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Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards

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Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impacts Division
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CHAPTER 3
COST, ECONOMIC, AND ENERGY IMPACTS

This chapter reports the compliance cost, economic, and energy impact analysis performed for the Mercury and Air Toxics Standards (MATS). EPA used the Integrated Planning Model (IPM), developed by ICF Consulting, to conduct its analysis. IPM is a dynamic linear programming model that can be used to examine air pollution control policies for SO_2, NO_x, Hg, HCl, and other air pollutants throughout the United States for the entire power system. Documentation for IPM can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm, and updates specific to the MATS modeling are in the "Documentation Supplement for EPA Base Case v.4.10_MATS – Updates for Final Mercury and Air Toxics Standards (MATS) Rule" (hereafter IPM 4.10 Supplemental Documentation for MATS).

3.1 Background

Over the last decade, EPA has on several occasions used IPM to consider pollution control options for reducing power-sector emissions.[1] Most recently EPA used IPM extensively in the development and analysis of the impacts of the Cross-State Air Pollution Rule (CSAPR).[2] As discussed in Chapter 2, MATS coincides with a period when many new pollution controls are being installed. Many are needed for compliance with NSR settlements and state rules, while others may have been planned in expectation of CAIR and its replacement, the CSAPR.

The emissions scenarios for the RIA reflects the Cross-State Air Pollution Rule (CSAPR) as finalized in July 2011 and the emissions reductions of SO_X, NO_X, directly emitted PM, and CO_2 are consistent with application of federal rules, state rules and statutes, and other binding, enforceable commitments in place by December 2010 for the analysis timeframe.[3]

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[1] Many EPA analyses with IPM have focused on legislative proposals with national scope, such as EPA's IPM analyses of the Clean Air Planning Act (S.843 in 108th Congress), the Clean Power Act (S.150 in 109th Congress), the Clear Skies Act of 2005 (S.131 in 109th Congress), the Clear Skies Act of 2003 (S.485 in 108th Congress), and the Clear Skies Manager's Mark (of S.131). These analyses are available at EPA's website: (http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html). EPA also analyzed several multi-pollutant reduction scenarios in July 2009 at the request of Senator Tom Carper to illustrate the costs and benefits of multiple levels of SO_2 and NO_X control in the power sector.

[2] Additionally, IPM has been used to develop the NO_X Budget Trading Program, the Clean Air Interstate Rule programs, the Clean Air Visibility Programs, and other EPA regulatory programs for the last 15 years.

[3] Consistent with the mercury risk deposition modeling for MATS, EPA did not model non-federally enforceable mercury-specific emissions reduction rules in the base case or MATS policy case (see preamble section III.A). Note that this approach does not significantly affect SO_2 and NO_X projections underlying the cost and benefit results presented in this RIA

EPA has made these base case assumptions recognizing that the power sector will install a significant amount of pollution controls in response to several requirements. The inclusion of CSAPR and other regulatory actions (including federal, state, and local actions) in the base case is necessary in order to reflect the level of controls that are likely to be in place in response to other requirements apart from MATS. This base case will provide meaningful projections of how the power sector will respond to the cumulative regulatory requirements for air emissions in totality, while isolating the incremental impacts of MATS relative to a base case with other air emission reduction requirements separate from today's action.

The model's base case features an updated Title IV SO_2 allowance bank assumption and incorporates updates related to the Energy Independence and Security Act of 2007. Some modeling assumptions, most notably the projected demand for electricity, are based on the 2010 Annual Energy Outlook from the Energy Information Administration (EIA). In addition, the model includes existing policies affecting emissions from the power sector: the Title IV of the Clean Air Act (the Acid Rain Program); the NO_x SIP Call; various New Source Review (NSR) settlements[4]; and several state rules[5] affecting emissions of SO_2, NO_x, and CO_2 that were finalized through June of 2011. IPM includes state rules that have been finalized and/or approved by a state's legislature or environmental agency, with the exception of non-federal mercury-specific rules. The IPM 4.10 Supplemental Documentation for MATS contains details on all of these other legally binding and enforceable commitments for installation and operation of pollution controls. This chapter focuses on results of EPA's analysis with IPM for the model's 2015 run-year in connection with the compliance date for MATS.

MATS establishes National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for the "electric utility steam generating unit" source category, which includes those units that combust coal or oil for the purpose of generating electricity for sale and distribution through the national electric grid to the public.

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[4] The NSR settlements include agreements between EPA and Southern Indiana Gas and Electric Company (Vectren), Public Service Enterprise Group, Tampa Electric Company, We Energies (WEPCO), Virginia Electric & Power Company (Dominion), Santee Cooper, Minnkota Power Coop, American Electric Power (AEP), East Kentucky Power Cooperative (EKPC), Nevada Power Company, Illinois Power, Mirant, Ohio Edison, Kentucky Utilities, Hoosier Energy, Salt River Project, Westar, Puerto Rico Power Authority, Duke Energy, American Municipal Power, and Dayton Power and Light. These agreements lay out specific NO_x, SO_2, and other emissions controls for the fleets of these major Eastern companies by specified dates. Many of the pollution controls are required between 2010 and 2015.

[5] These include current and future state programs in Alabama, Arizona, California, Colorado, Connecticut, Delaware, Georgia, Illinois, Kansas, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, New Hampshire, New Jersey, New York, North Carolina, Oregon, Pennsylvania, Tennessee, Texas, Utah, Washington, West Virginia, and Wisconsin the cover certain emissions from the power sector.

Coal-fired electric utility steam generating units include electric utility steam generating units that burn coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other supplemental fuels. Examples of supplemental fuels include petroleum coke and tire-derived fuels. The NESHAP establishes standards for HAP emissions from both coal- and oil-fired EGUs and will apply to any existing, new, or reconstructed units located at major or area sources of HAP. Although all HAP are pollutants of interest, those of particular concern are hydrogen fluoride (HF), hydrogen chloride (HCl), dioxins/furans, and HAP metals, including antimony, arsenic, beryllium, cadmium, chromium, cobalt, mercury, manganese, nickel, lead, and selenium.

This rule affects any fossil fuel fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered an electric utility steam generating unit. The rule affects roughly 1,400 EGUs: approximately 1,100 existing coal-fired generating units and 300 oil-fired steam units, should those units combust oil. Of the 600 power plants potentially covered by this rule, about 430 have coal-fired units only, 30 have both coal- and oil- or gas-fired steam units, and 130 have oil- or gas-fired steam units only. Note that only steam electric units combusting coal or oil are covered by this rule.

EPA analyzed for the RIA the input-based (lbs/MMBtu) MATS control requirements shown in Table 3-1. In this analysis, EPA does not model an alternative SO_2 standard. Coal steam units with access to lignite in the modeling are subjected to the “Existing coal-fired unit low Btu virgin coal” standard. For further discussion about the scope and requirements of MATS, see the preamble or Chapter 1 of this RIA.

Table 3-1. Emissions Limitations for Coal-Fired and Solid Oil-Derived Fuel-Fired Electric Utility Steam Generating Units

Subcategory	Filterable Particulate Matter	Hydrogen Chloride	Mercury
Existing coal-fired unit not low Btu virgin coal	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.020 lb/MWh)	1.2 lb/TBtu (0.020 lb/GWh)
Existing coal-fired unit low Btu virgin coal	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.020 lb/MWh)	11.0 lb/TBtu (0.20 lb/GWh) 4.0 lb/TBtu[a] (0.040 lb/GWh[a])
Existing - IGCC	0.040 lb/MMBtu (0.40 lb/MWh)	0.00050 lb/MMBtu (0.0050 lb/MWh)	2.5 lb/TBtu (0.030 lb/GWh)
Existing – Solid oil-derived	0.0080 lb/MMBtu (0.090 lb/MWh)	0.0050 lb/MMBtu (0.080 lb/MWh)	0.20 lb/TBtu (0.0020 lb/GWh)
New coal-fired unit not low Btu virgin coal	0.0070 lb/MWh	0.40 lb/GWh	0.00020 lb/GWh
New coal-fired unit low Btu virgin coal	0.0070 lb/MWh	0.40 lb/GWh	0.040 lb/GWh
New – IGCC	0.070 lb/MWh[b] 0.090 lb/MWh[c]	0.0020 lb/MWh[d]	0.0030 lb/GWh[e]
New – Solid oil-derived	0.020 lb/MWh	0.00040 lb/MWh	0.0020 lb/GWh

Note: lb/MMBtu = pounds pollutant per million British thermal units fuel input
lb/TBtu = pounds pollutant per trillion British thermal units fuel input
lb/MWh = pounds pollutant per megawatt-hour electric output (gross)
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross)
[a] Beyond-the-floor limit as discussed elsewhere
[b] Duct burners on syngas; based on permit levels in comments received
[c] Duct burners on natural gas; based on permit levels in comments received
[d] Based on best-performing similar source
[e] Based on permit levels in comments received

Table 3-2. Emissions Limitations for Liquid Oil-Fired Electric Utility Steam Generating Units

Subcategory	Filterable PM	Hydrogen Chloride	Hydrogen Fluoride
Existing – Liquid oil-continental	0.030 lb/MMBtu (0.30 lb/MWh)	0.0020 lb/MMBtu (0.010 lb/MWh)	0.00040 lb/MMBtu (0.0040 lb/MWh)
Existing – Liquid oil-non-continental	0.030 lb/MMBtu (0.30 lb/MWh)	0.00020 lb/MMBtu (0.0020 lb/MWh)	0.000060 lb/MMBtu (0.00050 lb/MWh)
New – Liquid oil – continental	0.070 lb/MWh	0.00040 lb/MWh	0.00040 lb/MWh
New – Liquid oil – non-continental	0.20 lb/MWh	0.0020 lb/MWh	0.00050 lb/MWh

EPA used the Integrated Planning Model (IPM) v.4.10 to assess the impacts of the MATS emission limitations for coal-fired electricity generating units (EGU) in the contiguous United States. IPM modeling did not subject oil-fired units to policy criteria.[6] Furthermore, IPM modeling did not include generation outside the contiguous U.S., where EPA is aware of only 2 facilities that would be subject to the coal-fired requirements of the final rule. Given the limited number of potentially impacted facilities, limited availability of input data to inform the modeling, and limited connection to the continental grid, EPA did not model the impacts of the rule beyond the contiguous U.S.

Mercury emissions are modeled as a function of mercury content of the fuel type(s) consumed at each plant in concert with that plant's pollutant control configuration. HCl emissions are projected in a similar fashion using the chlorine content of the fuel(s). For both mercury and HCl, EGUs in the model must emit at or below the final mercury and HCl emission rate standards in order to operate from 2015 onwards. EGUs may change fuels and/or install additional control technology to meet the standard, or they may choose to retire if it is more economic for the power sector to meet electricity demand with other sources of generation. See IPM 4.10 documentation and IPM 4.10 Supplemental Documentation for MATS for more details.

Total PM emissions are calculated exogenously to IPM, using EPA's Source Classification Code (SCC) and control-based emissions factors. SCC is a classification system that describes a generating unit's characteristics.

[6] EPA did not model the impacts of MATS on oil-fired units using IPM. Rather, EPA performed an analysis of impacts on oil-fired units for the final rule. The results are summarized in Appendix 3A.

Instead of emission limitations for the organic HAP, EPA is proposing that if requested, owners or operators of EGUs submit to the delegated authority or EPA, as appropriate, documentation showing that an annual performance test meeting the requirements of the rule was conducted. IPM modeling of the MATS policy assumes compliance with these work practice standards.

Electricity demand is anticipated to grow by roughly 1 percent per year, and total electricity demand is projected to be 4,103 billion kWh by 2015. Table 3-3 shows current electricity generation alongside EPA's base case projection for 2015 generation using IPM. EPA's IPM modeling for this rule relies on EIA's *Annual Energy Outlook for 2010*'s electric demand forecast for the US and employs a set of EPA assumptions regarding fuel supplies and the performance and cost of electric generation technologies as well as pollution controls.[7] The base case includes CSAPR as well as other existing state and federal programs for air emissions control from electric generating units, with the exception of state mercury rules.

[7] Note that projected electricity demand in AEO 2010 is about 2% higher than the AEO 2011 projection in 2015. Since this RIA assumes higher electricity demand in 2015 than is shown in the latest AEO projection, it is possible that the model may be taking compliance actions to meet incremental electricity demand that may not actually occur, and projected compliance costs may therefore be somewhat overstated in this analysis.

Table 3-3. 2009 U.S. Electricity Net Generation and EPA Base Case Projections for 2015-2030 (Billion kWh)

	Historical	Base Case		
	2009	**2015**	**2020**	**2030**
Coal	1,741	1,982	2,002	2,027
Oil	36	0.11	0.13	0.21
Natural Gas	841	710	847	1,185
Nuclear	799	828	837	817
Hydroelectric	267	286	286	286
Non-hydro Renewables	116	252	289	333
Other	10	45	45	55
Total	3,810	**4,103**	**4,307**	**4,702**

Source: 2009 data from AEO Annual Energy Review, Table 8.2c Electricity Net Generation: Electric Power Sector by Plant Type, 1989-2010; Projections from Integrated Planning Model run by EPA, 2011.

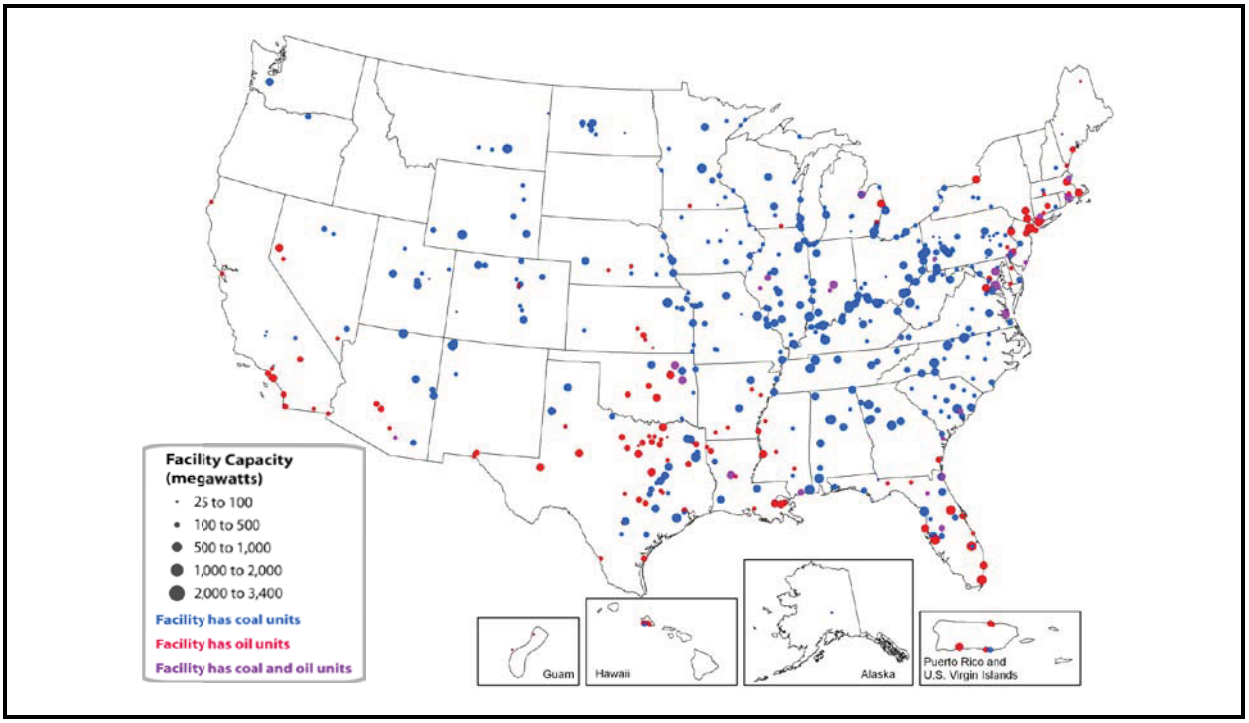


Figure 3-1. Geographic Distribution of Affected Units, by Facility, Size and Fuel Source in 2012

Source/Notes: National Electric Energy Data System (NEEDS 4.10 MATS) (EPA, December 2011) and EPA's Information Collection Request (ICR) for New and Existing Coal- And Oil-Fired Electric Utility Stream Generation Units (2010). This map displays facilities that are included in the NEEDS 4.10 MATS data base and that contain at least one oil-fired steam generating unit or one coal-fired steam generating unit that generates more than 25 megawatts of power. This includes coal-fired units that burn petroleum coke and that turn coal into gas before burning (using integrated gasification combined cycle or IGCC). NEEDS reflects available capacity on-line by the end of 2011; this includes committed new builds and committed retirements of old units. Only coal and oil-fired units are covered by this rule. Some of the oil units displayed on the map are capable of burning oil and/or gas. If a unit burns only gas, it will not be covered in the rule. In areas with a dense concentration of facilities, the facilities on the map may overlap and some may be impossible to see. IPM modeling did not include generation outside the contiguous U.S., where EPA is aware of only two facilities that would be subject to the coal-fired requirements of the final rule. Given the limited number of potentially impacted facilities, limited availability of input data to inform the modeling, and limited connection to the continental grid, EPA did not model the impacts of the rule beyond the contiguous U.S. Facilities outside the contiguous U.S. are displayed based on data from EPA's 2010 ICR for the rule.

As noted above, IPM has been used for evaluating the economic and emission impacts of environmental policies for over two decades. The economic modeling presented in this chapter has been developed for specific analyses of the power sector. Thus, the model has been designed to reflect the industry as accurately as possible. To that end, EPA uses a series of capital charge factors in IPM that embody financial terms for the various types of investments that the power sector considers for meeting future generation and environmental constraints.

The model applies a discount rate of 6.15% for optimizing the sector's decision-making over time. IPM's discount rate, designed to represent a broad range of private-sector decisions for power generation, rates differs from discount rates used in other analyses in this RIA, such as the benefits analysis which each assume alternative social discount rates of 3% and 7%. These discount rates represent social rates of time preference, whereas the discount rate in IPM represents an empirically-informed price of raising capital for the power sector. Like all other assumed price inputs in IPM, EPA uses the best available information from utilities, financial institutions, debt rating agencies, and government statistics as the basis for the capital charge rates and the discount rate used for power sector modeling in IPM.

More detail on IPM can be found in the model documentation, which provides additional information on the assumptions discussed here as well as all other assumptions and inputs to the model (http://www.epa.gov/airmarkets/progsregs/epa-ipm). Updates specific to MATS modeling are also in the IPM 4.10 Supplemental Documentation for MATS.

3.2 Projected Emissions

MATS is anticipated to achieve substantial emissions reductions from the power sector. Since the technologies available to meet the emission reduction requirements of the rule reduce multiple air pollutants, EPA expects the rule to yield a broad array of pollutant reductions from the power sector. The primary pollutants of concern under MATS from the power sector are mercury, acid gases such as hydrogen chloride (HCl), and HAP metals, including antimony, arsenic, beryllium, cadmium, chromium, cobalt, mercury, manganese, nickel, lead, and selenium. EPA has extensively analyzed mercury emissions from the power sector, and IPM modeling assesses the mercury contents in all coals and the removal efficiencies of relevant emission control technologies (e.g., ACI). EPA also models emissions and the pollution control technologies associated with HCl (as a surrogate for acid gas emissions). Like SO_2, HCl is removed by both scrubbers and DSI (dry sorbent injection). Projected emissions are based on both control technology and detailed coal supply curves used in the model that reflect the chlorine content of coals, which corresponds with the supply region, coal grade, and sulfur, mercury, and ash content of each coal type. This information is critical for accurately projecting future HCl emissions, and for understanding how the power sector will respond to a policy requiring reductions of multiple HAPs.

Generally, existing pollution control technologies reduce emissions across a range of pollutants. For example, both FGD and SCR can achieve notable reductions in mercury in addition to their primary targets of SO_2 and NO_X reductions. DSI will reduce HCl emissions while

also yielding substantial SO_2 emission reductions, but is not assumed in EPA modeling to result in mercury reductions. Since there are many avenues to reduce emissions, and because the power sector is a highly complex and dynamic industry, EPA employs IPM in order to reflect the relevant components of the power sector accurately, while also providing a sophisticated view of how the industry could respond to particular policies to reduce emissions. For more detail on how EPA models emissions from the power sector, including recent updates to include acid gases, see IPM 4.10 Supplemental Documentation for MATS.

Under MATS, EPA projects annual HCl emissions reductions of 88 percent in 2015, Hg emissions reductions of 75 percent in 2015, and $PM_{2.5}$ emissions reductions of 19 percent in 2015 from coal-fired EGUs greater than 25 MW. In addition, EPA projects SO_2 emission reductions of 41 percent, and annual CO_2 reductions of 1 percent from coal-fired EGUs greater than 25 MW by 2015, relative to the base case (see Table 3-4).[8] Mercury emission projections in EPA's base case are affected by the incidental capture in other pollution control technologies (such as FGD and SCR) as described above.

Table 3-4. Projected Emissions of SO_2, NO_X, Mercury, Hydrogen Chloride, PM, and CO_2 with the Base Case and with MATS, 2015

		Million Tons			Thousand Tons		CO_2
		SO_2	NO_X	Mercury (Tons)	HCl	$PM_{2.5}$	(Million Metric Tonnes)
Base	All EGUs	3.4	1.9	28.7	48.7	277	2,230
	Covered EGUs	3.3	1.7	26.6	45.3	270	1,906
MATS	All EGUs	2.1	1.9	8.8	9.0	227	2,215
	Covered EGUs	1.9	1.7	6.6	5.5	218	1,882

Source: Integrated Planning Model run by EPA, 2011

[8] The CO_2 emissions reported from IPM account for the direct CO_2 emissions from fuel combustion and CO_2 created from chemical reactions in pollution controls to reduced sulfur.

APPENDIX 5A
IMPACT OF THE INTERIM POLICY SCENARIO ON EMISSIONS

5A.1 Introduction

This section summarizes the emissions inventories that are used to create emissions inputs to the air quality modeling performed for this rule. A summary of the emissions reductions that were modeled for this rule is provided. Note that the emissions processing and corresponding air quality modeling were used to develop BPT scaling factors for the benefits calculation as described in this RIA. More information on this approach can be found in Appendix 5C. The emissions inventories were processed into the form required by the Community Multi-scale Air Quality (CMAQ) model. CMAQ simulates the numerous physical and chemical processes involved in the formation, transport, and destruction of ozone, particulate matter and air toxics.

