impact on heat rates, as can some NO_x combustion control measures. Fuel switching may increase energy costs in other sectors, and add to transportation issues and secondary environmental impacts from shifts in fuel extraction and fuel delivery.

Electricity demand to operate post-combustion controls will also negatively impact net heat rate or reduce the amount of electricity delivered to the grid. FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

The primary environmental impact of FGD systems is the generation of wastewater and sludge from the SO_2 removal process. When the exhaust gas from the boiler enters the FGD the SO_2, metals, and other solids are removed from the exhaust and collected in the FGD liquid. The liquid slurry collects in the bottom of the FGD in a reaction tank. The slurry is then dewatered and a portion of the contaminant-laden water is removed from the system as wastewater. Waste from the FGD systems will increase sulfate, metals, and solids loading in a facility's wastewater, potentially impacting community wastewater treatment facilities for smaller units that do not have self-contained water treatment systems.

In some cases FGD operation necessitates installation of a clarifier on site to remove excessive pollutants from wastewater. This places additional burdens on a facility or community wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge must be stabilized prior to land filling. If a calcium sulfate sludge is produced, dewatering alone is necessary before land filling, however, SO_2 removal costs are higher due to increased equipment costs for this type of control system. In some cases calcium sulfate sludge can be sold for use in cement manufacturing.

With wet FGD technologies a significant visible plume is present from the source due to condensation of water vapor as it exits the smoke stack. Although the water eventually evaporates and the plume disappears, community impact may be significant.

FACTOR 4 – REMAINING USEFUL LIFE

Available information for remaining useful life estimates of EGU boilers indicates a wide range of operating lifetimes, depending on size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies are 50 years or more. Additionally, implementation of regulations over the years has resulted in retrofitting that has ultimately increased the expected life span of many EGUs. The lifetime of an EGU may be extended through repair, repowering, or other strategies if the unit is more economical to run than to replace with power from other sources. This may be particularly likely if the unit serves an area which has limited transmission capacity available to bring in other power.

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CHAPTER 4

SOURCE CATEGORY ANALYSIS: INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS

SOURCE CATEGORY DESCRIPTION

The MANE-VU contribution assessment demonstrated that SO_2 emissions are the principal contributor to visibility impairment in Class I areas in the northeast. After electric generation units (EGUs), Industrial, Commercial, and Institutional (ICI) boilers and heaters are the next largest class of pollution sources that contribute to SO_2 emissions. NO_x emissions may also contribute to visibility impairment and ICI boilers are an important contributor to NO_x emissions inventory (NESCAUM, 2006). MANE-VU previously developed an assessment (MACTEC, 2007) of SO_2 control technologies to achieve reasonable progress goals with respect to the four factors listed in Section 169A of the Clean Air Act. The information presented in this Chapter is an update to some parts of the MACTEC report and now includes NO_x control technologies.

Types of ICI Boilers

Typical industrial applications include chemical, refining, manufacturing, metals, paper, petroleum, food production and a wide variety of other small industries. Commercial and institutional boilers are normally used to produce steam and hot water for space heating in office buildings, hotels, apartment buildings, hospitals, universities, and similar facilities. A fairly wide range of fuels are used by ICI boilers, ranging from coal, petroleum coke, distillate and residual fuel oils, natural gas, wood waste or other classes of waste products. Boilers aggregated under the ICI classification are generally smaller than boilers in the electric power industry, and typically have a heat input in the 10 to 250 MMBTU/hr range; however, ICI boilers can be as large as 1,000 MMBTU/hr or as small as 0.5 MMBTU/hour.

The process that a particular unit serves strongly influences the boiler fuel choice. For example, the iron and steel industry uses coal to generate blast furnace gas or coke oven gas that is used in boilers, resulting in sulfur emissions. Pulp and paper processing may use biomass as a fuel. Units with short duty cycles may utilize oil or natural gas as a fuel. The use of a wide variety of fuels is an important characteristic of the ICI boiler category. While many boilers are capable of co-firing liquid or gaseous fuels in conjunction with solid fuels, boilers are usually designed for optimum combustion of a single, specific fuel. Changes to the fuel type may, therefore, reduce the capacity, duty cycle, or efficiency of the boiler.

Boiler design also plays a role in the uncontrolled emission rate. Most ICI boilers are of three basic designs: water tube, fire tube, or cast iron. The fuel-firing configuration is a second major identifier of boiler design for solid fuels. Stoker boilers are the oldest technology and are still widely used for solid-fueled boilers. Pulverized coal boilers succeeded stokers as a more efficient method of burning coal and are used in larger boiler designs. Circulating fluidized bed (CFB) boilers are the most recent type of boiler for solid fuel combustion and are becoming more commonplace. CFB boilers are capable of burning a variety of fuels, and are more efficient and less polluting than stoker or pulverized coal boilers. Combined heat and power (CHP) or

cogeneration technologies are also used to produce electricity and steam or hot water from a single unit. Some ICI boilers are used only in the colder months for space heating, while others have high capacity utilization year round.

Clean Air Act Regulations Controlling ICI Boilers

Emissions from ICI boilers are currently governed by multiple State and federal regulations under Titles I, III, and IV of the Clean Air Act (CAA). Each of these regulatory programs is discussed in the following paragraphs.

Title I regulates criteria pollutants by requiring local governments to adopt State Implementation Plans (SIPs) that set forth their strategy for achieving reductions in the particular criteria pollutant(s) for which they are out of attainment. The SIP requirements include Reasonably Available Control Technology (RACT) requirements, but more stringent requirements may be imposed depending on the locale's degree of non-attainment with ambient air standards.

Title I also imposes New Source Performance Standards (NSPS) on certain specified categories of new and modified large stationary sources. In 1986, EPA codified the NSPS for industrial boilers (40 CFR part 60, subparts Db and Dc). Subpart Db applies to fossil fuel-fired ICI units greater than 100 MMBTU per hour that were constructed or modified after June 19, 1984. Subpart Dc applies to fossil fuel-fired ICI units from 10 to 100 MMBTU per hour that were constructed or modified after June 9, 1989. EPA revises the NSPS from time to time to reflect improvements in control methods. The EPA promulgated revised NSPS for SO_2, NO_x, and PM for subparts Db and Dc on February 27, 2006. In 2012, EPA promulgated several minor amendments, technical clarifications, and corrections to existing NSPS provisions for large and small ICI boilers.

In addition, Title I subjects new and modified large stationary sources that increase their emissions to permitting requirements that impose control technologies of varying levels of stringency (known as New Source Review, or NSR). NSR prescribes control technologies for new plants and for plant modifications that result in a significant increase in emissions, subjecting them to Best Available Control Technology (BACT) in attainment areas and to the Lowest Achievable Emission Rate (LAER) in nonattainment areas. Control strategies that constitute BACT and LAER evolve over time and are reviewed on a case by case basis in State permitting proceedings.

In 1999, EPA published a final rule to address a type of visibility impairment known as regional haze. The regional haze rule required States to submit implementation plans to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas. As required by the CAA, EPA included in the final regional haze rule a requirement for best available retrofit technology (BART) for certain large stationary sources, including ICI boilers, that were built between 1962 and 1977.

The Boiler MACT (Maximum Achievable Control Technology) rule under Title III of the CAA has a long history. EPA published the first Boiler MACT rule in 2004. Litigation forced the rule to be vacated just before the compliance deadline in 2007. The EPA finalized a revised version of the rule in March 2011 to meet a court-ordered deadline. On November 5, 2015, EPA issued

the final reconsideration rule. The Boiler MACT rule is intended to substantially reduce emissions of toxic air pollutants from ICI boilers. These MACT standards apply to ICI boilers located at major sources of hazardous air pollutants (HAPs). There are many options for complying with the MACT standards, ranging from continued use of existing control systems to fuel switching to the installation of a fabric filter and wet scrubber technologies. Thus, the control technologies used to reduce the level of HAPs emitted from affected sources are also expected to reduce emissions of PM, and to a lesser extent, SO_2 and NO_x emissions.

Title IV of the CAA addresses acid rain by focusing primarily on power plant emissions of SO_2. Title IV includes an Opt-in Program that allows sources not required to participate in the Acid Rain Program the opportunity to enter the program on a voluntary basis and receive their own acid rain allowances. The Opt-in Program offers sources such as ICI boilers a financial incentive to voluntarily reduce its SO_2 emissions. By reducing emissions below allowance allocation, an opt-in source will have unused allowances, which it can sell in the SO_2 allowance market.

The regulation of ICI boilers by various CAA programs has resulted in a variety of unit level emission limits resulting from SIP, NSPS, NSR, BART or MACT requirements. Thus, the specific emission limits and control requirements for an existing ICI boiler vary greatly and depend on boiler age, size, fuel type and geographic location.

Emission and Fuel Consumption Trends

Tables 4.1 and 4.2 show trends in point source SO_2 and NO_x emissions from ICI boilers for the MANE-VU, Midwest Regional Planning Organization (MRPO), and the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) states. Emissions have declined since 2002 in all three RPOs. SO_2 emissions from ICI boilers have decreased by about 62% in the MANE-VU region between 2002 and 2011, by 33% in the MRPO region, and by 52% in the VISTAS region. NO_x emissions from ICI boilers have decreased by about 42% in the MANE-VU region between 2002 and 2011, by 46% in the MRPO region, and by 38% in the VISTAS region. Note that emission estimates for 2014 are currently be quality assured and are not available for analysis.

There are several factors likely contributing to the emission reductions between 2002 and 2011:

- Industrial and commercial fuel consumption data from the Energy Information Administration (EIA) shows a transition from sulfur containing fuels (coal, residual oil) to natural gas. This transition is driven by both environmental and economic concerns. Nationally, residual oil consumption by industrial and commercial sources has decreased by 74% between 2002 and 2013, while coal consumption was 16% less in 2011 than in 2002. Natural gas consumption in 2014 was about 4% higher than in 2002.

- New or improved pollution controls have been installed. For example, the EPA petroleum refinery enforcement initiative (EPA, 2015d) settlements cover 109 refineries in 32 states and territories. These settlements have required significant reductions in SO_2 and NO_x emissions from refinery boilers.

Table 4.1 Trends in SO_2 Emissions (tons/year) from ICI Boilers

Primary Fuel	2002	2007/2008	2011	2014	2018
MANE-VU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT)					
Coal	88,092	72,820	50,893	Not Available	23,045
Oil	48,509	35,010	9,859	Not Available	4,659
Gas	35,049	3,595	306	Not Available	253
Wood	1,048	1,680	1,102	Not Available	538
Other	1,436	561	3,319	Not Available	385
Total	**174,134**	**113,667**	**65,479**	Not Available	**28,880**
MRPO (IL, IN, OH, MI, WI)					
Coal	223,986	242,909	157,445	Not Available	71,853
Oil	17,421	5,575	1,057	Not Available	305
Gas	21,842	16,662	344	Not Available	339
Wood	304	384	806	Not Available	540
Other	2,606	2,413	19,309	Not Available	12,035
Total	**266,159**	**267,942**	**178,961**	Not Available	**85,072**
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)					
Coal	193,645	150,211	100,258	Not Available	19,953
Oil	47,869	22,514	6,064	Not Available	1,991
Gas	21,125	13,868	3,429	Not Available	3,377
Wood	14,951	15,690	8,980	Not Available	1,867
Other	5,378	3,952	9,672	Not Available	3,404
Total	**282,968**	**206,234**	**128,403**	Not Available	**30,592**

MANE-VU emissions obtained from 2002, 2007 and 2011 inventories prepared by MARAMA
MRPO and VISTAS emissions obtained from 2002, 2008 and 2011 EPA national emission inventories
Based on point source inventory with Source Classification Codes in the 1-02-xxx-xx and 1-03-xxx-xx series.
2014 emissions are currently being quality assured and are not available for this analysis.
2018 emissions are projections from the MARAMA ALPHA2 regional emission inventory.

Table 4.2 Trends in NO_x Emissions (tons/year) from ICI Boilers

Primary Fuel	2002	2007/2008	2011	2014	2018
MANE-VU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, and VT)					
Coal	21,785	18,205	12,918	Not Available	6,600
Oil	17,816	14,694	5,193	Not Available	4,701
Gas	23,812	17,196	14,467	Not Available	12,941
Wood	4,117	4,616	4,526	Not Available	4,383
Other	547	761	2,405	Not Available	2,489
Total	**68,077**	**55,472**	**39,509**	Not Available	**31,114**
MRPO (IL, IN, OH, MI, WI)					
Coal	61,558	54,454	37,793	Not Available	30,804
Oil	8,533	1,597	390	Not Available	314
Gas	61,558	32,612	23,544	Not Available	22,990
Wood	3,974	4,264	4,134	Not Available	3,951
Other	1,249	1,481	7,553	Not Available	6,468
Total	**136,872**	**94,408**	**73,414**	Not Available	**64,527**
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)					
Coal	90,470	64,100	50,733	Not Available	36,175
Oil	13,571	6,793	2,943	Not Available	2,962
Gas	40,660	21,255	17,295	Not Available	17,074
Wood	32,471	32,980	27,009	Not Available	25,387
Other	8,779	7,720	8,018	Not Available	6,930
Total	**185,950**	**132,848**	**105,997**	Not Available	**88,529**

MANE-VU emissions obtained from 2002, 2007 and 2011 inventories prepared by MARAMA
MRPO and VISTAS emissions obtained from 2002, 2008 and 2011 EPA national emission inventories
Based on point source inventory with Source Classification Codes in the 1-02-xxx-xx and 1-03-xxx-xx series.
2014 emissions are currently being quality assured and are not available for this analysis.
2018 emissions are projections from the MARAMA ALPHA2 regional emission inventory.

- Energy efficiency has improved. Faced with steadily increasing energy bills, many companies and institutions have implemented energy saving measures. It is estimated that basic boiler tune-up procedures can add up savings of up to 5% or more of energy use with little or no costs, while more formal energy management schemes can reduce consumption by 20 to 30% or more (ABB, 2012).
- Some facilities and/or emission units have shut down due to the general decline in U.S. manufacturing. According to the Bureau of Labor Statistics, manufacturing employment in the U.S. declined by 20% between 2002 and 2014 (BLS, 2015).

There are many other state- or facility-specific reasons that would also help explain the decrease in SO_2 and NO_x emissions from ICI boilers. It is beyond the scope of this project to identify all possible reasons.

Also shown in Tables 4.1 and 4.2 are emission projections for 2018 (MARAMA, 2015). These projections take into account forecasted growth (both positive and negative) in energy consumption, as well as the impact of on-the-books regulatory programs that will result in emission reductions after 2011. Emissions of both SO_2 and NO_x are projected to continue to decline in all three RPOs.

FACTOR 1 – COST OF COMPLIANCE

Air pollution control technologies for ICI boilers have advanced substantially over the past 25 years. Changes in energy markets have affected the availability and price of different types of fuels used by ICI boilers, resulting in changes in emission levels. In addition, advances in power generation technologies, energy efficiency and renewable energy have the potential to further reduce emissions from these facilities. The focus of this evaluation is on the first two categories mentioned above - emission control technologies and cleaner fuels. The timing and magnitude of reductions from the other strategies – improved technologies, demand reduction/energy efficiency, and renewable power should be considered as part of a longer-term solution.

Pollutant emission controls are generally divided into three major types, as follows:

- Pre-combustion controls, in which fuel substitutions are made or fuel pre-processing is performed to reduce pollutant formation in the combustion unit.
- Combustion controls, in which operating and equipment modifications are made to reduce the amount of pollutants formed during the combustion process; or in which a material is introduced into the combustion unit along with the fuel to capture the pollutants formed before the combustion gases exit the unit.
- Post-combustion controls, in which one or more air pollution control devices are used at a point downstream of the furnace combustion zone to remove the pollutants from the post-combustion gases.

The following sections provide a brief summary of SO_2 and NO_x control options and costs, drawing heavily on recent work sponsored by regional planning organizations. More detailed descriptions of the options can be found in the literature cited in the list of references.

Identification of Available SO_2 Control Options

SO_2 is an undesirable by-product of the combustion sulfur-bearing fossil fuels. Coal deposits contain sulfur in amounts ranging from trace quantities to as high as 8% or more. Untreated distillate oils typically have sulfur contents less than 0.5% while residual oil can have 1-2% sulfur by weight. Petroleum coke, a byproduct of the oil refining process, may have as much as 6% sulfur. Process gases, such as coke oven gas or refinery fuel gas, if not desulfurized, can result in substantial levels of SO_2 when burned. Pipeline quality natural gas contains virtually no sulfur, while landfill gas may contain varying amounts of sulfur depending on the materials contained in the landfill. Essentially all of the sulfur in the fuel is oxidized to form SO_2 (a very small percentage is further oxidized to sulfur trioxide (SO_3) depending on fuel and boiler characteristics).

Since the relationship between sulfur content in the fuel and SO_2 emissions is essentially linear the emission reduction benefits of fuel switching (for example from higher- to lower-sulfur coal, from higher-sulfur oils to lower-sulfur oils, or from coal/oil to natural gas) are directly proportional to the difference in sulfur contents of fuels. Therefore, changing fuels, or cleaning fuels in the case of process gases or some coals, are the principal means of reducing sulfur emissions without adding flue gas treatment methods. Major issues associated with fuel substitution include price, availability, transportation, and suitability of the boiler or plant to accommodate the new fuel.

Many industrial and commercial sources can reduce the amount of SO_2 created through changes in fuel; however, in many cases such changes may be uneconomical or impractical. For this reason, gas treatment methods that capture the SO_2 that is formed from these industrial sources may be the most effective form of controlling SO_2 emissions. Post-combustion controls reduce SO_2 emissions by reacting the SO_2 in the flue gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. Post-combustion SO_2 reduction technologies are commonly referred to as Flue Gas Desulfurization (FGD) or SO_2 "scrubbers", broadly grouped into wet FGD, dry FGD, and dry sorbent injection (DSI) technologies.

A summary of available SO_2 control technology options are shown in Table 4.3. The method of SO_2 control appropriate for any individual ICI boiler is dependent upon the type of boiler, type of fuel, capacity utilization, and the types and staging of other air pollution control devices. However, cost effective emissions reduction technologies for SO_2 are available and have proven effective in reducing emissions from the exhaust gas stream of ICI boilers.

Cost of Compliance – SO_2 Control Options

To compare the various control options, information has been compiled on the cost-effectiveness of fuel switching and retrofitting controls. In general, cost-effectiveness improves as boiler size and capacity factor (a measure of boiler utilization) increases. All costs estimates for years other than 2014 were converted to 2014 dollars using the Chemical Engineering Plant Index, except where noted.

Table 4.3 Available SO_2 Control Options for ICI Boilers

Technology	Description	Applicability	Performance
Switch to Natural Gas (virtually 0% sulfur)	Replace coal combustion with natural gas	Potential control measure for all coal-,oil-, and process-gas fired ICI boilers	Virtually eliminate SO_2 emissions by switching to natural gas
Switch to a Lower Sulfur Oil	Replace higher-sulfur residual oil with lower-sulfur oil; replace high sulfur distillate oil with ultra-low sulfur distillate oil	Potential control measure for all oil-fired ICI boilers currently using higher sulfur content residual or distillate oils	50-80% reduction in SO_2 emissions by switching to a lower-sulfur oil
Switch to a Low Sulfur Coal (generally <1% sulfur)	Replace high-sulfur bituminous coal combustion with lower-sulfur coal	Potential control measure for all coal-fired ICI boilers currently using coal with high sulfur content	50-80% reduction in SO_2 emissions by switching to a lower-sulfur coal
Coal Cleaning	Coal is washed to remove some of the sulfur and ash prior to combustion	Potential control measure for all coal-fired ICI boilers	20-25% reduction in SO_2 emissions
Combustion Control	Introduce a reactive material, such as limestone or bi-carbonate, into combustion chamber along with the fuel	Applicable to pulverized coal-fired boilers and circulating fluidized bed boilers	40%-85% reductions in SO_2 emissions
Flue Gas Desulfurization (FGD) – Wet	Remove SO_2 from flue gas by dissolving it in a lime or limestone slurry or other alkaline chemicals	Applicable to all coal-fired ICI boilers	30-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Dry	A fine mist containing lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	60-95%+ reduction in SO_2 emissions
Flue Gas Desulfurization (FGD) – Dry Sorbent Injection	Powdered lime or other suitable sorbent is injected directly into flue gas	Applicable primarily for boilers currently firing low to medium sulfur fuels	40-60% reduction in SO_2 emissions

Table references: Staudt, 2012; NESCAUM 2009; OTC/LADCO 2010; STAPPA/ALAPCO 2006.

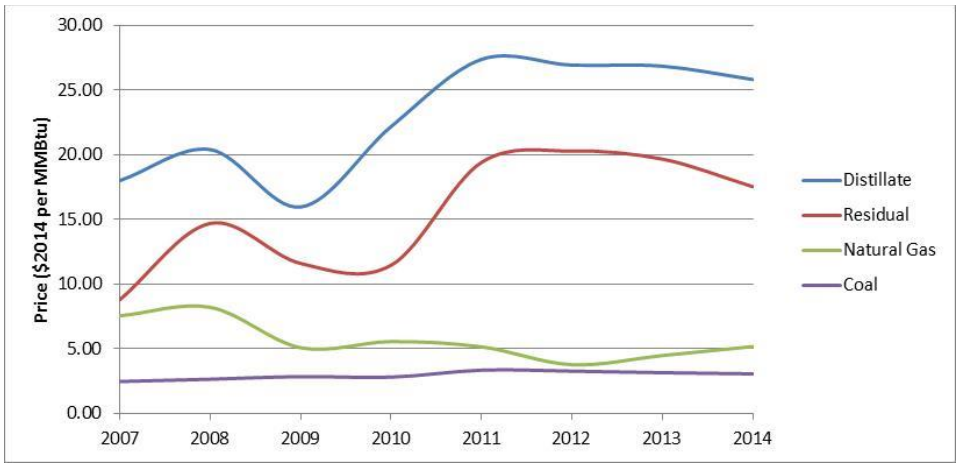
Cost of Switching to Lower Sulfur Fuels

In many cases, switching to lower sulfur fuels is one of the most straightforward and technologically feasible strategies for reducing emissions, but it is not a trivial undertaking (NACAA, 2015). For any existing ICI boiler, there are reasons the current fuels are used and other fuels are not used. Similarly, there are reasons the primary fuel is primary and the backup fuels are backups. These decisions are influenced by many different factors, such as delivered fuel costs, fuel handling system design, boiler design, availability of natural gas pipeline capacity, and so forth. Switching fuels will be most feasible from a technological perspective where a boiler is already designed to combust more than one type of fuel.

Many ICI boilers that are not already using low-emitting fuels as a primary energy source are using higher-emitting fuels for economic reasons. However, the underlying changes in the relative costs of different fuels can determine if fuel switching is an emission control option. Figure 4.1 shows the relative changes in the real price of fossil fuels used by industrial sources

between 2007 and 2014 (EIA, 2015e). Fuel prices in the figure are all presented in terms of price per MMBTU to make the prices comparable.

Figure 4.1 Real Prices of Fossil Fuels for Industrial Sources



Source: EIA, 2015e

National average natural gas prices are significantly lower today than they were a decade ago. The real price of natural gas for industrial sources is 31% lower in 2014 than it was in 2007. Coal prices have risen by 25% during the same period. Natural gas is significantly cheaper than either distillate or residual oil, and is becoming more competitive with coal. Beginning in 2006, natural gas became less expensive on a BTU basis when compared to residual fuel oil. Beginning in 2009, that difference grew so that high sulfur residual fuel oil was more than 3-4 times the cost of natural gas on a BTU basis.

Conversion from coal or oil to natural gas, or co-firing natural gas, may be a viable option for some facilities that have adequate supply of gas to their site. Natural gas will virtually eliminate SO_2 emissions and will be beneficial to emissions of other pollutants, such as CO_2, NO_x, mercury, and particulate matter. A natural gas conversion will require modification of the burners; however, this is often much less expensive than other options such as flue gas desulfurization. Capital cost will also be impacted by the cost of any needed modifications to the natural gas supply (Staudt, 2012).

For those ICI boilers capable of burning multiple fuels, the cost of switching from oil to natural gas can be largely determined by the price of natural gas relative to oil prices. Through 2005, natural gas prices were generally higher than oil prices (dollars per MMBTU). But beginning in 2006 and continuing to the present, natural gas prices have been lower than oil prices. Thus, switching from oil to natural gas would result in fuel cost savings where natural gas is available.

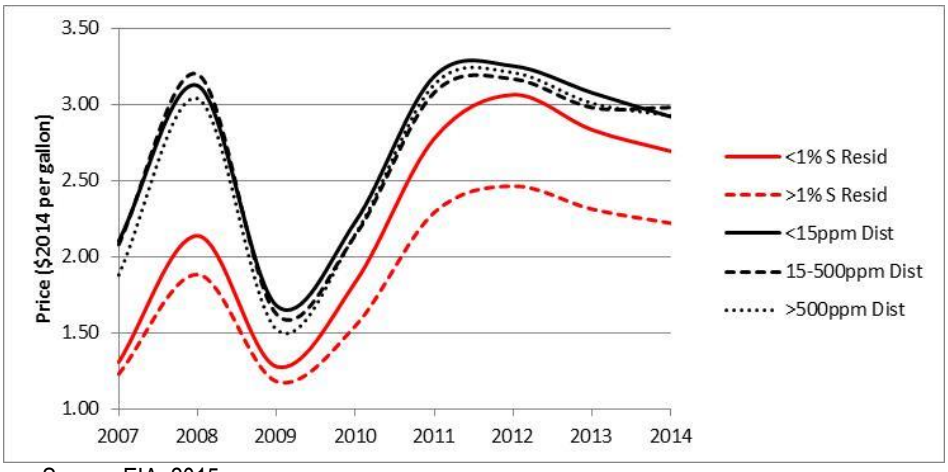
The real price gap between natural gas and coal decreased between 2007 and 2014, with natural gas costing $5.09 per MMBTU more than coal in 2007. The price gap dropped to as low as $0.50 in 2012 and $2.11 in 2014. With these price differentials, the cost effectiveness of switching from 1% sulfur coal to natural gas would range from $600 – 2,600 per ton, and from $1,200 – 5,200 for 0.5% sulfur coal, assuming that an existing boiler is capable for firing either fuel.

Switching fuels from one distillate oil to another will entail minimal capital cost. Changing from a residual fuel or other heavy fuel to distillate may require some changes to atomizers to adjust for the lighter fuel, but this is a relatively small cost. The primary cost associated with switching from high-sulfur to low-sulfur fuel oil is the differential in fuel prices.

Figure 4.2 shows the national real prices per gallon for residual oil and distillate oil from 2007 through 2014 (EIA, 2015e). The differential between low (less than 1 percent sulfur) and high (greater than 1 percent sulfur) sulfur residual oil has been increasing in recent years (note: the EIA prices for residual oil do not include a breakdown for very low sulfur residual oil {less than 0.31 percent sulfur}). The price of ultra-low sulfur (<15 ppm sulfur) distillate oil in recent years has been at times about 30% higher than the price of high sulfur residual oil. The EIA prices for No. 2 (distillate) oil are broken out by ultra-low (<15 ppm sulfur), low-sulfur (15-500 ppm sulfur), and high-sulfur (>500 ppm sulfur). These prices do not show much difference in price as a function of sulfur content of No. 2 oil.

Figure 4.3 shows the national stocks of residual oil and distillate oil from 2004 through 2014 (EIA, 2015e). Stocks of low sulfur distillate oil have risen dramatically over the past few years, while stocks of low sulfur residual oil have been decreasing but remain substantial.

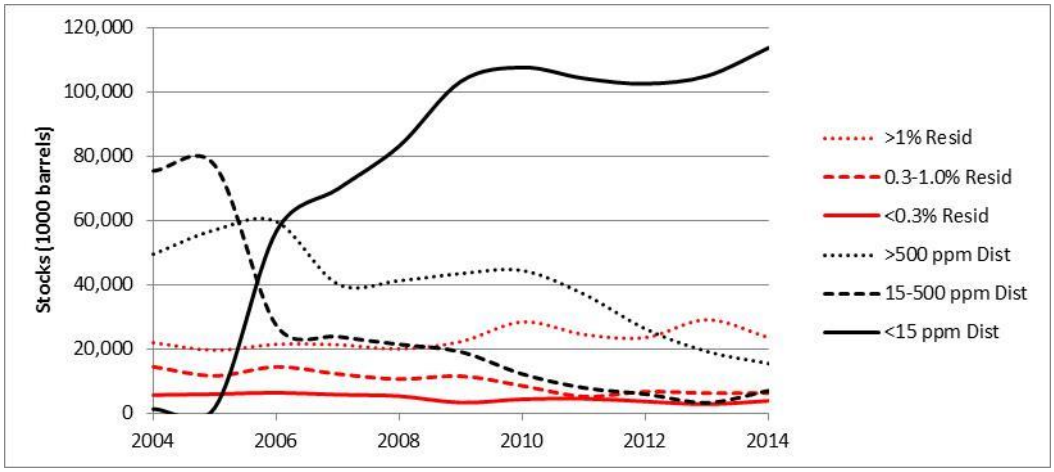
Figure 4.2 National Prices for High and Low Sulfur Residual and Distillate Fuel Oil



Source: EIA, 2015e

The potential increased costs (in fuel only) for switching to lower-sulfur fuel oil can be estimated as shown in the following example for a 250 MMBTU boiler in which average 2011-2014 fuel prices are used. If the high-sulfur residual oil is assumed to be 2 percent S, the low-sulfur residual oil is assumed to be 0.5 percent S, the high sulfur distillate oil is 3000 ppm, and the ultra-low sulfur distillate oil is assumed to be 15 ppm S, then the cost for fuel switching is as follows:

Figure 4.3 National Stocks of High and Low Sulfur Residual and Distillate Fuel Oil



Source: EIA, 2015e

Table 4.4 Example of Costs of Switching to Low-Sulfur Fuel Oil

Fuel Switch	SO_2 Reduction (tons)	\$2014/ton SO_2 Removed
From 2% S to 0.5% Residual Oil	1,135	4,400
From 2% S Residual to 15 ppm S Distillate	1,512	5,000
From 3000 ppm S to 15 ppm S Distillate	219	1,900

These costs are only fuel costs, and do not include any equipment costs needed to switch fuels (for example, burner changes when switching from residual to distillate oil).

The cost estimates in Table 4-4 suggest that for the sample boiler described above, switching from a 2.0 percent sulfur residual fuel oil to a low-sulfur residual oil (0.5 percent S) would provide a cost-effective sulfur removal strategy at about $4,400 per ton of SO_2 removed. The cost-effectiveness of switching to ultra-low sulfur distillate oil is estimated to be about $5,000 per ton. The cost effectiveness of switching from high sulfur to ultra-low sulfur distillate is estimated to be about $1,900 per ton.

Some ICI boilers may be able to switch from high-sulfur to low-sulfur coal without serious capital investment. The sulfur content, heating values and prices of coals mined in various regions of the country vary considerably (See Table 4.6). Central Appalachian coals, which are lower in sulfur than Illinois Basin or Northern Appalachian coals, generally have high heating value and are more accessible than low-sulfur western coal. The use of low-sulfur western coals may incur substantial transportation costs that would increase the cost of the delivered coal over local coal that is higher in sulfur. Even if such a fuel is available, use of the lower-sulfur coal that must be transported long distances from the supplier may not be cost competitive with burning higher sulfur fuel supplied by near-by suppliers. Thus, the cost-effectiveness of switching from high-sulfur to low-sulfur coal is very much dependent on the transportation costs which vary greatly by geographic location of the boiler.

Table 4.6 Average Weekly Coal Commodity Spot Priced ($2014 per ton)

Week Ended	Central Appalachia 12,500 Btu, 1.2 lbs SO_2 / MMBTU	Northern Appalachia 13,000 Btu, <3.0 lbs SO_2 / MMBTU	Illinois Basin 11,800 Btu, 5.0 lbs SO_2 / MMBTU	Powder River Basin 8,800 lbs SO_2 / MMBTU	Uinta Basin 11,700 Btu, 0.8 lbs SO_2 / MMBTU
23-Oct-15	$49.00	$52.00	$32.75	$11.55	$40.55
30-Oct-15	$49.00	$52.00	$32.75	$11.55	$40.55
6-Nov-15	$49.00	$52.00	$32.75	$11.55	$40.55
13-Nov-15	$43.50	$48.95	$32.60	$11.55	$40.65
20-Nov-15	$43.50	$48.95	$32.60	$11.55	$40.65

Source: http://www.eia.gov/coal/news_markets/
Note: The historical data file of spot prices is proprietary and cannot be released by EIA

Because industrial boilers are more likely to use local coals, for many industrial boiler owners coal cleaning may be a more economically viable approach for reducing coal sulfur than purchase of lower sulfur coals from western states (Staudt, 2012). Sulfur may be removed from l through cleaning measures that remove rock and pyrite (including pyritic sulfur). Most coals experience some form of cleaning prior to shipment in order to remove impurities and increase the heating value of the delivered coal. To the extent that sulfur may be in these impurities, sulfur can be removed as well; however, some sulfur is organically bound to the coal and cannot be removed through physical separation. Chemical cleaning measures chemically remove impurities.

Up to 60% sulfur (on a heating value basis) is removed through physical cleaning methods from uncleaned coal depending upon the coal and the practice used (Staudt, 2012). However, 60% represents the best potential technology while common commercial practice reduces coal sulfur by about 40%. Higher sulfur reductions are possible if chemical cleaning methods are considered. Current data was unavailable for the cost of coal cleaning. However, because it has been used in practice, it is certainly an approach that is available and feasible, and is likely to be economically viable for many industrial facilities.

Table 4.7 summarizes the cost-effectiveness of options for replacing high-sulfur fuels with low-sulfur alternatives.

Table 4.7 Summary of Cost-Effectiveness of Low Sulfur Fuel Options

Control Technology	Fuel Type	Cost Effectiveness ($/ton removed) 2014$
Switch to natural gas	Distillate/Residual Oil	Likely cost savings given current price trends
Switch from coal to gas	Coal	600 to 5,200, depending of sulfur content of the coal (for boilers already designed to use multiple fuels)
Switch from high to low sulfur oil	Residual Oil	4,000 to 5,100 (fuel costs only)
Switch from high sulfur residual to ultra-low sulfur distillate	Residual Oil	4,500 to 5,700 (fuel costs only)
Switch from high to ultra-low sulfur	Distillate Oil	0 to 3,300 (fuel costs only)
Convert from high to low sulfur coal	Coal	Not estimated due to variability in availability of low sulfur coal and facility-specific transportation costs
Coal Cleaning	Coal	Currently not available

Cost of Post-Combustion Gas Treatment Technologies

While many ICI boilers can accommodate fuel changes to reduce the amount of SO_2 emitted, in many other cases such changes may be uneconomical or impractical. For this reason, gas treatment methods that capture and control the SO_2 that is formed may be the most effective form of control. Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium- or sodium-based) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use, depending on the technology used. The types of flue gas SO_2 treatment methods are generally grouped into three categories:

- Wet scrubbers (or FGD) combine a mixture of lime or limestone and water with boiler flue gases to remove SO_2 and acid gases. The mixture is either injected into the scrubber with the flue gas, or the flue gas bubbles up through the mixture. The SO_2 is absorbed into the slurry and reacts with limestone to form an insoluble sludge. The sludge is disposed of in a pond specifically constructed for the purpose or is recovered as a salable byproduct. Wet scrubbers achieve SO_2 removal efficiencies of 90 to 98%.
- Dry scrubbers spray very finely powdered lime or other absorbents into a vessel where they combine with boiler flue gases to remove SO_2 and acid gases. The SO_2 is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate as in a wet scrubber. The resulting sorbent is captured with a particulate control device such as an electrostatic precipitator or baghouse. Dry scrubbers general achieve removal efficiencies of 90 to 93%.
- Dry sorbent injection (DSI) systems inject sorbents, such as Trona (a naturally-occurring mineral), into the boiler flue gas ductwork to remove SO_2 and acid gases. The sorbent is then captured in the particulate matter removal system (either an electrostatic precipitator or a baghouse). DSI systems achieve 40 to 75% removal.

More detailed descriptions of these technologies can be found in recent literature cited below.

Estimates of the SO_2 post-combustion control costs for ICI boilers were obtained from published values in recent literature. The estimates previously used in the *2007 Assessment* (MACTEC, 2007) were not used because the EPA publications that served as the basis for those cost estimates are dated, and more recent cost factors are available. A brief summary of the key elements of these studies is provided below.

- In December 2005, environmental commissioners from Northeast and Midwest States initiated a state collaborative process. A staff-level workgroup was formed in 2006 to evaluate control options ICI boilers. To develop improved control cost estimates for ICI boilers, the workgroup assembled detailed information on direct capital equipment costs, direct installation costs, indirect capital costs and direct and indirect operating costs. These data were used in cost estimation algorithms that were originally modeled after the factor cost estimate methodology found in the EPA *Air Pollution Control Cost Manual*. Factor cost estimates are based on empirical factors that are used to estimate the cost of various elements. The algorithms were coded in a user friendly format (Excel spreadsheets) and account for the key variables that impact the cost analysis, including: boiler type and size, type of fuel combusted, type of emission control, uncontrolled and controlled emission rates, capital cost of control equipment (e.g., purchased equipment

cost), financial costs (e.g., interest rates), unit capacity factor (hours/year), flue gas flow rates, and commodity prices (e.g., lime, water). For further information on the cost estimation methodology, see: Bodnarik, 2009 and OTC/LADCO, 2010.

- MARAMA and the Institute of Clean Air Companies (ICAC) sponsored the Advances in Air Pollution Control Technologies Workshop to provide state/local agency staff with the latest information on current and emerging emission control technologies. Cost estimates for several control technologies were developed by Dr. James Staudt using proprietary algorithms or algorithms developed for others (EPA). All cost data was benchmarked against independent data. See: Staudt, 2011.
- The Lake Michigan Air Directors Consortium (LADCO) sponsored a report that examined the inventory of SO_2 emissions and the candidate SO_2 control measures in the LADCO Region for industrial sources. The costs were developed from several references and therefore cover a wide range of situations and time periods. See: Staudt, 2012.

These studies provided valuable information on control options and cost effectiveness estimates for ICI boilers. Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2014 using the Chemical Engineering Plant Cost Index values. Table 4.8 summarizes the published SO_2 control costs for a number of SO_2 control technologies.

Table 4.8 Summary of Cost-Effectiveness of SO_2 Post-Combustion Control Options

Control Option	Fuel Type	Emission Reduction	Boiler Size (MMBTU/hr)	Cost-Effectiveness ($2014 / ton of SO_2 Removed	Reference
Dry FDG	Wall-fired Coal	85% from 5.0 to 0.75 lb MMBTUSO_2/MMBTU	100 250 750	1,785 – 7,711 1,655 – 4,021 1,594 – 2,387	Bodnarik, 2009
Dry FDG	Coal	90% from 5.75 to 0.58 lb SO_2/MMBTU	210 420 630	1,106 774 663	Staudt, 2011,
Dry FDG	Coal	90% from 2.59 to 0.26 lb SO_2/MMBTU	210 420 630	2,211 1,548 1,327	Staudt, 2011
Dry FDG	Coal	90% from 1.15 to 0.12 lb SO_2/MMBTU	210 420 630	4,643 3,206 2,653	Staudt, 2011
Dry FDG	Coal	90% from 0.5 to 0.05 lb SO_2/MMBTU	210 420 630	10,503 7,297 5,970	Staudt, 2011
Dry FDG	Wall-fired Coal	95% from 5.0 to 0.25 lb SO_2/MMBTU	100 250 750	1,594 – 6,899 1,484 – 3,600 1,424 – 2,136	Bodnarik, 2009
Wet FGD	Wall-fired Coal	85% from 5.0 to 0.75 lb SO_2/MMBTU	100 250 750	1,845 – 7,531 1,574 – 3,841 1,444 – 2,226	Bodnarik, 2009
Wet FGD	Coal	90% from 5.75 to 0.58 lb SO_2/MMBTU	210 420 630	884 697 663	Staudt, 2011

Control Option	Fuel Type	Emission Reduction	Boiler Size (MMBTU/hr)	Cost-Effectiveness ($2014 / ton of SO_2 Removed	Reference
Wet FGD	Coal	90% from 2.59 to 0.26 lb SO_2/MMBTU	210 420 630	1,249 984 918	Staudt, 2011
Wet FGD	Coal	90% from 1.15 to 0.12 lb SO_2/MMBTU	210 420 630	1,979 1,548 1,404	Staudt, 2011
Wet FGD	Coal	90% from 0.5 to 0.05 lb SO_2/MMBTU	210 420 630	4,168 3,250 2,874	Staudt, 2011
Wet FGD	Wall-fired Coal	95% from 5.0 to 0.25 lb SO_2/MMBTU	100 250 750	1,655 – 6,739 1,404 – 3,440 1,294 – 1,875	Bodnarik, 2009
Dry Sorbent Injection with Existing ESP	Coal	90% from 2.59 to 0.26 lb SO_2/MMBTU	210 420 630	4,422 3,925 3,814	Staudt, 2011
Dry Sorbent Injection with Existing ESP	Coal	90% from 1.15 to 0.12 lb SO_2/MMBTU	210 420 630	3,206 3,040 2,985	Staudt, 2011
Dry Sorbent Injection with Existing ESP	Coal	90% from 0.5 to 0.05 lb SO_2/MMBTU	210 420 630	2,792 2,736 2,681	Staudt, 2011
Dry Sorbent Injection with New Baghouse	Coal	90% from 2.59 to 0.26 lb SO_2/MMBTU	210 420 630	9,950 6,633 5,528	Staudt, 2011
Dry Sorbent Injection with New Baghouse	Coal	90% from 1.15 to 0.12 lb SO_2/MMBTU	210 420 630	4,754 3,427 3,206	Staudt, 2011
Dry Sorbent Injection with New Baghouse	Coal	90% from 0.5 to 0.05 lb SO_2/MMBTU	210 420 630	3,206 2,322 2,211	Staudt, 2011

As can be seen in Table 4.8 above, there are several factors that impact cost-effectiveness:

- Uncontrolled SO_2 level – lower initial SO_2 levels will result in higher costs represented in $/ton of SO_2 removed.
- Boiler size – Larger boilers tend to benefit from economies of scale in terms of capital cost.
- Technology type – The capital costs of wet scrubbers are higher than those for dry scrubbers, although the cost effectiveness values of wet and dry processes are similar.

The cost effectiveness values for post-combustion SO_2 control options for ICI boilers are higher than those for EGUs because of the above reasons. See Chapter 2 for additional information on the cost effectiveness values for post-combustion SO_2 control options for EGUs.

Identification of NO_x Control Options

The formation of NO_x is a byproduct of the combustion of fossil fuels. Nitrogen contained in the fuels, as well as the nitrogen in the air, will react with oxygen during combustion to form NO_x. The degree to which this formation evolves depends on many factors including both the combustion process itself and the properties of the particular fuel being burned. This is why similar boilers firing different fuels or similar fuels burned in different boilers can yield different NO_x emissions.

A variety of approaches to minimize or reduce NO_x emissions into the atmosphere have been and continue to be developed (NESCAUM, 2009). A relatively simple way of understanding the many technologies available for NO_x emission control is to divide them into two major categories: (1) those that minimize the formation of NO_x itself during the combustion process (e.g., smaller quantities of NO_x are formed during combustion); and (2) those that reduce the amount of NO_x after it is formed during combustion, but prior to exiting the stack into the atmosphere. It is common to refer to the first approach as combustion modifications, whereas technologies in the second category are termed post-combustion controls. Combinations of some of these technologies are not only possible, but are also often desirable as they may produce more effective NO_x control than the application of a stand-alone technology.

A summary of available NO_x control technology options are shown in Table 4.9. Combustion modifications can vary from simple "tuning" or optimization efforts to the deployment of dedicated technologies such as Low NO_x Burners (LNB), Overfire Air (OFA) or Flue Gas Recirculations (FGR). Conventional, commercial post-combustion NO_x controls include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). They are fundamentally similar, in that they use an ammonia-containing reagent to react with the NO_x produced in the boiler to convert the NO_x to harmless nitrogen and water. SNCR accomplishes this at higher temperatures (1,700ºF-2,000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 700ºF) and hence, needs a catalyst to produce the desired reaction between ammonia and NO_x.

Cost of Compliance – NO_x Control Options

To compare the various control options, information has been compiled on the cost-effectiveness of fuel switching and retrofitting controls. In general, cost-effectiveness increases as boiler size and capacity factor (a measure of boiler utilization) increases. All costs estimates for years other than 2014 were converted to 2014 dollars using the Chemical Engineering Plant Index, except where noted.

Reducing the amount of fuel used by boilers is one of the most cost effective ways to control NO_x emissions. Tuning-up a boiler optimizes the air-fuel mixture for the operating range of the boiler which ensures less fuel is wasted, and reduces emissions produced by inefficient combustion. Conducting an energy assessment of the systems and processes that the boiler supports helps to identify opportunities to improve boiler system efficiencies and reduce fuel use. EPA has estimated that the initial set-up for a boiler tune-up ranges from $3,000 to $7,000 per boiler, and thereafter, an annual tune-up costs $1,000 per boiler per year (EPA, 2013).

Table 4.9 Available NO_x Control Options For ICI Boilers

Technology	Description	Applicability	Performance
Boiler Tuning or Optimization	Adjusting the fuel/air ratio to operate the boiler more efficiently	Applicable to all ICI boilers	5 to 15% reduction in NO_x emissions
Low Excess Air	Involves limiting the amount of excess air in order to limit the amount of extra nitrogen and oxygen that enters the flame	Applicable to most ICI boiler types	5 to 10% reduction in NO_x emissions
Low-NO_x Burners	Involves changing the design of a standard burner in order to create a larger flame to lower flame temperatures and lower thermal NO_x formation which, in turn, results in lower overall NO_x emissions.	Applicable to most ICI boiler types	~ 50% for traditional LNB ~ 65% for ultra LNB ~ 85% for next generation ultra LNB
Overfire Air	Combustion air is diverted from the burners to create a fuel rich zone in the lower furnace. Peak flame temperatures are reduced to limit thermal NO_x formation.	Applicable to most ICI boiler types	5 to 15% reduction in NO_x emissions
Flue Gas Recirculation	Recirculates a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NO_x formation.	Applicable to most ICI boiler types	30 to 60% reduction in NO_x emissions
Selective Noncatalytic Reduction	Involves injection of a NO_x reducing agent, such as ammonia or urea, in the boiler exhaust gases at temperatures of approximately 1400-2000°F	ICI boilers operating at higher temperatures	25 to 50% reduction in NO_x emissions
Selective Catalytic Reduction	Involves injection of ammonia or urea into the exhaust gases in the presence of a catalyst at temperatures between 500° and 1200°F	ICI boilers operating at lower temperatures	90% reduction in NO_x emissions
Technology Combinations	Combination of a combustion modifications such as LNB/OFA with a post-combustion technology such as SCR or SNCR	Applicable to most ICI boiler types	Can exceed 90% reduction in NO_x emissions

Table references: NESCAUM 2009; EPA 2015e; EPA 2015f

EPA estimated that the tune-up will achieve at least a 1% improvement in efficiency which will result in fuel savings costs that will offset the tune-up costs. EPA also estimated that the one-time cost of an energy assessment ranges from $2,500 to $75,000 depending on the size of the facility. Energy assessments at selected manufacturing facilities shows that facilities can reduce fuel/energy use by 10 to 15%, with the fuel savings costs offsetting the cost of the energy assessment.