As part of the analysis for this rulemaking, the modeling system was used to calculate daily and annual $PM_{2.5}$ concentrations, 8-hr maximum ozone and visibility impairment. Model predictions of $PM_{2.5}$ and ozone are used in a relative sense to estimate scenario-specific, future-year design values of $PM_{2.5}$ and ozone. These are combined with monitoring data to estimate population-level exposures to changes in ambient concentrations for use in estimating health and welfare effects. In the remainder of this section we provide an overview of (1) the emissions components of the modeling platform, (2) the development of the 2005 base year emissions, (3) the development of the future year baseline emissions, and (4) the development of the future year control case emissions.

5A.2 Overview of Modeling Platform and Emissions Processing Performed

A modeling platform is the collection of the inputs to an air quality model, including the settings and data used for the model, including emissions data, meteorology, initial conditions, and boundary conditions. The 2005-based air quality modeling platform used for this RIA includes 2005 base year emissions and 2005 meteorology for modeling ozone and $PM_{2.5}$ with CMAQ. In support of this rule, EPA modeled the air quality in the Eastern and the Western United States using two separate model runs, each with a horizontal grid resolution of 12 km x 12 km. These 12 km modeling domains were “nested” within a modeling domain covering the remainder of the lower 48 states and surrounding areas using a grid resolution of 36 x 36 km. The results from the 36-km modeling were used to provide incoming “boundary” for the 12km grids. Additional details on the non-emissions portion of the 2005v4.3 modeling platform used for this RIA are described in the air quality modeling section (Appendix 5B).

The 2005-based air quality modeling platform used in support of this RIA is version 4.3 and is referred to as the 2005v4.3 platform. It is an update to the 2005-based platform, version 4.1 (i.e., 2005v4.1) used for the proposal modeling and for the appropriate and necessary finding. The Technical Support Document "Preparation of Emissions Inventories for the Version 4.1, 2005-based Platform" (see http://www.epa.gov/ttn/chief/emch/index.html#toxics) provides information on the platform used for the proposed version of this rule and for the appropriate and necessary finding. The 2005v4.3 platform builds upon the 2005-based platform, version 4.2 which was the version of the platform used for the final Cross-State Air Pollution Rule and incorporated changes made in response to public comments on the proposed version of that rule. Detailed documentation about the 2005v4.3 platform emissions inventories used for this rule can be found in the "Emissions Modeling for the Final Mercury and Air Toxics Standards Technical Support Document".

5A.3 Development of 2005 Base Year Emissions

Emissions inventory inputs representing the year 2005 were developed to provide a base year for forecasting future air quality. The emission source sectors and the basis for current and future-year inventories include Electric Generating Utility point sources, non-EGU point sources, and the following types of sources with inventories primarily at the county level: onroad mobile, nonroad mobile, nonpoint, and fires. The specific sectors used for modeling are listed and defined in detail in the "Emissions Modeling for the Final Mercury and Air Toxics Standards Technical Support Document". The inventories used include emissions of criteria pollutants, and for some sectors the pollutants benzene, formaldehyde, acetaldehyde and methanol are used to speciate VOC into the chemical species needed by CMAQ.

The 2005v4 platform was the initial starting point for the 2005v4.3 platform used for this modeling. There were two intermediate versions: the version used for the MATS proposal modeling (2005v4.1), and the version used for the final Cross-State Air Pollution Rule modeling (2005v4.2). The basis of the 2005v4 platform and subsequent versions is the U.S. inventory is the 2005 National Emission Inventory (NEI), version 2 from October 6, 2008 (http://www.epa.gov/ttn/chief/net/2005inventory.html). The 2005 NEI v2 includes 2005-specific data for point and mobile sources, while most nonpoint data were carried forward from version 3 of the 2002 NEI.

Emissions for point sources were primarily from the 2005 NEI v2 inventory, consisting mostly of 2005 values with some 2002 emissions values used where 2005 data were not available. The point sources are split into "EGU" (aka "ptipm") and "Non-EGU" (aka

"ptnonipm") sectors for modeling purposes based on the matching of the unit level data in the NEI units in the National Electric Energy Database System (NEEDS) version 4.10 database. All units that matched NEEDS were included in the EGU sector so that the future year emissions could easily be taken from the Integrated Planning Model (IPM) as its outputs are also based on the NEEDS units. Efforts made to ensure the quality of the 2005 EGU inventory included ensuring that there were not duplicate emissions (e.g., data pulled forward from earlier inventories), accounting for plants or units that shutdown prior to 2005, adding estimates for ethanol plants, and accounting for installed emissions control devices.

The 2005 annual NO_X and SO_2 emissions for sources in the EGU sector are based primarily on data from EPA's Clean Air Markets Division's Continuous Emissions Monitoring (CEM) program, with other pollutants estimated using emission factors and the CEM annual heat input. For EGUs without CEMs, emissions were obtained from the state-submitted data in the NEI. For the 2005 base year, the annual EGU NEI emissions were allocated to hourly emissions values needed for modeling based on the 2004, 2005, and 2006 CEM data. The NO_X CEM data were used to create NO_X-specific profiles, the SO_2 data were used to create SO_2-specific profiles, and the heat input data were used to allocate all other pollutants. The three years of data were used to create monthly profiles by state, while the 2005 data were used to create state-averaged profiles for allocating monthly emissions to daily. These daily values were input into SMOKE, which utilized state-averaged 2005-based hourly profiles to allocate to hourly values. This approach to temporal allocation was used for all base and control cases modeled to provide a temporal consistency between the years modeled without tying the temporalization to the events of a single year.

For nonpoint sources, the 2002 NEI v2 inventory was augmented with updated oil and gas exploration emissions for Texas and Oklahoma (for CO, NO_X, PM, SO_2, VOC). These oil and gas exploration emissions were in addition to oil and gas data previously available in the 2005 v4 platform that includes emissions within the following states: Arizona, Colorado, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, and Wyoming.

The commercial marine category 3 (C3) vessel emissions portion of the nonroad sector used point-based gridded 2005 emissions that reflect the final projections developed for the category 3 commercial marine Emissions Control Area (ECA) proposal to the International Maritime Organization (EPA-420-F-10-041, August 2010). These emissions include Canada as part of the ECA, and were updated using region-specific growth rates and thus contain Canadian province codes. The state/federal water boundaries were based on a file available

from the Mineral Management Service (MMS) that specifies boundaries ranging from three to ten nautical miles from the coast.

The onroad emissions were primarily based on the version of the Motor Vehicle Emissions Simulator (MOVES) (http://www.epa.gov/otaq/models/moves/) used for the Tier 3 proposed rule. The first step was to run MOVES to output emission factors for a set of counties with characteristics representative of the counties within the continental United States. Data for each representative county included county-specific fuels, vehicle age distribution, inspection and maintenance programs, temperatures and relative humidity. The emission factors produced by MOVES were then combined by SMOKE with county-based activity data (vehicle miles traveled, speed data, and vehicle population) and gridded temperature data to create hourly, gridded emissions. Additional information on this approach is available in the "Emissions Modeling for the Final Mercury and Air Toxics Standards Technical Support Document".

The nonroad emissions utilized the National Mobile Inventory Model (NMIM) to run the NONROAD model for all states to create county/month emissions, updated from the annual emissions in the 2005 NEI v2 with some improvements. For this case, NMIM was run using representing county mode, with improved fuels, an improved toxics emission factor (1,3-butadiene for 2-stroke snowmobiles), and a small coding change that enabled NONROAD to process 15% ethanol (E15) fuels.

Other emissions inventories used included average-year county-based inventories for emissions from wildfires and prescribed burning. These emissions are intended to be representative of both base and future years and are held constant for each. As a result, post-processing techniques minimize their impact on the modeling results. The 2005v4.3 platform utilizes the same 2006 Canadian inventory and a 1999 Mexican inventory as were used since the v4 platform, as these were the latest available data from these countries.

Once developed, the emissions inventories were processed to provide the hourly, gridded emissions for the model-species needed by CMAQ. Details on this processing are further described in the "Emissions Modeling for the Final Mercury and Air Toxics Standards Technical Support Document". Table 5A-1 provides summaries of the 2005 U.S. emissions inventories modeled for this rule by sector. Tables 5A-2 through 5A-3 provide state-level summaries of SO_2, and $PM_{2.5}$ by sector. Note that the nonroad columns include emissions from traditional nonroad sources that are found "on-land," along with commercial marine sources. The nonpoint columns include area fugitive dust, agriculture, and other nonpoint emissions.

Table 5A-1. 2005 US Emissions by Sector

Emissions Sector	2005 NO_X [tons/yr]	2005 SO_2 [tons/yr]	2005 $PM_{2.5}$ [tons/yr]	2005 PM_{10} [tons/yr]	2005 NH_3 [tons/yr]	2005 CO [tons/yr]	2005 VOC [tons/yr]
Agriculture					3,251,990		
Area fugitive dust			1,030,391	8,858,992			
Average fires	189,428	49,094	684,035	796,229	36,777	8,554,551	1,958,992
Commercial marine Category 3 (US)	130,164	97,485	10,673	11,628		11,862	4,570
EGU	3,729,161	10,380,883	496,877	602,236	21,995	603,788	41,089
Locomotive/marine	1,922,723	153,068	56,666	59,342	773	270,007	67,690
Non-EGU point	2,213,471	2,030,759	433,346	647,873	158,342	3,201,418	1,279,308
Nonpoint	1,696,902	1,216,362	1,079,906	1,349,639	133,962	7,410,946	7,560,061
Nonroad	2,031,527	196,277	201,406	210,767	1,971	20,742,873	2,806,422
Onroad	8,235,002	168,480	301,073	369,911	144,409	41,117,658	3,267,931
US Total	**20,148,378**	**14,292,410**	**4,294,373**	**12,906,616**	**3,750,218**	**81,913,104**	**16,986,064**

Table 5A-2. 2005 Base Year SO_2 Emissions (tons/year) for States by Sector

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	460,123	66,373	52,325	5,622	3,554	983	588,980
Arizona	52,733	23,966	2,571	6,151	3,622	2,888	91,931
Arkansas	66,384	13,039	27,260	5,678	1,918	728	115,008
California	601	33,097	77,672	40,222	4,526	6,735	162,852
Colorado	64,174	1,550	6,810	4,897	2,948	1,719	82,098

(continued)

Table 5A-2. 2005 Base Year SO_2 Emissions (tons/year) for States by Sector (continued)

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Connecticut	10,356	1,831	18,455	2,557	1,337	4	34,540
Delaware	32,378	34,859	1,030	2,657	486	6	71,416
District of Columbia	1,082	686	1,559	414	205	0	3,947
Florida	417,321	57,429	70,490	31,190	12,388	7,018	595,836
Georgia	616,063	52,827	56,829	9,224	6,939	2,010	743,893
Idaho	0	17,151	2,915	2,304	902	3,845	27,117
Illinois	330,382	131,357	5,395	19,305	6,881	20	493,339
Indiana	878,979	86,337	59,775	9,437	4,641	24	1,039,194
Iowa	130,264	41,010	19,832	8,838	2,036	25	202,004
Kansas	136,520	12,926	36,381	8,035	1,978	103	195,943
Kentucky	502,731	25,808	34,229	6,943	3,240	364	573,315
Louisiana	109,875	165,705	2,378	25,451	2,902	892	307,202
Maine	3,887	18,512	9,969	1,625	963	150	35,106
Maryland	283,205	34,988	40,864	9,353	3,016	32	371,458
Massachusetts	84,234	19,620	25,261	6,524	2,669	93	138,402
Michigan	349,877	76,510	42,066	14,626	8,253	91	491,423
Minnesota	101,678	24,603	14,747	10,409	2,934	631	155,002
Mississippi	75,047	29,892	6,796	5,930	2,590	1,051	121,306
Missouri	284,384	78,308	44,573	10,464	4,901	186	422,816
Montana	19,715	11,056	2,600	3,813	874	1,422	39,480
Nebraska	74,955	7,910	7,659	9,199	1,510	105	101,337
Nevada	53,363	2,253	12,477	2,880	656	1,346	72,975
New Hampshire	51,445	3,155	7,408	789	746	38	63,580
New Jersey	57,044	7,639	10,726	13,321	3,038	61	91,830
New Mexico	30,628	7,831	3,193	3,541	1,801	3,450	50,445
New York	180,847	58,426	125,158	15,666	6,258	113	386,468
North Carolina	512,231	59,433	22,020	8,766	6,287	696	609,433
North Dakota	137,371	9,582	6,455	5,986	533	66	159,994
Ohio	1,116,095	115,155	19,810	15,425	7,336	22	1,273,843

(continued)

Table 5A-2. 2005 Base Year SO_2 Emissions (tons/year) for States by Sector (continued)

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Oklahoma	110,081	40,482	8,556	5,015	3,039	469	167,642
Oregon	12,304	9,825	9,845	5,697	1,790	4,896	44,357
Pennsylvania	1,002,203	83,375	68,349	11,999	6,266	32	1,172,224
Rhode Island	176	2,743	3,365	816	254	1	7,354
South Carolina	218,781	31,495	13,489	7,719	3,589	646	275,719
South Dakota	12,215	1,702	10,347	3,412	623	498	28,797
Tennessee	266,148	65,693	32,714	6,288	5,538	277	376,659
Texas	534,949	223,625	115,192	34,944	16,592	1,178	926,480
Tribal	3	1,511	0	0	0	0	1,515
Utah	34,813	9,132	3,577	2,439	1,890	1,934	53,784
Vermont	9	902	5,385	385	342	49	7,073
Virginia	220,287	69,401	32,923	10,095	4,600	399	337,705
Washington	3,409	24,211	7,254	18,810	3,343	407	57,433
West Virginia	469,456	46,710	14,589	2,133	1,378	215	534,481
Wisconsin	180,200	66,807	6,369	7,163	3,647	70	264,256
Wyoming	89,874	22,321	6,721	2,674	721	1,106	123,417
Total	**10,380,883**	**2,030,759**	**1,216,362**	**446,831**	**168,480**	**49,094**	**14,292,410**

Table 5A-3. 2005 Base Year $PM_{2.5}$ Emissions (tons/year) for States by Sector

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	23,366	19,498	35,555	4,142	5,775	13,938	102,273
Arizona	7,418	3,940	21,402	4,486	6,920	37,151	81,316
Arkansas	1,688	10,820	34,744	3,803	3,102	10,315	64,472
California	347	21,517	94,200	22,815	26,501	97,302	262,682
Colorado	4,342	7,116	25,340	3,960	4,377	24,054	69,189
Connecticut	562	224	11,460	1,740	2,544	56	16,586
Delaware	2,169	1,810	1,590	818	922	87	7,397
District of Columbia	17	172	589	277	367	0	1,421

(continued)

Table 5A-3. 2005 Base Year $PM_{2.5}$ Emissions (tons/year) for States by Sector (continued)

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Florida	24,217	25,193	52,955	15,035	16,241	99,484	233,125
Georgia	28,057	12,666	63,133	6,504	12,449	24,082	146,892
Idaho	0	2,072	41,492	2,140	1,402	52,808	99,914
Illinois	16,585	15,155	74,045	12,880	12,574	277	131,516
Indiana	34,439	14,124	74,443	6,515	7,585	344	137,450
Iowa	8,898	6,439	54,312	6,969	3,468	349	80,436
Kansas	5,549	7,387	138,437	5,719	3,109	1,468	161,669
Kentucky	19,830	10,453	31,245	4,762	5,566	5,155	77,010
Louisiana	5,599	32,201	28,164	9,440	4,288	12,647	92,339
Maine	52	3,783	15,037	1,363	1,759	2,127	24,120
Maryland	15,417	6,768	23,323	3,410	5,504	531	54,952
Massachusetts	3,110	2,245	31,116	3,293	5,913	1,324	47,001
Michigan	11,022	12,926	47,722	8,561	13,006	1,283	94,520
Minnesota	3,262	10,538	73,990	8,541	6,842	8,943	112,116
Mississippi	2,029	10,602	34,217	4,133	4,195	14,897	70,074
Missouri	6,471	6,966	76,419	7,230	7,665	2,636	107,388
Montana	2,398	2,729	30,096	2,654	1,347	17,311	56,536
Nebraska	1,246	2,340	45,661	5,848	2,620	1,483	59,198
Nevada	3,341	4,095	9,920	2,212	1,290	19,018	39,876
New Hampshire	2,586	568	13,316	907	1,512	534	19,423
New Jersey	4,625	2,588	13,623	5,042	5,963	865	32,707
New Mexico	5,583	1,460	50,698	1,959	2,861	48,662	111,224
New York	9,648	4,994	48,540	8,607	11,139	1,601	84,529
North Carolina	16,967	12,665	49,551	6,272	8,939	9,870	104,264
North Dakota	6,397	598	41,504	4,552	976	934	54,962
Ohio	53,572	12,847	52,348	9,847	11,785	316	140,715
Oklahoma	1,411	6,246	90,047	3,765	4,559	6,644	112,672
Oregon	412	8,852	58,145	3,741	3,375	65,350	139,874
Pennsylvania	55,547	16,263	44,607	7,565	11,058	454	135,494

(continued)

Table 5A-3. 2005 Base Year $PM_{2.5}$ Emissions (tons/year) for States by Sector (continued)

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Rhode Island	10	256	1,289	394	577	14	2,540
South Carolina	14,455	4,779	26,598	3,491	5,061	9,163	63,548
South Dakota	390	2,982	33,678	2,910	1,056	7,062	48,079
Tennessee	12,856	21,912	32,563	5,072	8,514	3,934	84,851
Texas	21,464	37,563	194,036	21,361	29,859	21,578	325,861
Tribal	0	1,569	0	0	0	0	1,569
Utah	5,055	3,595	14,761	1,627	2,703	27,412	55,153
Vermont	37	337	6,943	479	605	696	9,098
Virginia	12,357	11,455	38,140	5,968	6,661	5,659	80,241
Washington	2,396	4,618	45,599	6,697	6,721	4,487	70,519
West Virginia	26,377	5,154	14,778	1,702	1,930	3,050	52,991
Wisconsin	5,233	7,967	37,277	6,083	6,783	994	64,337
Wyoming	8,068	10,298	31,645	1,455	1,103	15,686	68,254
Total	**496,877**	**433,346**	**2,110,298**	**268,745**	**301,073**	**684,035**	**4,294,373**

5A.4 Development of Future year baseline Emissions

The future year baseline scenario, also known as the "reference case", represents predicted emissions including adjustments for known promulgated federal measures for all sectors as of the year 2017, which is assumed to be representative of 2016. The EGU and mobile sectors reflect projected economic and fuel usage changes. Emissions from non-EGU stationary sectors have previously been shown to not be well correlated with economic forecasts, and therefore economic impacts were not included for non-EGU stationary sources. Like the 2005 base case, these emissions cases include criteria pollutants and for some sectors, benzene, formaldehyde, acetaldehyde and methanol from the inventory is used in VOC speciation. The future year baseline scenario represents predicted emissions in the absence of any further controls beyond those Federal measures already promulgated. For EGUs, all state and other programs available at the time of modeling have been included. For mobile sources, all national measures promulgated at the time of modeling have been included. Additional details on the future year baseline (i.e., reference case) emissions modeling can be found in the

"Emissions Modeling for the Final Mercury and Air Toxics Standards Technical Support Document".

The future year baseline EGU emissions were obtained using version 4.10 Final of the Integrated Planning Model (IPM) (http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html). The IPM is a multiregional, dynamic, deterministic linear programming model of the U.S. electric power sector. Version 4.10 Final reflects state rules and consent decrees through December 1, 2010, information obtained from the 2010 Information Collection Request (ICR), and information from comments received on the IPM-related Notice of Data Availability (NODA) published on September 1, 2010. Notably, IPM 4.1 Final included the addition of over 20 GW of existing Activated Carbon Injection (ACI) for coal-fired EGUs reported to EPA via the ICR. Additional unit-level updates that identified existing pollution controls (such as scrubbers) were also made based on the ICR and on comments from the IPM NODA. Units with SO_2 or NO_X advanced controls (e.g., scrubber, SCR) that were not required to run for compliance with Title IV, New Source Review (NSR), state settlements, or state-specific rules were modeled by IPM to either operate those controls or not based on economic efficiency parameters. The IPM run for future year baseline case modeled with CMAQ assumed that 100% of the HCl found in the coal was emitted into the atmosphere. However, in the final IPM results for the rule, neutralization of 75% of the available HCl was included based on recent findings.

Further details on the future year baseline EGU emissions inventory used for this rule can be found in the IPM v.4.10 Documentation, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html. The future year baseline modeled in IPM for this rule includes estimates of emissions reductions that will result from the Cross-State Air Pollution Rule. However, reductions from the Boiler MACT rule were not represented this modeling because the rule was stayed at the time the modeling was performed. A complete list of state regulations, NSR settlements, and state settlements included in the IPM modeling is given in Appendices 3-2, 3-3, and 3-4 beginning on p. 68 of http://www.epa.gov/airmarkets/progsregs/epa-ipm/CSAPR/docs/DocSuppv410_FTransport.pdf. For the future year baseline EGU emissions, the IPM outputs for 2020, which are also representative of the year 2017, were used as part of the 2017 reference case modeling. These emissions were very similar to the year 2015 emissions output from the same IPM modeling case.

Inventories of onroad mobile emissions for the future year baseline and control cases were created using the MOVES model with an approach consistent with the 2005 base year. As with the 2005 emissions, the future year onroad emissions were based on emission factors

developed using the Tier 3 version of MOVES processed through the SMOKE-MOVES interface. Future-year vehicle miles travelled (VMT) were projected from the 2005 NEI v2 VMT using growth rates from the 2009 Annual Energy Outlook (AEO) data. The VMT for heavy duty diesel vehicles class 8a and 8b was updated based on data from Oak Ridge National Laboratory. The future year onroad emissions reflect control program implementation through 2017 and include the Light-Duty Vehicle Tier 2 Rule, the Onroad Heavy-Duty Rule, the Mobile Source Air Toxics (MSAT) final rule, and the Renewable Fuel Standard version 2 (RFS2).

Future year nonroad mobile emissions were created using NMIM to run NONROAD in a consistent manner as was done for 2005, but with future-year equipment population estimates, fuels, and control programs. The fuels in 2017 are assumed to be E10. Emissions for locomotives and category 1 and 2 (C1 and C2) commercial marine vessels were derived based on emissions published in the Final Locomotive Marine Rule, Regulatory Impact Assessment, Chapter 3 (see http://www.epa.gov/otaq/locomotives.htm#2008final). The future year baseline nonroad mobile emissions reductions include emissions reductions to locomotives, various nonroad engines including diesel engines and various marine engine types, fuel sulfur content, and evaporative emissions standards, including the category 3 marine residual and diesel fuelled engines and International Maritime Organization standards which include the establishment of emission control areas for these ships. A summary of the onroad and nonroad mobile source control programs included in the projected future year baseline is shown in Table 5A-4.

Table 5A-4. Summary of Mobile Source Control Programs Included in the Future Year Baseline

National Onroad Rules:
Tier 2 rule (Signature date: February 28, 2000)
Onroad heavy-duty rule (February 24, 2009)
Final mobile source air toxics rule (MSAT2) (February 9, 2007)
Renewable fuel standard Version 2 (March 26, 2010)
Light duty greenhouse gas standards (May, 2010)
Corporate Average Fuel Economy (CAFE) standards for 2008–2011
Local Onroad Programs:
National low emission vehicle program (NLEV) (March 2, 1998)
Ozone transport commission (OTC) LEV Program (January, 1995)

(continued)

Table 5A-4. Summary of Mobile Source Control Programs Included in the Future Year Baseline (continued)

National Nonroad Controls:
Tier 1 nonroad diesel rule (June 17, 2004)
Phase 1 nonroad SI rule (July 3, 1995)
Marine SI rule (October 4, 1996)
Nonroad large SI and recreational engine rule (November 8, 2002)
Clean Air Nonroad Diesel Rule—Tier 4 (June 29, 2004)
Locomotive and marine rule (May 6, 2008)
Nonroad SI rule (October 8, 2008)
Aircraft:
Itinerant (ITN) operations at airports adjusted to year 2017
Locomotives:
Locomotive Emissions Final Rulemaking (December 17, 1997)
Clean Air nonroad diesel final rule—Tier 4 (June 29, 2004)
Locomotive rule (April 16, 2008)
Locomotive and marine rule (May 6, 2008)
Commercial Marine:
Locomotive and marine rule (May 6, 2008)
EIA fuel consumption projections for diesel-fueled vessels
Clean Air Nonroad Diesel Final Rule – Tier 4
Emissions Standards for Commercial Marine Diesel Engines (December 29,1999)
Tier 1 Marine Diesel Engines (February 28, 2003)
Category 3 marine diesel engines Clean Air Act and International Maritime Organization standards (April, 30, 2010)

For non-EGU point sources, emissions were projected by including emissions reductions and increases from a variety of source data. Other than for certain large municipal waste combustors and airports, non-EGU point source emissions were not grown using economic growth projections, but rather were held constant at the emissions levels in 2005. Emissions reductions were applied to non-EGU point source to reflect final federal measures, known plant closures, and consent decrees. The starting inventories for this rule were the projected

emission inventories developed for the 2005v4.2 platform for the final Cross-State Air Pollution Rule (see http://www.epa.gov/ttn/chief/emch/index.html#final). The most significant updates to the emission projections for this rule are the addition of future year ethanol, biodiesel and cellulosic plants that account for increased ethanol production from the Renewable Fuel Standard Rule that is incorporated into the base case for 2017.

Since aircraft at airports were treated as point emissions sources in the 2005 NEI v2, we developed future year baseline emissions for airports by applying projection factors based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast (TAF) system, published in January 2010 for these sources.

Emissions from stationary nonpoint sources were projected using procedures specific to individual source categories. Refueling emissions were projected using refueling emissions from MOVES inventory mode runs. Portable fuel container emissions were projected using estimates from previous rulemaking inventories compiled by the Office of Transportation and Air Quality (OTAQ). Emissions of ammonia and dust from animal operations were projected based on animal population data from the Department of Agriculture and EPA. Residential wood combustion emissions were projected by replacement of obsolete woodstoves with new woodstoves and a 1 percent annual increase in fireplaces. Landfill emissions were projected using MACT controls. Other nonpoint sources were held constant between the 2005 and future year scenarios.

A summary of all rules and growth assumptions impacting non-EGU stationary sources is provided in Table 5A-5, along with the affected pollutants. Note that reductions associated with the Boiler MACT are not included in the future year baseline.

Table 5A-5. Control Strategies and/or Growth Assumptions Included in the Future Year Baseline for Non-EGU Stationary Sources

MACT rules, national, VOC: national applied by SCC, MACT	VOC
Consent decrees and settlements, including refinery consent decrees, and settlements for: Alcoa, TX and Premcor (formerly MOTIVA), DE	All
Municipal waste combustor reductions—plant level	PM
Hazardous waste combustion	PM
Hospital/medical/infectious waste incinerator regulations	NO_x, PM, SO_2
Large municipal waste combustors—growth applied to specific plants	All

(continued)

Table 5A-5. Control Strategies and/or Growth Assumptions Included in the Future Year Baseline for Non-EGU Stationary Sources (continued)

MACT rules, plant-level, VOC: auto plants	VOC
MACT rules, plant-level, PM & SO_2: lime manufacturing	PM, SO_2
MACT rules, plant-level, PM: taconite ore	PM
Municipal waste landfills: projection factor of 0.25 applied	All
Livestock emissions growth from year 2002 to year 2017	NH_3, PM
Residential wood combustion growth and change-outs from years 2005 to year 2017	All
Gasoline Stage II growth and control via MOVES from year 2005 to year 2017	VOC
Portable fuel container mobile source air toxics rule 2: inventory growth and control from year 2005 to year 2017	VOC
NESHAP: Portland Cement (09/09/10)—plant level based on industrial sector integrated solutions (ISIS) policy emissions in 2013. The ISIS results are from the ISIS-cement model runs for the NESHAP and NSPS analysis of July 28, 2010 and include closures.	Hg, NO_X, SO_2, PM, HCl
New York ozone SIP standards	VOC, HAP VOC, NO_X
Additional plant and unit closures provided by state, regional, and EPA agencies	All
Emission reductions resulting from controls put on specific boiler units (not due to MACT) after 2005, identified through analysis of the control data gathered from the ICR from the ICI boiler NESHAP.	NO_X, SO_2, HCL
NESHAP: Reciprocating Internal Combustion Engines (RICE).	NO_X, CO, PM, SO_2
RICE controls applied to Phase II WRAP 2018 oil and gas emissions	VOC, SO_2, NO_X, CO
RICE controls applied to 2008 Oklahoma and Texas Oil and gas emissions	VOC, SO_2, NO_X, CO, PM
Ethanol plants that account for increased ethanol due to RFS2	All
State fuel sulfur content rules for fuel oil—effective in 2017, only in Maine, New Jersey, and New York	SO_2

In all future year cases, the same emissions were used for Canada and Mexico as were used in the 2005 base case because appropriate future year emissions for sources in these countries were not available. Future year emissions need to reflect expected percent reductions or increases between the base year and the future year to be considered appropriate for this type of modeling and such emissions were not available.

Table 5A-6 shows a summary of the 2005 and modeled future year baseline emissions for the lower 48 states. Tables 5A-7 and 5A-8 below provide summaries of SO_2 and $PM_{2.5}$ in the

2017 baseline for each sector by state. Table 5A-9 shows the future year baseline EGU emissions by state for all criteria air pollutants.

Table 5A-6. Summary of Modeled Base Case Annual Emissions (tons/year) for 48 States by Sector: SO_2 and $PM_{2.5}$

Source Sector SO_2 Emissions	2005	2017
EGU point	10,380,883	3,281,364
Non-EGU point	2,030,759	1,534,991
Nonpoint	1,216,362	1,125,985
Nonroad	446,831	15,759
On-road	168,480	29,288
Average fire	49,094	49,094
Total SO_2, all sources	**14,292,410**	**6,036,480**
Source Sector $PM_{2.5}$ Emissions	**2005**	**2017**
EGU point	496,877	276,430
Non-EGU point	433,346	411,437
Nonpoint	2,110,298	1,912,757
Nonroad	268,745	150,221
On-road	301,073	129,416
Average fire	684,035	684,035
Total $PM_{2.5}$, all sources	**4,294,373**	**3,564,296**

Table 5A-7. Future Year Baseline SO_2 Emissions (tons/year) for States by Sector

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	186,084	63,053	52,341	146	569	983	303,177
Arizona	36,996	24,191	2,467	59	724	2,888	67,324
Arkansas	92,804	12,160	26,801	123	314	728	132,929
California	5,346	21,046	67,846	3,311	2,087	6,735	106,370
Colorado	74,255	1,415	6,210	50	532	1,719	84,181
Connecticut	3,581	1,833	18,149	100	311	4	23,978

(continued)

Table 5A-7. Future Year Baseline SO_2 Emissions (tons/year) for States by Sector (continued)

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Delaware	2,835	4,770	1,018	500	91	6	9,220
District of Columbia	5	686	1,505	3	38	0	2,237
Florida	117,702	49,082	70,073	1,255	2,111	7,018	247,241
Georgia	96,712	44,248	55,946	192	1,158	2,010	200,266
Idaho	182	17,133	2,894	23	162	3,845	24,240
Illinois	118,217	81,683	5,650	295	1,107	20	206,971
Indiana	200,969	73,930	59,771	150	760	24	335,604
Iowa	85,178	22,865	19,929	86	324	25	128,407
Kansas	45,740	10,288	36,140	57	294	103	92,622
Kentucky	116,927	23,530	33,852	215	463	364	175,350
Louisiana	142,447	129,730	2,669	1,449	447	892	277,634
Maine	2,564	14,285	2,007	72	149	150	19,226
Maryland	29,786	33,562	40,642	494	593	32	105,110
Massachusetts	15,133	17,077	24,907	266	565	93	58,041
Michigan	163,168	48,697	42,185	448	995	91	255,584
Minnesota	52,380	24,742	14,635	220	558	631	93,164
Mississippi	34,865	24,284	6,635	208	396	1,051	67,440
Missouri	178,143	33,757	44,680	191	722	186	257,679
Montana	24,018	7,212	1,875	25	106	1,422	34,657
Nebraska	70,910	6,885	7,899	58	202	105	86,058
Nevada	14,140	2,132	12,028	27	200	1,346	29,873
New Hampshire	6,719	2,471	7,284	21	137	38	16,671
New Jersey	9,042	6,700	9,528	686	757	61	26,774
New Mexico	10,211	7,813	2,719	26	262	3,450	24,480
New York	14,653	45,222	71,060	659	1,466	113	133,173
North Carolina	71,113	58,517	21,713	197	890	696	153,125
North Dakota	105,344	9,915	5,559	36	71	66	120,991
Ohio	180,935	93,600	19,777	373	1,093	22	295,799

(continued)

Table 5A-7. Future Year Baseline SO_2 Emissions (tons/year) for States by Sector (continued)

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Oklahoma	141,433	27,873	7,731	49	501	469	178,056
Oregon	13,211	9,790	9,508	218	361	4,896	37,985
Pennsylvania	126,316	64,697	67,650	427	1,060	32	260,183
Rhode Island	0	2,745	3,338	33	85	1	6,202
South Carolina	103,694	28,536	13,310	294	500	646	146,980
South Dakota	29,711	1,655	10,301	23	86	498	42,273
Tennessee	33,080	59,145	32,624	154	757	277	126,037
Texas	249,748	129,667	108,633	1,146	2,483	1,178	492,855
Tribal	0	676	0	0	0	0	676
Utah	34,912	6,599	3,365	27	291	1,934	47,128
Vermont	264	902	5,283	8	129	49	6,634
Virginia	51,004	50,387	32,439	275	849	399	135,353
Washington	5,569	19,780	6,885	881	633	407	34,156
West Virginia	84,344	32,458	14,322	64	178	215	131,582
Wisconsin	50,777	61,080	6,260	122	633	70	118,941
Wyoming	48,198	20,491	5,944	18	87	1,106	75,844
Total	**3,281,364**	**1,534,991**	**1,125,985**	**15,759**	**29,288**	**49,094**	**6,036,480**

Table 5A-8. Future Year Baseline $PM_{2.5}$ Emissions (tons/year) for States by Sector

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Alabama	13,154	17,052	33,235	2,403	2,217	13,938	81,999
Arizona	3,889	3,809	20,214	2,674	2,762	37,151	70,498
Arkansas	2,838	10,527	33,486	2,042	1,242	10,315	60,450
California	475	20,693	73,607	14,875	13,492	97,302	220,443
Colorado	3,845	7,037	19,868	2,350	2,387	24,054	59,540
Connecticut	400	222	6,838	1,038	1,414	56	9,968
Delaware	434	772	1,207	383	375	87	3,259

(continued)

Table 5A-8. Future Year Baseline $PM_{2.5}$ Emissions (tons/year) for States by Sector (continued)

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
District of Columbia	1	172	536	139	154	0	1,002
Florida	12,723	24,620	50,472	8,100	7,652	99,484	203,050
Georgia	13,445	12,105	59,412	3,803	4,863	24,082	117,711
Idaho	36	2,076	40,288	1,186	714	52,808	97,108
Illinois	8,587	13,471	70,775	6,885	4,926	277	104,922
Indiana	22,354	13,570	72,501	3,491	3,380	344	115,640
Iowa	4,298	7,000	51,684	3,348	1,519	349	68,198
Kansas	3,199	6,895	136,633	2,872	1,268	1,468	152,335
Kentucky	12,078	10,353	26,811	2,717	2,059	5,155	59,173
Louisiana	3,093	30,865	27,082	5,107	1,673	12,647	80,467
Maine	355	3,543	8,213	881	750	2,127	15,869
Maryland	3,969	6,382	18,960	1,975	2,492	531	34,310
Massachusetts	1,465	2,123	23,729	1,914	2,590	1,324	33,145
Michigan	8,102	11,688	43,055	4,696	4,949	1,283	73,773
Minnesota	2,598	9,867	68,121	4,483	2,882	8,943	96,893
Mississippi	2,201	10,492	31,474	2,337	1,525	14,897	62,926
Missouri	7,061	6,384	69,722	3,954	3,059	2,636	92,816
Montana	3,870	2,562	28,479	1,332	492	17,311	54,048
Nebraska	2,358	2,834	44,904	2,967	919	1,483	55,465
Nevada	2,505	4,032	9,351	1,319	857	19,018	37,083
New Hampshire	1,130	464	8,981	576	663	534	12,348
New Jersey	2,452	2,520	8,559	2,929	3,244	865	20,569
New Mexico	3,153	1,442	49,789	1,148	1,103	48,662	105,298
New York	2,331	4,859	44,334	5,032	6,723	1,601	64,879
North Carolina	9,983	12,656	43,398	3,583	3,521	9,870	83,011
North Dakota	5,870	795	40,802	2,126	383	934	50,910
Ohio	18,920	12,353	47,811	5,302	5,013	316	89,715
Oklahoma	3,530	5,695	88,862	2,029	2,006	6,644	108,767

(continued)

Table 5A-8. Future Year Baseline $PM_{2.5}$ Emissions (tons/year) for States by Sector (continued)

State	EGU	Non-EGU	Nonpoint	Nonroad	Onroad	Fires	Total
Oregon	381	8,869	39,503	2,148	1,627	65,350	117,877
Pennsylvania	16,727	14,874	38,523	4,582	4,854	454	80,014
Rhode Island	4	256	1,070	222	383	14	1,949
South Carolina	9,997	4,527	23,430	1,932	1,929	9,163	50,978
South Dakota	737	2,399	32,697	1,339	416	7,062	44,650
Tennessee	5,053	21,553	28,449	2,939	3,057	3,934	64,985
Texas	21,677	34,648	187,604	11,901	9,289	21,578	286,698
Tribal	1	1,568	0	0	0	0	1,569
Utah	4,524	3,530	13,978	963	1,318	27,412	51,724
Vermont	67	336	4,930	307	653	696	6,989
Virginia	4,529	10,165	32,254	3,507	3,446	5,659	59,561
Washington	1,444	4,421	35,706	3,328	2,874	4,487	52,259
West Virginia	13,602	4,281	12,951	1,048	762	3,050	35,695
Wisconsin	5,323	7,853	27,656	3,161	3,148	994	48,135
Wyoming	5,662	10,225	30,812	850	392	15,686	63,626
Total	**276,430**	**411,437**	**1,912,757**	**150,221**	**129,416**	**684,035**	**3,564,296**

Table 5A-9. Future Year Baseline EGU CAP Emissions (tons/year) by State

State	CO	NO_X	VOC	SO_2	NH_3	PM_{10}	$PM_{2.5}$
Alabama	27,024	64,064	1,524	186,084	1,472	16,686	13,154
Arizona	16,797	36,971	825	36,996	1,163	5,038	3,889
Arkansas	9,925	36,297	658	92,804	560	3,507	2,838
California	45,388	20,910	1,031	5,346	2,519	580	475
Colorado	9,006	50,879	636	74,255	398	4,605	3,845
Connecticut	9,180	2,738	139	3,581	313	431	400
Delaware	4,256	2,452	132	2,835	119	580	434
District of Columbia	67	11	2	5	3	1	1

(continued)

Table 5A-9. Future Year Baseline EGU CAP Emissions (tons/year) by State (continued)

State	CO	NO_X	VOC	SO_2	NH_3	PM_{10}	$PM_{2.5}$
Florida	72,915	83,174	2,253	117,702	3,997	19,098	12,723
Georgia	16,537	43,778	1,293	96,712	903	18,668	13,445
Idaho	1,532	613	41	182	57	38	36
Illinois	51,862	56,128	3,091	118,217	1,437	9,926	8,587
Indiana	30,587	106,881	2,295	200,969	1,317	33,816	22,354
Iowa	8,316	42,698	791	85,178	452	5,735	4,298
Kansas	5,066	25,163	683	45,740	305	3,996	3,199
Kentucky	37,287	71,259	1,604	116,927	928	16,279	12,078
Louisiana	32,626	33,509	852	142,447	1,427	3,677	3,093
Maine	12,789	6,121	306	2,564	269	366	355
Maryland	13,446	17,933	533	29,786	301	5,322	3,969
Massachusetts	7,128	7,991	279	15,133	395	1,915	1,465
Michigan	25,856	66,846	1,497	163,168	874	11,056	8,102
Minnesota	9,365	36,867	746	52,380	460	3,034	2,598
Mississippi	9,704	27,319	440	34,865	469	3,113	2,201
Missouri	16,499	52,464	1,714	178,143	740	9,093	7,061
Montana	5,266	20,946	338	24,018	198	6,117	3,870
Nebraska	4,691	28,898	542	70,910	292	2,948	2,358
Nevada	9,677	15,627	438	14,140	953	3,095	2,505
New Hampshire	5,667	4,908	206	6,719	207	1,234	1,130
New Jersey	25,831	11,178	823	9,042	747	2,948	2,452
New Mexico	9,079	65,189	574	10,211	570	3,833	3,153
New York	19,731	21,172	731	14,653	1,076	3,248	2,331
North Carolina	17,367	44,141	1,076	71,113	654	13,368	9,983
North Dakota	7,437	53,778	867	105,344	383	6,757	5,870
Ohio	33,481	93,150	2,005	180,935	1,317	25,688	18,920
Oklahoma	26,165	47,454	957	141,433	1,073	4,457	3,530
Oregon	5,905	10,828	203	13,211	381	446	381

(continued)

Table 5A-9. Future Year Baseline EGU CAP Emissions (tons/year) by State (continued)

State	CO	NO_X	VOC	SO_2	NH_3	PM_{10}	$PM_{2.5}$
Pennsylvania	38,767	123,501	2,023	126,316	1,522	22,117	16,727
Rhode Island	1,748	456	44	0	136	7	4
South Carolina	10,305	37,516	726	103,694	515	14,469	9,997
South Dakota	742	14,293	129	29,711	48	764	737
Tennessee	10,693	16,982	862	33,080	406	6,313	5,053
Texas	78,317	145,182	4,975	249,748	5,304	31,404	21,677
Tribal	601	73	15	0	47	2	1
Utah	5,632	67,476	526	34,912	279	5,843	4,524
Vermont	1,868	458	52	264	25	69	67
Virginia	30,205	39,408	821	51,004	1,115	5,404	4,529
Washington	7,183	14,284	326	5,569	346	1,706	1,444
West Virginia	15,496	54,247	1,320	84,344	658	18,415	13,602
Wisconsin	19,247	35,179	1,137	50,777	649	6,503	5,323
Wyoming	9,087	71,380	970	48,198	481	7,385	5,662
Total	**873,344**	**1,930,769**	**46,050**	**3,281,364**	**40,259**	**371,101**	**276,430**

Note: Emission estimates apply to all fossil Electric Generating Units, including those with capacity < 25MW.

5A.5 Development of Future Year Control Case Emissions for Air Quality Modeling

For the future year control case (i.e., policy case) air quality modeling**,** the emissions for all sectors were unchanged from the base case modeling except for those from EGUs. The IPM model was used to prepare the future year policy case for EGU emissions. The air quality modeling for MATS relied on EGU emission projections from an interim IPM platform based on the Cross-state Air Pollution Rule version 4.10_FTransport, and was subsequently updated during the rulemaking process. The updates made include: updated assumptions regarding the removal of HCl by alkaline fly ash in subbituminous and lignite coals; an update to the fuel-based mercury emission factor for petroleum coke, which was corrected based on re-examination of the 1999 ICR data; updated capital cost for new nuclear capacity and nuclear life extension costs; corrected variable operating and maintenance cost (VOM) for ACI retrofits; adjusted coal rank availability for some units, consistent with EIA From 923 (2008); updated state rules in Washington and Colorado; and numerous unit-level revisions based on comments received through the notice and comment process. In particular, the policy case modeled with

CMAQ did not include the neutralization of 75% of HCl as did the final policy case. Additional details on the version of IPM used to develop the control case are available in Chapter 3.

The changes in EGU SO_2, and $PM_{2.5}$ emissions as a result of the policy case for the lower 48 states are summarized in Table 5A-10. Table 5A-11 shows the CAP emissions for the modeled MATS control case by State. State-specific difference summaries of EGU SO_2 and $PM_{2.5}$ for the sum of the lower 48 states are shown in Tables 5A-12 and 5A-13, respectively.

Table 5A-10. Summary of Emissions Changes for the MATS AQ Modeling in the Lower 48 States

Future Year EGU Emissions	SO_2	$PM_{2.5}$
Base case EGU emissions (tons)	3,281,364	276,430
Control case EGU emissions (tons)	1,866,247	223,320
Reductions to base case in control case (tons)	1,415,117	53,110
Percentage reduction of base EGU emissions	43%	19%
Total Man-Made Emissions[a]		
Total base case emissions (tons)	6,036,480	3,564,296
Total control case emissions (tons)	4,621,363	3,511,186
Percentage reduction of all man-made emissions	23%	1%

[a] In this table, man-made emissions includes average fires.