As mentioned in the previous section, switching from high sulfur fuels (coal, residual oil) to low sulfur fuels (ultra-low-sulfur distillate, natural gas) may be a cost-effective strategy for reducing SO_2 emissions. The per Btu NO_x emissions for high sulfur fuels are higher than for low-sulfur fuels (e.g., uncontrolled NO_x emissions for coal are generally 0.4 – 0.8 lbs/MMBTU, 0.2 – 0.4 lbs/MMBTUMMBTU for residual oil, and 0.1 – 0.2 lbs/MMBTUMMBTU for distillate oil and natural gas). The switch from high-sulfur fuels to low- or no-sulfur fuels will also have a NO_x reduction co-benefit.

Estimates of the NO_x combustion modification and post-combustion control costs for ICI boilers were obtained from published values in recent literature. The estimates previously used in the *2007 Assessment* (MACTEC, 2007) were not used here because the EPA publications that served as the basis for those cost estimates are dated, and more recent cost factors are available. A brief summary of the key elements of these studies is provided below.

- In December 2005, environmental commissioners from Northeast and Midwest States initiated a state collaborative process. A staff-level workgroup was formed in 2006 to evaluate control options ICI boilers. To develop improved control cost estimates for ICI boilers, the workgroup assembled detailed information on direct capital equipment costs, direct installation costs, indirect capital costs and direct and indirect operating costs. These data were used in cost estimation algorithms that were originally modeled after the factor cost estimate methodology found in the US EPA *Air Pollution Control Cost Manual*. Factor cost estimates are based on empirical factors that are used to estimate the cost of various elements. The algorithms were coded in a user friendly format (Excel spreadsheets) and account for the key variables that impact the cost analysis, including: boiler type and size, type of fuel combusted, type of emission control, uncontrolled and controlled emission rates, capital cost of control equipment (e.g., purchased equipment cost), financial costs (e.g., interest rates), unit capacity factor (hours/year), flue gas flow rates, and commodity prices (e.g., lime, water). See: Bodnarik, 2009 and OTC/LADCO, 2010.
- MARAMA and the Institute of Clean Air Companies (ICAC) sponsored Advances in Air Pollution Control Technologies Workshop to provide state/local agency staff with the latest information on current and emerging emission control technologies. Cost estimates for several control technologies were developed by Dr. James Staudt using proprietary algorithms or algorithms developed for others (EPA). All cost data was benchmarked against independent data. See: Staudt, 2011.
- The Ontario Ministry of Environment sponsored a study air pollution control options at six refineries in Ontario. The study included the development of the sizing and costing algorithms (SCAs) for the 24 emission reduction technologies, including refinery boilers and heaters. The SCAs were modeled after the factor cost estimate methodology found in

the US EPA *Air Pollution Control Cost Manual*, included independent purchased equipment costs from current vendor data for Ontario locations. Equations were developed to fit the vendor data for cost of equipment of different sizes found at individual facilities. Factors were developed to estimate cost of auxiliary equipment, direct costs, indirect costs, and operating costs. Since this project used confidential business information, the algorithms were applied for this study for fictitious installations generally representative of the industry sector. See: EHS, 2014.

These studies provided valuable information on control options and cost effectiveness estimates for ICI boilers.

In theory, most of the technologies described above can be used together (NESCAUM, 2009). However, NO_x reductions are not necessarily additive, and more importantly, the economics of the combined technologies may or may not be cost-effective. Such analyses are highly specific to the site and strategy. However, several such technology combinations are considered attractive and have gained acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NO_x levels entering the SCR/SNCR system.

Literature values of capital costs have been reported for different base years. The calculated capital cost values from the literature were normalized to a base year of 2014 using the Chemical Engineering Plant Cost Index values. Table 4-9 summarizes the published NO_x control costs for a number of NO_x control technologies and combinations of control technologies.

Table 4.9 Summary of Cost-Effectiveness of NO_x Control Options

Control Option	Fuel Type	Emission Reduction	Boiler Size (MMBTU/hr)	Cost-Effectiveness ($2014 / ton of NO_x Removed	Reference
Overfire Air	Natural Gas	25% from 0.20 to 0.15 lb NO_x/MMBTU	100 200 300 400	4,533 2,709 1,990 1,685	Staudt, 2011
Low NO_x Burners	Natural Gas	50% from 0.20 to 0.10 lb NO_x /MMBTU	100 200 300 400 500	2,764 1,714 1,327 1,161 1,050	Staudt, 2011
Low NO_x Burners	Natural Gas, Distillate Oil	50% from 0.20 to 0.10 lb NO_x /MMBTU	50 100 250 750	10,930 – 43,721 5,475 – 21,861 2,196 – 8.744 730 – 2,918	Bodnarik, 2009
Ultra-low NO_x Burners	Natural Gas	70% from 0.20 to 0.05 lb NO_x /MMBTU	100 200 300 400 500	2,211 1,548 1,161 1,050 995	Staudt, 2011
Ultra-low NO_x Burners	Refinery Fuel Gas and/or Oil	70% from 0.14 to 0.03 lb NO_x /MMBTU	50 - 500	1,357	EHS, 2014

Control Option	Fuel Type	Emission Reduction	Boiler Size (MMBTU/hr)	Cost-Effectiveness ($2014 / ton of NO_x Removed	Reference
Overfire Air	Residual Oil	25% from 0.37 to 0.28 lb NO_x /MMBTU	100 200 300 400 500	2,018 1,050 691 553 442	Staudt, 2011
Low NO_x Burners	Residual Oil	50% from 0.4 to 0.2 lb NO_x /MMBTU	50 100 250 750	5,475 – 21,861 2,738 – 10,930 1,093 – 4,372 365 – 1,454	Bodnarik, 2009
Low NO_x Burners	Residual Oil	50% from 0.37 to 0.185 lb NO_x /MMBTU	100 200 300 400 500	1,271 691 470 415 331	Staudt, 2011
Low NO_x Burners plus Flue Gas Recirculation	Residual Oil	60% from 0.4 to 0.16 lb NO_x /MMBTU	50 100 250 750	13,237 – 26,875 6,618 – 13,437 2,647 – 5,375 882 – 1,795	Bodnarik, 2009
Low NO_x Burners plus Overfire Air	Residual Oil	65% from 0.37 to 0.13 lb NO_x /MMBTU	100 200 300 400 500	912 498 415 276 221	Staudt, 2011
Overfire Air	Coal	25% from 0.7 to 0.52 lb NO_x /MMBTU	100 200 300 400 500	1,493 896 674 608 498	Staudt, 2011
Low NO_x Burners	Wall-fired Coal	50% from 0.7 to 0.35 lb NO_x /MMBTU	50 100 250 750	3,129 – 12,495 1,564 – 6,247 626 – 2,497 209 - 833	Bodnarik, 2009
Low NO_x Burners	Coal	65% from 0.7 to 0.25 lb NO_x /MMBTU	100 200 300 400 500	1,050 691 652 553 470	Staudt, 2011
SNCR	Not specified	25 to 65%, depending on fuel and type of industry	50 100 250 750	12,000 7,500 5,000 2,500	EPA, 2015e
SNCR	Residual Oil	50% from 0.4 to 0.2 lb NO_x /MMBTU	50 100 250 750	10,579 – 14,881 5,916 – 8,062 3,119 – 3,981 1,875 – 2,156	Bodnarik, 2009
SNCR	Wall-fired Coal	45% from 0.7 to 0.39 lb NO_x /MMBTU	50 100 250 750	7,230 – 9,958 4,272 – 5,636 2,487 – 3,038 1,695 – 1,885	Bodnarik, 2009

Control Option	Fuel Type	Emission Reduction	Boiler Size (MMBTU/hr)	Cost-Effectiveness ($2014 / ton of NO_x Removed	Reference
SNCR plus Low NO_x Burners plus Overfire Air	Coal	75% from 0.7 to 0.18 lb NO_x /MMBTU	100 200 300 400 500	2,018 1,327 1,050 940 829	Staudt, 2011
SCR	Refinery Fuel Gas and/or Oil	90%	100 250 500 750	12,704 8,662 7,507 5,775	EHS, 2014
SCR	Residual Oil	85% from 0.4 to 0.0.675 lb NO_x /MMBTU	50 100 250 750	11,251 – 39,911 5,856 – 20,156 2,627 – 8,353 1,183 – 3, 089	Bodnarik, 2009
SCR	Wall-fired Coal	85% from 0.7 to 0.11 lb NO_x /MMBTU	50 100 250 750	6,518 – 22,904 3,440 – 11,632 1,594 – 4,874 772 – 1,865	Bodnarik, 2009

FACTOR 2 – COMPLIANCE TIMEFRAME

States typically need 2-3 years to develop new regulations, and sources generally are given a 2-4 year phase-in period to comply with new rules. Most MACT standards allow a 3-year compliance period. States generally provided a 2-year period for compliance with RACT rules. For the purposes of this review, we have assumed that a 2-year period after SIP submittal is adequate for pre-combustion controls (fuel switching or cleaning) and a three year period for the installation of post combustion controls.

For BART control measures, the BART guidelines required States to establish enforceable limits and require compliance with the BART emission limitations no later than 5 years after EPA approves the regional haze SIP.

Refiners in the United States are already producing ultra-low sulfur distillate oil which may be marketed as diesel fuel in accordance with EPA on-road and off-road fuel sulfur content standards. ICI boilers would not have to retrofit or install expensive control technology to burn ultra-low sulfur distillate oil, and compliance with the standard is simply driven by supply and demand.

For combustion based and post-combustion based engineering and construction leads times will vary between 2 and 5 years depending on the size of the facility and specific control technology selected.

FACTOR 3 – ENERGY AND NON-ENVIRONMENTAL IMPACTS

Fuel switching and cleaning do not significantly affect the efficiency of the boiler but may add to transportation issues and secondary environmental impacts from waste disposal and material

handling operations (e.g. fugitive dust). FGD systems typically operate with high pressure drops across the control equipment, resulting in a significant amount of electricity required to operate blowers and circulation pumps. In addition, some combinations of FGD technology and plant configuration may require flue gas reheating to prevent physical damage to equipment, resulting in higher fuel usage.

The primary environmental impact of FGD systems is the generation of wastewater and sludge from the SO_2 removal process. When the exhaust gas from the boiler enters the FGD the SO_2, metals, and other solids are removed from the exhaust and collected in the FGD liquid. The liquid slurry collects in the bottom of the FGD in a reaction tank. The slurry is then dewatered and a portion of the contaminant-laden water is removed from the system as wastewater. Waste from the FGD systems will increase sulfate, metals, and solids loading in a facility's wastewater, potentially impacting community wastewater treatment facilities for smaller units that do not have self-contained water treatment systems. In some cases FGD operation necessitates installation of a clarifier on site to remove excessive pollutants from wastewater. This places additional burdens on a facility or community wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge must be stabilized prior to landfilling. If a calcium sulfate sludge is produced, dewatering alone is necessary before land filling, however, SO_2 removal costs are higher due to increased equipment costs for this type of control system. In some cases calcium sulfate sludge can be sold for use in cement manufacturing.

With wet FGD technologies a significant visible plume is present from the source due to condensation of water vapor as it exits the smoke stack. Although the water eventually evaporates and the plume disappears, community impact may be significant.

Reducing the sulfur contents of distillate fuel oil has a variety of beneficial consequences for ICI boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings. According to a study conducted by the New York State Energy Research and Development Authority (NYSERDA), boiler deposits are reduced by a factor of two by lowering the fuel sulfur content from 1,400 ppm to 500 ppm. These reductions in buildup of deposits result in longer service intervals between cleanings. (NYSERDA, 2005)

FACTOR 4 – REMAINING USEFUL LIFE

The remaining useful life of the source depends primarily on the age of the boiler, which must be evaluated on a source-by-source basis. Other source-specific factors affecting remaining useful life estimates of ICI boilers include average operating hours, capacity factors, size of the unit, capacity factor, and level of maintenance performed. Typical life expectancies range from about 10 years up to over 30 years.

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CHAPTER 8

SOURCE CATEGORY ANALYSIS: HEATING OIL

BACKGROUND

Source Category Description

Americans use many different energy sources to heat their homes, including heating oil, natural gas, electricity, bottled propane, and kerosene. Renewable sources, including wood combustion and solar photovoltaic installations, are becoming more common. Energy prices, availability of supplies, age of the residence and climate play a big role in the type and amount of fuel used.

Heating oil (alternatively referred to as fuel oil or #2 distillate heating oil) is a middle-distillate refined petroleum product comparable to diesel fuel (except for additives and sulfur content). Heating oil burners emit a variety of air pollutants that: contribute to the formation of ozone and fine particulate matter, regional haze; play a part in acid deposition and nitrification of water bodies; add to the global mercury pool; and factor in the build-up of greenhouse gasses in the atmosphere (NESCAUM, 2005). Of primary concern for this analysis, the combustion of heating oil is a significant source of sulfur dioxide (SO_2) emissions in the MANE-VU region.

Heating oil is particularly important in the MANE-VU region. The 2009 Residential Energy Consumption Survey (EIA, 2013) determined that about 42% of homes in New England reported heating oil as the main heating energy source. In the southern part of the MANE-VU region, 22% of homes used oil for home heating. Nationally, only 6% of homes used oil. Natural gas is the most widely used energy source for home heating in the southern part of the MANE-VU region, electricity is most prevalent in the Southeastern U.S. and natural gas dominates in the Midwest.

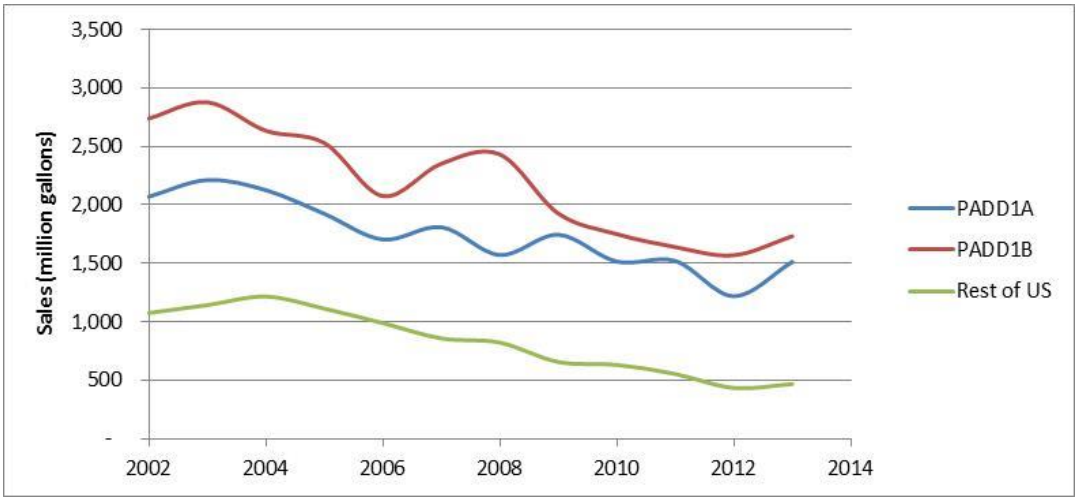
Consumption and Emission Trends

For decades, space heating and cooling has accounted for more than half of all residential energy consumption. Estimates show that 48% of energy consumption in U.S. homes in 2009 was for heating and cooling, down from 58% in 1993 (EIA, 2012). Factors underpinning this trend are increased adoption of more efficient equipment, better insulation, more efficient windows, and population shifts to warmer climates.

The demand for heating oil in the U.S. has been declining over the last decade. Figure 8.1 shows the trends in residential heating oil sales for the New England states, the other MANE-VU states, and the remainder of the U.S. (EIA, 2015). In New England, heating oil consumption decreased from 2.1 billion gallons in 2002 to 1.5 billion gallons in 2013, a decrease of about 27%. The decreases in consumption over this period were even larger in the other MANE-VU states (37% decrease) and nationally (56% decrease).

A recent study by the Congressional Research Service identified some of the reasons for declining heating oil demand (CRS, 2014). According to the CRS, no single factor explains the

Figure 8.1 Trends in Residential Heating Oil Sales



PADD 1A (New England: CT, ME, MA, NH, RI, and VT)
PADD 1B (Central Atlantic: DE, DC, MD, NJ, NY, and PA)
Source: EIA, 2015

Northeast's declining demand for heating oil. Steady price increases for heating oil appear to correlate with declining demand and consumers may have responded by using less heating oil (heating oil price trends are discussed in greater detail later in this Chapter). Some residential consumers may have switched to electricity, natural gas, bottled gas, or kerosene. More energy-efficient and better-insulated new houses could have replaced older units. Newer, more efficient oil-heat furnaces could have replaced older units.

In addition, a recent EIA study shows that wood as the main heating source in homes has gained popularity in many areas of the country in recent years. The increase is most notable in the Northeast, where there was at least a 50% increase from 2005 to 2012 in the number of households that rely on wood as the main heating source (EIA, 2014). As discussed later in this Chapter, heating oil prices have declined dramatically since 2014 and are forecasted to remain low for the next few years, which may lead to increased demand as consumers choose heating oil over other fuels.

As heating oil sales have decreased, so too have the emissions of SO_2 from the combustion of heating oil. Table 8.1 shows the trends in SO_2 emissions from residential heating oil combustion for the MANE-VU states and states in the neighboring RPOs. SO_2 emissions are directly proportional to amount of fuel consumed and fuel oil sulfur content. While consumption has decreased, the sulfur content has remained about the same from 2002 to 2012, ranging from 2,000 to 3,000 parts per million.

As discussed in the next section, some MANE-VU states began restricting the sulfur content heating oil in 2012, and most states will have heating oil sulfur restriction in place by 2018. Preliminary projections estimate that SO_2 emissions from heating oil combustion may decrease by as much as 95-99% by 2018 in the MANE-VU region. Final projections are not available for this report.

Table 8.1 Trends in SO_2 Emissions from Residential Heating Oil Combustion

RPO	**2002**	**2007/2008**	**2011**	**2014**
MANE-VU	130,736	95,864	71,429	Not yet available
MRPO	8,750	7,458	3,848	Not yet available
VISTAS	9,947	8,814	5,843	Not yet available

MANE-VU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, and VT)
MRPO (IL, IN, OH, MI, WI)
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)
MANE-VU emissions obtained from 2002, 2007 and 2011 inventories prepared by MARAMA
MRPO and VISTAS emissions obtained from 2002, 2008 and 2011 EPA national emission inventories

Regulatory History

MANE-VU developed a low sulfur heating oil strategy to help states develop Regional Haze State Implementation Plans (MANE-VU, 2007):

- A strategy in the inner zone States (New Jersey, New York, Delaware, and Pennsylvania, or portion thereof) to reduce the sulfur content of heating oil to 500 ppm by no later than 2012 and to further the reduce the sulfur content to 15 ppm by 2016;
- A strategy in the outer zone States (remainder of MANE-VU region) to reduce the sulfur content heating oil to 500 ppm by no later than 2014 and to further reduce the sulfur content to 15 ppm by 2018.

The status of the heating oil sulfur in fuel rules in each state is summarized in Table 8.2.

Table 8.2 Sulfur Limits for Heating Oil in the MANE-VU Region (as of January 15, 2016)

Jurisdiction	Sulfur Restriction	Regulatory Citation
CT	500 ppm July 1, 2014 through June 30, 2018 15 ppm after July 1, 2018	Connecticut General Statutes section 16a-21a – Sulfur content of home heating oil and off-road diesel fuel.
DE	3000 ppm prior to July 1, 2016 15 ppm after July 1, 2016	DE Admin Code - 1108 - Sulfur Dioxide Emissions from Fuel Burning Equipment
DC	500 ppm July 1, 2016 through June 30, 2018 15 ppm after July 1, 2018	Section 801, Sulfur Content of Fuel Oils
MA	500 ppm July 1, 2014 through June 30, 2018 15 ppm after July 1, 2018	310 CMR 7.05 (1)(a)1: Table 1 : Sulfur Content Limit of Liquid Fossil Fuel
MD	500 ppm beginning July 2016; working on a new regulation in 2016 for a 15 ppm limit by July 2018	26.11.09.07 Control of Sulfur Oxides From Fuel Burning Equipment.
ME	15 ppm after July 1, 2018	An Act to Achieve Regional Uniformity in Sulfur Standards for Heating Oil (Chapter 106 rulemaking underway to make it consistent with statute)
NH	4000 ppm; legislative actions expected in 2016 for a 15 ppm limit by July 2018	Part Env-A 1603 Sulfur Content Limitation for Liquid Fuels
NJ	500 ppm July 1, 2014 through June 30, 2016 15 ppm after July 1, 2016	Title 7, Chapter 27, Subchapter 9 Sulfur in Fuels

Jurisdiction	Sulfur Restriction	Regulatory Citation
NY	15 ppm after July 1, 2012	Subpart 225-1 Fuel Composition and Use - Sulfur Limitations
PA	2000 to 5000 ppm through June 30, 2016, depending on air basin 500 ppm after July 1, 2016	§ 123.22. Combustion units
Philadelphia	2000 ppm until June 30, 2015 15 ppm after July 1, 2015	Regulation III – Control of Sulfur Compound Emissions
RI	500 ppm July 1, 2014 through June 30, 2018 15 ppm after July 1, 2018	Air Pollution Control Regulations No. 8 Sulfur Content of Fuels
VT	500 ppm July 1, 2014 through June 30, 2018 15 ppm after July 1, 2018	5-221(1) Sulfur Limitations in Fuel

FOUR FACTOR ANALYSIS OF POTENTIAL CONTROL SCENARIOS FOR EMISSIONS FROM HEATING OIL COMBUSTION

The remainder of this memorandum presents the four factor analysis that was applied to the heating oil sulfur reduction regulations. The four factors are: cost of compliance, time necessary for compliance, energy and non-air impacts, and remaining useful life of the sources. This document primarily focuses on reducing the sulfur content of heating oil to 15 ppm.

Costs of Compliance

This section first summarizes the costs for retrofitting refineries so that they could supply 15 ppm heating oil in sufficient quantities to meet MANE-VU heating oil demands. This is followed by a discussion of the price impacts for consumers.

Domestic oil refiners have already made extensive capital investments to produce lower sulfur distillate fuels to comply with EPA's national ultra-low sulfur diesel (ULSD) requirements for transportation fuels. Beginning in September 2006, the permissible level of sulfur in highway diesel fuel was 15 ppm. Prior to that, highway low sulfur diesel fuel was refined to contain 500 ppm sulfur. By 2010, all highway diesel fuel was to meet the 15 ppm sulfur requirement. Diesel fuel intended for locomotive, marine and non-road engines and equipment was required to meet the low sulfur diesel fuel maximum specification of 500 ppm sulfur in 2007. By June 2010, the ULSD fuel standard of 15 ppm sulfur applied to all non-road diesel fuel production. Beginning in 2012, locomotive and marine diesel fuel was required to meet the ULSD fuel standard of 15 ppm sulfur.

In its highway and nonroad diesel fuel rulemakings, EPA developed cost estimates for the deployment and implementation of desulfurization technologies at refineries (EPA, 2000; EPA, 2004). Table 8.3 summarizes EPA's cost estimates. For the highway ULSD rule, EPA estimated that it would cost existing refineries an average of $47.8 million (2002 dollars) per refinery to install desulfurization technologies to meet the highway ULSD requirements. EPA estimated that the total capital costs were $5.45 billion.