Table 5A-11. EGU Emissions Totals for the Modeled MATS Control Case in the Lower 48 States

State	CO	NO_X	VOC	SO_2	NH_3	PM_{10}	$PM_{2.5}$
Alabama	20,873	61,863	1,313	68,517	1,235	9,734	7,844
Arizona	13,238	34,804	749	23,459	921	4,264	3,494
Arkansas	9,036	35,788	642	35,112	490	1,696	1,593
California	56,360	27,159	1,307	5,041	2,548	1,057	942
Colorado	8,219	44,409	582	19,564	358	3,492	2,859
Connecticut	8,017	2,800	136	1,400	313	439	412
Delaware	1,312	2,527	67	4,160	93	3,056	1,455
District of Columbia							
Florida	66,378	61,676	2,055	64,791	3,482	16,434	11,377

(continued)

Table 5A-11. EGU Emissions Totals for the Modeled MATS Control Case in the Lower 48 States (continued)

State	CO	NO_X	VOC	SO_2	NH_3	PM_{10}	$PM_{2.5}$
Georgia	14,217	41,006	1,197	78,197	790	11,165	9,742
Idaho	1,523	609	41	182	56	38	36
Illinois	24,365	50,655	2,353	103,867	1,050	7,309	6,588
Indiana	17,061	102,045	1,872	156,781	1,110	29,683	20,388
Iowa	7,340	41,247	747	48,030	410	3,318	2,947
Kansas	4,683	22,136	623	22,767	282	2,504	2,263
Kentucky	25,911	70,126	1,476	125,430	882	12,544	10,635
Louisiana	28,171	31,655	767	30,509	1,261	2,003	1,899
Maine	10,992	5,683	302	1,372	267	342	331
Maryland	4,283	16,554	400	18,091	211	3,851	3,143
Massachusetts	5,408	7,211	226	5,033	344	1,702	1,267
Michigan	18,792	60,982	1,215	82,834	718	8,261	6,893
Minnesota	8,699	34,942	709	33,214	430	3,332	2,936
Mississippi	8,782	20,749	410	15,975	397	1,949	1,720
Missouri	12,249	52,755	1,605	95,965	686	5,216	4,809
Montana	2,223	19,758	264	6,399	133	2,637	1,727
Nebraska	4,493	28,180	533	34,631	277	2,152	1,828
Nevada	7,178	14,382	336	6,372	725	2,626	2,073
New Hampshire	6,781	4,862	232	2,102	232	1,336	1,264
New Jersey	8,350	7,699	315	6,404	546	2,020	1,583
New Mexico	7,987	64,922	545	9,984	554	2,961	2,750
New York	18,725	20,863	699	28,174	1,086	3,123	2,350
North Carolina	15,195	35,309	1,033	59,551	602	8,885	7,988
North Dakota	7,266	53,267	858	23,889	371	5,940	5,051
Ohio	29,956	85,565	1,852	139,208	1,229	19,599	15,823
Oklahoma	26,687	44,725	892	44,602	970	2,293	2,056
Oregon	6,002	9,671	198	3,565	379	241	233
Pennsylvania	24,865	104,906	1,645	93,606	1,349	17,330	14,080

(continued)

Table 5A-11. EGU Emissions Totals for the Modeled MATS Control Case in the Lower 48 States (continued)

State	CO	NO_X	VOC	SO_2	NH_3	PM_{10}	$PM_{2.5}$
Rhode Island	1,721	443	43	0	134	7	4
South Carolina	9,826	37,849	725	40,901	459	9,627	6,963
South Dakota	641	14,290	117	2,483	41	260	245
Tennessee	5,551	16,931	723	42,666	334	6,721	5,272
Texas	71,475	138,086	4,444	105,958	4,774	25,359	17,601
Tribal	266	32	7	0	21	1	1
Utah	4,003	65,286	474	17,007	241	4,755	3,896
Vermont	1,868	458	52	264	25	69	67
Virginia	26,778	37,255	707	33,704	748	5,306	4,506
Washington	6,334	3,834	179	854	254	183	176
West Virginia	13,923	47,836	1,263	66,857	632	14,321	11,572
Wisconsin	16,124	32,865	1,012	28,322	578	4,725	3,969
Wyoming	7,516	71,135	932	28,456	467	5,946	4,671
Total	**707,640**	**1,789,790**	**40,875**	**1,866,247**	**35,493**	**281,811**	**223,320**

Table 5A-12. State Specific Changes in Annual EGU SO_2 for the Lower 48 States

State	Future Year Baseline SO_2 (tons)	Future Year Policy Case SO_2 (tons)	EGU SO_2 Reduction (tons)	EGU SO_2 Reduction (%)
Alabama	186,084	68,517	117,568	63%
Arizona	36,996	23,459	13,537	37%
Arkansas	92,804	35,112	57,692	62%
California	5,346	5,041	305	6%
Colorado	74,255	19,564	54,690	74%
Connecticut	3,581	1,400	2,181	61%
Delaware	2,835	4,160	-1,324	-47%
District of Columbia	5	0	5	100%

(continued)

Table 5A-12. State Specific Changes in Annual EGU SO_2 for the Lower 48 States (continued)

State	Future Year Baseline SO_2 (tons)	Future Year Policy Case SO_2 (tons)	EGU SO_2 Reduction (tons)	EGU SO_2 Reduction (%)
Florida	117,702	64,791	52,911	45%
Georgia	96,712	78,197	18,515	19%
Idaho	182	182	0	0%
Illinois	118,217	103,867	14,350	12%
Indiana	200,969	156,781	44,189	22%
Iowa	85,178	48,030	37,148	44%
Kansas	45,740	22,767	22,973	50%
Kentucky	116,927	125,430	-8,503	-7%
Louisiana	142,447	30,509	111,938	79%
Maine	2,564	1,372	1,191	46%
Maryland	29,786	18,091	11,695	39%
Massachusetts	15,133	5,033	10,100	67%
Michigan	163,168	82,834	80,334	49%
Minnesota	52,380	33,214	19,165	37%
Mississippi	34,865	15,975	18,890	54%
Missouri	178,143	95,965	82,177	46%
Montana	24,018	6,399	17,618	73%
Nebraska	70,910	34,631	36,279	51%
Nevada	14,140	6,372	7,768	55%
New Hampshire	6,719	2,102	4,618	69%
New Jersey	9,042	6,404	2,638	29%
New Mexico	10,211	9,984	228	2%
New York	14,653	28,174	-13,521	-92%
North Carolina	71,113	59,551	11,562	16%
North Dakota	105,344	23,889	81,455	77%
Ohio	180,935	139,208	41,727	23%
Oklahoma	141,433	44,602	96,831	68%

(continued)

Table 5A-12. State Specific Changes in Annual EGU SO_2 for the Lower 48 States (continued)

State	Future Year Baseline SO_2 (tons)	Future Year Policy Case SO_2 (tons)	EGU SO_2 Reduction (tons)	EGU SO_2 Reduction (%)
Oregon	13,211	3,565	9,646	73%
Pennsylvania	126,316	93,606	32,710	26%
Rhode Island	0	0	0	N/A
South Carolina	103,694	40,901	62,793	61%
South Dakota	29,711	2,483	27,228	92%
Tennessee	33,080	42,666	-9,586	-29%
Texas	249,748	105,958	143,790	58%
Tribal	0	0	0	N/A
Utah	34,912	17,007	17,905	51%
Vermont	264	264	0	0%
Virginia	51,004	33,704	17,300	34%
Washington	5,569	854	4,716	85%
West Virginia	84,344	66,857	17,488	21%
Wisconsin	50,777	28,322	22,454	44%
Wyoming	48,198	28,456	19,742	41%
Total	**3,281,364**	**1,866,247**	**1,415,117**	

Table 5A-13. State Specific Changes in Annual EGU $PM_{2.5}$ for the Lower 48 States

State	Future Year Baseline $PM_{2.5}$ (tons)	Future Year Policy Case $PM_{2.5}$ (tons)	EGU $PM_{2.5}$ Reduction (tons)	EGU $PM_{2.5}$ Reduction (%)
Alabama	13,154	7,844	5,310	40%
Arizona	3,889	3,494	395	10%
Arkansas	2,838	1,593	1,246	44%
California	475	942	-467	-98%
Colorado	3,845	2,859	985	26%
Connecticut	400	412	-12	-3%

(continued)

Table 5A-13. State Specific Changes in Annual EGU $PM_{2.5}$ for the Lower 48 States (continued)

State	Future Year Baseline $PM_{2.5}$ (tons)	Future Year Policy Case $PM_{2.5}$ (tons)	EGU $PM_{2.5}$ Reduction (tons)	EGU $PM_{2.5}$ Reduction (%)
Delaware	434	1,455	-1,021	-235%
District of Columbia	1	0	1	100%
Florida	12,723	11,377	1,346	11%
Georgia	13,445	9,742	3,703	28%
Idaho	36	36	0	0%
Illinois	8,587	6,588	2,000	23%
Indiana	22,354	20,388	1,966	9%
Iowa	4,298	2,947	1,351	31%
Kansas	3,199	2,263	936	29%
Kentucky	12,078	10,635	1,443	12%
Louisiana	3,093	1,899	1,193	39%
Maine	355	331	24	7%
Maryland	3,969	3,143	826	21%
Massachusetts	1,465	1,267	198	14%
Michigan	8,102	6,893	1,210	15%
Minnesota	2,598	2,936	-339	-13%
Mississippi	2,201	1,720	481	22%
Missouri	7,061	4,809	2,252	32%
Montana	3,870	1,727	2,143	55%
Nebraska	2,358	1,828	530	22%
Nevada	2,505	2,073	432	17%
New Hampshire	1,130	1,264	-134	-12%
New Jersey	2,452	1,583	868	35%
New Mexico	3,153	2,750	403	13%
New York	2,331	2,350	-19	-1%
North Carolina	9,983	7,988	1,995	20%
North Dakota	5,870	5,051	819	14%

(continued)

Table 5A-13. State Specific Changes in Annual EGU $PM_{2.5}$ for the Lower 48 States (continued)

State	Future Year Baseline $PM_{2.5}$ (tons)	Future Year Policy Case $PM_{2.5}$ (tons)	EGU $PM_{2.5}$ Reduction (tons)	EGU $PM_{2.5}$ Reduction (%)
Ohio	18,920	15,823	3,097	16%
Oklahoma	3,530	2,056	1,474	42%
Oregon	381	233	148	39%
Pennsylvania	16,727	14,080	2,646	16%
Rhode Island	4	4	0	2%
South Carolina	9,997	6,963	3,033	30%
South Dakota	737	245	492	67%
Tennessee	5,053	5,272	-219	-4%
Texas	21,677	17,601	4,077	19%
Tribal	1	1	1	56%
Utah	4,524	3,896	627	14%
Vermont	67	67	0	0%
Virginia	4,529	4,506	24	1%
Washington	1,444	176	1,268	88%
West Virginia	13,602	11,572	2,031	15%
Wisconsin	5,323	3,969	1,354	25%
Wyoming	5,662	4,671	991	17%
Total	**276,430**	**223,320**	**53,110**	

CHAPTER 7
STATUTORY AND EXECUTIVE ORDER ANALYSES

7.1 Introduction

This chapter presents discussion and analyses relating to Executive Orders and statutory requirements relevant for the final Mercury and Air Toxics Standards (MATS). We discuss the analysis conducted to comply with Executive Order (EO) 12866 and the Paperwork Reduction Act (PRA) as well as potential impacts to affected small entities required by the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA). We also describe the analysis conducted to meet the requirements of the Unfunded Mandates Reform Act of 1995 (UMRA) assessing the impact of the final rule on state, local and tribal governments and the private sector. In addition, we address the requirements of EO 13132: Federalism; EO 13175: Consultation and Coordination with Indian Tribal Governments; EO 13045: Protection of Children from Environmental Health and Safety Risks; EO 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use; the National Technology Transfer and Advancement Act; EO 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations; and the Congressional Review Act.

7.2 Executive Order 12866: Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order (EO) 12866 (58 FR 51,735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 any changes in response to OMB recommendations have been documented in the docket for this action. In addition, EPA prepared this Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action.

When estimating the human health benefits and compliance costs detailed in this RIA, the EPA applied methods and assumptions consistent with the state-of-the-science for human health impact assessment, economics and air quality analysis. The EPA applied its best professional judgment in performing this analysis and believes that these estimates provide a reasonable indication of the expected benefits and costs to the nation of this rulemaking. This RIA describes in detail the empirical basis for the EPA's assumptions and characterizes the

various sources of uncertainties affecting the estimates below. In doing what is laid out above in this paragraph, the EPA adheres to EO 13563, "Improving Regulation and Regulatory Review," (76 FR 3821; January 18, 2011), which is a supplement to EO 12866.

In addition to estimating costs and benefits, EO 13563 focuses on the importance of a "regulatory system [that]...promote[s] predictability and reduce[s] uncertainty" and that "identify[ies] and use[s] the best, most innovative, and least burdensome tools for achieving regulatory ends." In addition, EO 13563 states that "[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote such coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation." We recognize that the utility sector faces a variety of requirements, including ones under CAA section 110(a)(2)(D) dealing with the interstate transport of emissions contributing to ozone and PM air quality problems, with coal combustion wastes, and with the implementation of CWA section 316(b). In developing today's final rule, the EPA recognizes that it needs to approach these rulemakings in ways that allow the industry to make practical investment decisions that minimize costs in complying with all of the final rules, while still achieving the fundamentally important environmental and public health benefits that underlie the rulemakings.

A summary of the monetized costs, benefits, and net benefits for the final rule at discount rates of 3 percent and 7 percent is the Executive Summary and Chapter 8 of this RIA.

7.3 Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The information collection requirements are not enforceable until OMB approves them.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all owners and operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR Part 2, subpart B. This final rule requires maintenance inspections of the control devices but would not require any notifications or reports beyond those required by

the General Provisions. The recordkeeping provisions require only the specific information needed to determine compliance.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $158 million. This includes 698,907 labor hours per year at a total labor cost of $49 million per year, and total non-labor capital costs of $108 million per year. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and recordkeeping. Initial capital expenses to purchase monitoring equipment for affected units are estimated at a cost of $231 million. This includes 504,629 labor hours at a total labor cost of $35 million for planning, selection, purchase, installation, configuration, and certification of the new systems and total non-labor capital costs of $196 million. All burden estimates are in 2007 dollars and represent the most cost effective monitoring approach for affected facilities.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations are listed in 40 CFR Part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR Part 9 in the Federal Register to display the OMB control number for the approved information collection requirements contained in this final rule.

7.4 Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) a small business that is an electric utility producing 4 billion kilowatt-hours or less as defined by NAICS codes 221122 (fossil fuel-fired electric utility steam generating units) and 921150 (fossil fuel-fired electric utility steam generating units in Indian country); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the Panel Report (EPA-HQ-OAR-2009-0234-2921). A summary of the Panel's recommendations is presented at 76 FR 24975.

As required by section 604 of the RFA, we also prepared a final regulatory flexibility analysis (FRFA) for today's final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA is summarized below and in the preamble.

7.4.1 Reasons Why Action Is Being Taken

In 2000, the EPA made a finding that it was appropriate and necessary to regulate coal- and oil-fired electric utility steam generating units (EGUs) under Clean Air Act (CAA) section 112 and listed EGUs pursuant to CAA section 112(c). On March 29, 2005 (70 FR 15,994), the EPA published a final rule (2005 Action) that removed EGUs from the list of sources for which regulation under CAA section 112 was required. That rule was published in conjunction with a rule requiring reductions in emissions of mercury from EGUs pursuant to CAA section 111, i.e., CAMR, May 18, 2005, 70 FR 28606). The Section 112(n) Revision Rule was vacated on February 8, 2008, by the U.S. Court of Appeals for the District of Columbia Circuit. As a result of that vacatur, CAMR was also vacated and EGUs remain on the list of sources that must be regulated under CAA section 112. This action provides the EPA's final NESHAP for EGUs.

7.4.2 Statement of Objectives and Legal Basis for Final Rules

MATS will protect air quality and promote public health by reducing emissions of HAP. In the December 2000 regulatory determination, the EPA made a finding that it was appropriate and necessary to regulate EGUs under CAA section 112. The February 2008 vacatur of the 2005 Action reverted the status the rule to the December 2000 regulatory determination. CAA section 112(n)(1)(A) and the 2000 determination do not differentiate between EGUs located at major versus area sources of HAP. Thus, the NESHAP for EGUs will regulate units at both major and area sources. Major sources of HAP are those that have the potential to emit at least 10 tons per year (tpy) of any one HAP or at least 25 tpy of any combination of HAP. Area sources are any stationary sources of HAP that are not major sources.

7.4.3 Summary of Issues Raised during the Public Comment Process on the IRFA

The EPA received a number of comments related to the Regulatory Flexibility Act during the public comment process. A consolidated version of the comments received is reproduced below. These comments can also be found in their entirety in the response to comment document in the docket.

Comment: Several commenters expressed concern with the SBAR panel. Some believe Small Entity Representatives (SERs) were not provided with regulatory alternatives including descriptions of significant regulatory options, differing timetables, or simplifications of compliance and reporting requirements, and subsequently were not presented with an opportunity to respond. One commenter believes the EPA's formal SBAR Panel notification and subsequent information provided by the EPA to the Panel did not include information on the potential impacts of the rule as required by section 609(b)(1). Additional commenters suggested that the EPA's rulemaking schedule put pressure on the SBAR Panel through the abbreviated preparation for the Panel. Commenters also expressed concerns that the EPA did not provide participants more than cursory background information on which to base their comments. One commenter stated that the EPA did not provide deliberative materials, including draft proposed rules or discussions of regulatory alternatives, to the SBAR Panel members. One commenter stated the SBAR Panel Report does not meet the statutory obligation to recommend less burdensome alternatives. The commenter suggested the EPA panel members declined to make recommendations that went further than consideration or investigation of broad regulatory alternatives, with the exception of those recommendations in which the EPA rejected alternative interpretations of the CAA section 112 and relevant court cases. Two stated that the EPA did not respond to the concerns of the small business community, the SBA, or OMB, ignoring concerns expressed by the SER panelists. One commenter believes the EPA failed to convene required meetings and hearings with affected parties as required by law for small business entities. One commenter stated that the SERs' input is very important because more than 90 percent of public power utility systems meet the definition and qualify as small businesses under the SBREFA.

Response: The RFA requires that SBAR Panels collect advice and recommendations from SERs on the issues related to:

- the number and description of the small entities to which the proposed rule will apply;

- the projected reporting, record keeping and other compliance requirements of the proposed rule;
- duplication, overlap or conflict between the proposed rule and other federal rules; and
- alternatives to the proposed rule that accomplish the stated statutory objectives and minimize any significant economic impact on small entities.

The RFA does not require a covered agency to create or assemble information for SERs or for the government panel members. While section 609(b)(4) requires that the government Panel members review any material the covered agency has prepared in connection with the RFA, the law does not prescribe the materials to be reviewed. The EPA's policy, as reflected in its RFA guidance, is to provide as much information as possible, given time and resource constraints, to enable an informed Panel discussion. In this rulemaking, because of a court-ordered deadline, the EPA was unable to hold a pre-panel meeting but still provided SERs with the information available at the time, held a standard Panel Outreach meeting to collect verbal advice and recommendations from SERs, and provided the standard 14-day written comment period to SERs. The EPA received substantial input from the SERs, and the Panel report describes recommendations made by the Panel on measures the Administrator should consider that would minimize the economic impact of the proposed rule on small entities. The EPA complied with the RFA.

Comment: One commenter requested that the EPA work with utilities such that new regulations are as flexible and cost efficient as possible.

Response: In developing the final rule, the EPA has considered all information provided prior to, as well as in response to, the proposed rule. The EPA has endeavored to make the final regulations flexible and cost efficient while adhering to the requirements of the CAA.

Comment: One commenter was concerned about the ability of small entities or nonprofit utilities such as those owned and/or operated by rural electric co-op utilities, and municipal utilities to comply with the proposed standards within three years. The commenter believes that the EPA disregarded the SER panelists who explained that under these current economic conditions they have constraints on their ability to raise capital for the construction of control projects and to acquire the necessary resources in order to meet a three-year compliance deadline. Two commenters expressed concern that smaller utilities and those in rural areas will be unable to get vendors to respond to their requests for proposals, because they will be able to make more money serving larger utilities.

Response: The preamble to the proposed rule (76FR 25054, May 3, 2011) provides a detailed discussion of how the EPA determined compliance times for the proposed (and final) rule. The EPA has provided pursuant to section 112(i)(3)(A) the maximum three-year period for sources to come into compliance. Sources may also seek a one-year extension of the compliance period from their title V permitting authority if the source needs that time to install controls. CAA section 112(i)(3)(B). If the situation described by commenters (i.e., where small entities or nonprofit utilities constraints on ability to raise capital for construction of control projects and to acquire necessary resources) results in the source needing additional time to install controls, they would be in a position to request the one-year extension. The EPA discusses in more detail in section VII of this preamble how the agency plans to address those units that are still unable to comply within the statutorily mandated period.

Comment: Several commenters believe the EPA did not adequately consider the disproportionately large impact on smaller generating units. The commenters note the diseconomies in scale for pollution controls for such units. One commenter noted the rule will create a more serious compliance hurdle for small communities that depend on coal-fired generation to meet their base load demand. The commenter notes that by not subcategorizing units, the EPA is dictating a fuel switch due to the disproportionately high cost on small communities. The other commenter believes the MACT and NSPS standards are unachievable by going too far without really considering the impacts on small municipal units, as public powers is critical to communities, jobs, economic viability and electric reliability. A generating and transmissions electric cooperative which qualifies as a small entity believes the rule will ultimately result in increased electricity costs to its members and will negatively impact the economies of the primarily rural areas that they serve. Another commenter believes there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units, particularly given the current market situation and applicable equitable factors. The commenter suggests both the EPA's and SBA's analyses focus exclusively on the effects on entities causing HAP emissions and primarily on those operating obsolete EGUs, and fail to consider either impacts on downwind businesses and governments or the positive impacts on small entities and governments owning and operating competing, clean and modern EGUs.

Response: The EPA disagrees with the commenters' belief that the impacts on smaller generating units were not adequately considered when developing the rule. The EPA determined the number of potentially impacted small entities and assessed the potential impact of the proposed action on small entities, including municipal units. A similar assessment

was conducted in support of the final action. Specifically, the EPA estimated the incremental net annualized compliance cost, which is a function of the change in capital and operating costs, fuel costs, and change in revenue. The projected compliance cost was considered relative to the projected revenue from generation. Thus, the EPA's analysis accounts not only for the additional costs these entities face resulting from compliance, but also the impact of higher electricity prices. The EPA evaluated suggestions from SERs, including subcategorization recommendations. In the preamble to the proposed rule, the EPA explains that, normally, any basis for subcategorizing must be related to an effect on emissions, rather than some difference which does not affect emissions performance. The EPA does not see a distinction between emissions from smaller generating units versus larger units. The EPA acknowledges the comment that there is no legal or factual basis for creating subcategories or weaker standards for state, tribal, or municipal governments or small entities that are operating obsolete units.

Comment: One commenter notes that the EPA recognizes LEEs in the rule such that they should receive less onerous monitoring requirements; however, the EPA does not recognize that small and LEEs also need and merit more flexible and achievable pollution control requirements. The commenter notes that the capital costs for emissions control at small utility units is disproportionately high due to inefficiencies in Hg removal, space constraints for control technology retrofits, and the fact that small units have fewer rate base customers across which to spread these costs. The commenter cites the Michigan Department of Environmental Quality report titled “Michigan’s Mercury Electric Utility Workgroup, Final Report on Mercury Emissions from Coal-Fired Power Plants,” (June 2005). The commenter notes that the EPA has addressed such concerns previously, citing the RIA for the 1997 8-hour ozone standard. The commenter also suggests smaller utility systems generally have less capital to invest in pollution control than larger, investor-owned systems, due to statutory inability to borrow from the private capital markets, statutory debt ceilings, limited bonding capacity, borrowing limitations related to fiscal strain posed by other, non-environmental factors, and other limitations.

Response: The EPA acknowledges that the rule contains reduced monitoring requirements for existing units that qualify as LEEs. Although the EPA does not believe that reduced pollution control requirements are warranted for LEEs, including small entity LEEs, we believe that flexible and achievable pollution control requirements are promoted through alternative standards, alternative compliance options, and emissions averaging as a means of demonstrating compliance with the standards for existing EGUs.

Comment: One commenter believes that the EPA should develop more limited monitoring requirements for small EGUs. The commenter notes small entities do not possess the monetary resources, manpower, or technical expertise needed to operate cutting-edge monitoring techniques such as Hg CEMS and PM CEMs. The commenter notes the EPA could have identified monitoring alternatives to the SER panel for consideration.

Response: The EPA provided monitoring alternatives to using PM CEMS, HCl CEMS, and Hg CEMS in its proposed standards and in this final rule. The continuous compliance alternatives are available to all affected sources, including small entities. As alternatives to the use of PM CEMS and HCl CEMS, sources are allowed to conduct additional performance testing. Sorbent trap monitoring is allowed in lieu of Hg CEMS.

Comment: Several commenters believe the EPA has not sufficiently complied with the requirements of the RFA or adequately considered the impact this rulemaking would have on small entities. One commenter believes the EPA has not engaged in meaningful outreach and consultation with small entities and therefore recommends that the EPA seek to revise the court-ordered deadlines to which this rulemaking is subject, re-convene the SBAR panel, prepare a new initial regulatory flexibility analysis (IRFA), and issue it for additional public comment prior to final rulemaking. The commenter believes the IRFA does not sufficiently consider impacts on small entities as identified in the SBAR Panel Report. The commenter believes it is not apparent that the EPA considered the recommendations of the Panel. The commenter believes the description of significant alternatives in the IRFA is almost entirely quoted from the SBAR Panel Report, which the commenter does not believe is an adequate substitute for the EPA's own analysis of alternatives. The commenter also notes the EPA does not discuss the potential impacts of its decisions on small entities or the impacts of possible flexibilities. Where the EPA does consider regulatory alternatives in principle, the commenter believes it does not provide sufficient support for its decisions to understand on what basis the EPA rejected alternatives that may or may not have reduced burden on small entities while meeting the stated objectives of the rule. Additionally, the commenter notes that the EPA did not evaluate the economic or environmental impacts of significant alternatives to the proposed rule. One commenter believes that the EPA's stated reasons for declining to specify or analyze an area source standard are inadequate under the RFA. The commenter believes the EPA must give serious consideration to regulatory alternatives that accomplish the stated objectives of the CAA while minimizing any significant economic impacts on small entities and that the EPA has a duty to specify and analyze this option or to more clearly state its policy reasons for excluding serious consideration of a separate standard for area sources. A commenter believes

the EPA did not fully consider the subcategorization of sources such as boilers designed to burn lignite coals versus other fossil fuels, especially in regard to non-Hg metal and acid gas emissions. The commenter references the SBAR Panel Report suggestion provided in the preamble of the proposed rule that the EPA consider developing an area source vs. major source distinction for the source category and the EPA's response. Another commenter is concerned that the recommendations made by the SER participants were ignored and not discussed in the rulemaking. Specifically, the commenter notes the EPA did not discuss subcategorizing by age, type of plant, fuel, physical space constraints or useful anticipated life of the plant. Nor did the EPA establish GACT for smaller emitters to alleviate regulatory costs and operational difficulties. A commenter believes it is likely that different numerical or work practice standards are appropriate for area sources of HAP.

Response: The EPA disagrees with one commenter's assertion that the agency has not complied with the requirements of the RFA. The EPA complied with both the letter and spirit of the RFA, notwithstanding the constraints of the court-ordered deadline. For example, the EPA notified the Chief Counsel for Advocacy of the SBA of its intent to convene a Panel; compiled a list of SERs for the Panel to consult with; and convened the Panel. The Panel met with SERs to collect their advice and recommendations; reviewed the EPA materials; and drafted a report of Panel findings. The EPA further disagrees with the commenter's assertion that the EPA's IRFA does not sufficiently consider impacts on small entities. The EPA's IRFA, which is included in chapter 10 of the RIA for the proposed rule, addresses the statutorily required elements of an IRFA such as, the economic impact of the proposed rule on small entities and the Panel's findings.

The EPA disagrees with the comment that recommendations made by the SERs and not considered or discussed in the proposed rulemaking such as recommendations regarding subcategorization and separate GACT standards for area sources. The preamble to the proposed standards includes a detailed discussion of how the EPA determined which subcategories and sources would be regulated (76 FR 25036-25037, May 3, 2011). In that discussion, the EPA explains the rationale for its proposed subcategories based on five unit design types. In addition, the EPA acknowledges the subcategorization suggestions from the SERs and explains its reasons for not subcategorizing on those bases. The preamble to the proposed standards also includes a discussion of the SERs' suggestion that area source EGUs be distinguished from major-source EGUs and the EPA's reasons for not making that distinction (76 FR 25020-25021, May 3, 2011).

The EPA also disagrees with the suggestion that the Agency pursue an extension of the timeline for final rulemaking such that the SBAR Panel can be reconvened and a new IRFA can be

prepared and released for public comment prior to the final rulemaking. The EPA entered into a Consent Decree to resolve litigation alleging that the EPA failed to perform a non-discretionary duty to promulgate CAA section 112(d) standards for EGUs. *American Nurses Ass'n v. EPA*, 08-2198 (D.D.C.). That Decree required the EPA to sign the final MATS rule by November 16, 2011, unless the agency sought to extend the deadline consistent with the requirements of the modification provision of the Consent Decree. If plaintiffs in the *American Nurses* litigation objected to an extension request, which the EPA believes would have been likely based on their comments on the proposed rule, the Agency would have had to file a motion with the Court seeking an extension of the deadline. Consistent with governing case law, the Agency would have been required to demonstrate in its motion for extension that it was impossible to finalize the rule by the deadline provided in the Consent Decree. *See Sierra Club v. Jackson*, Civil Action No. 01-1537 (D.D.C.) (Opinion of the Court denying EPA's motion to extend a consent decree deadline). The EPA negotiated a 30-day extension and was able to complete the rule by December 16, 2011; accordingly, the Agency had no basis for seeking a further extension of time.

A detailed description of the changes made to the rule since proposal, including those made as a result of feedback received during the public comment process can be found in sections VI (NESHAP) and X (NSPS) in the preamble. Changes explained in the identified sections include those related to applicability; subcategorization; work practices; periods of startup, shutdown, and malfunction; initial testing and compliance; continuous compliance; and notification, recordkeeping, and reporting.

7.4.4 Description and Estimate of the Affected Small Entities

For the purposes of assessing the impacts of MATS on small entities, a small entity is defined as:

(1) A small business according to the Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity. The range of small business size standards for electric utilities is 4 billion kilowatt hours (kWh) of production or less;

(2) A small government jurisdiction that is a government of a city, county, town, district, or special district with a population of less than 50,000; and

(3) A small organization that is any not for profit enterprise that is independently owned and operated and is not dominant in its field.

The EPA examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected entities will install control technologies in compliance with MATS. The SBREFA analysis does not examine potential indirect economic impacts associated with this rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

The EPA used Velocity Suite's Ventyx data as a basis for identifying plant ownership and compiling the list of potentially affected small entities. The Ventyx dataset contains detailed ownership and corporate affiliation information. The analysis focused only on those EGUs affected by the rule, which includes units burning coal, oil, petroleum coke, or coal refuse as the primary fuel, and excludes any combustion turbine units or EGUs burning natural gas. Also, because the rule does not affect combustion units with an equivalent electricity generating capacity up to 25 megawatts (MW), small entities that do not own at least one combustion unit with a capacity greater than 25 MW were removed from the dataset. For the affected units remaining, boiler and generator capacity, heat input, generation, and emissions data were aggregated by owner and then by parent company. Entities with more than 4 billion kWh of annual electricity generation were removed from the list, as were municipal owned entities serving a population greater than 50,000. For cooperatives, investor-owned utilities, and subdivisions that generate less than 4 billion kWh of electricity annually but which may be part of a large entity, additional research on power sales, operating revenues, and other business activities was performed to make a final determination regarding size. Finally, small entities for which the EPA's modeling with the Integrated Planning Model (IPM) does not project generation in 2015 in the base case were omitted from the analysis because they are not projected to be operating and, thus, are not projected to face the costs of compliance with the rule. After omitting entities for the reasons above, the EPA identified a total of 82 potentially affected small entities that are affiliated with 102 electric generating units.

7.4.5 Compliance Cost Impacts

This section presents the methodology and results for estimating the impact of MATS on small entities in 2015 based on the following endpoints:

- annual economic impacts of MATS on small entities and

- ratio of small entity compliance cost impacts to revenues from electricity generation.[1]

7.4.5.1 Methodology for Estimating Impacts of MATS on Small Entities

EPA estimated compliance costs of MATS as follows:

$$C_{Compliance} = \Delta C_{Operating+Capital} + \Delta C_{Fuel} - \Delta R$$

where C represents a component of cost as labeled, and Δ R represents the value of change in electricity generation, calculated as the difference in revenues between the base case and MATS.

Based on this formula, compliance costs for a given small entity could either be positive or negative (i.e., cost savings) based on their compliance choices and market conditions. Under MATS, some units will forgo some level of electricity generation (and, thus, revenues) to comply and this impact will be lessened on those entities by the projected increase in electricity prices under the MATS scenario (which raises their revenues from the remainder of their sales). On the other hand, some units may increase electricity generation, and coupled with the increase in electricity prices, will see an increase in electricity revenues resulting in lower net compliance costs. If entities are able to increase revenue more than an increase in retrofit and fuel costs, ultimately they will have negative net compliance costs (or savings). Because this analysis evaluates the total costs as a sum of the costs associated with compliance choices as well as changes in electricity revenues, it captures savings or gains such as those described. As a result, what EPA describes as a cost is really more of a measure of the net economic impact of the rule on small entities.

For this analysis, EPA used unit-level IPM parsed outputs – from modeling runs conducted with EPA's base case v4.10_MATS assumptions – to estimate costs based on the parameters above. These impacts were then summed for each small entity, adjusting for ownership share.[2] Net impact estimates were based on the following: changes in operating and capital costs, driven mainly by retrofit installations or upgrades, change in fuel costs, and

[1] This methodology for estimating small entity impacts has been used in recent EPA rulemakings such as the CSAPR promulgated by EPA in July, 2011.

[2] Unit-level cost impacts are adjusted for ownership shares for individual small entities, so as not to overestimate burden on each company. If an individual unit is owned by multiple small entities, total costs for that unit to meet MATS obligations are distributed across all owners based on the percentage of the unit owned by each company. Ownership percentage was estimated based on the Ventyx database.

change in electricity generation revenues under MATS relative to the base case. These individual components of compliance cost were estimated as follows:

(1) **Operating and capital costs:** Using the IPM parsed outputs for the base case and MATS policy case, EPA identified units that installed one or more pollution control technologies under the rule. The equations for calculating operating and capital costs were adopted from technology assumptions used in EPA's version of IPM (version 4.10). The model calculates the capital cost (in $/MW); the fixed operation and maintenance (O&M) cost (in $/MW-year); and the variable O&M cost (in $/MWh).

(2) **Fuel costs:** Fuel costs were estimated by multiplying fuel input (in million British thermal units, MMBtu) by region and fuel prices ($/MMBtu) from EPA's modeling with IPM. The incremental fuel expenditures under MATS were then estimated by taking the difference in fuel costs between MATS and the base case.

(3) **Value of electricity generated:** EPA estimated the value of electricity generated by multiplying the electricity generation from EPA's IPM modeling results with the regionally-adjusted retail electricity price ($/MWh), for all entities except those categorized as "Private" in Ventyx. For private entities, EPA used wholesale electricity price instead of retail electricity price because most of the private entities are independent power producers (IPP). IPPs sell their electricity to wholesale purchasers and do not own transmission facilities and, thus, their revenue was estimated based on wholesale electricity prices.

7.4.5.2 Results

The number of potentially affected small entities by ownership type and potential impacts of MATS are summarized in Table 7-1. All costs are presented in 2007 dollars. EPA estimated the annualized net compliance cost to small entities to be approximately $106 million in 2015.

Table 7-1. Projected Impact of MATS on Small Entities in 2015

EGU Ownership Type	Number of Potentially Affected Entities	Number of Entities Projected to Withdraw all Affected Units as Uneconomic	Total Net Compliance Costs (2007$ millions)	Number of Small Entities with Compliance Cost > 1% of Generation Revenues	Number of Small Entities with Compliance Cost > 3% of Generation Revenues
Co-Op	19	0	-29.7	9	8
IOU	8	0	33.0	7	5
Municipal	42	0	49.7	16	15
Sub-division	9	0	44.8	4	3
Private	4	3	8.4	4	4
Total	**82**	**3**	**106**	**40**	**35**

Notes: The total number of entities with costs greater than 1 percent or 3 percent of revenues includes only entities experiencing positive costs. About 23 of the 82 total potentially affected small entities are estimated to have cost savings under MATS (see text above for an explanation).

Definitions of ownership types are based on those provided by Ventyx's Energy Velocity.

Co-op (Cooperative): non-profit, customer-owned electric companies that generate and/or distribute electric power.

IOU (Investor-Owned Utility): Includes Investor Owned assets (e.g., a marketer, independent power producer, financial entity) and electric companies owned by stockholders, etc.

Municipal: A municipal utility, responsible for power supply and distribution in a small region, such as a city.

Sub-division: Political Subdivision Utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.

Private: Similar to investor-owned, but ownership shares are not openly traded on the stock markets.

Source: ICF International analysis based on IPM modeling results

EPA assessed the economic and financial impacts of the final rule using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent. Of the 82 small entities identified, EPA's analysis shows 40 entities may experience compliance costs greater than 1 percent of base generation revenues in 2015, and 35 may experience compliance costs greater than 3 percent of base revenues.[3] Also, all generating capacity at 3 small entities is projected to be uneconomic to maintain. In this analysis, the cost of withdrawing a unit as uneconomic is estimated as the base case profit that is forgone by not operating under the policy case. Because 35 of the 82 total entities, or more than 40 percent, are estimated to incur compliance cost greater than 3 percent of base revenues, EPA has

[3] One percent and three percent of generation revenue criteria based on: "EPA's *Action Development Process*: Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act." OPEI Regulatory Development Series. November 2006. This can be found on the Internet at http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf.

concluded that it cannot certify that there will be no SISNOSE for this rule. Results for small entities discussed here, however, do not account for the reality that electricity markets are regulated in parts of the country. Entities operating in regulated or cost-of-service markets should be able to recover all of their costs of compliance through rate adjustments.

Note that the estimated costs for small entities are significantly lower than those estimated by EPA for the MATS proposal (which were $379 million). This is driven by a small group of units (less than 6 percent) which were projected to be uneconomic to operate under the proposal (and hence incurred lost profits due to lost electricity revenues), but are now projected to continue their operations under MATS. In addition, EPA's modeling indicates one unit that would have operated at a low capacity factor under the base case would find it economical to increase its generation significantly under MATS to meet electricity demand in its region. Excluding this unit, the total cost impacts across all entities would be roughly $175 million. Changes in compliance behavior for this small group of units, in particular the one unit which operates at a higher capacity factor, has a substantial impact on total costs for the entire group as their increased generation revenues offsets a large portion of the compliance costs.

The separate components of annualized costs to small entities under MATS are summarized in Table 7-2. The most significant components of incremental costs to these entities are increased capital and operating costs for retrofits, followed by changes in electricity revenues (i.e., cost savings).

Table 7-2. Incremental Annualized Costs under MATS Summarized by Ownership Group and Cost Category in 2015 (2007$ millions)

EGU Ownership Type	Capital+ Operating Costs ($MM)	Fuel Costs ($MM)	Change in Electricity Revenue ($MM)	Total
	A	B	C	**=A+B-C**
Co-Op	161.5	86.4	277.5	-29.7
IOU	39.3	0	6.3	33.0
Municipal	76.4	1.9	28.7	49.7
Sub-division	73.9	2.2	31.3	44.8
Private	5.5	0	-2.9	8.4
Total	**356**	**91**	**341**	**106**

Note: Totals may not add due to rounding.
Source: ICF International analysis based on IPM modeling results

Capital and operating costs increase across all ownership types, but the direction of changes in electricity revenues vary among ownership types. All ownership types, with the exception of private entities, experience a net gain in electricity revenues under the MATS, unlike projections from EPA's modeling during the proposal, where only municipals benefitted from higher electricity revenues. The change in electricity revenue takes into account both the profit lost from units that do not operate under the policy case and the difference in revenue for operating units under the policy case. According to EPA's modeling, an estimated 274 MW of capacity owned by small entities is considered uneconomic to operate under the policy case, resulting in a net loss of $13 million (in 2007$) in profits. On the other hand, many operating units actually increase their electricity revenue due to higher electricity prices under MATS. In addition, as mentioned above, EPA's modeling indicates one unit finds it economical to increase its capacity factor significantly under the policy case which results in significantly higher revenues offsetting the costs.

7.4.6 Description of Steps to Minimize Impacts on Small Entities

Consistent with the requirements of the RFA and SBREFA, the EPA has taken steps to minimize the significant economic impact on small entities. Because this rule does not affect units with a generating capacity of less than 25 MW, small entities that do not own at least one generating unit with a capacity greater than 25 MW are not subject to the rule. According to the EPA's analysis, among the coal- and oil-fired EGUs (i.e., excluding combined cycle gas turbines and gas combustion turbines) about 26 potentially small entities only own EGUs with a

capacity less than or equal to 25 MW, and none of those entities are subject to the final rule based on the statutory definition of potentially regulated units.

For units affected by the proposed rule, the EPA considered a number of comments received, both during the Small Business Advocacy Review (SBAR) Panel and the public comment period. While none of the alternatives adopted are specifically applied to small entities, the EPA believes these modifications will make compliance less onerous for all regulated units, including those owned by small entities.

7.4.6.1 Work Practice Standards

Consistent with Sierra Club v. EPA, the EPA proposed numerical emission standards that would apply at all times, including during periods of startup and shutdown. After reviewing comments and other data regarding the nature of these periods of operation, the EPA is finalizing a work practice standard for periods of start up and shut down. The EPA is also finalizing work practice standards for organic HAP from all subcategories of EGUs. The EPA has chosen to finalize work practice standards because the significant majority of data for measured organic HAP emissions from EGUs are below the detection levels of the EPA test methods, and, as such, the Agency considers it impracticable to reliably measure emissions from these units. Descriptions of the work practice requirements for startup and shutdown, as well as organic HAP, can be found in Section VI.D-E. of the preamble.

7.4.6.2 Continuous Compliance and Notification, Record-keeping, and Reporting

The final rule greatly simplifies the continuous compliance requirements and provides two basic approaches for most situations: use of continuous monitoring and periodic testing. The frequency of periodic testing has been decreased from monthly in the proposal to quarterly in the final rule. In addition to simplifying compliance, the EPA believes these changes considerably reduce the overall burden associated with recordkeeping and reporting. These changes to the final rule are described in more detail in Section VI.G-H. of the preamble.

7.4.6.3 Subcategorization

The Small Entity Representatives on the SBAR Panel were generally supportive of subcategorization and suggested a number of additional subcategories the EPA should consider when developing the final rule. While it was not practicable to adopt the proposed subcategories, the EPA maintained the existing subcategories and split the “liquid oil-fired units” subcategory into two individual subcategories – continental and non-continental units.

7.4.6.4 MACT Floor Calculations

As recommended by the EPA SBAR Panel representative, the EPA established the MACT floors using all the available ICR data that was received to the maximum extent possible consistent with the CAA requirements. The Agency believes this approach reasonably ensures that the emission limits selected as the MACT floors adequately represent the level of emissions actually achieved by the average of the units in the top 12 percent, considering operational variability of those units. Additionally, following proposal, the EPA reviewed and revised the procedure intended to account for the contribution of measurement imprecision to data variability in establishing effective emissions limits.

7.4.6.5 Alternatives Not Adopted

The EPA chose not to adopt several of the suggestions posed either during the SBAR Panel or public comment period. The EPA did not propose a percent reduction standard as an alternative to the concentration-based MACT floor. The percent reduction format for Hg and other HAP emissions would not have addressed the EPA's desire to promote, and give credit for, coal preparation practices that remove Hg and other HAP before firing. Also, to account for the coal preparation practices, sources would be required to track the HAP concentrations in coal from the mine to the stack, and not just before and after the control device(s), and such an approach would be difficult to implement and enforce. Furthermore, the EPA does not believe the percent reduction standard is in line with the Court's interpretation of the Clean Air Act section 112 requirements. Even if we believed it was appropriate to establish a percent reduction standard, we do not have the data necessary to establish percent reduction standards for HAP, as explained further in the response to comments document.