Table 8.3 EPA Estimated Costs of Desulfurizing Highway and Nonroad Diesel Fuel to Meet a 15 ppm Standard (2002 Dollars)

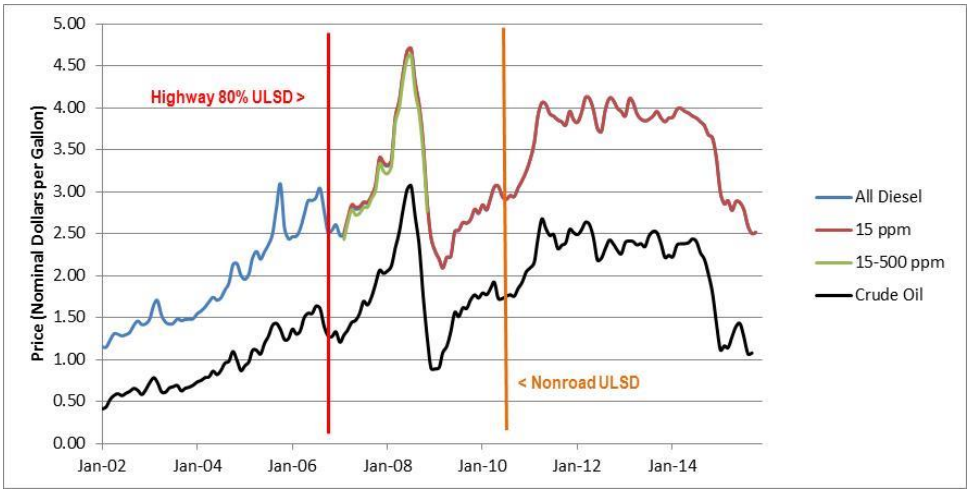
	Highway ULSD Rule	Nonroad ULSD Rule
Total Capital Cost ($million)	5,450	2,730
Average Capital Cost per Refinery ($million)	47.8	42.7
Average Operating Cost per Refinery ($million per year)	9.0	10.6
Per Gallon Cost (cents/gallon)	3.6	7.1

Source: EPA, 2000; EPA, 2004.

For complying with the 15 ppm sulfur cap standards applicable to nonroad diesel fuel in 2010 and to locomotive and marine diesel fuel in 2012, refiners were able to use the experience gained from complying with the 15 ppm highway diesel fuel standard. EPA projected that some refiners will utilize lower cost advanced desulfurization technologies recently commercialized. Others would rely on extensions of conventional hydrotreating technology which most refiners were already using to comply with the 15 ppm cap for highway diesel fuel in 2006. For the nonroad ULSD, EPA estimated that it would cost existing refineries an average of $42.7 million (2002 dollars) per refinery to install desulfurization technologies to meet the nonroad ULSD requirements. Total capital costs were estimated to be $2.73 billion. EPA estimated the average costs for 15 ppm sulfur nonroad fuel to be an additional 7.1 cents per gallon in 2014.

How have the EPA low sulfur highway and nonroad requirements affected diesel prices? Figure 8.2 shows that the shift to ULSD was relatively small in terms of the absolute price of diesel fuel compared to the magnitude of volatility in crude oil prices (EIA, 2015). The petroleum refining industry has a long history of cyclical performance. Cycles in the industry have been historically related to movements in the price of crude oil, which is the primary cost element in refinery operations, and this will likely remain true in the future. About 60 % of the price of a gallon of diesel fuel is contained in the raw crude oil. The remaining cost of producing diesel fuel is found in refining, marketing, taxes and other expenses. As a result, the price for 15 ppm sulfur diesel in 2015 is about the same as higher sulfur diesel before the EPA requirements took effect.

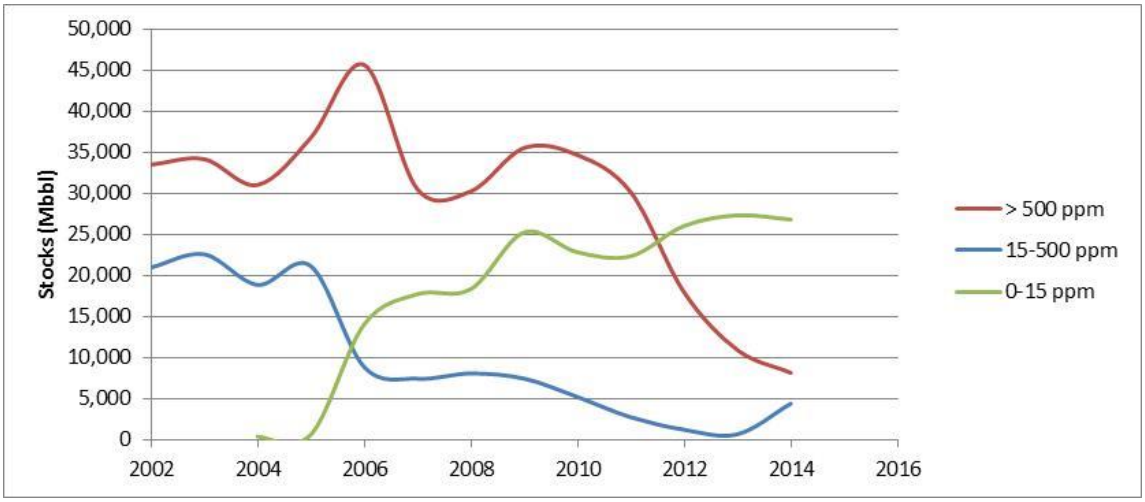
Figure 8.2 Comparison of Refiner Cost of Oil to Diesel Retail Prices



Source of Cost Data: EIA, 2015.

As a result of these EPA rulemakings, technologies are currently available to achieve significant reductions in heating oil sulfur as many refiners are already meeting a 15 ppm average for transportation fuels. Refineries have already made significant capital investments required for the production of LSD and ULSD fuel oil. EIA reported that total ULSD production progress has been good and has been able to meet the demand. Distillate stocks of ULSD have risen significantly in the East Coast over the past few years, as shown in Figure 8.3.

Figure 8.3 Trends in Distillate Stocks in PADD 1 (East Coast)



Source: EIA, 2015.

As a result of state actions to implement the MANE-VU low sulfur heating oil strategy, refiners are continuing to make further upgrades to produce ultra-low sulfur heating oil. These capital investments are expected to be considerably lower than those needed to meet the highway and nonroad sulfur requirements. Heating oil is only 11% of the total distillate production in the region and just over 3% of total refinery output.

Since refiners are already producing 15 ppm heating oil to meet New York's requirement for 15 ppm heating oil, how have heating oil prices been affected? Figure 8.4 shows the trends in heating oil prices in New York (NYSERDA, 2015). The maximum weekly heating oil price for the 2011/2012 heating season (before the 15 ppm requirements took effect) was $4.17 per gallon, and the maximum price for the 2012/2013 heating season was $4.25 per gallon, or 8 cents higher than the previous heating season. With the recent drop in crude oil prices, the weekly price per gallon for the 2014/2015 season dropped from $3.81 in September 2014 to $3.02 in February 2015. The price at the beginning of the 2015/2016 heating season was about $2.50 per gallon.

Thus, the anticipated cost increase from a shift to ULSD will be relatively small in terms of the absolute price of heating oil compared to the magnitude of volatility in crude oil prices. The price of heating oil once a complete shift to ULSD occurs will be set by the larger oil market.

Finally, according to the Consumer Energy Council of America (CECA, 2015), research indicates that the slight fuel price premium is more than compensated by cost savings associated with longer equipment life, greater fuel stability, and reduced maintenance and cleanings of the heating equipment.

Figure 8.4 Trends in Heating Oil Prices in New York State

Source: NYSERDA, 2015.

Time Necessary for Compliance

Refiners have demonstrated that they have been able to meet ULSD specifications for highway vehicles and nonroad equipment given sufficient lead time for the necessary investments. Past experience suggests at least 5 years will be needed for the industry to make the necessary investments for the heating oil market. Refiners in the U.S. have already made the switch to producing low sulfur fuel for highway vehicles, nonroad equipment, and the New York residential heating oil market. This same fuel can be marketed as heating oil since it is very similar to the highway/nonroad diesel fuel already produced.

The capacity for producing ULSD already exists among U.S. refiners, and 15 ppm heating oil is already being supplied for the extensive New York market. Some time may be required to allow petroleum marketers to adjust to distributing ULSD to heating oil customers, however, the distribution network for motor fuels and heating oil are already in place. With the phased-in timing for the remaining states, there appears to be sufficient time to allow refiners to add any additional heating oil capacity that may be required.

Small refiners may need more time to comply with a low sulfur control program. Small refiners generally have a more difficult time in obtaining funding for capital projects, and must plan further in advance of when the funds are needed. In EPA's nonroad ULSD rulemaking, small refiners were provided additional time (up to three years) to provide enough time to select the most advantageous desulfurization equipment, and for securing capital funds to purchase and construct the desulfurization equipment.

Existing stocks of heating oil with higher than 15 ppm sulfur content may be in existence for several months after the date for refineries to produce only 15 ppm sulfur content heating oil. It may take several months for the full benefits of any ultra-low sulfur in fuel standard to be observed as the blending of varying sulfur content fuels will be occurring during this transition period. Therefore, the fuel oil that is actually stored within a tank and eventually combusted may

not initially meet the 15 ppm standard, but will eventually be blended down to be below the 15 ppm sulfur content standard after repeated tank refills.

Finally, existing residential furnaces and boilers do not need to be retrofitted or modified to combust heating oil with a 15 ppm sulfur content. Consequently, the time necessary for compliance does not hinge on the replacement of existing heating oil furnaces or boilers to newer models.

Energy and Non-Air Environmental Impacts

Reducing the sulfur contents of heating oil has a variety of beneficial consequences for residential furnaces and boilers. Low sulfur distillate fuel is cleaner burning and emits less particulate matter which reduces the rate of fouling of heating units substantially and permits longer time intervals between cleanings.

The decreased sulfur levels would enable manufacturers to develop more efficient furnaces and boilers by using more advanced condensing furnaces and boilers. These boilers recoup energy that is normally lost to the heating of water vapor in the exhaust gases. Historically, the use of high sulfur fuels prevented this due to the corrosion of the furnace/boiler due to the creation of sulfuric acid in the exhaust gases. The increased efficiency results in a decrease in the amount of heating oil a heating unit uses, therefore, this would make a switch to lower sulfur heating oil more attractive and cost effective.

Remaining Useful Life of the Source

Residential furnaces and boilers have finite life times, but they do not need to be replaced to burn low or ultra-low sulfur fuel. Taking sulfur out of fuel causes no problems for oil heating equipment or storage tanks. On the contrary there is a great benefit to reducing sulfur because sulfur when burned will cause sooting and scaling and reduce efficiency. Reducing the amount of sulfur prolongs the life of heat exchangers, particularly those in condensing boilers and furnaces (Irving, 2016).

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CHAPTER 9

SOURCE CATEGORY ANALYSIS: RESIDENTIAL WOOD COMBUSTION

BACKGROUND

The MANE-VU Contribution Assessment and other MANE-VU reports have documented that visibility impairment in this region is primarily due to regional secondary sulfate (NESCAUM 2006). In addition, biomass combustion as a contributor to visibility impairment in MANE-VU Class I areas. Biomass combustion emissions due to human activity primarily derive from residential wood combustion. While some biomass burning occurs throughout the year, residential wood combustion occurs predominantly in the winter months, potentially contributing to wintertime peaks in PM concentrations.

MANE-VU previously developed an assessment (MACTEC, 2007) of control technologies to achieve reasonable progress goals with respect to the four factors listed in Section 169A of the Clean Air Act. The information presented in this Chapter is an update to some parts of the MACTEC report.

Source Category Description

Wood heating devices embody a variety of products that provide heat for residential consumers by burning wood or other solid biomass fuel. Indoor wood-burning devices can provide space heating for a single room or can be central heaters for a residential home. Indoor heating devices include freestanding wood stoves, pellet stoves, fireplace inserts, and forced-air furnaces. Outdoor wood heating devices, also known as outdoor wood boilers (OWBs) or hydronic heaters, are typically located adjacent to the home they heat in small sheds with short smoke stacks. OWBs are discussed in Chapter 10. Other wood-burning devices include low-mass fireplaces, open masonry fireplaces, fireplaces, fire pits, chimineas, cook stoves, masonry heaters, and pizza ovens. Campfires also generate air pollution, but are not considered in this analysis due to lack of available data. Table 9.1 provides a summary of the key characteristics of the types of devices included in this category.

Table 9.1 Types of Residential Wood Combustion Devices

Device Type	Description	Emission Characteristics
Indoor and Outdoor Fireplaces	Combustion air is drawn from the natural draft created by fire, and that same draft vents the exhaust gases through the chimney.	Typically have low efficiencies due to the large amount of heated room air that is exhausted out of the chimney; considered more of an aesthetic feature than a functional heating device
Fireplace Inserts	A type of heater/stove that is designed to fit inside the firebox of an existing wood-burning fireplace	Closed-door system, improves combustion by slowing down the fire, decreasing the excess air, and increasing the fire's temperature
Woodstoves - Conventional	Enclosed combustion devices that provide direct space heating for a specific room or area of a home	Units manufactured before 1990, do not have any emission reduction technology or design features
Woodstoves – EPA-certified, non-catalytic	Enclosed combustion devices that provide direct space heating for a	Relies on high temperatures (>1,000°F) within the fire box to fully combust the combustible gases

Device Type	Description	Emission Characteristics
	specific room or area of a home	and particles in the wood smoke
Woodstoves - EPA-certified, catalytic	Enclosed combustion devices that provide direct space heating for a specific room or area of a home	Presence of a catalytic element lowers the temperature at which wood smoke chemical compounds combust.
Wood Pellet Stoves	Uses tightly compacted pellets of wood or sawdust as fuel; a feed device regulates the amount of fuel that is released from a hopper into the heating chamber, which is where the combustion takes place	Typically more efficient in terms of combustion and heating than standard wood stoves but require electricity to operate the fans, controls, and pellet feeders
Masonry Heaters	Similar in appearance to fireplace, but are used primarily to generate heat, whereas fireplaces typically serve a more aesthetic purpose.	Cleaner-burning and more heat-efficient form of primary and supplemental radiative heat than a traditional fireplace
Force-Air Furnaces	Typically located inside a house and provides controlled heat throughout a home using a network of air ducts	PM emissions 7-8 times higher compared to woodstoves or pellet stoves
Fire Pits, Chimineas, Cook Stoves, Pizza Ovens, Campfires	Outdoor appliances involve using wood fuel for cooking or heating.	Used primarily for recreational purposes

Source: EPA, 2015a.

Thermal output, typically expressed in British thermal units per hour (BTU/hr), is the heat output measure that tells the amount of heat produced each hour. A higher BTU/hr rate suggests that a stove will produce more heat per hour than a stove with a lower rating. Depending on design and size characteristics, a space heating device heat output rating ranges between 8,000 and 90,000 BTU/hr. Larger heating systems designed to provide whole home heating have heat output ratings that range from 100,000 to greater than one million BTU/hr.

Emission and Consumption Trends

Table 9.2 shows the CO, $PM_{2.5}$ and VOC emissions in 2011 from residential wood combustion for the MANE-VU, MRPO, and VISTAS RPO states. The emission estimates were developed by EPA using the Residential Wood Combustion Tool. This tool computes county-and SCC-level emissions of criteria air pollutants for the entire country. EPA updated the inputs to the tool for the 2011 National Emission Inventory in partnership with the Eastern Regional Technical Advisory Committee (ERTAC). Emission trends over the past decade are not available due to improvements in emission factors and emission estimation methodologies. The new Residential Wood Combustion Tool used a new suite of source categories, new emission factors and new calculation methodology. Thus, the resulting emissions for this sub-category of area emissions are not comparable between older and newer inventories.

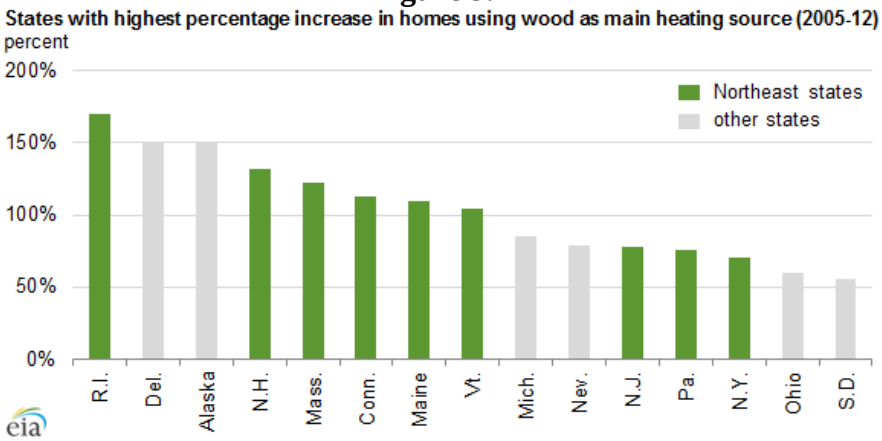
Wood as a main heating source in homes has gained popularity in many areas of the country in recent years, but the increase is most notable in the Northeast (EIA, 2014). As shown in Figure 9.1, most states in the MANE-VU RPO saw at least a 50% increase from 2005 to 2012 in the number of households that rely on wood as the main heating source. As the price of fuel oil and kerosene in this region increased during that period, fuel oil and kerosene use has declined in recent years as many households have turned to lower-cost alternatives, including wood.

Table 9.2 Residential Wood Combustion Emissions (tons/year)

SCC	Description	CO	$PM_{2.5}$	VOC
MANE-VU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT)				
2104008100	Fireplace: general	51,945	8,228	6,589
2104008210	Woodstove: fireplace inserts; non-EPA certified	108,528	14,389	24,922
2104008220	Woodstove: fireplace inserts; EPA certified; non-catalytic	21,437	2,984	1,827
2104008230	Woodstove: fireplace inserts; EPA certified; catalytic	5,387	1,053	774
2104008310	Woodstove: freestanding, non-EPA certified	237,219	31,451	54,474
2104008320	Woodstove: freestanding, EPA certified, non-catalytic	45,572	6,344	3,884
2104008330	Woodstove: freestanding, EPA certified, catalytic	12,234	2,391	1,758
2104008400	Woodstove: pellet-fired, general (freestanding or insert)	3,859	743	10
2104008510	Furnace: Indoor, cordwood-fired, non-EPA certified	43,894	6,599	2,821
2104008700	Outdoor wood burning device (fire-pits, chimineas, etc.)	17,503	2,772	2,220
2104009000	Total: All Combustor Types	5,541	1,299	1,752
	TOTAL	**553,119**	**78,253**	**101,031**
MRPO (IL, IN, OH, MI, WI)				
2104008100	Fireplace: general	43,425	6,878	5,508
2104008210	Woodstove: fireplace inserts; non-EPA certified	52,583	6,972	12,075
2104008220	Woodstove: fireplace inserts; EPA certified; non-catalytic	11,581	1,612	987
2104008230	Woodstove: fireplace inserts; EPA certified; catalytic	2,821	551	405
2104008310	Woodstove: freestanding, non-EPA certified	127,979	16,968	29,389
2104008320	Woodstove: freestanding, EPA certified, non-catalytic	24,787	3,450	2,113
2104008330	Woodstove: freestanding, EPA certified, catalytic	16,139	3,154	2,319
2104008400	Woodstove: pellet-fired, general (freestanding or insert)	1,548	298	4
2104008510	Furnace: Indoor, cordwood-fired, non-EPA certified	91,898	13,815	5,906
2104008700	Outdoor wood burning device (fire-pits, chimineas, etc.)	48,581	7,695	6,162
2104009000	Total: All Combustor Types	6,115	1,433	1,934
	TOTAL	**427,457**	**62,826**	**66,802**
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)				
2104008100	Fireplace: general	58,045	9,194	7,363
2104008210	Woodstove: fireplace inserts; non-EPA certified	63,043	8,358	14,477
2104008220	Woodstove: fireplace inserts; EPA certified; non-catalytic	12,302	1,712	1,048
2104008230	Woodstove: fireplace inserts; EPA certified; catalytic	3,039	594	437
2104008310	Woodstove: freestanding, non-EPA certified	59,788	7,927	13,729
2104008320	Woodstove: freestanding, EPA certified, non-catalytic	11,663	1,624	994
2104008330	Woodstove: freestanding, EPA certified, catalytic	2,882	563	414
2104008400	Woodstove: pellet-fired, general (freestanding or insert)	227	44	1
2104008510	Furnace: Indoor, cordwood-fired, non-EPA certified	4,216	634	271
2104008700	Outdoor wood burning device (fire-pits, chimineas, etc.)	763	121	97
2104009000	Total: All Combustor Types	4,565	1,070	1,444
	TOTAL	**220,533**	**31,841**	**40,275**

Source: EPA, 2014

Figure 9.1



Source: EIA, 2014. Note: EIA excludes DE, MD, and DC from "Northeast states"

The American Community Survey (ACS) shows similar trends in the recent increase in the use of wood as the primary home heating fuel (Census, 2015). The number of households using wood as the primary home heating energy sources increased from 436,365 in 2010 to 542,851 in 2014 in the Northeast Census region (includes all MANE-VU jurisdictions except DC, DE, and MD). This is an increase of about 6% annual growth rate for a 25% increase over the five year period. In 2014, the ACS showed that 2.6% of all households in the Northeast used wood as the primary heating energy source. For the South Census region (which includes DC, DE, and MD), the ACS reported only a 4% increase over the five year period and that 1.3% of households used wood as the primary heating energy source.

Clean Air Act Programs Controlling Residential Wood Combustion

EPA adopted a Residential Wood Burning Heaters New Source Performance Standard (NSPS) in 1988. It placed limits on indoor wood stoves, but explicitly exempted other wood burning devices. In addition to the NSPS exemptions, the different types of unregulated residential wood burning devices have greatly expanded since 1988. The 1988 NSPS set no emission limits for many types of devices now on the market, such as OWBs and pellet stoves.

On February 3, 2015, EPA updated the NSPS for residential wood heaters to make new heaters significantly cleaner. The 1988 rule applied to adjustable burn-rate woodstoves (designed to allow the owner to adjust the airflow to change the rate at which wood burns), including a type of adjustable burn-rate woodstove known as a fireplace insert. Since that time, the technology for reducing emissions from wood heaters has significantly improved and now is available to make a range of wood heaters more efficient and less polluting. The 2015 NSPS updates PM emissions limits for newly manufactured adjustable-rate woodstoves and set the first federal air standards for pellet stoves and a type of previously unregulated woodstove known as a "single burn-rate" stove (designed so the owner cannot adjust the airflow). EPA is phasing in requirements over five years to allow manufacturers time to adapt emission control technologies to their particular model lines.

EPA does not regulate the manufacture and use of wood-burning fireplaces. Rather, EPA manages a Voluntary Wood-Burning Fireplace Program to encourage the development and sale

of lower-emitting wood-burning fireplaces. EPA's fireplace program covers new masonry and prefabricated (low-mass) fireplaces and retrofit devices for existing fireplaces. Fireplace retrofits can reduce pollution up to 70 percent if installed properly. Manufacturers may apply to become program partners. To participate, manufacturers have fireplaces or retrofit devices tested and certified by an independent laboratory. EPA reviews the test results and determines whether a fireplace or retrofit device meets the program emission level. EPA-qualified units are marked with a hangtag and included in a list on the Burn Wise website (EPA, 2015g).

Several MANE-VU states have implemented voluntary wood stove change-out programs. Qualifying residents often receive incentives such as rebates, low/no interest loans and discounts to replace their old, conventional wood stoves and fireplace inserts with cleaner-burning, more efficient EPA-certified gas, pellet, electric or wood stoves and fireplaces. Households that participate in change-outs must surrender their old wood stoves to be recycled.

FACTOR 1 – COST OF COMPLIANCE

There are several strategies for reducing emissions from residential wood combustion: (1) regulatory approaches to reducing wood smoke, (2) voluntary programs to replace old, inefficient wood stoves and fireplaces, and (3) education and outreach tools to promote cleaner burning.