The EPA chose not to establish GACT standards for area sources for a number of reasons. The data show that similar HAP emissions and control technologies are found on both major and area sources greater than 25 MWe, and some large units are synthetic area sources. In fact, because of the significant number of well-controlled EGUs of all sizes, we believe it would be difficult to make a distinction between MACT and GACT. Moreover, the EPA believes the standards for area source EGUs should reflect MACT, rather than GACT, because there is no essential difference between area source and major source EGUs with respect to emissions of HAP.

The EPA chose not to exercise its discretionary authority to establish health-based emission standards for HCL and other HAP acid gases. Given the limitations of the currently available information (e.g., the HAP mix where EGUs are located, and the cumulative impacts of

respiratory irritants from nearby sources), the environmental effects of HCl and the other acid gas HAP, and the significant co-benefits from reductions in criteria pollutants the EPA determined that setting a conventional MACT standard for HCl and the other acid gas HAP was the appropriate course of action.

As required by section 212 of SBREFA, the EPA also is preparing a Small Entity Compliance Guide to help small entities comply with this rule. Small entities will be able to obtain a copy of the Small Entity Compliance guide at the following Web site: http://www.epa.gov/airquality/powerplanttoxics/actions.html.

7.5 Unfunded Mandates Reform Act (UMRA) Analysis

Title II of the UMRA of 1995 (Public Law 104-4)(UMRA) establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under Section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that "includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more ... in any one year." A "Federal mandate" is defined under Section 421(6), 2 U.S.C. 658(6), to include a "Federal intergovernmental mandate" and a "Federal private sector mandate." A "Federal intergovernmental mandate," in turn, is defined to include a regulation that "would impose an enforceable duty upon State, Local, or tribal governments," Section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is "a condition of Federal assistance," Section 421(5)(A)(i)(I). A "Federal private sector mandate" includes a regulation that "would impose an enforceable duty upon the private sector," with certain exceptions, Section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under Section 202 of the UMRA, Section 205, 2 U.S.C. 1535, of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes an explanation why that alternative was not adopted.

In a manner consistent with the intergovernmental consultation provisions of Section 204 of the UMRA, EPA carried out consultations with the governmental entities affected by this rule. EPA held meetings with states and tribal representatives in which the Agency presented its

plan to develop a proposal and provided opportunities for participants to provide input as part of the rulemaking process. EPA has also analyzed the economic impacts of MATS on government entities and this section presents the results of that analysis. The UMRA analysis does not examine potential indirect economic impacts associated with the rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

7.5.1 Identification of Affected Government Entities

Using Ventyx data, EPA identified state- and municipality-owned utilities and subdivisions that would be affected by this rule. EPA then used IPM parsed outputs (based on EPA modeling assumptions) to associate these entities with individual generating units. The analysis focused only on EGUs affected by MATS, which includes units burning coal, oil, petroleum coke, or waste coal as the primary fuel, and excludes any combustion turbine units. Entities that did not own at least one unit with a generating capacity of greater than 25 MW were also removed from the dataset because of their exemption from the rule. Finally, government entities for which EPA's modeling does not project generation in 2015 under the base case were also exempted from this analysis, because they are not projected to operate and are thus not projected to face compliance costs with this rule. Based on this, EPA identified 96 state, municipal, and sub-divisions affiliated with 172 electric generating units that are potentially affected by MATS.

7.5.2 Compliance Cost Impacts

After identifying the potentially affected government entities, EPA estimated the impact of MATS in 2015 based on the following:

- total impacts of compliance on government entities and
- ratio of government entity impacts to revenues from electricity generation.

7.5.2.1 Methodology for Estimating Impacts MATS on Government Entities

EPA estimated compliance costs of MATS as follows:

$$C_{Compliance} = \Delta C_{Operating+Capital} + \Delta C_{Fuel} - \Delta R$$

where C represents a component of cost as labeled, and Δ R represents the retail value of change in electricity generation, calculated as the difference in projected revenues between the base case and MATS.

Based on this formula, compliance costs for a given government entity could either be positive or negative (i.e., cost savings) based on their compliance choices and market conditions. Under MATS, some units will forgo some level of electricity generation (and thus revenues) to comply and this impact will be lessened on those entities by the projected increase in electricity prices under MATS. On the other hand, some units may increase electricity generation, and coupled with the increase in electricity prices, will see an increase in electricity revenues resulting in lower net compliance costs. If entities are able to increase revenue more than an increase in retrofit and fuel costs, ultimately they will have negative net compliance costs (or savings). Because this analysis evaluates the total costs as a sum of the costs associated with compliance choices as well as changes in electricity revenues, it captures savings or gains such as those described. As a result, what EPA describes as a cost is really more of a measure of the net economic impact of the rule on government entities.

For this analysis, EPA used unit-level data from IPM runs conducted with EPA's modeling assumptions to estimate costs based on the parameters above. These impacts were then aggregated for each government entity, adjusting for ownership share. Compliance cost estimates were based on the following: changes in capital and operating costs, change in fuel costs, and change in electricity generation revenues under MATS relative to the base case. These components of compliance cost were estimated as follows:

(1) Capital and operating costs: Using EPA's modeling results for the base case and the MATS policy case, EPA identified units that install control technology under this rule and the technologies installed. The equations for calculating operating and capital costs were adopted from EPA's version of IPM (version 4.10_MATS). The model calculates the capital cost (in $/MW); the fixed operation and maintenance (O&M) cost (in $/MW-year); and the variable O&M cost (in $/MWh)

(2) Fuel costs: Fuel costs were estimated by multiplying fuel input (MMBtu) by region and fuel prices ($/MMBtu) from EPA's modeling. The change in fuel expenditures under MATS was then estimated by taking the difference in fuel costs between MATS and the base case.

(3) Value of electricity generated: EPA estimated the value of electricity generated by multiplying the estimated electricity generation from EPA's IPM modeling results with the regional-adjusted retail electricity prices ($/MWh).

7.5.2.2 Results

As was done for the small entities analysis, EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, and our results focus on those entities for which this measure could be greater than 1 percent or 3 percent of base revenues. EPA projects that 42 government entities will have compliance costs greater than 1 percent of base generation revenue in 2015 and 32 may experience compliance costs greater than 3 percent of base revenues. Overall, 6 units owned by government entities are projected to be uneconomic to maintain.

The separate components of the annualized costs to government entities under MATS are summarized in Table 7-3 below. The most significant components of incremental costs to these entities are the increased capital and operating costs, followed by increases in electricity revenues (i.e., a cost saving).

Table 7-3. Incremental Annualized Costs under MATS Summarized by Ownership Group and Cost Category (2007$ millions) in 2015

EGU Ownership Type	Capital Costs + Operating Costs($MM)	Fuel Costs ($ MM)	Change in Revenue ($ MM)	Total
	A	B	C	=A+B-C
Sub-Division	128.0	50.7	106.4	72.3
State	65.9	1.2	32.7	34.4
Municipal	516.3	45.4	374.3	187.4
Total	**710**	**97**	**513**	**294**

Note: Totals may not add due to rounding.
Definitions of ownership types are based on those provided by Ventyx's Energy Velocity.
Municipal: A municipal utility, responsible for power supply and distribution in a small region, such as a city.
Sub-division: Political Subdivision Utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.
Source: ICF International analysis based on IPM modeling results

The number of potentially affected government entities by ownership type and potential impacts of MATS are summarized in Table 7-4. All costs are reported in 2007$ millions. EPA estimated the annualized net compliance cost to government entities to be approximately $294 million in 2015.

Table 7-4. Summary of Potential Impacts on Government Entities under MATS in 2015

EGU Ownership Type	Number of Potentially Affected Entities	Number of Entities Withdrawing all Affected units	Total Net Costs of MACT compliance ($ MM)	Number of Government Entities with Compliance Cost > 1% of Generation Revenues	Number of Government Entities with Compliance Cost > 3% of Generation Revenues
Sub-Division	11	0	72.3	5	4
State	5	0	34.4	4	3
Municipal	80	0	187.4	33	25
Total	**96**	**0**	**294**	**42**	**32**

Note: The total number of entities with costs greater than 1 percent or 3 percent of revenues includes only entities experiencing positive costs. About 30 of the 96 total potentially affected government entities are estimated to have cost savings under the MACT policy case (see text above for an explanation).
Source: ICF International analysis based on IPM modeling results

Capital and operating costs increase over all ownership types. All ownership types, however, also experience a net gain in electricity revenue, mainly due to higher electricity prices under the policy case. As described in the small entity analysis, the change in electricity revenue takes into account both the profit lost from units that do not operate under the policy case and the difference in revenue for operating units under the policy case. According to EPA's modeling, an estimated 757 MW of electricity generation is estimated to be uneconomic to operate under the policy case, accounting for about $20 million in lost profits. On the other hand, many operating units actually increase their electricity revenue due to higher electricity prices under the MATS policy scenario.

7.6 Executive Order 13132, Federalism

Under EO 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or the EPA consults with state and local officials early in the process of developing the final action.

The EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the Federal government will not provide the funds necessary to pay those costs. Accordingly, the EPA provides the following federalism summary impact statement as required by section 6(b) of EO 13132.

Based on estimates in the RIA, provided in the docket, the final rule may have federalism implications because the rule may impose approximately $294 million in annual direct compliance costs on an estimated 96 state or local governments. Specifically, we estimate that there are 80 municipalities, 5 states, and 11 political subdivisions (i.e., a public district with territorial boundaries embracing an area wider than a single municipality and frequently covering more than one county for the purpose of generating, transmitting and distributing electric energy) that may be directly impacted by this final rule. Responses to the EPA's 2010 ICR were used to estimate the nationwide number of potentially impacted state or local governments. As previously explained, this 2010 survey was submitted to all coal- and oil-fired EGUs listed in the 2007 version of DOE/EIA's "Annual Electric Generator Report," and "Power Plant Operations Report."

The EPA consulted with state and local officials in the process of developing the rule to permit them to have meaningful and timely input into its development. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the rule, answer questions, and solicit input.

7.7 Executive Order 13175, Consultation and Coordination with Indian Tribal Governments

EPA has concluded that this action may have tribal implications. The EPA offered consultation with tribal officials early in the regulation development process to permit them an opportunity to have meaningful and timely input. Consultation letters were sent to 584 tribal leaders and provided information regarding the EPA's development of this rule and offered consultation. Three consultation meetings were held: December 7, 2010, with the Upper Sioux Community of Minnesota; December 13, 2010, with the Moapa Band of Paiutes, Forest County Potawatomi, Standing Rock Sioux Tribal Council, and Fond du Lac Band of Chippewa; January 5, 2011, with the Forest County Potawatomi and a representative from the National Tribal Air Association. In these meetings, the EPA presented the authority under the CAA used to develop these rules and an overview of the industry and the industrial processes that have the potential for regulation. Tribes expressed concerns about the impact of EGUs on Indian country. Specifically, they were concerned about potential Hg deposition and the impact on the water resources of the Tribes, with particular concern about the impact on subsistence lifestyles for fishing communities, the cultural impact of impaired water quality for ceremonial purposes, and the economic impact on tourism. In light of these concerns, the Tribes expressed interest in an expedited implementation of the rule. Other concerns expressed by Tribes related to how the Agency would consider variability in setting the standards and the use of tribal-specific fish

consumption data from the Tribes in our assessments. They were not supportive of using work practice standards as part of the rule and asked the Agency to consider going beyond the MACT floor to offer more protection for the tribal communities.

In addition to these consultations, the EPA also conducted outreach on this rule through presentations at the National Tribal Forum in Milwaukee, WI; phone calls with the National Tribal Air Association; and a webinar for Tribes on the proposed rule. The EPA specifically requested tribal data that could support the appropriate and necessary analyses and the RIA for this rule. In addition, the EPA held individual consultations with the Navajo Nation on October 12, 2011; as well as the Gila River Indian Community, Ak-Chin Indian Community, and the Hopi Nation on October 14, 2011. These Tribes expressed concerns about the impact of the rule on the Navajo Generating Station (NGS), the impact on the cost of the water allotted to the Tribes from the Central Arizona Project (CAP), the impact on tribal revenues from the coal mining operations (i.e., assumptions about reduced mining if NGS were to retire one or more units), and the impacts on employment of tribal members at both the NGS and the mine. More specific comments can be found in the docket.

7.8 Protection of Children from Environmental Health and Safety Risks

This final rule is subject to EO 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by EO 12866, and the EPA believes that the environmental health or safety risk addressed by this action may have a disproportionate effect on children. Accordingly, we have evaluated the environmental health or safety effects of the standards on children.

Although this final rule is based on technology performance, the standards are designed to protect against hazards to public health with an adequate margin of safety as described in the preamble. The protection offered by this rule may be particularly important for children, especially the developing fetus. As referenced in Chapter 4 of this RIA, “Mercury and Other HAP Benefits Analysis,” children are more vulnerable than adults to many HAP emitted by EGUs due to differential behavior patterns and physiology. These unique susceptibilities were carefully considered in a number of different ways in the analyses associated with this rulemaking, and are summarized in the RIA.

7.9 Statement of Energy Effects

Our analysis to comply with EO 13211 (Statement of Energy Effects) can be found in Section 3.16 of this RIA.

7.10 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Public Law No. 104-113; 15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. The EPA cites the following standards in the final rule: EPA Methods 1, 2, 2A, 2C, 2F, 2G, 3A, 3B, 4, 5, 5D, 17, 19, 23, 26, 26A, 29, 30B of 40 CFR Part 60 and Method 320 of 40 CFR Part 63. Consistent with the NTTAA, the EPA conducted searches to identify voluntary consensus standards in addition to these EPA methods. No applicable voluntary consensus standards were identified for EPA Methods 2F, 2G, 5D, and 19. The search and review results have been documented and are placed in the docket for the proposed rule.

The three voluntary consensus standards described below were identified as acceptable alternatives to EPA test methods for the purposes of the final rule.

The voluntary consensus standard American National Standards Institute (ANSI) / American Society of Mechanical Engineers (ASME) PTC 19-10-1981, “Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus]” is cited in the final rule for its manual method for measuring the O2, CO2, and CO content of exhaust gas. This part of ANSI/ASME PTC 19-10-1981 is an acceptable alternative to Method 3B.

The voluntary consensus standard ASTM D6348-03 (Reapproved 2010), “Standards Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy” is acceptable as an alternative to Method 320 and is cited in the final rule, but with several conditions: (1) The test plan preparation and implementation in the Annexes to ASTM D-6348-03, Sections A1 through A8 are mandatory; and (2) In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5). In order for the test data to be acceptable for a compound, %R must be 70 % ≥ R ≤ 130%. If the %R value does not meet this criterion for a target compound, the test data are not acceptable for that compound and the test must be repeated for that analyte (i.e., the sampling and/or analytical procedure should be adjusted before a

retest). The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound by using the following equation: Reported Result = (Measured Concentration in the Stack x 100) / % R.

The voluntary consensus standard ASTM D6784-02, "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)," is an acceptable alternative to use of EPA Method 29 for Hg only or Method 30B for the purpose of conducting relative accuracy tests of mercury continuous monitoring systems under this final rule. Because of the limitations of this method in terms of total sampling volume, it is not appropriate for use in performance testing under this rule. In addition to the voluntary consensus standards the EPA used in the final rule, the search for emissions measurement procedures identified 16 other voluntary consensus standards. The EPA determined that 14 of these 16 standards identified for measuring emissions of the HAP or surrogates subject to emission standards in the final rule were impractical alternatives to EPA test methods for the purposes of this final rule. Therefore, the EPA does not intend to adopt these standards for this purpose. The reasons for this determination for the 14 methods are discussed below, and the remaining 2 methods are discussed later in this section.

The voluntary consensus standard ASTM D3154-00, "Standard Method for Average Velocity in a Duct (Pitot Tube Method)," is impractical as an alternative to EPA Methods 1, 2, 3B, and 4 for the purposes of this rulemaking because the standard appears to lack in quality control and quality assurance requirements. Specifically, ASTM D3154-00 does not include the following: (1) proof that openings of standard pitot tube have not plugged during the test; (2) if differential pressure gauges other than inclined manometers (e.g., magnehelic gauges) are used, their calibration must be checked after each test series; and (3) the frequency and validity range for calibration of the temperature sensors.

The voluntary consensus standard ASTM D3464-96 (Reapproved 2001), "Standard Test Method Average Velocity in a Duct Using a Thermal Anemometer," is impractical as an alternative to EPA Method 2 for the purposes of this rule primarily because applicability specifications are not clearly defined, e.g., range of gas composition, temperature limits. Also, the lack of supporting quality assurance data for the calibration procedures and specifications, and certain variability issues that are not adequately addressed by the standard limit the EPA's ability to make a definitive comparison of the method in these areas.

The voluntary consensus standard ISO 10780:1994, “Stationary Source Emissions–Measurement of Velocity and Volume Flowrate of Gas Streams in Ducts,” is impractical as an alternative to EPA Method 2 in this rule. The standard recommends the use of an L-shaped pitot, which historically has not been recommended by the EPA. The EPA specifies the S-type design which has large openings that are less likely to plug up with dust.

The voluntary consensus standard, CAN/CSA Z223.2-M86 (1999), “Method for the Continuous Measurement of Oxygen, Carbon Dioxide, Carbon Monoxide, Sulphur Dioxide, and Oxides of Nitrogen in Enclosed Combustion Flue Gas Streams,” is unacceptable as a substitute for EPA Method 3A because it does not include quantitative specifications for measurement system performance, most notably the calibration procedures and instrument performance characteristics. The instrument performance characteristics that are provided are non-mandatory and also do not provide the same level of quality assurance as the EPA methods. For example, the zero and span/calibration drift is only checked weekly, whereas the EPA methods require drift checks after each run.

Two very similar voluntary consensus standards, ASTM D5835-95 (Reapproved 2001), “Standard Practice for Sampling Stationary Source Emissions for Automated Determination of Gas Concentration,” and ISO 10396:1993, “Stationary Source Emissions: Sampling for the Automated Determination of Gas Concentrations,” are impractical alternatives to EPA Method 3A for the purposes of this final rule because they lack in detail and quality assurance/quality control requirements. Specifically, these two standards do not include the following: (1) sensitivity of the method; (2) acceptable levels of analyzer calibration error; (3) acceptable levels of sampling system bias; (4) zero drift and calibration drift limits, time span, and required testing frequency; (5) a method to test the interference response of the analyzer; (6) procedures to determine the minimum sampling time per run and minimum measurement time; and (7) specifications for data recorders, in terms of resolution (all types) and recording intervals (digital and analog recorders, only).

The voluntary consensus standard ISO 12039:2001, “Stationary Source Emissions--Determination of Carbon Monoxide, Carbon Dioxide, and Oxygen--Automated Methods,” is not acceptable as an alternative to EPA Method 3A. This ISO standard is similar to EPA Method 3A, but is missing some key features. In terms of sampling, the hardware required by ISO 12039:2001 does not include a 3-way calibration valve assembly or equivalent to block the sample gas flow while calibration gases are introduced. In its calibration procedures, ISO 12039:2001 only specifies a two-point calibration while EPA Method 3A specifies a three-point calibration. Also, ISO 12039:2001 does not specify performance criteria for calibration error,

calibration drift, or sampling system bias tests as in the EPA method, although checks of these quality control features are required by the ISO standard.

The voluntary consensus standard ASTM D6522-00, “Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers” is not an acceptable alternative to EPA Method 3A for measuring CO and O2 concentrations for this final rule as the method is designed for application to sources firing natural gas.

The voluntary consensus standard ASME PTC-38-80 R85 (1985), “Determination of the Concentration of Particulate Matter in Gas Streams,” is not acceptable as an alternative for EPA Method 5 because ASTM PTC-38-80 is not specific about equipment requirements, and instead presents the options available and the pros and cons of each option. The key specific differences between ASME PTC-38-80 and the EPA methods are that the ASME standard: (1) allows in-stack filter placement as compared to the out-of-stack filter placement in EPA Methods 5 and 17; (2) allows many different types of nozzles, pitots, and filtering equipment; (3) does not specify a filter weighing protocol or a minimum allowable filter weight fluctuation as in the EPA methods; and (4) allows filter paper to be only 99 percent efficient, as compared to the 99.95 percent efficiency required by the EPA methods.

The voluntary consensus standard ASTM D3685/D3685M-98, “Test Methods for Sampling and Determination of Particulate Matter in Stack Gases,” is similar to EPA Methods 5 and 17, but is lacking in the following areas that are needed to produce quality, representative particulate data: (1) requirement that the filter holder temperature should be between 120oC and 134oC, and not just “above the acid dew-point;” (2) detailed specifications for measuring and monitoring the filter holder temperature during sampling; (3) procedures similar to EPA Methods 1, 2, 3, and 4, that are required by EPA Method 5; (4) technical guidance for performing the Method 5 sampling procedures, e.g., maintaining and monitoring sampling train operating temperatures, specific leak check guidelines and procedures, and use of reagent blanks for determining and subtracting background contamination; and (5) detailed equipment and/or operational requirements, e.g., component exchange leak checks, use of glass cyclones for heavy particulate loading and/or water droplets, operating under a negative stack pressure, exchanging particulate loaded filters, sampling preparation and implementation guidance, sample recovery guidance, data reduction guidance, and particulate sample calculations input.

The voluntary consensus standard ISO 9096:1992, “Determination of Concentration and Mass Flow Rate of Particulate Matter in Gas Carrying Ducts - Manual Gravimetric Method,” is not acceptable as an alternative for EPA Method 5. Although sections of ISO 9096 incorporate EPA Methods 1, 2, and 5 to some degree, this ISO standard is not equivalent to EPA Method 5 for collection of PM. The standard ISO 9096 does not provide applicable technical guidance for performing many of the integral procedures specified in Methods 1, 2, and 5. Major performance and operational details are lacking or nonexistent and detailed quality assurance/quality control guidance for the sampling operations required to produce quality, representative particulate data (e.g., guidance for maintaining and monitoring train operating temperatures, specific leak check guidelines and procedures, and sample preparation and recovery procedures) are not provided by the standard, as in EPA Method 5. Also, details of equipment and/or operational requirements, such as those specified in EPA Method 5, are not included in the ISO standard, e.g., stack gas moisture measurements, data reduction guidance, and particulate sample calculations.