Compliance Costs – Regulatory Approaches

The primary regulatory approach is the establishment of performance standards for new wood heaters. For 2015 NSPS revisions, EPA made estimates of the cost-effectiveness of the new standards (EPA, 2015b). Table 9.3 is a snapshot of EPA's final cost-effectiveness calculation for pellet stoves assuming a 2.5% growth rate. The cost components consisted of capital costs per model (R&D, engineering labor, tooling, equipment integration, preliminary testing, and other costs to design and manufacture the modified wood stove model) and other fixed costs per model (certification testing and safety testing, roll-out of the modified products including store display models and burn programs, brochures, user manuals, training and product discounts).

Table 9.3 $PM_{2.5}$ Cost Effectiveness of NSPS for Pellet Stoves

			Annual Snapshots				Emission Reduction Cumulative per Year		
Year[3]	Nationwide Annual Cost[1] ($)	Nationwide Average Annual Cost ($)	Baseline $PM_{2.5}$ Emissions[2] (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction (tons)	CE based on nationwide average annual cost ($/ton)	Baseline $PM_{2.5}$ Emissions (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction[6] (tons)
2015 [4]	1,484,192	857,473	58	58	0	N/A	58	58	0
2016	1,484,192	857,473	59	59	0	N/A	117	117	0
2017	1,484,192	857,473	61	61	0	N/A	177	177	0
2018	1,564,285	857,473	62	62	0	N/A	239	239	0
2019	1,564,285	857,473	64	64	0	N/A	303	*303*	0
2020 [4]	1,564,285	857,473	65	29	36	23,667	368	332	36
2021	412,963	857,473	67	30	37	23,090	435	362	73
2022	412,963	857,473	69	30	38	22,526	504	392	111
2023	412,963	857,473	70	31	39	21,977	574	423	150

Year[3]	Nationwide Annual Cost[1] ($)	Nationwide Average Annual Cost ($)	Annual Snapshots: Baseline $PM_{2.5}$ Emissions[2] (tons)	Annual Snapshots: NSPS $PM_{2.5}$ Emissions[2] (tons)	Annual Snapshots: Emission Reduction (tons)	Annual Snapshots: CE based on nationwide average annual cost ($/ton)	Emission Reduction Cumulative per Year: Baseline $PM_{2.5}$ Emissions (tons)	Emission Reduction Cumulative per Year: NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction Cumulative per Year: Emission Reduction[6] (tons)
2024	412,963	857,473	72	32	40	21,441	646	455	190
2025	412,963	857,473	74	33	41	20,918	720	488	231
2026	412,963	857,473	76	34	42	20,408	795	522	273
2027	412,963	857,473	78	34	43	19,910	873	556	317
2028	412,963	857,473	79	35	44	19,425	952	592	361
2029	412,963	857,473	81	36	45	18,951	1,034	628	406
2030							1,034	628	406
2031							1,034	628	406
2032							1,034	628	406
2033							1,034	628	406
2034							1,034	628	406
2035							976	570	406
2036							917	511	406
2037							856	450	406
2038							794	388	406
2039							731	325	406
2040							665	296	370
2041							599	266	333
2042							530	236	294
2043							460	204	255
2044							388	172	215
2045							314	140	174
2046							238	106	132
2047							161	72	89
2048							81	36	45
Nationwide cumulative cost[5] ($):			12,862,099						
Cumulative Emission Reduction over 20-year stove lifespan (tons)			6,374						
CE based on total cost & cumulative emission reduction over 20-year emitting lifespan ($ per ton)			2,018						

[1] Estimated nationwide annual costs are in 2013 $ and are based on a 6-year amortization period of R&D costs at a 7% interest rate (during 2015-2020), plus annual certification and reporting & recordkeeping costs (ongoing through 2029, representing a 10 year model life). Years 2030 through 2048 are past the 10-year model design lifespan used in this analysis.

[2] Estimated annual emissions are based on a forecasted revenue growth rate (as a surrogate for shipments) of 2.5% from 2015 through 2029, for the purposes of a sensitivity analysis.

[3] These heaters have in-home emitting lifespans of 20 years; thus pellet stoves shipped in 2029 will be emitting through 2048.

[4] Estimated emissions assume Step 1 standard becomes effective in 2015 and Step 2 standard in 2020. For pellet stoves, estimates assume that most models already meet the Step 1 limit and that manufacturers will certify and sell existing models meeting Step 1 standard during 2015 through 2019. Therefore no emission reductions are estimated until Step 2 in 2020.

[5] The nationwide cumulative cost represents the cost to manufacturers resulting from the R&D re-design to meet the NSPS and the NSPS-caused certification and reporting & recordkeeping costs to bring these stoves to market from 2015 through 2029.

[6] In order to not overstate emission reductions caused by the NSPS, emissions are reduced to discount pellet stoves already meeting the Step 2 limit (i.e., 70% of pellet stoves already meet the Step 2 limit).

Source: EPA, 2015a

As shown in Table 9.3 above, EPA estimated a cost-effectiveness of $2,018 per ton of $PM_{2.5}$ removed. The cost-effectiveness was based on total cost and cumulative emission reduction over 20-year emitting lifespan. The final estimates were made based on 2013 dollars and a 7% interest rate applied to the amortized costs during the 6-year R&D period and a 2.5% annual growth rate.

EPA also prepared cost-effectiveness estimates for VOC and CO, although these pollutants do not have emission limits under the final NSPS. EPA prepared a sensitivity analysis in which they varied the growth rate from 2.0% to 2.1%, 2.5% and 3.0%, which caused the emission estimates and resulting cost-effectiveness to vary. Table 9.4 summarizes the range of cost-effectiveness results of EPA's analyses for four types of devices, three pollutants, two interest rates, and three growth rates.

Table 9.4 $PM_{2.5}$, CO, and VOC Cost Effectiveness of NSPS for Various New Wood Heaters

Device Type	Pollutant	Interest Rate for Amortized Costs (%)	Annual Growth Rate (%)	Cost-Effectiveness based on total cost & cumulative emission reduction over 20-year emitting lifespan ($2013 per ton)
Wood Stove	$PM_{2.5}$	7	2.0	519
Wood Stove	$PM_{2.5}$	3	2.0	456
Wood Stove	$PM_{2.5}$	7	2.5	501
Wood Stove	$PM_{2.5}$	7	3.0	483
Wood Stove	CO	7	3.0	30
Wood Stove	VOC	7	3.0	327
Pellet Stove	$PM_{2.5}$	7	2.0	2,174
Pellet Stove	$PM_{2.5}$	3	2.0	2,024
Pellet Stove	$PM_{2.5}$	7	2.5	2,018
Pellet Stove	$PM_{2.5}$	7	3.0	1,874
Pellet Stove	CO	7	3.0	390
Pellet Stove	VOC	7	3.0	151,080
Single Burn Rate Stoves	$PM_{2.5}$	7	2.0	34
Single Burn Rate Stoves	$PM_{2.5}$	3	2.0	30
Single Burn Rate Stoves	$PM_{2.5}$	7	2.5	32
Single Burn Rate Stoves	$PM_{2.5}$	7	3.0	30
Single Burn Rate Stoves	CO	7	3.0	5
Single Burn Rate Stoves	VOC	7	3.0	17
Force-air Furnaces	$PM_{2.5}$	7	2.0	69
Force-air Furnaces	$PM_{2.5}$	3	2.0	61
Force-air Furnaces	$PM_{2.5}$	7	2.5	64
Force-air Furnaces	$PM_{2.5}$	7	3.0	60
Force-air Furnaces	CO	7	3.0	11
Force-air Furnaces	VOC	7	3.0	58

Source: EPA, 2015b; EPA, 2015c; EPA, 2015d; EPA, 2015e; EPA, 2015f.

Other regulatory approaches have been developed primarily to address local air pollution episodes (EPA, 2013), including:

- **Wood-burning Curtailment Programs**. Implement a mandatory curtailment program, also known as "burn bans," when weather conditions lead to air inversions which can lead to locally unhealthy levels of air pollution. Although curtailment programs are not always popular with the public, this measure can be highly effective at reducing wood smoke and has been successfully implemented in a number of communities.
- **Opacity and Visible Emission Limits**. Implement a program that allows no visible wood smoke or establishing opacity limits that restrict the percentage of light that may be prevented from passing through the smoke plume. The no visible emission option is easier to enforce than an opacity program, which require personnel qualified as opacity readers to determine compliance.
- **Restrictions on Wood Moisture Content**. Wood that is not properly seasoned will burn less efficiently and release more harmful pollutants. Implement a program to allow only the sale and/or burning of dry seasoned wood (e.g., less than 20% moisture) in wood burning appliances. To increase the likelihood that stove owners will burn seasoned wood, some air pollution control agencies have encouraged the use of wood moisture meters, which cost less than $25.
- **Removal of Old Wood Stoves upon Resale of a Home**. Some local communities require the removal and destruction of old wood stoves upon the resale of a home. This requirement has proven effective in locations like Mammoth Lakes, CA; Washoe County, NV; and the State of Oregon.
- **Restrictions of Wood-Burning Devices in New Construction**. Banning the installation of any wood-burning hearth appliances in new construction, or restricting the number and density of new wood-burning appliances in a given area.

Cost data and the emission reduction potentials for these other regulatory approaches are not readily available.

Compliance Costs – Voluntary Approaches

In addition to regulatory programs, several state and local agencies have implemented wood stove and fireplace replacement programs to help address wood smoke issues (EPA, 2013). These programs are designed to motivate households to replace older technologies with safer, more efficient, cleaner burning technologies. These programs are most effective when they also include education and outreach to ensure that households burn wood more efficiently and cleanly.

EPA estimates that more than 24,000 wood stoves and fireplaces have been replaced or retrofitted in 50 communities, resulting in approximately 3,700 tons of fine particle emissions reduced each year. EPA developed a table that lists residential wood combustion control measures to reduce $PM_{2.5}$ and other pollutants. This table is presented as Table 9.5 and includes estimated control efficiency and cost effectiveness numbers along with additional information.

Table 9.5 $PM_{2.5}$ Control Efficiency and Cost Effectiveness of Certain Residential Wood Combustion Control Measures

Appliance	Control Measure	Control Efficiency	Estimated Cost Effectiveness ($2012/ton)	Description/Notes/Caveats
Fireplaces	Use EPA Phase 2 Qualified Units	70%	$9,500	If new fireplace construction is allowed, approve only EPA Phase 2 qualified models. Under the EPA Wood-burning Fireplace Program, cleaner wood-burning fireplaces are qualified when their $PM_{2.5}$ emissions are at or below the Phase 2 $PM_{2.5}$ emissions level.
Fireplaces	Use Gas Logs in Existing Wood-burning Fireplaces	100%	$11,000	Incentives by various air districts in CA have helped retrofit thousands of open fireplaces to gas log sets. In addition to vented gas log sets, the option exists to install vented gas stove inserts into a wood-burning fireplace. Unlike gas logs, which provide little heat, a gas stove insert can be an efficient and clean way to heat a room. The cost per ton of $PM_{2.5}$ reductions will likely be greater as gas stove inserts cost more than gas log sets.
Fireplaces	Install Retrofit Devices into Existing Wood-burning Fireplaces	75%	$9,500	Provide incentives to encourage use of fireplace retrofit devices. Under the EPA Wood-burning Fireplace Program, retrofit devices are qualified when their $PM_{2.5}$ emissions are at or below the program Phase 2 $PM_{2.5}$ emissions level.
Wood Stoves	Wood to Wood Replacement Program	60%	$9,900	Implement a program and provide incentives to replace old uncertified wood stoves with new EPA-certified wood stoves. Education on proper wood stove use (e.g., burn only dry wood) and maintenance is critical.
Wood Stoves	Wood to Gas Replacement Program	99%	$7,200	Implement an incentive program to replace old, uncertified wood stoves with new gas stoves or gas logs.

Source: EPA, 2013

CSRA (MARAMA's contractor for this effort) independently estimated the cost-effectiveness of replacing older technology wood-burning devices with devices that are compliant with the Step 2 emission limits contained in the 2015 NSPS revisions.

- First, CSRA calculated the annualized cost for an NSPS-compliance stove, which take into account the capital costs associated with the installation/replacement of each newer technology and the annual maintenance cost. For this analysis, CSRA assumed other annual costs (chimney cleaning, fuel costs) would remain the same after the replacement as before the replacement. Table 9.6 summarized these cost calculations.
- CSRA calculated the emission reductions associated with replacing existing devices with NSPS Step 2 compliance devices. CSRA did this for three annual consumption scenarios, since the average amount of wood burned varies from the colder northern region of MANE-VU to the southern region. The wood consumption scenarios represent the low, average, and high state-level annual consumption per device (OMNI, 2006).
- Finally, CSRA calculated the cost-effectiveness of each replacement scenario by dividing the annualized replacement cost by the emission reduction.

Table 9-6 Cost Calculations for Three Types of NSPS-compliant Wood Stoves

	Wood Stove noncatalytic		Wood Stove catalytic		Pellet Stove	
	Average	**High**	**Average**	**High**	**Average**	**High**
CAPITAL COSTS						
Equipment Cost[1] ($2014)	848	2,800	848	2,800	1,279	3,500
Installation Cost[1] ($2014)	500	500	500	500	300	300
Total Capital Investment	1,348	3,300	1,348	3,300	1,579	3,800
Annual interest rate (%)	7.0	7.0	7.0	7.0	7.0	7.0
System lifespan (years)	20	20	20	20	20	20
Capital recovery factor	0.0944	0.0944	0.0944	0.0944	0.0944	0.0944
Annualized Capital Cost ($2014)	**127**	**311**	**127**	**311**	**149**	**359**
OPERATING COSTS (not including the cost of wood)						
Catalyst Replacement[3] ($2014)	0	0	43	43	0	0
Power Usage[4] (kw)	0	0	0	0	0.38	0.38
Hours Used Annually (hrs)	0	0	0	0	1,368	1,368
Electricity cost[5] ($2014)/kw-hr)	0.1762	0.1762	0.1762	0.1762	0.1762	0.1762
Annual Electricity Cost ($2014)	0	0	0	0	97	97
Annual Operating Cost ($2014)	**0**	**0**	**43**	**43**	**97**	**97**
TOTAL ANNUALIZED COST ($2014)	**127**	**311**	**170**	**354**	**241**	**450**

(1) Source: EPA, 2015a; Table 3-13, 2008 costs escalated to 2014 using Chemical Engineering Plant Index
(2) Source: EPA, 2015a; Table 3-12, 2008 costs escalated to 2014 using Chemical Engineering Plant Index
(3) Source: OMNI, 2006; Catalyst replacement cost, relevant only to the certified catalytic cordwood stoves and inserts was annualized from the data provided by the hearth products retailers.
(4) Source: OMNI, 2006; Electricity costs are relevant for stoves that have electrical components. For example, pellet stoves require electricity to run their fan, auger, and other control components.
(5) Source: EIA, 2015; used a rate of $0.1762 per kw-hr (New England average residential rate, September 2014).

Tables 9.7, 9.8 and 9.9 summarize the emission reduction and cost-effectiveness calculations for $PM_{2.5}$, VOC, and CO, respectively. The tables allow for a direct comparison of the cost burden for each realistic mitigation option that would be shouldered by residential users.

Table 9.7 $PM_{2.5}$ Cost-Effectiveness for Several Woodstove Change-Out Options

Annual tons Burned	$PM_{2.5}$ Emission Factor (lbs/ton)		Annual $PM_{2.5}$ Emissions (lbs)		Emission Reduction (lbs)	Annualized Replacement Cost ($2014)	Cost Effectiveness ($2014/ton)
	Existing	NSPS Step 2	Existing	NSPS Step 2			
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	30.6	3.89	35.2	4.5	30.7	127	8,269
2.77	30.6	3.89	84.8	10.8	74.0	127	3,433
3.53	30.6	3.89	108.0	13.7	94.3	127	2,694
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	30.6	7.79	35.2	9.0	26.2	170	12,962
2.77	30.6	7.79	84.8	21.6	63.2	170	5,381
3.53	30.6	7.79	108.0	27.5	80.5	170	4,223
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	30.6	1.36	35.2	1.6	33.6	241	14,334
2.77	30.6	1.36	84.8	3.8	81.0	241	5,951
3.53	30.6	1.36	108.0	4.8	103.2	241	4,670
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	8.76	3.89	10.1	4.5	5.6	127	45,353
2.77	8.76	3.89	24.3	10.8	13.5	127	18,829
3.53	8.76	3.89	30.9	13.7	17.2	127	14,775
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	8.76	7.79	10.1	9.0	1.1	170	304,796
2.77	8.76	7.79	24.3	21.6	2.7	170	126,540
3.53	8.76	7.79	30.9	27.5	3.4	170	99,296
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	8.76	1.36	10.1	1.6	8.5	241	56,639
2.77	8.76	1.36	24.3	3.8	20.5	241	23,514
3.53	8.76	1.36	30.9	4.8	26.1	241	18,452
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	9.72	3.89	11.2	4.5	6.7	127	37,885
2.77	9.72	3.89	26.9	10.8	16.1	127	15,728
3.53	9.72	3.89	34.3	13.7	20.6	127	12,342
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	9.72	7.79	11.2	9.0	2.2	170	153,188
2.77	9.72	7.79	26.9	21.6	5.3	170	63,598
3.53	9.72	7.79	34.3	27.5	6.8	170	49,905
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	9.72	1.36	11.2	1.6	9.6	241	50,135
2.77	9.72	1.36	26.9	3.8	23.2	241	20,814
3.53	9.72	1.36	34.3	4.8	29.5	241	16,333
Replace Old Pellet-fired Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	3.06	1.36	3.5	1.6	2.0	241	246,547
2.77	3.06	1.36	8.5	3.8	4.7	241	102,357
3.53	3.06	1.36	10.8	4.8	6.0	241	80,320

Table 9.8 VOC Cost-Effectiveness for Several Woodstove Change-Out Options

Annual tons Burned	VOC Emission Factor (lbs/ton)		Annual VOC Emissions (lbs)		Emission Reduction (lbs)	Annualized Replacement Cost ($2014)	Cost Effectiveness ($2014/ton)
	Existing	NSPS Step 2	Existing	NSPS Step 2			
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	53.0	5.33	61.0	6.1	54.8	127	4,633
2.77	53.0	5.33	146.8	14.8	132.0	127	1,924
3.53	53.0	5.33	187.1	18.8	168.3	127	1,509
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	53.0	12.0	61.0	13.8	47.2	170	7,211
2.77	53.0	12.0	146.8	33.2	113.6	170	2,994
3.53	53.0	12.0	187.1	42.4	144.7	170	2,349
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	53.0	0.02	61.0	0.0	60.9	241	7,911
2.77	53.0	0.02	146.8	0.1	146.8	241	3,284
3.53	53.0	0.02	187.1	0.1	187.0	241	2,577
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	12.0	5.33	13.8	6.1	7.7	127	33,114
2.77	12.0	5.33	33.2	14.8	18.5	127	13,748
3.53	12.0	5.33	42.4	18.8	23.5	127	10,788
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	12.0	12.0	13.8	13.8	0.0	170	No reduction
2.77	12.0	12.0	33.2	33.2	0.0	170	No reduction
3.53	12.0	12.0	42.4	42.4	0.0	170	No reduction
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	12.0	0.02	13.8	0.0	13.8	241	34,986
2.77	12.0	0.02	33.2	0.1	33.2	241	14,525
3.53	12.0	0.02	42.4	0.1	42.3	241	11,398
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	15.0	5.33	17.3	6.1	11.1	127	22,841
2.77	15.0	5.33	41.6	14.8	26.8	127	9,483
3.53	15.0	5.33	53.0	18.8	34.1	127	7,441
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	15.0	12.0	17.3	13.8	3.5	170	98,551
2.77	15.0	12.0	41.6	33.2	8.3	170	40,915
3.53	15.0	12.0	53.0	42.4	10.6	170	32,106
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	15.0	0.02	17.3	0.0	17.2	241	27,979
2.77	15.0	0.02	41.6	0.1	41.5	241	11,616
3.53	15.0	0.02	53.0	0.1	52.9	241	9,115
Replace Old Pellet-fired Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	0.041	0.02	0.0	0.0	0.0	241	19,958,592
2.77	0.041	0.02	0.1	0.1	0.1	241	8,286,058
3.53	0.041	0.02	0.1	0.1	0.1	241	6,502,091

Table 9.9 CO Cost-Effectiveness for Several Woodstove Change-Out Options

Annual tons Burned	CO Emission Factor (lbs/ton)		Annual CO Emissions (lbs)		Emission Reduction (lbs)	Annualized Replacement Cost ($2014)	Cost Effectiveness ($2014/ton)
	Existing	NSPS Step 2	Existing	NSPS Step 2			
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	231	62.6	265.4	72.0	193.4	127	1,313
2.77	231	62.6	639.3	173.4	465.9	127	545
3.53	231	62.6	814.7	221.0	593.7	127	428
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	231	83.5	265.4	96.0	169.4	170	2,007
2.77	231	83.5	639.3	231.3	408.0	170	833
3.53	231	83.5	814.7	294.8	520.0	170	654
Replace Old non-EPA Certified Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	231	7.1	265.4	8.2	257.3	241	1,874
2.77	231	7.1	639.3	19.7	619.6	241	778
3.53	231	7.1	814.7	25.1	789.7	241	610
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	141	62.6	161.9	72.0	89.9	127	2,824
2.77	141	62.6	390.0	173.4	216.6	127	1,173
3.53	141	62.6	497.0	221.0	276.0	127	920
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	141	83.5	161.9	96.0	65.9	170	5,160
2.77	141	83.5	390.0	231.3	158.7	170	2,142
3.53	141	83.5	497.0	294.8	202.3	170	1,681
Replace Old EPA Certified non-Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	141	7.1	161.9	8.2	153.8	241	3,135
2.77	141	7.1	390.0	19.7	370.3	241	1,301
3.53	141	7.1	497.0	25.1	472.0	241	1,021
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified non-Catalytic Stove							
1.15	104	62.6	120.1	72.0	48.1	127	5,284
2.77	104	62.6	289.2	173.4	115.8	127	2,194
3.53	104	62.6	368.5	221.0	147.6	127	1,721
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Catalytic Stove							
1.15	104	83.5	120.1	96.0	24.0	170	14,146
2.77	104	83.5	289.2	231.3	57.9	170	5,873
3.53	104	83.5	368.5	294.8	73.8	170	4,608
Replace Old EPA Certified Catalytic Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	104	7.1	120.1	8.2	111.9	241	4,308
2.77	104	7.1	289.2	19.7	269.5	241	1,788
3.53	104	7.1	368.5	25.1	343.5	241	1,403
Replace Old Pellet-fired Stove with NSPS Step 2 EPA Certified Pellet-fired Stove							
1.15	15.9	7.1	18.3	8.2	10.1	241	47,628
2.77	15.9	7.1	44.0	19.7	24.4	241	19,774
3.53	15.9	7.1	56.1	25.1	31.1	241	15,516

Compliance Costs – Education and Outreach

Wood smoke education and outreach is an important part of reducing $PM_{2.5}$. Engaging the public and giving them the tools to make informed decisions about what they burn and how they burn have been in effect for many years and have been proven effective (EPA, 2013). With proper burning techniques and well-seasoned wood, emissions (even in older wood-burning appliances) can be significantly reduced. While a new wood stove, hydronic heater, or wood-burning fireplace will typically pollute less than older appliances when used properly, it is important to emphasize that how a user operates their appliance is equally important in maximizing energy efficiency and reducing emissions.

For example, EPA's Burn Wise program (EPA, 2015g) serves as a resource for states and communities. Burn Wise is a way to encourage the importance of burning the right wood, the right way, in the right wood-burning appliance. The program offers a website, outreach tools and information to help consumers make informed decisions about what it means to burn wise. Several MANE-VU states have already developed similar education and outreach programs in their states.

Information about the costs associated with developing and implementing education and outreach programs at the state level are currently not available.

FACTOR 2 – COMPLIANCE TIMEFRAME

New woodstoves meeting more stringent PM emissions standards would be phased in slowly as older woodstoves are replaced. EPA's Step 1 NSPS emissions limits became effective nationally in 2015. EPA's Step 2 NSPS PM emissions limits become effective nationally in 2020. Thus, full compliance is likely to be around 2040, at the earliest.

Replacement of wood-fired stoves manufactured before the state or EPA standards took effect will gradually occur over the assumed 20 year life span of the units. Since they are designed to last for approximately 20 years, woodstove operators would likely be reluctant to replace them immediately. It is possible for older outdoor wood-fired boilers to be replaced more quickly given the proper economic incentives.

FACTOR 3 – ENERGY AND NON-ENVIRONMENTAL IMPACTS

Other factors beyond $PM_{2.5}$ and regional haze (i.e., VOC and fine particles) should also influence RWC regulatory policy. The greenhouse gas benefits of biomass combustion and the minimal acid gas emissions (acid precipitation impacts) from wood combustion are strong environmental advantages. Further, the fact that wood is a domestic renewable energy source and the fact that the cost of natural gas, propane, and fuel oil have a history of rising together have been responsible for the increase in the use of RWC.

For example, Renewable Heat NY is a program to help the high-efficiency, low-emission biomass heating industry reach scale. It encourages quicker development of the industry, raises consumer awareness, support the development of New York-based advanced technology heating products, and develop local sustainable heating markets that use biomass as fuel. Renewable Heat NY also aims to reduce wood smoke, fine particles and carbon monoxide emissions.

EPA noted in its 2015 NSPS revisions that the final rule is not likely to have any significant adverse energy effects. In general, EPA expects the NSPS to improve technology, including energy efficiency. Reducing emissions and increasing efficiency might increase the use of wood fuel, which would relieve pressure on traditional coal or petroleum based energy sources (and greenhouse gas emissions). But it is difficult to determine the precise energy impacts because wood-fueled appliances compete with other biomass forms as well as more traditional oil, electricity and natural gas. Robust data are not available to determine the potential conversion to other types of fuels and their associated appliances if the consumer costs of wood-fueled appliances increase and at what level that increase would drive consumer choice.

The increased use of residential wood combustion devices may have a variety of non-air impacts on the environment, especially on forest and water resources (MACTEC, 2007). The potential impacts are outlined below.

Nuisance Smoke: Outdoor wood-fired boilers typically have very short stacks, and are prone to smoke. The short stacks oftentimes prevent proper mixing of the smoke and soot with the surrounding air, thereby creating nuisance smoke problems for surrounding houses or communities.

Water: Increased logging to satisfy the demand for firewood may increase runoff of silts and sediments into adjacent creeks and rivers. This increased sediment load in rivers can affect aquatic ecosystems that are integral to rivers and streams.

Soils: Increased logging may impact soils in many ways. For example, heavy machinery used to fell and process trees may lead to rutting and compaction of the soil, which in turn leads to higher erosion and/or altered vegetative regrowth.

Wildlife: Increased logging may put pressure on existing wildlife populations in the US Northeast by altering their critical habitat.

Threatened and Endangered Species: Increased logging in Northeast may impact threatened and endangered species through habitat destruction or alteration.

Any mandatory change out program should be mindful that even with assistance, woodstove change out programs will impact families that are least able to bear the burden of additional costs. Voluntary programs do not impose this economic burden on families less able to bear associated costs.

FACTOR 4 – REMAINING USEFUL LIFE

Most wood heaters in consumer homes emit for at least 20 years and often much longer (EPA, 2015a). However, in order to address industry comments, EPA used a 10-year model design lifespan for estimating costs and assumed a 20-year appliance emitting lifespan. This assumption was made to best characterize the actual use lifespan given that most stoves in consumer homes emit for at least 20 years and often much longer. EPA assumed that models do not come into

compliance until the year they are required to, although some models will meet the NSPS Step 2 PM limit prior to the 2020 compliance year and will therefore be emitting less than baseline levels prior to that year.

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CHAPTER 10

SOURCE CATEGORY ANALYSIS: OUTDOOR WOOD-FIRED BOILERS

BACKGROUND

The MANE-VU Contribution Assessment and other MANE-VU reports have documented that visibility impairment in this region is primarily due to regional secondary sulfate (NESCAUM 2006a). In addition, biomass combustion as a contributor to visibility impairment in MANE-VU Class I areas. Biomass combustion emissions due to human activity primarily derive from residential wood combustion. While some biomass burning occurs throughout the year, residential wood combustion occurs predominantly in the winter months, potentially contributing to wintertime peaks in PM concentrations.

MANE-VU previously developed an assessment (MACTEC, 2007) of control technologies to achieve reasonable progress goals with respect to the four factors listed in Section 169A of the Clean Air Act. The information presented in this Chapter is an update to some parts of the MACTEC report.

Source Category Description

An outdoor wood heater, also often called an outdoor wood-fired boiler (OWB), is a type of hydronic heater that is designed to be the home's primary heating system. OWBs are located in structure detached from the home and have the appearance of a small shed with a smokestack. OWBs burn wood to heat a liquid contained in a closed-loop system. The heated liquid is then circulated to the house to provide heat and hot water. OWBs are typically sold in areas with cold climates where wood may be the most readily available fuel source. In addition to OWBs, there is an emerging market for indoor hydronic heaters. Currently, the indoor hydronic heater market is approximately 10% of the OWB market (EPA, 2015a).

Manufacturers design OWBs to burn large amounts of wood over long periods of time. OWBs vary in size ranging from 115,000 BTU/hr to 3.2 million BTU/hr, although residential OWBs tend to be less than 1 million BTU/hr. According to sales data, the size of the most commonly sold unit is 500,000 BTU/hr. OWBs heat buildings ranging in size from 1,800 square feet to 20,000 square feet (NESCAUM, 2006b).

Typically, the dimensions of an OWB are three to five feet wide, six to nine feet deep, and six to ten feet tall, including the height of the chimney. Inside the OWB is an oversized firebox that can accommodate extremely large loads. Firebox sizes will vary with each unit but tend to range in size from 20 cubic feet up to 150 cubic feet. Industry literature indicates that a commonly sized residential unit can easily accommodate wood pieces that are 30 inches in diameter and 72 inches long. Surrounding the firebox is a water jacket that can be heated to temperatures up to 190°F. The OWB cycles water through the jacket to deliver hot water to the building. Water pipes run underground to deliver hot water for both space heating and domestic use (EPA, 2015a).

Consumption and Emission Trends

Table 10.1 shows the CO, $PM_{2.5}$ and VOC emissions in 2011 from outdoor wood boilers for the MANE-VU, MRPO, and VISTAS RPO states. The emission estimates were developed by EPA using the Residential Wood Combustion Tool. This tool computes county-and SCC-level emissions of criteria and HAPs for the entire country. EPA updated the inputs to the tool for the 2011 National Emission Inventory in partnership with the Eastern Regional Technical Advisory Committee (ERTAC). Emission trends over the past decade are not available due to improvements in emission factors and emission estimation methodologies. The new Residential Wood Combustion Tool used a new suite of source categories, new emission factors and a new calculation methodology. Thus, the resulting emissions for this sub-category of area emissions are not comparable between older and newer inventories.

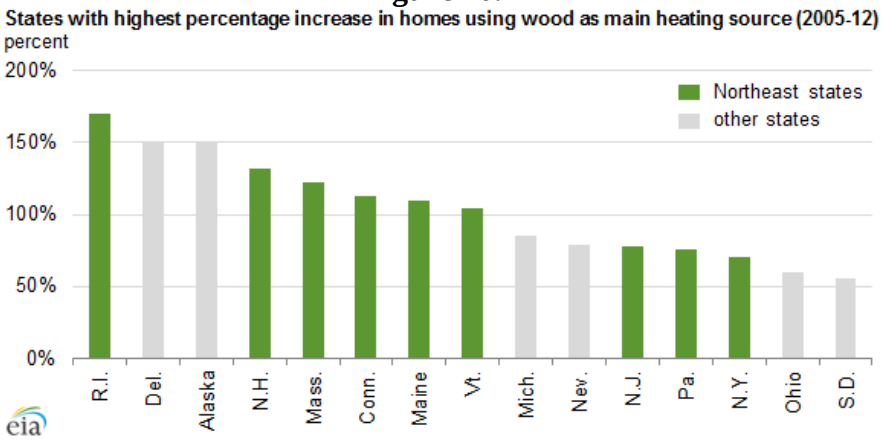
Table 10.1 2011 Emissions from Outdoor Wood Boilers (tons/year)
SCC = 21-04-008-610, Outdoor Hydronic Heaters

RPO	# of OWB	CO	$PM_{2.5}$	VOC
MANE-VU	63,150	107,468	19,105	20,120
MRPO	135,409	307,951	54,747	57,655
VISTAS	17,025	16,645	2,959	3,116

Source: EPA Residential Wood Combustion Tool (EPA 2014)
MANEVU (CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, and VT)
MRPO (IL, IN, OH, MI, WI)
VISTAS (AL, FL, GA, KY, MS, NC, SC, TN, VA, WV)

Wood as a main heating source in homes has gained popularity in many areas of the country in recent years, but the increase is most notable in the Northeast (EIA, 2014). As shown Figure 10.1, most states in MANE-VU RPO saw at least a 50% jump from 2005 to 2012 in the number of households that rely on wood as the main heating source. As the price of fuel oil and kerosene in this region increased during that period, fuel oil and kerosene use has declined in recent years as many households have turned to lower-cost alternatives, including wood.

Figure 10.1



Source: EIA, 2014. EIA used the Census definition of "Northeast states," which excludes DE, DC, and MD.

The American Community Survey (ACS) shows similar trends in the recent increase in the use of wood as the primary home heating fuel (Census, 2015). The number of households using wood as the primary home heating energy sources increased from 436,365 in 2010 to 542,851 in 2014 in the Northeast Census region (includes all MANE-VU jurisdictions except DC, DE, and MD). This is an increase of about 6% annual growth rate for a 25% increase over the five year period. In 2014, the ACS showed that 2.6% of all households in the Northeast used wood as the primary heating energy source. For the South Census region (which includes DC, DE, and MD), the ACS reported only a 4% increase over the five year period and that 1.3% of households used wood as the primary heating energy source.

Obviously not all of the growth in wood use will be for outdoor wood boilers. Future demand for outdoor wood boilers will be somewhat dependent on the price of wood fuel relative to electric, heating oil and gas heat, as well as consumer preferences. The recent drop in the price of heating oil over the past two years makes predictions of future growth subject to considerable uncertainty. Previous studies reported that over 155,000 outdoor wood boilers were in use in the United States in 2006 (NESCAUM, 2006). The NESCAUM report also estimated annual growth in sales of outdoor wood boilers of between 30 and 128%, resulting in a prediction that over 500,000 outdoor wood boilers would be in use before the end of 2010 if trends in annual sales continued to follow growth rates observed between 1990 and 2006. However, EPA estimated that there were only about 250,000 units for the 2011 NEI (EPA, 2014) using the Residential Wood Consumption Tool. EPA also estimated that 13,385 hydronic central heating systems were shipped in 2008 (EPA, 2015), and EPA projected an annual growth rate of 2-3%.

Regulatory History

EPA adopted a New Source Performance Standard (NSPS) for Residential Wood Burning Heaters in 1988. It placed limits on indoor wood stoves, but explicitly exempted other wood burning devices. In addition to the NSPS exemptions, the types of unregulated residential wood burning devices have greatly expanded since 1988. The 1988 NSPS does not limit emissions from many types of devices now in the market, such as OWBs and pellet stoves.

On January 29, 2007, NESCAUM made available its "Outdoor Hydronic Heater Model Regulation." The model rule was designed to serve as a template to assist State and local agencies in adopting requirements that will reduce air pollution from OWBs. The model rule was developed in cooperation with a number of States and EPA. The model rule contains a single method for regulating new units with respect to the critical elements and contemplates that States may propose alternative approaches for other provisions. It also provides alternatives for states to consider for regulating previously installed units (NESCAUM 2007).

NESCAUM's model rule sets standards for particulate matter (PM) emissions by phases for residential and commercial boilers. The PM standards for both boiler types are identical. Phase I calls for a PM emission limit of 0.44 pounds per million BTU heat input. This standard was to be met by March 31, 2008. Phase II calls for a PM emission standard of 0.32 lb/MMBTU which was to be met by March 31, 2010. Table 10.2 summarizes each of the MANE-VU states regulatory and voluntary efforts to control emissions from outdoor wood boilers. Most states have adopted regulations similar to the NESCAUM's model rule.

In 2007, EPA launched a voluntary program to encourage manufacturers to make hydronic heaters cleaner. Through the voluntary Hydronic Heater Program, manufacturers have redesigned some models to make new units available to consumers that are 90 percent cleaner on average than unqualified models, based on laboratory testing (EPA, 2016).

Table 10.2 State Programs for Outdoor Wood Boilers in the MANE-VU Region (as of December10, 2015)

Jurisdiction	OWB Control Requirements	Regulatory Citation
CT	Setback and stack height requirements; voluntary purchase of new OWBs in accordance with EPA's voluntary Hydronic Heaters Program; Outdoor Wood-fired Furnace incentive program to replace older furnaces	Section 22a-174k of CT General Statutes
DE	Nothing specific to OWBs	
DC	Nothing specific to OWBs	
MA	PM limit of 0.32 lbs/MMBTU by December 26, 2008, for new units; setback and stack height requirements; visible emission limitations	310 CMR 7.26(50) Outdoor Hydronic Heaters
MD	PM limit of 0.32 lbs/MMBTU by April 1, 2010 for new units	Title 26, Subtitle 11, Section 26.11.09.11
ME	PM limit of 0.32 lbs/MMBTU by April 1, 2010 for new units; setback and stack height requirements; visible emission limitations	Chapter 150: Control of Emissions from Outdoor Wood Boilers
NH	PM limit of 0.32 lbs/MMBTU by April 1, 2010 for new units; setback and stack height requirements; visible emission limitations	Chapter 125-R Outdoor Wood-Fired Hydronic Heaters
NJ	Visible emission limitations	7:27-3.2 Smoke emissions from stationary indirect heat exchanges
NY	PM limit of 0.32 lbs/MMBTU by April 15, 2011 for new units; setback and stack height requirements; visible emission limitations	6 NYCRR Part 247 Outdoor Wood Boilers
PA	PM limit of 0.32 lbs/MMBTU by May 31, 2011 for new units; setback and stack height requirements	123.14. Outdoor wood-fired boilers
RI	PM limit of 0.32 lbs/MMBTU by July 1, 2011 for new units	Air Pollution Control Regulation No. 48 – Outdoor Wood Boilers
VT	PM limit of 0.32 lbs/MMBTU by March 31, 2010 for new units; setback and stack height requirements; visible emission limitations; voluntary OWB change out program with financial incentives to encourage replacement of older OWBs (suspended 9/30/2015)	5-204 Outdoor Wood Fired Boilers

On February 3, 2015, EPA revised the NSPS to include several types of previously unregulated new wood heaters, including outdoor and indoor wood-fired boilers (also known as hydronic heaters), and indoor wood-burning forced air furnaces. The revised NSPS has a 2-step approach to emission limits and compliance deadlines for newly manufactured units. The Step 1 PM emissions limit, effective in 2015, is identical to the current qualifying level for EPA's voluntary Hydronic Heater Program of 0.32 pounds per million BTU heat output (weighted average), with a cap of 18 grams per hour for individual test runs. The Step 2 emission limit is 0.10 pounds per million BTU heat output for each burn rate, with an alternative limit of 0.15 pounds per million BTU heat output for each burn rate is tested with cordwood. The Step 2 compliance date (2020) is 5 years after the final rule was published.

NESCAUM conducted tests on an OWB and reported in 2008 that it was technically feasible to add controls to existing OWB, but that no commercial retrofit products were available. NESCAUM indicated that significant emissions reductions could be achieved through add-on controls, and also that the species of wood and the moisture content of the wood burned strongly affected emissions (NESCAUM, 2008). This indicates that education on the proper use of OWB could reduce emissions from existing units.

FACTOR 1 – COST OF COMPLIANCE

There are several strategies for reducing emissions from outdoor wood boilers: (1) regulatory approaches to reducing wood smoke, (2) voluntary programs to replace old, inefficient wood stoves and fireplaces, and (3) education and outreach tools to promote cleaner burning.

Compliance Costs – Regulatory Approaches

The primary regulatory approach is the establishment of performance standards for new wood heaters. For new outdoor wood boilers under the 2015 NSPS revisions, EPA made estimates of the cost-effectiveness of the new standards (EPA, 2015b). Table 10.3 is a snapshot of EPA's final cost-effectiveness calculation for Force Air Furnaces and Hydronic Heating Systems.

Table 10.3 $PM_{2.5}$ Cost Effectiveness of NSPS for Hydronic Heating Systems

			Annual Snapshots				Emission Reduction Cumulative per Year		
Year[3]	Nationwide Annual Cost[1] ($)	Nationwide Average Annual Cost ($)	Baseline $PM_{2.5}$ Emissions[2] (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction (tons)	CE based on nationwide average annual cost ($/ton)	Baseline $PM_{2.5}$ Emissions (tons)	NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction[6] (tons)
2015 [4]	24,855,398	10,321,500	3,710	371	3,339	3,091	3,710	371	3,339
2016	24,855,398	10,321,500	3,803	380	3,423	3,015	7,514	751	6,762
2017	24,855,398	10,321,500	3,898	390	3,508	2,942	11,412	1,141	10,271
2018	24,894,927	10,321,500	3,996	400	3,596	2,870	15,408	1,541	13,867
2019	24,894,927	10,321,500	4,096	410	3,686	2,800	19,503	1,950	17,553
2020 [4]	24,894,927	10,321,500	4,198	131	4,067	2,538	23,701	2,082	21,620
2021	619,059	10,321,500	4,303	134	4,168	2,476	28,004	2,216	25,788
2022	619,059	10,321,500	4,411	138	4,273	2,416	32,415	2,354	30,061
2023	619,059	10,321,500	4,521	141	4,380	2,357	36,936	2,495	34,440
2024	619,059	10,321,500	4,634	145	4,489	2,299	41,569	2,640	38,929
2025	619,059	10,321,500	4,750	148	4,601	2,243	46,319	2,788	43,531
2026	619,059	10,321,500	4,868	152	4,716	2,188	51,187	2,940	48,247
2027	619,059	10,321,500	4,990	156	4,834	2,135	56,178	3,096	53,081
2028	619,059	10,321,500	5,115	160	4,955	2,083	61,292	3,256	58,036
2029	619,059	10,321,500	5,243	164	5,079	2,032	66,535	3,420	63,115
2030							66,535	3,420	63,115
2031							66,535	3,420	63,115
2032							66,535	3,420	63,115
2033							66,535	3,420	63,115
2034							66,535	3,420	63,115
2035							62,825	3,049	59,776
2036							59,022	2,669	56,353
2037							55,123	2,279	52,844

Year[3]	Nationwide Annual Cost[1] ($)	Nationwide Average Annual Cost ($)	Annual Snapshots: Baseline $PM_{2.5}$ Emissions[2] (tons)	Annual Snapshots: NSPS $PM_{2.5}$ Emissions[2] (tons)	Annual Snapshots: Emission Reduction (tons)	Annual Snapshots: CE based on nationwide average annual cost ($/ton)	Emission Reduction Cumulative per Year: Baseline $PM_{2.5}$ Emissions (tons)	Emission Reduction Cumulative per Year: NSPS $PM_{2.5}$ Emissions[2] (tons)	Emission Reduction Cumulative per Year: Emission Reduction[6] (tons)
2038							51,128	1,879	49,248
2039							47,032	1,470	45,562
2040							42,834	1,339	41,495
2041							38,531	1,204	37,327
2042							34,120	1,066	33,054
2043							29,600	925	28,675
2044							24,966	780	24,186
2045							20,216	632	19,584
2046							15,348	480	14,868
2047 [3]							10,358	324	10,034
2048 [3]							5,243	164	5,079
Nationwide cumulative cost[5] ($):			154,822,505						
Cumulative Emission Reduction over 20-year stove lifespan (tons)			856,776						
CE based on total cost & cumulative emission reduction over 20-year emitting lifespan ($ per ton)			181						

[1] Estimated nationwide annual costs are in 2013 $ and are based on a 6-year amortization period of R&D costs at a 7% interest rate (during 2015-2020), plus annual certification and reporting & recordkeeping costs (ongoing through 2029, representing a 10 year model life). Years 2030 through 2048 are past the 10-year model design lifespan used in this analysis.

[2] Except for an adjustment in year 2012 based on an industry projection (NERA), estimated annual emissions are based on a forecasted revenue growth rate (as a surrogate for shipments) of 2.5% from 2015 through 2029, for the purposes of a sensitivity analysis.

[3] These heaters have in-home emitting lifespans of at least 20 years; thus hydronic heaters shipped in 2029 will be emitting through 2048.

[4] Estimated emissions assume Step 1 standard becomes effective in 2015 and Step 2 standard in 2020.

[5] The nationwide cumulative cost represents the cost to manufacturers resulting from the R&D re-design to meet the NSPS and the NSPS-caused certification and reporting & recordkeeping costs to bring these heaters to market from 2014 through 2029.

[6] In order to not overstate emission reductions caused by the NSPS, emissions are reduced to discount hydronic heaters already meeting the Step 2 limit (i.e., 18% of hydronic heaters are estimated to already meet the Step 2 limit).

Source: EPA, 2015a

The cost components consisted of capital costs per model (R&D, engineering labor, tooling, equipment integration, preliminary testing, and other costs to design and manufacture the modified wood stove model) and other fixed costs per model (certification testing and safety testing, roll-out of the modified products including store display models and burn programs, brochures, user manuals, training and product discounts).

As shown in Table 10.3 above, EPA estimated a cost-effectiveness of $181 per ton of $PM_{2.5}$ removed. The cost-effectiveness was based on total cost and cumulative emission reduction over 20-year emitting lifespan. The final estimates were made based on 2013 dollars and a 7% interest rate applied to the amortized costs during the 6-year R&D period and a 2.5% annual growth rate.

EPA also prepared cost-effectiveness estimates for VOC and CO, although these pollutants do not have emission limits under the final NSPS. EPA also prepared a sensitivity analysis in which they varied the growth in shipments from 2.0% to 2.1%, 2.5% and 3.0%, which caused the emission estimates and resulting cost-effectiveness to vary. Table 10.4 summarizes the range of results of EPA's cost-effectiveness analyses for new hydronic heaters for three pollutants, two interest rates, and three growth rates.

Table 10.4 $PM_{2.5}$, CO, and VOC Cost Effectiveness of NSPS for New Hydronic Heaters

Pollutant	Interest Rate for Amortized Costs (%)	Annual Growth Rate (%)	Cost-Effectiveness based on total cost & cumulative emission reduction over 20-year emitting lifespan ($2013 per ton)
$PM_{2.5}$	7	2.0	192
$PM_{2.5}$	3	2.0	170
$PM_{2.5}$	7	2.5	181
$PM_{2.5}$	7	3.0	170
CO	7	3.0	30
VOC	7	3.0	161

Source: EPA, 2015b: EPA, 2015c; EPA, 2015d; EPA, 2015e; EPA, 2015f.

Compliance Costs – Voluntary Approaches

In addition to regulatory programs, several state and local agencies have implemented wood stove and fireplace replacement programs to help address wood smoke issues (EPA, 2013). These programs are designed to motivate households to replace older technologies with safer, more efficient, cleaner burning technologies. These programs are most effective when they also include education and outreach to ensure that households burn wood more efficiently and cleanly.