The voluntary consensus standard CAN/CSA Z223.1-M1977, “Method for the Determination of Particulate Mass Flows in Enclosed Gas Streams,” is not acceptable as an alternative for EPA Method 5. Detailed technical procedures and quality control measures that are required in EPA Methods 1, 2, 3, and 4 are not included in CAN/CSA Z223.1. Second, CAN/CSA Z223.1 does not include the EPA Method 5 filter weighing requirement to repeat weighing every 6 hours until a constant weight is achieved. Third, EPA Method 5 requires the filter weight to be reported to the nearest 0.1 milligram (mg), while CAN/CSA Z223.1 requires reporting only to the nearest 0.5 mg. Also, CAN/CSA Z223.1 allows the use of a standard pitot for velocity measurement when plugging of the tube opening is not expected to be a problem. The EPA Method 5 requires an S-shaped pitot.

The voluntary consensus standard EN 1911-1,2,3 (1998), “Stationary Source Emissions-Manual Method of Determination of HCl-Part 1: Sampling of Gases Ratified European Text-Part 2: Gaseous Compounds Absorption Ratified European Text-Part 3: Adsorption Solutions Analysis and Calculation Ratified European Text,” is impractical as an alternative to EPA Methods 26 and 26A. Part 3 of this standard cannot be considered equivalent to EPA Method 26 or 26A because the sample absorbing solution (water) would be expected to capture both HCl and chlorine gas, if present, without the ability to distinguish between the two. The EPA Methods 26 and 26A use an acidified absorbing solution to first separate HCl and chlorine gas so that they can be selectively absorbed, analyzed, and reported separately. In addition, in EN 1911 the absorption

efficiency for chlorine gas would be expected to vary as the pH of the water changed during sampling.

The voluntary consensus standard EN 13211 (1998), is not acceptable as an alternative to the Hg portion of EPA Method 29 primarily because it is not validated for use with impingers, as in the EPA method, although the method describes procedures for the use of impingers. This European standard is validated for the use of fritted bubblers only and requires the use of a side (split) stream arrangement for isokinetic sampling because of the low sampling rate of the bubblers (up to 3 liters per minute, maximum). Also, only two bubblers (or impingers) are required by EN 13211, whereas EPA Method 29 require the use of six impingers. In addition, EN 13211 does not include many of the quality control procedures of EPA Method 29, especially for the use and calibration of temperature sensors and controllers, sampling train assembly and disassembly, and filter weighing.

Two of the 16 voluntary consensus standards identified in this search were not available at the time the review was conducted for the purposes of the final rule because they are under development by a voluntary consensus body: ASME/BSR MFC 13M, "Flow Measurement by Velocity Traverse," for EPA Method 2 (and possibly 1); and ASME/BSR MFC 12M, "Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters," for EPA Method 2.

Finally, in addition to the three voluntary consensus standards identified as acceptable alternatives to EPA methods required in the final rule, the EPA is also specifying four voluntary consensus standards in the rule for use in sampling and analysis of liquid oil samples for moisture content. These standards are: ASTM D95-05 (Reapproved 2010), "Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation", ASTM D4006-11, "Standard Test Method for Water in Crude Oil by Distillation", ASTM D4177-95 (Reapproved 2010), "Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, and ASTM D4057-06 (Reapproved 2011), "Standard Practice for Manual Sampling of Petroleum and Petroleum Products."

Table 5, section 4.1.1.5 of appendix A, and section 3.1.2 of appendix B to subpart UUUUU, 40 CFR Part 63, list the EPA testing methods included in the final rule. Under section 63.7(f) and section 63.8(f) of subpart A of the General Provisions, a source may apply to the EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures specified.

7.11 Environmental Justice

7.11.1 Environmental Justice Impacts

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice (EJ) part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the U.S.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, or indigenous populations because it increases the level of environmental protection for all affected populations.

This final rule establishes national emission standards for new and existing EGUs that combust coal and oil. The EPA estimates that there are approximately 1,400 units located at 575 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from EGUs. This includes metals (Hg, As, Be, Cd, Cr, Pb, Mn, Ni, and Se), organics (POM, acetaldehyde, acrolein, benzene, dioxins, ethylene dichloride, formaldehyde, and PCB), and acid gases (HCl and HF). At sufficient levels of exposure, these pollutants can cause a range of health effects including cancer; irritation of the lungs, skin, and mucous membranes; effects on the central nervous system such as memory and IQ loss and learning disabilities; damage to the kidneys; and other acute health disorders.

The final rule will also result in substantial reductions of criteria pollutants such as CO, PM, and SO2. Sulfur dioxide is a precursor pollutant that is often transformed into fine PM ($PM_{2.5}$) in the atmosphere. Reducing direct emissions of $PM_{2.5}$ and SO2 will, as a result, reduce concentrations of $PM_{2.5}$ in the atmosphere. These reductions in $PM_{2.5}$ will provide large health benefits, such as reducing the risk of premature mortality for adults, chronic and acute bronchitis, childhood asthma attacks, and hospitalizations for other respiratory and cardiovascular diseases. (For more details on the health effects of metals, organics, and $PM_{2.5}$, please refer to Chapters 4 and 5 of this RIA.) This final rule will also have a small effect on electricity and natural gas prices but has the potential to affect the cost structure of the utility industry and could lead to shifts in how and where electricity is generated.

Today's final rule is one of a group of regulatory actions that the EPA will take over the next several years to respond to statutory and judicial mandates that will reduce exposure to HAP and $PM_{2.5}$, as well as to other pollutants, from EGUs and other sources. In addition, the EPA will pursue energy efficiency improvements throughout the economy, along with other Federal agencies, states and other groups. This will contribute to additional environmental and public health improvements while lowering the costs of realizing those improvements. Together, these rules and actions will have substantial and long-term effects on both the U.S. power industry and on communities currently breathing dirty air. Therefore, we anticipate significant interest in these actions from EJ communities, as well as many others.

7.11.1.1 Key EJ Aspects of the Rule

This is an air toxics rule; therefore, it does not permit emissions trading among sources. Instead, this final rule will place a limit on the rates of Hg and other HAP emitted from each affected EGU. As a result, emissions of Hg and other HAP such as HCl will be substantially reduced in the vast majority of states. In some states, however, there may be small increases in Hg and other HAP emissions due to shifts in electricity generation from EGUs with higher emission rates to EGUs with already low emission rates. Hydrogen chloride emissions are projected to increase at a small number of sources but that does not lead to any increased emissions at the state level.

The primary risk analysis to support the finding that this final rule is both appropriate and necessary includes an analysis of the effects of Hg from EGUs on people who rely on freshwater fish they catch as a regular and frequent part of their diet. These groups are characterized as subsistence level fishing populations or fishers. A significant portion of the data in this analysis came from published studies of EJ communities where people frequently consume locally-caught freshwater fish. These communities included: (1) White and black populations (including female and poor strata) surveyed in South Carolina; (2) Hispanic, Vietnamese and Laotian populations surveyed in California; and (3) Great Lakes tribal populations (Chippewa and Ojibwe) active on ceded territories around the Great Lakes. These data were used to help estimate risks to similar populations beyond the areas where the study data was collected. For example, while the Vietnamese and Laotian survey data were collected in California, given the ethnic (heritage) nature of these high fish consumption rates, we assumed that they could also be associated with members of these ethnic groups living elsewhere in the U.S. Therefore, the high-end consumption rates referenced in the California study for these ethnic groups were used to model risk at watersheds elsewhere in the U.S. As a result of this approach, the specific fish consumption patterns of several different EJ groups are

fundamental to the EPA's assessment of both the underlying risks that make this final rule appropriate and necessary, and of the analysis of the benefits of reducing exposure to Hg and the other hazardous air pollutants.

The EPA's analysis of risks from consumption of Hg-contaminated fish is contained in Chapter 4 of this RIA. The effects of this final rule on the health risks from Hg and other HAP are presented in the preamble and in the RIA for this rule.

7.11.1.2 Potential Environmental and Public Health Impacts to Vulnerable Populations

The EPA has conducted several analyses that provide additional insight on the potential effects of this rule on EJ communities. These include: (1) The socio-economic distribution of people living close to affected EGUs who may be exposed to pollution from these sources; and (2) an analysis of the distribution of health effects expected from the reductions in $PM_{2.5}$ that will result from implementation of this final rule (''co-benefits'').

Socio-economic distribution. As part of the analysis for this final rule, the EPA reviewed the aggregate demographic makeup of the communities near EGUs covered by this final rule. Although this analysis gives some indication of populations that may be exposed to levels of pollution that cause concern, it does NOT identify the demographic characteristics of the most highly affected individuals or communities. EGUs usually have very tall emission stacks; this tends to disperse the pollutants emitted from these stacks fairly far from the source. In addition, several of the pollutants emitted by these sources, such as a common form of mercury and SO2, are known to travel long distances and contribute to adverse impacts on the environment and human health hundreds or even thousands of miles from where they were emitted (in the case of elemental mercury, globally).

The proximity-to-the-source review is included in the analysis for this final rule because some EGUs emit enough hazardous air pollutants such as Nickel or Chromium (VI) to cause elevated lifetime cancer risks greater than 1 in a million in nearby communities. In addition, the EPA's analysis indicates that there are localized areas with elevated levels of Hg deposition around most U.S. EGUs.[4]

The analysis of demographic data used proximity-to-the-source as a surrogate for exposure to identify those populations considered to be living near affected sources, such that they have notable exposures to current hazardous air pollutant emissions from these sources. The demographic data for this analysis were extracted from the 2000 census data which were

[4] See Excess Local Deposition TSD for more detail.

provided to the EPA by the US Census Bureau. Distributions by race are based on demographic information at the census block level, and all other demographic groups are based on the extrapolation of census block group level data to the census block level. The socio-demographic parameters used in the analysis included the following categories: Racial (White, African American, Native American, Other or Multiracial, and All Other Races); Ethnicity (Hispanic); and Other (Number of people below the poverty line, Number of people with ages between 0 and 18, Number of people greater than or equal to 65, Number of people with no high school diploma).

In determining the aggregate demographic makeup of the communities near affected sources, the EPA focused on those census blocks within three miles of affected sources and determined the demographic composition (e.g., race, income, etc.) of these census blocks and compared them to the corresponding compositions nationally. The radius of three miles (or approximately 5 kilometers) is consistent with other demographic analyses focused on areas around potential sources. In addition, air quality modeling experience has shown that the area within three miles of an individual source of emissions can generally be considered the area with the highest ambient air levels of the primary pollutants being emitted for most sources, both in absolute terms and relative to the contribution of other sources (assuming there are other sources in the area, as is typical in urban areas). While facility processes and fugitive emissions may have more localized impacts, the EPA acknowledges that because of various stack heights there is the potential for dispersion beyond 3 miles. To the extent that any minority, low income, or indigenous subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also stands to see increased environmental and health benefit from the emissions reductions called for by this rule.

The results of EPA's demographic analysis for coal fired EGUs are shown in Table 7-5.

The data indicate that affected sources are located in areas where the minority share of the population living within a three mile buffer is higher than the national average by 12 percentage points or 48%. For these same areas, the percent of the population below the poverty line is also higher than the national average by 4 percentage points or 31%. These results are presented in more detail in the ''Review of Proximity Analysis,'' February 2011, a copy of which is available in the docket.

$PM_{2.5}$ (co-benefits) analysis. As mentioned above, many of the steps EGUs take to reduce their emissions of air toxics as required by this final rule will also reduce emissions of

PM and SO2. As a result, this final rule will reduce concentrations of $PM_{2.5}$ in the atmosphere. Exposure to $PM_{2.5}$ can cause or contribute to adverse health effects, such as asthma and heart disease, that significantly affect many minority, low-income, and tribal individuals and their communities. Fine PM ($PM_{2.5}$) is particularly (but not exclusively) harmful to children, the elderly, and people with existing heart and lung diseases, including asthma. Exposure can cause premature death and trigger heart attacks, asthma attacks in children and adults with asthma, chronic and acute bronchitis, and emergency room visits and hospitalizations, as well as milder illnesses that keep children home from school and adults home from work. Missing work due to illness or the illness of a child is a particular problem for people who have jobs that do not provide paid sick days. Low-wage employees also risk losing their jobs if they are absent too often, even if it is due to their own illness or the illness of a child or other relative. Finally, many individuals in these communities lack access to high quality health care to treat these types of illnesses. Due to all these factors, many minority and low-income communities are particularly susceptible to the health effects of $PM_{2.5}$ and receive a variety of benefits from reducing it.

We estimate that in 2016 the annual PM related benefits of the final rule for adults include approximately 4,200 to 11,000 fewer premature mortalities, 2,800 fewer cases of chronic bronchitis, 4,800 fewer non-fatal heart attacks, 2,600 fewer hospitalizations (for respiratory and cardiovascular disease combined), 3.2 million fewer days of restricted activity due to respiratory illness and approximately 540,000 fewer lost work days. We also estimate substantial health improvements for children in the form of 130,000 fewer asthma attacks, 3,100 fewer emergency room visits due to asthma, 6,300 fewer cases of acute bronchitis, and approximately 140,000 fewer cases of upper and lower respiratory illness.

We also examined the level of $PM_{2.5}$ mortality risks prior to the implementation of the rule according to race, income, and educational attainment. We then estimated the change in $PM_{2.5}$ mortality risk as a result of this final rule among people living in the counties with the highest (top 5 percent) $PM_{2.5}$ mortality risk in 2005. We then compared the change in risk among the people living in these ‘‘high-risk’’ counties with people living in all other counties.

In 2005, people living in the highest risk counties and in the poorest counties were estimated to be at substantially higher risk of $PM_{2.5}$- related death than people living in the other 95 percent of counties. This was true regardless of race; the difference between the groups of counties for each race was large while the differences among races in both groups of counties were very small. In contrast, the analysis found that people with less than high school education were predicted to have significantly greater risk from $PM_{2.5}$ mortality than people with a greater than high school education. This was true both for the highest-risk counties and

for the other counties. In summary, the analysis indicates that in 2005, educational status, living in one of the poorest counties, and living in a high-risk county are associated with higher estimated $PM_{2.5}$ mortality risk while race is not.

Our analysis predicts that this final rule will likely significantly reduce the risk of $PM_{2.5}$-related premature mortality among all populations of different races living throughout the U.S. compared to both 2005 and 2016 pre-rule (i.e., base case) levels. The analysis indicates that people living in counties with the highest rates (top 5 percent) of $PM_{2.5}$ mortality risk in 2005 receive the largest reduction in mortality risk after this rule takes effect. We also estimate that people living in the poorest 5 percent of the counties will experience a larger reduction in $PM_{2.5}$ mortality risk when compared to all other counties. More information can be found below in section 7.11.3.

The EPA estimates that the benefits of the final rule are likely distributed among races, income levels, and levels of education fairly evenly, although there is insufficient data to generate different concentration response functions for each demographic group. However, the analysis does indicate that this final rule in conjunction with the implementation of existing or final rules (e.g., the Cross-State Air Pollution Rule) may help reduce the disparity in risk between those in the highest-risk counties and the other 95 percent of counties for all races and educational levels.

Table 7-5. Comparative Summary of the Demographics within 5 Kilometers (3 Miles) of the Affected Sources (population in millions)[a]

	Population	White	African American	Native American	Other or Multiracial	Minority[b]	Hispanic or Latino[c]	Age 0–17	Age 65+	No High School Diploma	Below Poverty Line
Near source total (3 mi)	13.9	8.78	2.51	0.10	2.52	5.13	2.86	3.37	1.65	2.20	2.43
% of near source total		63%	18%	1%	18%	37%	21%	24%	12%	16%	17%
National total	285	215	35.0	2.49	33.3	70.8	39.1	77.4	35.4	36.7	37.1
% of national total		75%	12%	1%	12%	25%	14%	27%	12%	13%	13%

Sources: The demographics are from the U.S. Census Bureau, 2000. Information on the facilities is from U.S. EPA.

a Racial and ethnic categories overlap and cannot be summed.

b The "Minority" population is the overall population (in the first row) minus white population (in the second row).

c The Census Bureau defines "Hispanic or Latino" as an ethnicity rather than a racial category, Hispanics or Latinos may belong to any race.

7.11.1.3 Meaningful Public Participation

The EPA defines ''environmental justice'' to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. To promote meaningful involvement, the EPA publicized the rulemaking via newsletters, EJ listserves, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (http://yosemite.epa.gov/opei/RuleGate.nsf/). During the comment period, the EPA discussed the proposed rule via a conference call with communities, conducted a community-oriented webinar on the proposed rule, and posted the webinar presentation on- line. The EPA also held three public hearings to receive additional input on the proposal.

Once this rule is finalized, affected EGUs will need to update their Title V operating permits to reflect their new emission limits, any other new applicable requirements, and the associated monitoring and recordkeeping from this rule. The Title V permitting process provides that when most permits are reopened (for example, to incorporate new applicable requirements) or renewed, there must be opportunity for public review and comments. In addition, after the public review process, the EPA has an opportunity to review the proposed permit and object to its issuance if it does not meet CAA requirements.

7.11.1.4 Summary

This final rule strictly limits the emissions rate of Hg and other HAP from every affected EGU. The EPA's analysis indicates substantial health benefits, including for vulnerable populations, from reductions in $PM_{2.5}$.

The EPA's analysis also indicates reductions in risks for individuals, including for members of minority populations, who eat fish frequently from U.S. lakes and rivers and who live near affected sources. Based on all the available information, the EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low income, or indigenous populations. The EPA is providing multiple opportunities for EJ communities to both learn about and comment on this rule and welcomes their participation.

7.11.2 Analysis of High Risk Sub-Populations

In addition to the previously described assessment of EJ impacts, EPA is providing a qualitative assessment of sub-populations with particularly high potential risks of mercury exposure due to high rates of fish consumption. These populations overlap in many cases with

traditional EJ populations and would benefit from mercury reductions resulting from this rule. This section describes the available information on consumption rates for subpopulations with high fish consumption, and shows their locations in the U.S. Because of their high rates of fish consumption, reductions in mercury occurring in waterbodies where these populations catch fish will have a larger IQ benefit for these populations relative to the general fish consuming population.

Based on a detailed review of the literature, EPA identified several high-risk sub-populations (Moya, 2004; Burger, 2002, Shilling et al., 2010, Dellinger, 2004). The analysis of potentially high-risk groups focuses on six subpopulations:

- low-income African-American recreational/subsistence fishers in the Southeast region[5]
- low-income white recreational/subsistence fishers in the Southeast region
- low-income female recreational/subsistence fishers
- Hispanic subsistence fishers
- Laotian subsistence fishers
- Chippewa/Ojibwe Tribe members in the Great Lakes area

These specific subpopulations were selected based on published empirical evidence of particularly high self-caught freshwater fish consumption rates among these groups. Evidence for the first three groups is based on a study by Burger (2002), which collected survey data from a random sample of participants in the Palmetto Sportsmen's Classic in Columbia, SC. Of 458 respondents, 39 were black, 415 were white, and 149 were female. The sample size for the black population is relatively small, which increases uncertainty, particularly in higher percentile consumption rate values provided for this group. In this study, results are also split out for poor respondents (0–20K$ annual income). These consumption rates are relatively high, particularly for the higher percentiles. This observation forms the basis for our decision to assess a number of the subsistence populations only for watersheds located in US Census tracts containing members of source populations below the poverty line for the white and black populations.

[5]The low-income designation is based on Census 2000 estimates of populations living in poverty. The Southeast for purposes of this analysis comprises Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.

Evidence for the Hispanic and Laotian groups is based on a study by Shilling et al. (2010). This study looks at subsistence fishing activity among ethnic groups associated with more urbanized areas near the Sacramento and San Joaquin rivers in the Central Valley in CA. The authors note that many of these ethnic groups relied on fishing in origin countries and bring that practice here (e.g., Cambodian, Vietnamese and Mexican). The authors also note that fish consumption rates reported here for specific ethnic groups (specifically Southeast Asian) are generally in-line with rates seen in WA and OR studies. For the Chippewa population, we use results from a study by Dellinger (2004), which gathered data on self-reported fish consumption rates by Tribes in the Great Lakes area. Because fishing activity is highly variable across Tribes (and closely associated with heritage cultural practices) we have not extrapolated fishing behavior outside of the areas ceded to the Tribes covered in the study (regions in the vicinity of the Great Lakes). The terms "subsistence" and "recreational" fishing are based on the terminology used in these published studies to describe the population of interest. In general, subsistence fishers are individuals whose primary objective in fishing is to acquire food for household consumption. For recreational fishers, the primary objective is to enjoy the outdoor activity; however, fish consumption is also often an objective.

Table 7-6. Reported Distributions of Self-Caught Freshwater Fish Consumption Rates Among Selected Potentially High-Risk Subpopulations

	Self-Caught Freshwater Fish Consumption Rate (g/day)			
Population	**Sample Size**	**Mean (Median)**	**90th (95th) Percentile**	**Study**
Low-income African-American recreational/subsistence fishers in Southeast	39	171 (137)	446 (557)	Burger (2002)
Low-income white recreational/ subsistence fishers in Southeast	415	38.8 (15.3)	93 (129)	Burger (2002)
Low-income female recreational/ subsistence fishers	149	39.1 (11.6)	123 (173)	Burger (2002)
Hispanic subsistence fishers	45	25.8 (19.1)	98[a] (155.9)	Shilling et al. (2010)
Laotian subsistence fishers	54	47.2 (17)	144.8[a] (265.8)	Shilling et al. (2010)
Great Lakes tribal groups	822	60 (113[b])	136.2[a] (213.1)[a]	Dellinger (2004)

[a] Derived values using a log-normal distribution, based on the median and the 95th percentile or standard deviation reported in study.

[b] Standard deviation in parentheses, rather than median.

Using county-level growth projections, there were an estimated 3.09 million low-income African Americans in census tracts that have (1) at least one HUC-12 within 20 miles with a mercury fish tissue concentration estimate and (2) at least 25 African-American inhabitants living below the poverty level, and 3.56 million are projected to reside in these areas in 2016. The geographic distribution of the expected 2016 population is shown in Figure 7-1. The total low-income (below the poverty level) White population in the southeastern states was 3.26 million for 2005 and is projected to be 3.58 million in 2016. The geographic distribution of this population for 2016 is shown in Figure 7-2. The total modeled low-income female population was 18.4 million for 2005 and is projected to be 20.1 million for 2016. The geographic distribution of the population modeled for 2016 is shown in Figure 7-3. The total modeled Hispanic population was 19.6 million for 2005 and is projected to be 27.2 million in 2016. The geographic distribution of the population modeled for 2016 is shown in Figure 7-4. The total modeled Laotian population was 80,000 for 2005 and projected to be 137,500 in 2016. The geographic distribution of the population modeled for 2016 is shown in Figure 7-5. The total modeled Chippewa population used to simulate the distribution of IQ loss was 23,900 for 2005 and is projected to be 29,500 for 2016. The geographic distribution of the population modeled for 2016 is shown in Figure 7-6.