For outdoor wood furnaces manufactured before 2011 (before State-specific or EPA emission limits took effect), CSRA made a simple estimate of the cost-effectiveness of a change-out program in the MANE-VU region in the following manner:

- There were 63,150 OWBs in MANE-VU, and the 2011 $PM_{2.5}$, CO, and VOC emissions were previously shown in Table 10.1 (EPA, 2014);
- Individual NSPS-compliant OWBs retail for prices ranging from about $5,000 to $35,000, with the average of $7,433 (EPA, 2015a);
- Installation costs approximately $2,000 installed by a professional contractor, including all plumbing related to the set-up (EPA, 2015a);
- The annualized capital cost for replacement of an older OWB and installation of NSPS Step 2 OWB is $890 in 2014 dollars calculated assuming a 7% interest rate and 20 year lifespan.
- NSPS Step 2 compliant OWBs are 96.9% cleaner for $PM_{2.5}$ and CO, and 90% cleaner for VOC (EPA,2015a);

The estimated cost-effectiveness values are about $3,070 per ton of $PM_{2.5}$ reduced, $3,090 per ton of VOC reduced, and $540 per ton of CO reduced.

Compliance Costs – Education and Outreach

Wood smoke education and outreach is an important part of reducing $PM_{2.5}$. Engaging the public and giving them the tools to make informed decisions about what they burn and how they burn have been in effect for many years and have been proven effective (EPA, 2013). With proper burning techniques and well-seasoned wood, emissions (even in older wood-burning appliances) can be significantly reduced. While a new hydronic heater will typically pollute less than older units when used properly, it is important to emphasize that how a user operates their units is equally important in maximizing energy efficiency and reducing emissions.

For example, EPA's Burn Wise program (EPA, 2015g) serves as a resource for states and communities. Burn Wise is a way to encourage the importance of burning the right wood, the right way, in the right wood-burning appliance. The program offers a website, outreach tools and information to help consumers make informed decisions about what it means to burn wise. Several MANE-VU states have already developed similar education and outreach programs in their states.

Information about the costs associated with developing and implementing education and outreach programs at the state level are currently not available.

FACTOR 2 – COMPLIANCE TIMEFRAME

New outdoor wood boilers meeting more stringent PM emissions standards are likely to be phased in slowly as older boilers are replaced. Many MANE-VU states adopted a PM limit of 0.32 lbs/MMBTU for new units that became effective in 2010-2011 time period. EPA's Step 1 NSPS PM emissions limit of 0.32 lbs/MMBTU became effective nationally in 2015, and is identical to the current qualifying level for EPA's voluntary Hydronic Heater Program and most MANE-VU state limits. EPA's Step 2 NSPS PM emissions limit of 0.10 lbs/MMBTU becomes effective nationally in 2020. Thus, full compliance is likely to be around 2040, at the earliest.

Replacement of wood-fired boilers manufactured before the state or EPA standards took effect will gradually occur over the assumed 20 year life span of the units. Since they are designed to last for approximately 20 years, operators of the outdoor wood-fired boilers would likely be reluctant to replace them immediately. It is possible for older outdoor wood-fired boilers to be replaced more quickly given the proper economic incentives.

For example, Connecticut's initial round of the Good Deals for Good Neighbors program funded awards totaling $68,000 which resulted in the successful removal of a number of older, dirtier and improperly sited boilers. Under the Good Deals for Good Neighbors program, Connecticut will fund awards in the amounts of $3,000 and $6,000 for removal or removal and replacement of outdoor wood furnaces, respectively.

Vermont also offers a voluntary OWB Change-Out Program that provides financial incentives to encourage people to replace their old OWBs with cleaner, more efficient heating systems, including: (1) a Vermont-certified Phase II OWB that uses cordwood or wood pellets; (2) a

natural gas or propane furnace with a thermal efficiency of 95% or better, (3) a natural gas or propane boiler with a thermal efficiency of 90% or better; (4) an indoor cordwood or wood pellet boiler; or (5) an alternative heating system such as a geothermal heat pump. Vermont issued rebate vouchers for up to $6,000 to replace eligible OWBs and $1,000 to match manufacturer rebates to replace eligible OWBs.

The rate of retirement will depend on the available funding for the change-out programs.

FACTOR 3 – ENERGY AND NON-ENVIRONMENTAL IMPACTS

EPA noted in its 2015 NSPS revisions that the final rule is not likely to have any significant adverse energy effects. In general, EPA expects the NSPS to improve technology, including energy efficiency. Reducing emissions and increasing efficiency might increase the use of wood fuel, which would relieve pressure on traditional coal or petroleum based energy sources (and greenhouse gas emissions). It is difficult to determine the precise energy impacts because wood-fueled appliances compete with other biomass forms as well as more traditional oil, electricity and natural gas. Robust data are not available to determine the potential conversion to other types of fuels and their associated appliances if the consumer costs of wood-fueled appliances increase and at what level that increase would drive consumer choice.

The increased use of residential wood combustion devices may have a variety of non-air impacts on the environment, especially on forest and water resources (MACTEC, 2007). The potential impacts are outlined below.

Nuisance Smoke: Outdoor wood-fired boilers typically have very short stacks, and are prone to smoke. The short stacks oftentimes prevent proper mixing of the smoke and soot with the surrounding air, thereby creating nuisance smoke problems for surrounding houses or communities.

Water: Increased logging to satisfy the demand for firewood may increase runoff of silts and sediments into adjacent creeks and rivers. This increased sediment load in rivers can affect aquatic ecosystems that are integral to rivers and streams.

Soils: Increased logging may impact soils in many ways. For example, heavy machinery used to fell and process trees may lead to rutting and compaction of the soil, which in turn leads to higher erosion and/or altered vegetative regrowth.

Wildlife: Increased logging may put pressure on existing wildlife populations in the US Northeast by altering their critical habitat.

Threatened and Endangered Species: Increased logging in Northeast may impact threatened and endangered species through habitat destruction or alteration.

FACTOR 4 – REMAINING USEFUL LIFE

Most wood heaters in consumer homes emit for at least 20 years and often much longer (EPA, 2015a). EPA assumed that models do not come into compliance until the year they are required to, although some models will meet the NSPS Step 2 PM limit prior to the 2020 compliance year and will therefore be emitting less than baseline levels prior to that year. Data on the remaining useful life of existing OWV in MANE-VU is not available. The 2007 Assessment estimated that most units in operation at that time had been installed within the past fifteen years, so replacements might have begun as early as 2012.

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DRAFT MEMORANDUM

TO: Susan Wierman, MARAMA
Joseph Jakuta, OTC

FROM: Ed Sabo, CSRA

DATE: January 29, 2016

SUBJECT: Updates to CoST Control Measure Database

BACKGROUND

MARAMA has developed the capability to run EPA's Control Strategy Tool (CoST) model. CoST allows users to estimate the emission reductions and costs associated with future-year emission control strategies, and then to generate emission inventories that reflect the effects of applying the control strategies. Some of the underlying control and cost information in CoST tool is dated and EPA's project to update this data has been delayed due to resource constraints. This memorandum documents CSRA's efforts to update CoST with information from the analyses of the costs of potential measures to improve visibility in Class I areas in and near the Mid-Atlantic and Northeast region.

OVERVIEW OF COST

CoST[2] is a relational database that contains information on an extensive set of control measure cost information and algorithms for calculating emission reductions and costs associated with potential control strategies. A key component of CoST is the Control Measures Database (CMDB), which consists of the following tables for stationary sources:

- **Summary** table with general information about the control measure;
- **Efficiency** table describing the reductions achieved by, and the costs required to apply, the measure for each affected pollutant;
- **Source classification code (SCC)** table that identify the SCCs to which the control measure applies;
- **Equation** table that contains parameters used to compute the results of cost equations for measures to which the equation applies;
- **Reference** table providing additional information on the control measure and how its control efficiency and cost information were derived.
- **Parameter** table with information that does not fit well within one of the five previous categories, especially parameters that are unique to a single control measure or a subset of control measures.

For many of the control measures in CoST, a simple cost factor in terms of dollars per ton of pollutant reduced is used to calculate the cost of the control measure when applied to a specific

[2] Control Strategy Tool (CoST) software and documentation http://www3.epa.gov/ttn/ecas/cost.htm

source. However, a few control measures (especially those for EGUs and ICI boilers) use a more robust cost equation to determine engineering costs that take into account several variables for the source when those variables are available.

METHODOLOGY

CSRA used the following methodology to update the CoST CMDB:

- Review the existing CMDB control measures for electric generating units (EGUs); industrial, commercial and institutional (ICI) boilers; home heating oil; residential wood combustion; and outdoor wood boilers.
- Review the 2016 MANE-VU 4-factor analyses for the above categories and identify whether existing CMDB control measures should be updated or new control measures should be developed.
- Create new CMDB measures that uniquely identify the measure as representing the information contained in the MANE-VU 4-factor analyses. This was done by ending all CoST control measures abbreviations with "-MV." This allows the CoST user to easily select only those measures associated with the MANE-VU 4-factor analyses while not changing the original CoST data developed by EPA.
- Document the basis for developing the cost parameters using the COST_BASIS parameter field of the PROPS table. Where possible, CSRA updated the variables in the existing cost equations that take into account the variables that have the greatest impact on cost, in terms of both capital costs and operating and maintenance costs. If it is not possible to use a cost equation, CSRA calculated a cost-per-ton reduction factor.
- Review the source classification codes (SCCs) associated with each MANE-VU measure, and update the CoST SCC table as necessary.
- Update each of the six CMDB tables with the relevant information.
- Import the MANE-VU measures into the CMDB and verify that the information in the tables were correctly loaded into CoST.
- Test each MANE-VU control measure by running a CoST control strategy using a small subset of relevant inventory sources to verify the reasonableness of the resulting emission reduction and cost estimation calculations.

Table 1 summarizes the MANE-VU measures generated during this effort. Refer to the COST_BASIS parameter of the PROPS table to see the documentation of how each measure was developed.

Note that in testing the EGU control measures, CSRA identified two errors in the CoST model equations that result in anomalous results:

- CoST converts E6BTU/HR to MW using 1 MW = 3.412 MMBTU/hr. This conversion does not account for the 33% efficiency of a power plant that converts a fuel into electricity (e.g., the heat rate). The correct conversion factor should be 1 MW = 10.34 million BTU/hr (e.g., heat rate of 10,340 Btu/kw-hr). Of course, the precise heat rate is unit-specific, but for CoST purposes may not be needed although it can vary +/- 10%.
- CoST has an error in the code for calculating the scaling factor. The scaling factor used in calculating capitol cost in the code on page A-1 in the CoST Equations Document for design capacity < 500 MW is missing the design capacity in the denominator.

- Incorrect: scaling_factor_model_size ^ scaling_factor_exponent
- Correct: (scaling_factor_model_size/design_capacity)^scaling_factor_exponent

EPA acknowledged the error in the algorithm and indicated that they have not used the EGU control measure equations in CoST because they rely on IPM for control strategy information. EPA is currently reviewing and using the IPM documentation to update the EGU cost equations. When that effort is completed, EPA will revise the CoST code to implement the updates and ensure they are working error-free. EPA anticipates having the corrections completed. Until then, MARAMA should not use the control measures that utilize CoST equation 1 because of the erroneous results that it produces.

CSRA also conducted limited testing of all other CoST control measures (ICI boilers, heating oil, residential wood combustion, and outdoor wood boilers) developed for MANE-VU. Since these control measures use simple "cost per ton" factors instead of CoST equations, the application of the control measures to sample inventory sources is relatively straightforward. No anomalous results were observed during the testing for these source categories.

Table 1 – Control Measures Added to the CoST Control Measure Database

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
PBBFPHHWDS_MV	PM25-PRI	Curtailment Program, aka Burn Ban	Fireplaces, Hydronic Heaters, Wood Stoves	nonpt
PCTGLGFPL_MV	PM25-PRI	Convert to Gas Logs	Fireplaces	nonpt
PEP2QUFPL_MV	PM25-PRI	EPA Phase 2 Qualified Units	Fireplaces	nonpt
PIRDVCFPL_MV	PM25-PRI	Install Retrofit Devices	Fireplaces	nonpt
PNGSTWDSTV_MV	PM25-PRI	New gas stove or gas logs	Wood Stoves	nonpt
PROC2CABR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Catalytic Average Burn Rate	Wood Stoves	nonpt
PROC2CHBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Catalytic High Burn Rate	Wood Stoves	nonpt
PROC2CLBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Catalytic Low Burn Rate	Wood Stoves	nonpt
PROC2NCABR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 non-Catalytic Average Burn Rate	Wood Stoves	nonpt
PROC2NCHBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 non-Catalytic High Burn Rate	Wood Stoves	nonpt
PROC2NCLBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 non-Catalytic Low Burn Rate	Wood Stoves	nonpt
PROC2PABR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Pellet Average Burn Rate	Wood Stoves	nonpt
PROC2PHBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Pellet High Burn Rate	Wood Stoves	nonpt

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
PROC2PLBR_MV	PM25-PRI	Replace Old Certified Catalytic with 2015 NSPS Step 2 Pellet Low Burn Rate	Wood Stoves	nonpt
PRON2CABR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Catalytic Average Burn Rate	Wood Stoves	nonpt
PRON2CHBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Catalytic High Burn Rate	Wood Stoves	nonpt
PRON2CLBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Catalytic Low Burn Rate	Wood Stoves	nonpt
PRON2NCABR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 non-Catalytic Average Burn Rate	Wood Stoves	nonpt
PRON2NCHBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 non-Catalytic High Burn Rate	Wood Stoves	nonpt
PRON2NCLBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 non-Catalytic Low Burn Rate	Wood Stoves	nonpt
PRON2PABR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Pellet Average Burn Rate	Wood Stoves	nonpt
PRON2PHBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Pellet High Burn Rate	Wood Stoves	nonpt
PRON2PLBR_MV	PM25-PRI	Replace Old Non-cert with 2015 NSPS Step 2 Pellet Low Burn Rate	Wood Stoves	nonpt
PRONC2CABR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Catalytic Average Burn Rate	Wood Stoves	nonpt
PRONC2CHBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Catalytic High Burn Rate	Wood Stoves	nonpt
PRONC2CLBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Catalytic Low Burn Rate	Wood Stoves	nonpt
PRONC2NCABR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 non-Catalytic Average Burn Rate	Wood Stoves	nonpt

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
PRONC2NCHBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 non-Catalytic High Burn Rate	Wood Stoves	nonpt
PRONC2NCLBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 non-Catalytic Low Burn Rate	Wood Stoves	nonpt
PRONC2PABR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Pellet Average Burn Rate	Wood Stoves	nonpt
PRONC2PHBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Pellet High Burn Rate	Wood Stoves	nonpt
PRONC2PLBR_MV	PM25-PRI	Replace Old Certified Noncatalytic with 2015 NSPS Step 2 Pellet Low Burn Rate	Wood Stoves	nonpt
PROP2PABR_MV	PM25-PRI	Replace Old Pellet with 2015 NSPS Step 2 Pellet Average Burn Rate	Wood Stoves	nonpt
PROP2PHBR_MV	PM25-PRI	Replace Old Pellet with 2015 NSPS Step 2 Pellet High Burn Rate	Wood Stoves	nonpt
PROP2PLBR_MV	PM25-PRI	Replace Old Pellet with 2015 NSPS Step 2 Pellet Low Burn Rate	Wood Stoves	nonpt
PROWB2HH_MV	PM25-PRI	Replace Old Outdoor Wood Boiler with 2015 NSPS Step 2 Hydronic Heater	Hydronic Heaters	nonpt
SULSFRESHETH$_MV	SO2	Ultra-Low Sulfur Fuel	Residential Heating	nonpt
SULSFRESHETL$_MV	SO2	Ultra-Low Sulfur Fuel	Residential Heating	nonpt
NLNBOUBCW_MV	NOX	Low NOx Burner and Over Fire Air	Utility Boiler - Coal/Wall	ptipm
NLNBOUBCW2_MV	NOX	Low NOx Burner and Over Fire Air	Utility Boiler - Coal/Wall2	ptipm
NLNBUUBCW_MV	NOX	Low NOx Burner	Utility Boiler - Coal/Wall	ptipm

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
NLNBUUBCW2_MV	NOX	Low NOx Burner	Utility Boiler - Coal/Wall2	ptipm
NLNC1UBCT_MV	NOX	Low NOx Coal-and-Air Nozzles with cross-Coupled Overfire Air	Utility Boiler - Coal/Tangential	ptipm
NLNC1UBCT2_MV	NOX	Low NOx Coal-and-Air Nozzles with cross-Coupled Overfire Air	Utility Boiler - Coal/Tangential1	ptipm
NLNC2UBCT_MV	NOX	Low NOx Coal-and-Air Nozzles with separated Overfire Air	Utility Boiler - Coal/Tangential	ptipm
NLNC2UBCT2_MV	NOX	Low NOx Coal-and-Air Nozzles with separated Overfire Air	Utility Boiler - Coal/Tangential2	ptipm
NLNC3UBCT_MV	NOX	Low NOx Coal-and-Air Nozzles with Cross-Coupled and Separated Overfire Air	Utility Boiler - Coal/Tangential	ptipm
NLNC3UBCT2_MV	NOX	Low NOx Coal-and-Air Nozzles with Cross-Coupled and Separated Overfire Air	Utility Boiler - Coal/Tangential3	ptipm
NSCR_UBCT_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Coal/Tangential	ptipm
NSCR_UBCW_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Coal/Wall	ptipm
NSCR_UBCY_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Cyclone	ptipm
NSCR_UBOT_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Oil-Gas/Tangential	ptipm
NSCR_UBOW_MV	NOX	Selective Catalytic Reduction	Utility Boiler - Oil-Gas/Wall	ptipm
NSNCRUBCT_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Coal/Tangential	ptipm
NSNCRUBCW_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Coal/Wall	ptipm

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
NSNCRUBCY_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Cyclone	ptipm
NSNCRUBOT_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Oil-Gas/Tangential	ptipm
NSNCRUBOW_MV	NOX	Selective Non-Catalytic Reduction	Utility Boiler - Oil-Gas/Wall	ptipm
SDSIUBC_MV	SO2	Dry Sorbent Injection	Utility Boilers - Bituminous/Subbituminous Coal	ptipm
SLSDUBC1_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (100 to 299 MW)	ptipm
SLSDUBC2_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (300 to 499 MW)	ptipm
SLSDUBC3_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (500 to 699 MW)	ptipm
SLSDUBC4_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (700 to 999 MW)	ptipm
SLSDUBC5_MV	SO2	Lime Spray Dryer	Utility Boilers - Bituminous/Subbituminous Coal (Over 1000 MW)	ptipm
SLSFOUBC1_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (100 to 299 MW)	ptipm
SLSFOUBC2_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (300 to 499 MW)	ptipm
SLSFOUBC3_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (500 to 699 MW)	ptipm
SLSFOUBC4_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (700 to 999 MW)	ptipm
SLSFOUBC5_MV	SO2	Limestone Forced Oxidation	Utility Boilers - Bituminous/Subbituminous Coal (Over 1000 MW)	ptipm
NLNBCH$_MV	NOX	Low NOx Burners High Cost	ICI2 Boilers - Coal	ptnonipm

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
NLNBCL$_MV	NOX	Low NOx Burners Low Cost	ICI2 Boilers - Coal	ptnonipm
NLNBNGH$_MV	NOX	Low NOx Burners High Cost	ICI2 Boilers - Natural Gas	ptnonipm
NLNBNGL$_MV	NOX	Low NOx Burners Low Cost	ICI2 Boilers - Natural Gas	ptnonipm
NLNBOAROH$_MV	NOX	Low NOx Burners plus Overfire Air High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NLNBOAROL$_MV	NOX	Low NOx Burners plus Overfire Air Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NLNBROH$_MV	NOX	Low NOx Burners High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NLNBROL$_MV	NOX	Low NOx Burners Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NOACH$_MV	NOX	Overfire Air High Cost	ICI2 Boilers - Coal	ptnonipm
NOACL$_MV	NOX	Overfire Air Low Cost	ICI2 Boilers - Coal	ptnonipm
NOANGH$_MV	NOX	Overfire Air High Cost	ICI2 Boilers - Natural Gas	ptnonipm
NOANGL$_MV	NOX	Overfire Air Low Cost	ICI2 Boilers - Natural Gas	ptnonipm
NOAROH$_MV	NOX	Overfire Air High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NOAROL$_MV	NOX	Overfire Air Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NSCRCH$_MV	NOX	Selective Catalytic Reduction High Cost	ICI2 Boilers - Coal	ptnonipm
NSCRCL$_MV	NOX	Selective Catalytic Reduction Low Cost	ICI2 Boilers - Coal	ptnonipm
NSCRNGH$_MV	NOX	Selective Catalytic Reduction High Cost	ICI2 Boilers - Gas	ptnonipm
NSCRNGL$_MV	NOX	Selective Catalytic Reduction Low Cost	ICI2 Boilers - Gas	ptnonipm
NSCRROH$_MV	NOX	Selective Catalytic Reduction High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NSCRROL$_MV	NOX	Selective Catalytic Reduction Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NSNCRCHL$_MV	NOX	Selective non-Catalytic Reduction High Cost	ICI2 Boilers - Coal	ptnonipm
NSNCRCL$_MV	NOX	Selective non-Catalytic Reduction Low Cost	ICI2 Boilers - Coal	ptnonipm
NSNCRROH$_MV	NOX	Selective non-Catalytic Reduction High Cost	ICI2 Boilers - Residual Oil	ptnonipm
NSNCRROL$_MV	NOX	Selective non-Catalytic Reduction Low Cost	ICI2 Boilers - Residual Oil	ptnonipm
NULNBNGH$_MV	NOX	Ultra-Low NOx Burners High Cost	ICI2 Boilers - Natural Gas	ptnonipm
NULNBNGL$_MV	NOX	Ultra-Low NOx Burners Low Cost	ICI2 Boilers - Natural Gas	ptnonipm
SDFGDCH$_MV	SO2	Dry FGD High Cost	ICI2 Boilers - Coal	ptnonipm
SDFGDCL$_MV	SO2	Dry FGD Low Cost	ICI2 Boilers - Coal	ptnonipm
SDSICH$_MV	SO2	Dry Sorbent Injection High Cost	ICI2 Boilers - Coal	ptnonipm
SDSICL$_MV	SO2	Dry Sorbent Injection Low Cost	ICI2 Boilers - Coal	ptnonipm

CMDB Abbreviation (cmabbreviation)	Major Pollutant	Control Technology	Source Group	Sector
SFSC2GH$_MV	SO2	Fuel Switch Coal to Gas High $/ton	ICI2 Boilers - Coal	ptnonipm
SFSC2GL$_MV	SO2	Fuel Switch Coal to Gas Low $/ton	ICI2 Boilers - Coal	ptnonipm
SFSDOHS2ULSDH$_MV	SO2	Fuel Switch High Sulfur Distillate Oil to ULSD High Cost	ICI2 Boilers - Distillate Oil	ptnonipm
SFSDOHS2ULSDL$_MV	SO2	Fuel Switch High Sulfur Distillate Oil to ULSD Low Cost	ICI2 Boilers - Distillate Oil	ptnonipm
SFSO2G_MV	SO2	Fuel Switch Oil to Gas	ICI2 Boilers - Residual or Distillate Oil	ptnonipm
SFSROHS2LS_MV	SO2	Fuel Switch Residual Oil High to Low Sulfur	ICI2 Boilers - Residual Oil	ptnonipm
SFSROHS2ULSD_MV	SO2	Fuel Switch Residual Oil to ULSD	ICI2 Boilers - Residual Oil	ptnonipm
SWFGDCH$_MV	SO2	Wet FGD High Cost	ICI2 Boilers - Coal	ptnonipm
SWFGDCL$_MV	SO2	Wet FGD Low Cost	ICI2 Boilers - Coal	ptnonipm

APPENDIX M

Status of the Top 167 Electric Generating Units (EGUs) that Contributed to Visibility Impairment at MANE-VU Class I Areas during the 2008 Regional Haze Planning Period

Mid-Atlantic/Northeast Visibility Union
(MANE-VU)

July 25, 2016

The Mid-Atlantic/Northeast Visibility Union (MANE-VU) identified 167 Electric Generating Units (EGUs) as sources that most affected visibility in the MANE-VU Class I areas during the 2008 planning period. In establishing the reasonable progress goal for regional haze, MANE-VU Class I areas relied in part on implementation of emission reductions at the 167 EGU sources by 2018. These 167 EGU sources are located both within and outside MANE-VU.

The MANE-VU "Ask" requested a 90% or greater reduction in SO_2 emissions from 2002 levels at each of the 167 stacks identified by MANE-VU as contributing to visibility impairment at the MANE-VU Class I areas. If it is infeasible to achieve this level of reduction from a unit, the state could obtain the requested reduction from other units in the State.

The attached worksheets provide a summary of the status of controls at the 167 EGU units. New Jersey worked off of a previous analysis carried out by Maine to update the status of the controls at the units. Steps taken to update the worksheets are described as follows:

Step 1

The worksheet was updated with EGU control status from the National Electric Energy Data System (NEEDS) v5.14, and later NEEDS v5.15[1]. The worksheet previously had control status information from NEEDS v4.10. The worksheet was also updated with Environmental Protection Agency's (EPA) 2011 and 2015 Clean Air Markets Division (CAMD) Air Markets Program Data (AMPD),[2] updates from States (Georgia, Indiana, Massachusetts, Maryland, Maine, Michigan, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, and Virginia) and information from state SIPS (Ohio Regional Haze 5-Year Progress Report (January 2016)). "0" was assigned to units that had no values for SO_2 emissions in 2015 CAMD AMPD. Data from the Eastern Regional Technical Advisory Committee (ERTAC) was also reviewed to ensure consistency and accuracy.

Units with SO2 permit rates greater than 0.4lbs/mmBtu are highlighted in grey in the tables throughout the analysis. Note that some of the SO2 permit rates could be the permit rates at the units before controls were installed. For some of the units with SO2 permit rates greater than 0.4lbs/mmBtu, the actual amounts of SO2 emitted were less than 0.4lb/mmBtu. It is recommended that units with actual SO2 emissions greater than 0.4lbs/mmBtu be revisited in the future as resources allow.

Based on the information from the sources mentioned above, 46 out of the 167 units have been shut down, retired or decommissioned. The units eliminated are highlighted in grey in the tab "Retired_Shutdown_Decommissioned" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. These 46 units were eliminated in this step leaving 121 units.

Shawville is temporarily shut down to install equipment for burning natural gas. SO2 emissions are expected to be well below the 90% reduction expected at the Shawville units when they start burning natural gas. Shawville has retained its rights to burn coal, however, a federal regulation

[1] http://www.epa.gov/airmarkets/power-sector-modeling-platform-v515 (Accessed February 22, 2016)
[2] http://ampd.epa.gov/ampd/ (Accessed February 25, 2016)

requires the installation of scrubbers before they can burn coal. The enforceability of the controls on these units should be investigated in the future as resources allow.

The 46 units that were eliminated in this step are listed in Table 1.

Table 1: Shut Down, Retired or Decommissioned Units (46 Units)

STATE	ORIS ID	PLANT NAME	UNIT ID
DELAWARE	594	INDIAN RIVER	1
			2
			3
GEORGIA	709	HARLLEE BRANCH	3,4
INDIANA	988	TANNER'S CREEK	U1,U2,U3
			4*
	1010	WABASH RIVER	2*,3*,4*,5*,6*
MASSACHUSETTS	1606	MOUNT TOM	1
	1613	SOMERSET	8
	1626	SALEM HARBOR	1
			3
			4
NEW JERSEY	2378	B L ENGLAND	1
NEW YORK	2526	GOUDEY	11,12,13
	2527	GREENIDGE	6
	2549	C R HUNTLEY	67*,68*
			63,64,65,66
	2554	DUNKIRK	3,4
	2594	OSWEGO	5
	2642	ROCHESTER 7	3,4
NORTH CAROLINA	2709	LEE	3
	2713	L V SUTTON	3
OHIO	2830	WALTER C BECKJORD	6
	2832	MIAMI FORT	5-1,5-2,6
	2837	EASTLAKE	5
	2840	CONESVILLE	1,2
	2864	R E BURGER	5 THRU 8
	2872	MUSKINGUM RIVER	1,2,3,4
			5*
	7253	RICHARD GORSUCH	1,2,3,4
PENNSYLVANIA	3113	PORTLAND	1
			2
	3148	MARTINS CREEK	1,2
	3178	ARMSTRONG	2
	2179	HATFIELD'S FERRY	1,2
	3131	SHAWVILLE	3,4

STATE	ORIS ID	PLANT NAME	UNIT ID
SOUTH CAROLINA	3319	JEFFERIES	3
			4
TENNESSEE	3405	JOHN SEVIER	3,4
VIRGINIA	3803	CHESAPEAKE	3
			4
WEST VIRGINIA	3936	KANAWHA RIVER	1,2
	3938	PHILIP SPORN	51
			11,21,31,41
	3942	ALBRIGHT	3
	3947	KAMMER	1,2,3

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

Step 2

The remaining 121 units were reviewed for units that have 90% or greater SO_2 emission reductions from 2002 total SO_2 stack level emissions. The emission reduction was based on emissions reported as 2015 CAMD AMPD SO_2 stack level data. These units met the MANE-VU Ask at the stack level for a 90% or greater reduction. 83 units met this criterion, and were eliminated, leaving 38 units. The units eliminated are highlighted in light green in the tab "90%+Reduction" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. The 83 units that were eliminated are listed in Table 2.

Table 2: Units with 90% or Greater SO_2 Emission Reductions (2002-2015) (83 Units)

STATE	ORIS ID	PLANT NAME	UNIT ID
DELAWARE	593	EDGE MOOR	5
	594	INDIAN RIVER	4
GEORGIA	703	BOWEN	1BLR
			2BLR
			3BLR
			4BLR
ILLINOIS	861	COFFEEN	1,2
INDIANA	990	ELMER W STOUT	70
	1001	CAYUGA	1
			2
	1008	R GALLAGHER	1,2*
			3,4*
	6113	GIBSON	1,2
	6705	WARRICK	1,2
			4
KENTUCKY	1355	E W BROWN	2,3
	1378	PARADISE	3
	1384	COOPER	1,2*
	6041	H L SPURLOCK	1

STATE	ORIS ID	PLANT NAME	UNIT ID
			2
MARYLAND	602	BRANDON SHORES	1
			2
	1552	C P CRANE	1
			2
	1571	CHALK POINT	1,2*
	1572	DICKERSON	1,2,3
	1573	MORGANTOWN	1
			2
MASSACHUSETTS	1599	CANAL	1
			2
	1619	BRAYTON POINT	1
			2
			3
MICHIGAN	1702	DAN E KARN	3*,4*
	1733	MONROE	1,2
			3,4
NEW HAMPSHIRE	2364	MERRIMACK	1
			2
	8002	NEWINGTON	1
NEW JERSEY	2403	HUDSON	2
	2408	MERCER	1
			2
NEW YORK	2480	DANSKAMMER	4
	2516	NORTHPORT	3
	8006	ROSETON	1
NORTH CAROLINA	2712	ROXBORO	3A*,3B*
	2721	CLIFFSIDE	5
	2727	MARSHALL	3
			4
	6250	MAYO	1A,1B
	8042	BELEWS CREEK	1
			2
OHIO	2828	CARDINAL	3
	2832	MIAMI FORT	7
	2840	CONESVILLE	4
	2850	J M STUART	1
			2
			3
			4
	2866	W H SAMMIS	1*,2*
			3,4
			5

STATE	ORIS ID	PLANT NAME	UNIT ID
			6
			7
	2876	KYGER CREEK	1*,2*,3*,4*,5*
PENNSYLVANIA	3149	MONTOUR	1
	8226	CHESWICK	1
SOUTH CAROLINA	3297	WATEREE	WAT1
			WAT2
	3298	WILLIAMS	WIL1
	6249	WINYAH	1
TENNESSEE	3407	KINGSTON	1,2,3,4*,5
			6,7,8,9
VIRGINIA	3775	CLINCH RIVER	1,2
	3797	CHESTERFIELD	4
			5
			6
WEST VIRGINIA	3935	JOHN E AMOS	1*,2*
			3
	3943	FORT MARTIN	1
			2
	3948	MITCHELL	1,2
	6264	MOUNTAINEER	1

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

Step 3

The remaining 38 units were further reviewed for units that have scrubbers with at least 90% scrubber control efficiency. This was done on a case by case basis. SO_2 emission reductions at these units were between 85 and 89% in 2015 compared to 2002 levels. Some of these units had over 90% SO_2 emission reductions in 2014 but could have differed because of variations in amount of the unit's operation between later years and the 2002 base year. Units with wet scrubbers that were installed prior to 2002 were also eliminated even though some of them have emission reductions less than 85% when the wet scrubbers reported scrubber control efficiency of well over 90%. This could be as a result of how the scrubber was used; scrubber shut downs or inactivity, or emission reductions that may have already taken place before 2002. It could also be due to meteorological changes. In this step, 13 Units were eliminated, leaving 25. The units eliminated are highlighted in purple in the tab "Scrubber90%+" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. The 13 units that were eliminated are listed in Table 3.

Table 3: Units with Scrubbers with 90% or Higher Scrubber Efficiency
SO_2 Emission Reductions: 85%-89% (2002-2015) (13 Units)

STATE	ORIS ID	PLANT NAME	UNIT ID
INDIANA	983	CLIFTY CREEK	1*,2*,3*
			4*,5,6*
	6113	GIBSON	3,4
KENTUCKY	1364	MILL CREEK	4
	6018	EAST BEND	2
NORTH CAROLINA	2712	ROXBORO	1
			2
			4A*,4B*
OHIO	2828	CARDINAL	1
PENNSYLVANIA	3136	KEYSTONE	1*
	3140	BRUNNER ISLAND	1*,2*
			3
	3149	MONTOUR	2

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

Step 4

In this step, the remaining 25 units were reviewed for units that have scrubbers (both wet and dry) installed. Dry scrubbers are believed to be less efficient than wet ones (generally below 80% emission reduction), but according to a USEPA Air Pollution Control Technology fact sheet,[3] newer dry scrubbers are capable of higher control efficiencies, on the order of 90%. Some of the units that were eliminated in this step had scrubbers with 90% or higher efficiency but SO_2 emission reductions at these units in 2015 were less than 85% compared with 2002 levels. 14 units were eliminated in this step, leaving 11. 11 of these 14 units had wet scrubbers, while 3 had dry scrubbers. The units eliminated are highlighted in blue (wet scrubbers) and light blue (dry scrubbers) in the tab "Scrubbers" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. The 14 units that were eliminated are listed in Table 4.

Table 4: Units with Scrubbers (Wet and Dry)
SO_2 Emission Reductions: < 85% (2002-2015) (14 Units)

Units with Wet Scrubbers			
STATE	**ORIS ID**	**PLANT NAME**	**UNIT ID**
KENTUCKY	1356	GHENT	3,4
	1378	PARADISE	2
OHIO	2828	CARDINAL	2
	6019	W H ZIMMER	1
	6031	KILLEN STATION	2
	8102	GEN J M GAVIN	1

[3] http://www3.epa.gov/ttncatc1/dir1/ffdg.pdf (Accessed March 3, 2016)

Units with Wet Scrubbers			
STATE	**ORIS ID**	**PLANT NAME**	**UNIT ID**
			2
PENNSYLVANIA	3136	KEYSTONE	2*
WEST VIRGINIA	3954	MT STORM	1,2
	6004	PLEASANTS	1
			2
Units with Dry Scrubbers			
STATE	**ORIS ID**	**PLANT NAME**	**UNIT ID***
PENNSYLVANIA	3122	HOMER CITY	1*
			2*
TENNESSEE	3403	GALLATIN	3*,4*

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

It is recommended that the units in Table 4 be revisited to determine why their emissions are lower than expected.

Step 5

Units that have plans to retire or install newer controls by 2018 were eliminated in this step. Determinations were made based on updates from states and information from NEEDS v5.15. Six out of the remaining 11 units were eliminated, leaving 5 that will not meet the MANE-VU "Ask" by 2018. It is recommended that these units are reviewed again in the future to ensure that they either retired or installed controls. The units that were eliminated are highlighted in orange in the tab "Plans to Retire_Control" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. The 6 units that were eliminated in this step are listed in Table 5.

Table 5: Units with Plans to Retire or Install Newer Controls by 2018 (6 Units)

STATE	ORIS ID	PLANT NAME	UNIT ID
INDIANA	6166	ROCKPORT	MB1*,MB2*
KENTUCKY	1353	BIG SANDY	BSU1*, BSU2*
MAINE	1507	WILLIAM F WYMAN	4*
OHIO	2836	AVON LAKE	12*
TENNESSEE	3406	JOHNSONVILLE	1 THRU 10. 1*,2*,3*,4*
VIRGINIA	3809	YORKTOWN	1*,2

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

Step 6

The remaining 5 units were further reviewed for the quantity of SO_2 in pounds (lbs.) burned per Heat Input in MMBtu. This analysis was done using 2015 CAMD AMPD data. 0.1 – 0.4 was chosen as the acceptable rate. 1 unit was eliminated, leaving 4 units having higher SO_2 emissions than others. The unit that was eliminated is highlighted in brown in the tab "Heat Input" in the

spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X. The unit that was eliminated is listed in Table 6.

Table 6: Units with SO_2 (lbs) Burned per Heat Input (MMBtu) Between 0.1-0.4 (1 Unit)

STATE	ORIS ID	PLANT NAME	UNIT ID
NEW YORK	8006	ROSETON	2

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.

Step 7

The remaining 4 units were ranked from highest to lowest based on total stack level SO_2 emissions using 2015 CAMD AMPD. These units do not seem to have sufficient SO_2 controls installed. These 7 units are listed in the tab "Rank" in the spreadsheet "167 EGU Stacks that Impact MANE-VU Class I Areas" in Appendix X, and are also listed in Table 7.

Table 7: Units with Insufficient SO2 Controls (4 Units)

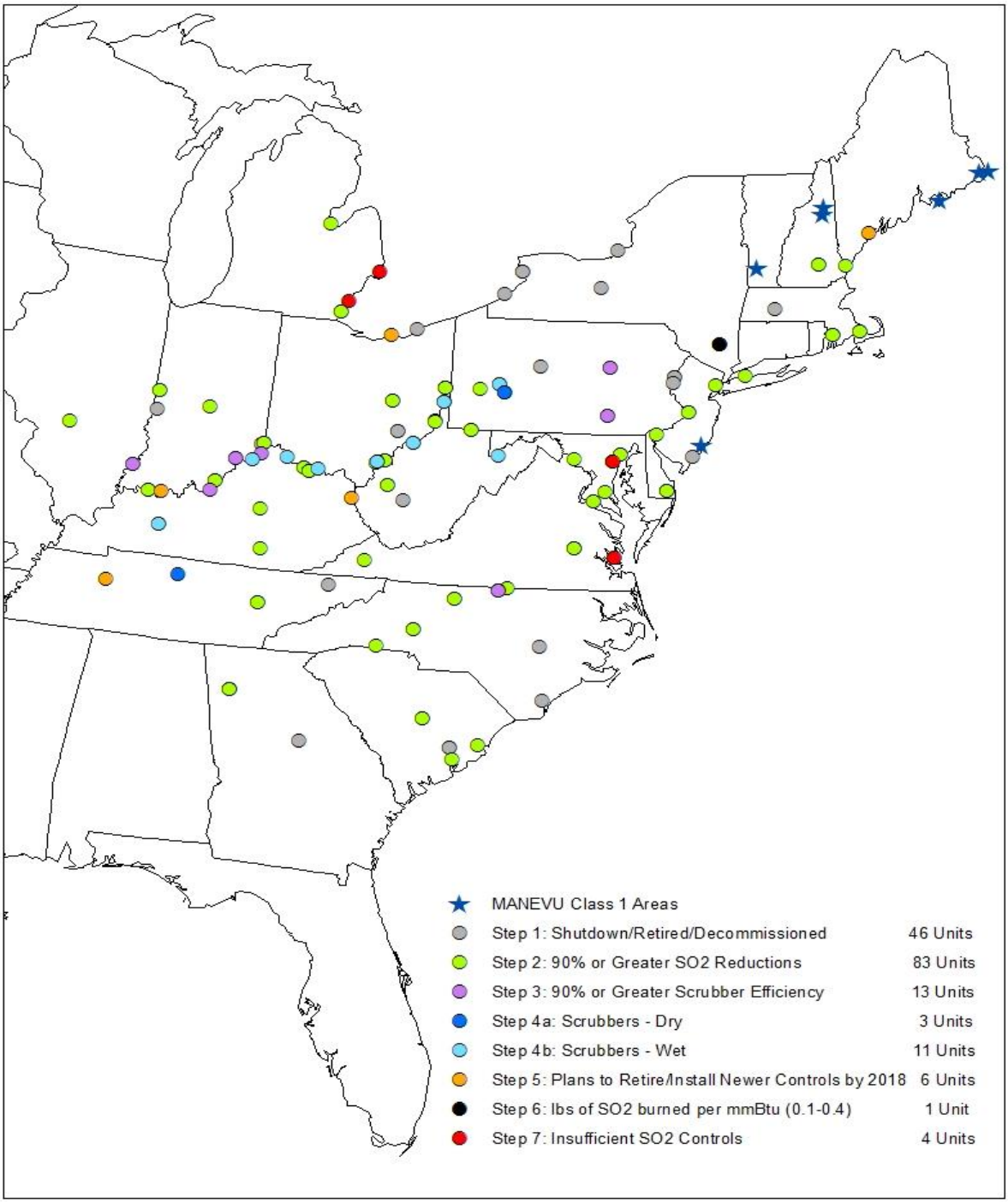
Plant	State	UNIT ID	ORIS ID	2015 CAMD SO_2 (tpy)	2002 CAMD SO_2 (tpy)	% Change 2002-2015
Trenton Channel	MI	9A*	1745	11,656	19,237	-39%
St. Clair	MI	7*	1743	8,938	15,980	-44%
Herbert A Wagner	MD	3*	1554	8,751	10,096	-13%
Yorktown	VA	3*	3809	2,070	10,567	-80%

Note: Units with SO_2 permit rate greater than 0.4lbs/mmBtu are highlighted.
* Units with actual amount of SO_2 emitted greater than 0.4lbs/mmBtu.

SO_2 emissions at Yorktown, Unit 3 has reduced in the past few years because utilization of the unit was reduced a lot. In addition, the unit falls under the Mercury and Air Toxics Standard (MATS) rule and is utilizing the annual capacity factor threshold in the MATS rule to comply. Yorktown, unit 3 does not have any scrubbers.

A map showing the locations of the 167 EGU units and their status is shown in Figure 1.

<u>Figure 1</u>: Status of Controls at Top 167 EGUs:
Contribution to Visibility Impairment
at MANE-VU Class I Areas



APPENDIX N

Mid-Atlantic/Northeast Visibility Union

MANE-VU

Reducing Regional Haze for Improved Visibility and Health

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION WITHIN MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations of MANE-VU through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

In addressing the emission reduction strategies in the Ask, the MANE-VU states will need to harmonize any activity on the strategies in the Ask with other federal or state

MANE-VU Class I Areas

ACADIA NATIONAL PARK ME

BRIGANTINE WILDERNESS NJ

GREAT GULF WILDERNESS NH

LYE BROOK WILDERNESS VT

MOOSEHORN WILDERNESS ME

PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH

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requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

Many of the MANE-VU states are also members of RGGI. RGGI is a market based cap-and-invest program designed to cost effectively reduce greenhouse gas emissions from the energy sector while returning value to rate-payers. One of the co-benefits of RGGI is that it will also significantly reduce SO_2 and NOx emissions, the two most important haze precursors. Because of this, the RGGI states, regionally, will likely achieve greater emission reductions than those envisioned in this Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;
2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution

analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

3. Each MANE-VU State that has not yet fully adopted an ultra-low sulfur fuel oil standard as requested by MANE-VU in 2007 - pursue this standard as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
    a. distillate oil to 0.0015% sulfur by weight (15 ppm),
    b. #4 residual oil within a range of 0.25 to 0.5% sulfur by weight,
    c. #6 residual oil within a range of 0.3 to 0.5% sulfur by weight.
4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;

5. Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:

    a. Striving to meet NOx emissions standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or
    b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or
    c. Obtaining equivalent alternative emission reductions on high electric demand days.

    High electric demand days are days when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet. Peaking combustion turbine is defined for the purposes of this "Ask" as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016;

    (Note: SO_2 emissions for fuel oil units are addressed with Ask item 3.a. above)

6. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
MA	Brayton Point	1619	4	4.3
MA	Canal Station	1599	1	3.0
MD	Herbert A Wagner	1554	3	3.8
MD	Luke Paper Company	7763811	001-0011-3-0018	6.0
MD	Luke Paper Company	7763811	001-0011-3-0019	5.9
ME	The Jackson Laboratory	7945211	7945211	10.2
ME	William F Wyman	1507	4	5.6
ME	Woodland Pulp LLC	5974211		7.5
NH	Merrimack	2364	2	3.3
NJ	B L England	2378	2,3	5.6
NY	Finch Paper LLC	8325211	12	5.9
NY	Lafarge Building Materials Inc	8105211	43101	8.1
PA	Brunner Island	3140	1,2	4.0
PA	Brunner Island	3140	3	3.8
PA	Homer City	3122	1	9.3
PA	Homer City	3122	2	8.1
PA	Homer City	3122	3	3.3
PA	Keystone	3136	1	3.2
PA	Keystone	3136	2	3.1
PA	Montour	3149	1	4.4
PA	Montour	3149	2	4.1
PA	Shawville	3131	3,4	3.6

APPENDIX P

Mid-Atlantic/Northeast Visibility Union

MANE-VU

Reducing Regional Haze for Improved Visibility and Health

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION BY THE ENVIRONMENTAL PROTECTION AGENCY AND FEDERAL LAND MANAGERS TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIP's, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class 1 area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being

MANE-VU Class I Areas

ACADIA NATIONAL PARK ME

BRIGANTINE WILDERNESS NJ

GREAT GULF WILDERNESS NH

LYE BROOK WILDERNESS VT

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PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH

ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

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on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

The transport range of visibility impairing pollutants has been demonstrated to be extensive and well beyond the MANE-VU region. For example, a wildfire near Fort McMurray, Alberta in western Canada last year brought visibility impairing fine particulate matter and ozone over 2000 miles into the region at concentrations that contributed to exceedances of the health standard in some locations. Clearly, states located beyond those that MANE-VU chose to consult for regional haze, can play an active role in impairing visibility at the MANE-VU Class I areas. Further, despite that onroad vehicles produce a significant portion of the visibility impairing pollutants that affect our Class I areas they are beyond our states' ability to regulate. Therefore, the MANE-VU Class I area states need additional help from the Environmental Protection Agency and Federal Land Managers in pursuing important reasonable emission control measures. These include, but are not limited to:

1. Federal Land Managers to consult with MANE-VU Class I area states when scheduling prescribed burns and ensure that these burns do not impact nearby IMPROVE visibility measurements and do not impact potential 20 percent most and least visibility impaired days;

2. EPA to develop measures that will further reduce emissions from heavy-duty onroad vehicles; and

3. EPA to ensure that Class I Area state "Asks" are addressed in "contributing" state SIPs prior to approval. In the case of this "Ask", contributing states are defined as those that the MANE-VU Class I area states requested for consultation.

MANE-VU considers these measures as reasonable and would further visibility improvement in our region's Class I areas.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017