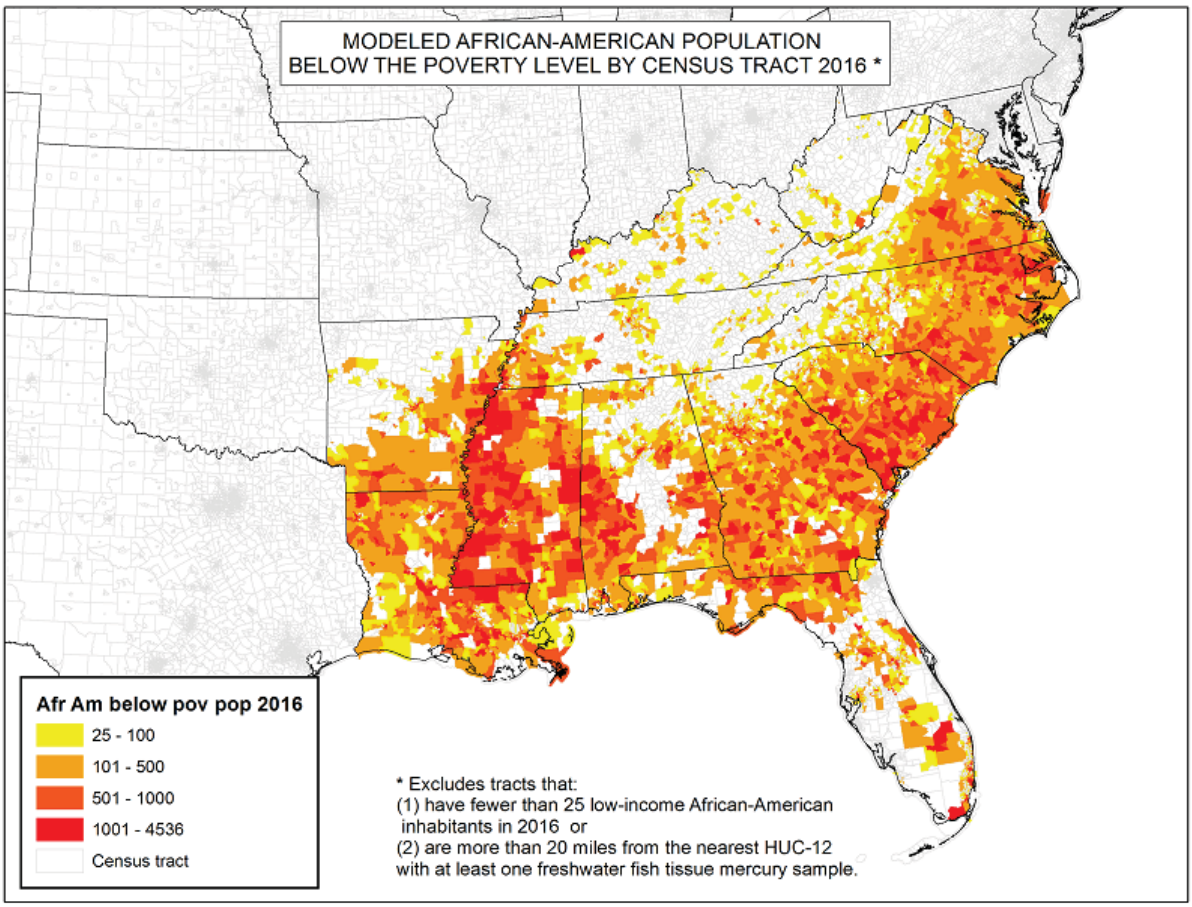


Figure 7-1. Projected African-American Population Below the Poverty Level by Census Tract in the Southeast for 2016

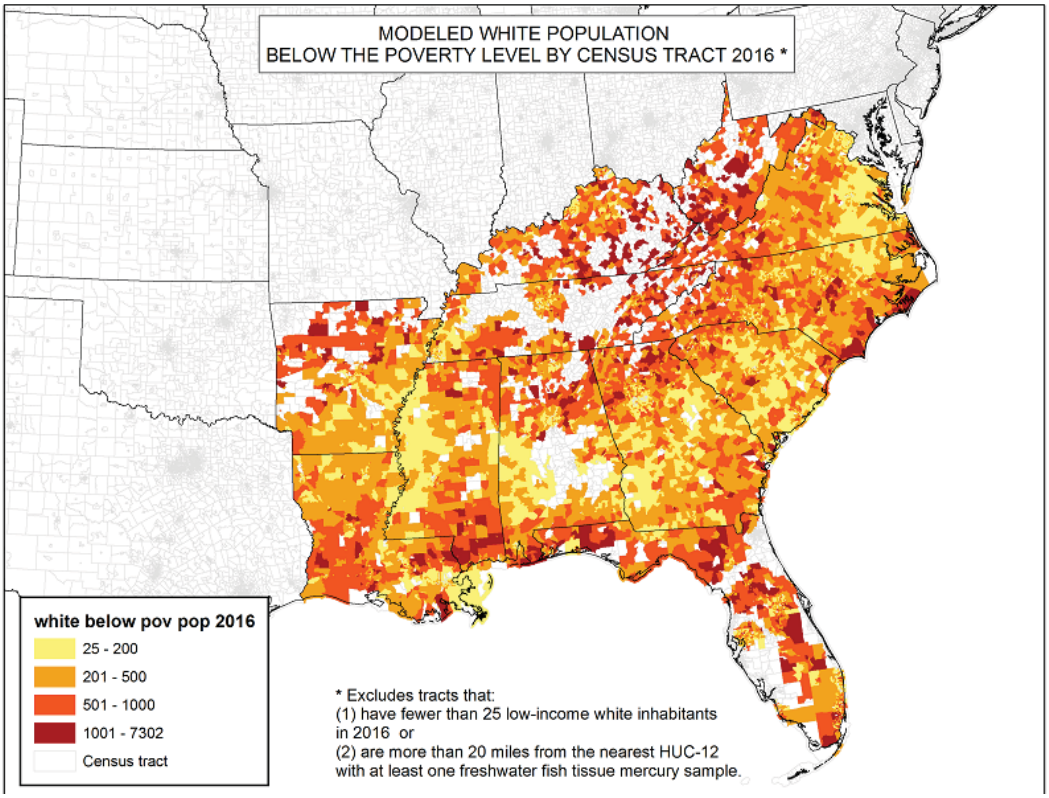


Figure 7-2. Projected White Population Below the Poverty Level by Census Tract in the Southeast for 2016

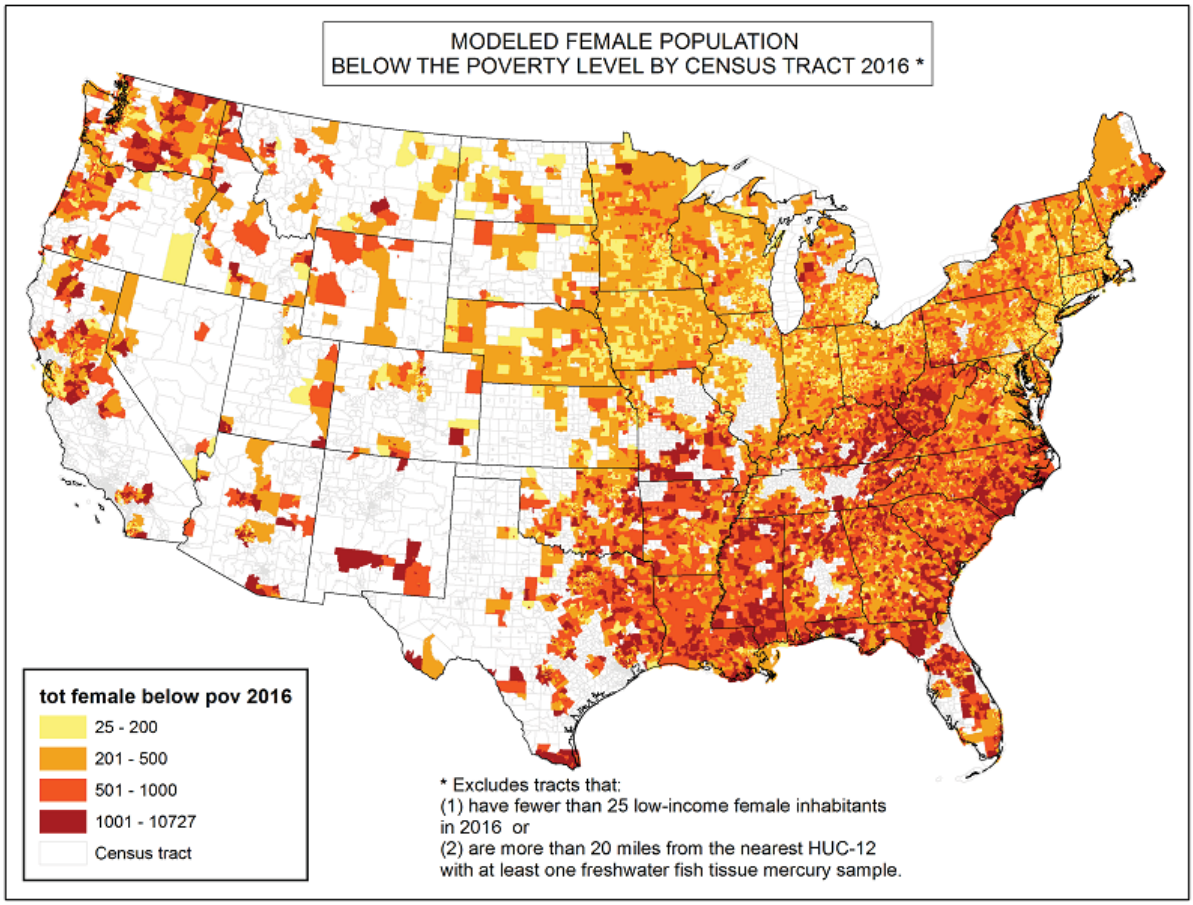


Figure 7-3. Projected Female Population Below the Poverty Level by Census Tract for 2016

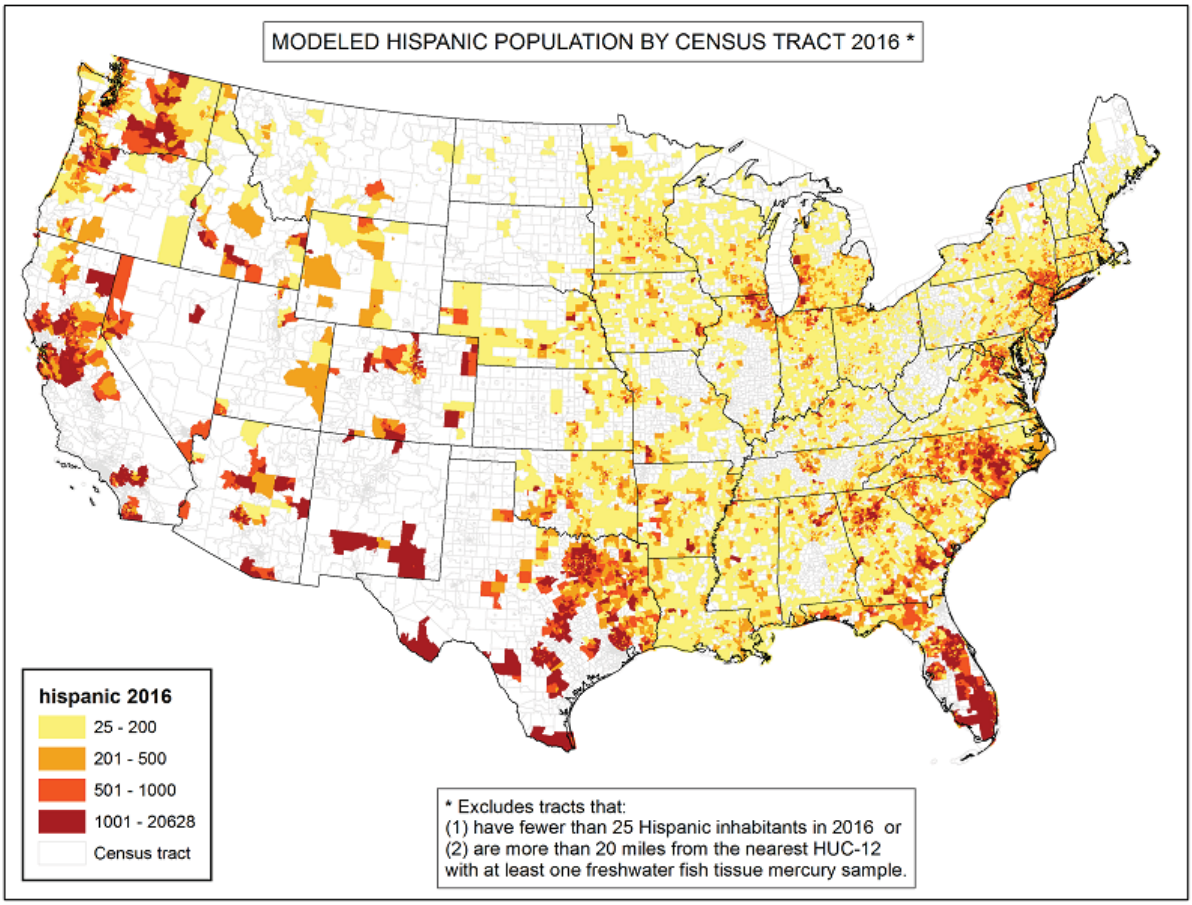
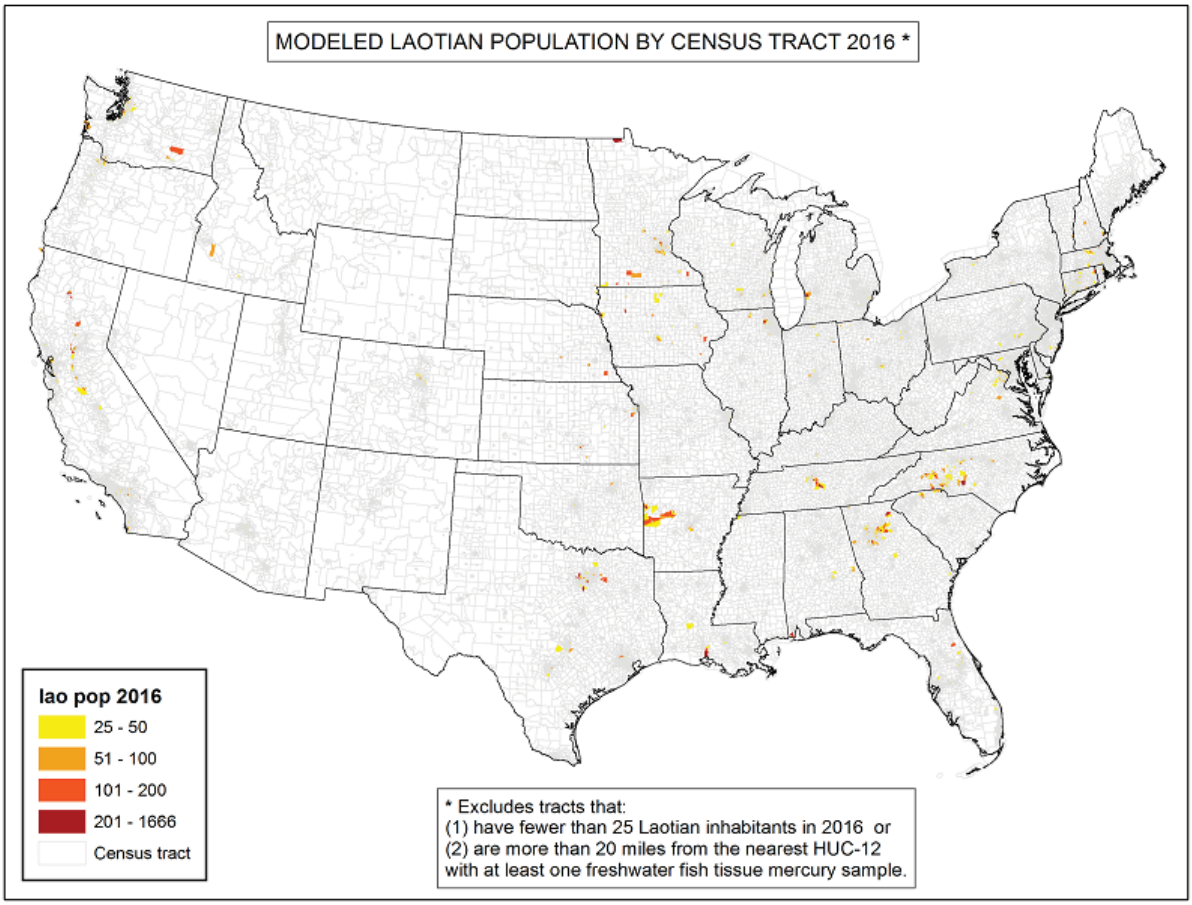


Figure 7-4. Modeled Hispanic Population by Census Tract for 2016


MODELED LAOTIAN POPULATION BY CENSUS TRACT 2016 *
lao pop 2016
25 - 50
51 - 100
101 - 200
201 - 1666
Census tract
* Excludes tracts that:
(1) have fewer than 25 Laotian inhabitants in 2016 or
(2) are more than 20 miles from the nearest HUC-12
with at least one freshwater fish tissue mercury sample.

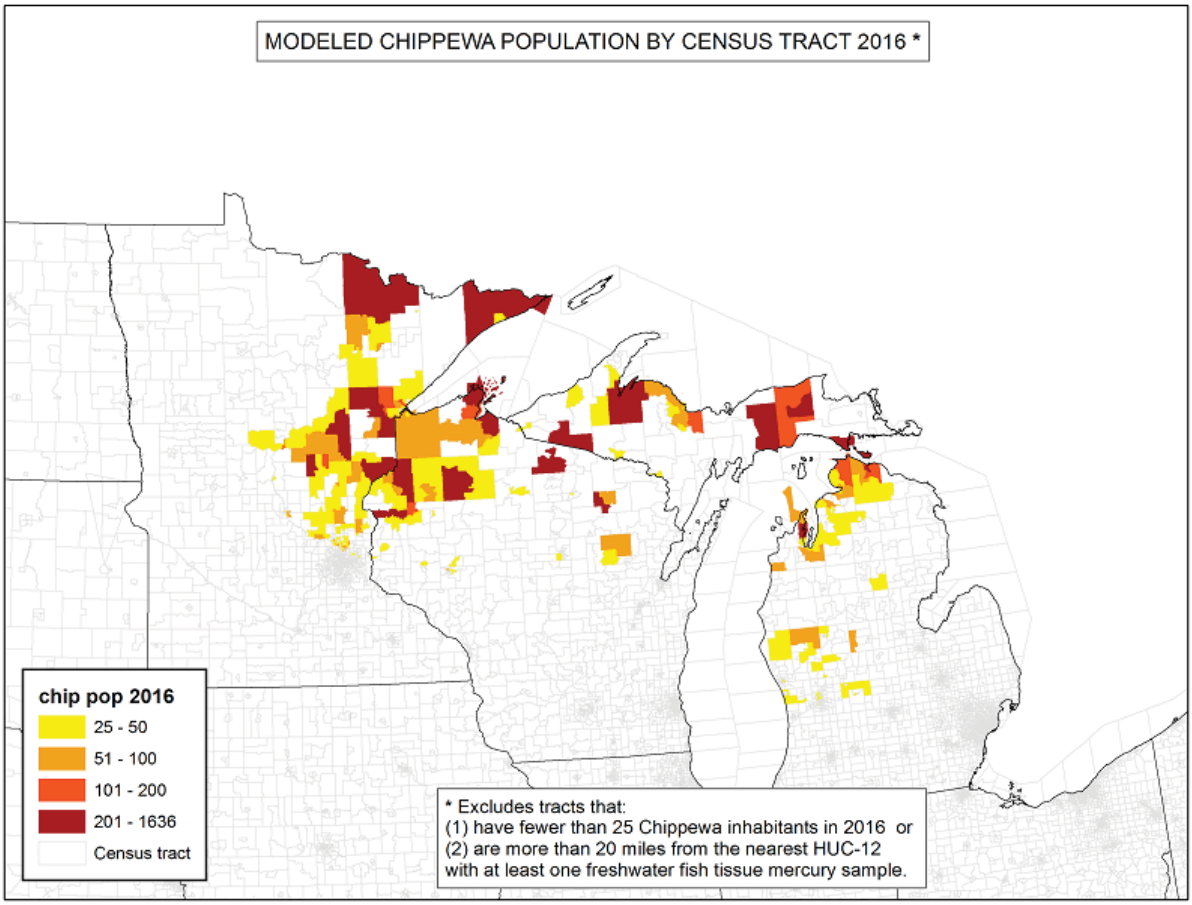


Figure 7-6. Modeled Chippewa Population by Census Tract in the Great Lakes Area for 2016.

7.11.3 Characterizing the Distribution of Health Impacts across Populations

EPA is developing new approaches and metrics to improve its characterization of the impacts of EPA rules on different populations. This analysis reflects one such approach, which explores two principal questions regarding the distribution of $PM_{2.5}$-related benefits resulting from the implementation of MATS:

1. What is the baseline distribution of $PM_{2.5}$-related mortality risk for adults according to the race, income and education of the population?

2. How does MATS change the distribution of $PM_{2.5}$ mortality risk among populations of different races—particularly among those populations at greatest risk in the baseline?[6]

In this analysis we estimated that $PM_{2.5}$ mortality risk from the modeled scenarios is not distributed equally throughout the U.S., or among populations of different levels of educational attainment—though the level of $PM_{2.5}$ mortality risk appears to be shared fairly equally among populations of different races. We estimate that the air quality and $PM_{2.5}$-related mortality risk improvements achieved by MATS are relatively equally distributed among minority populations, and that the rule reduces $PM_{2.5}$ mortality risk the most among those populations at greatest risk in the 2005 baseline we selected for this analysis. We note that while the methods used for this analysis have been employed in recent EPA Regulatory Impact Assessments (EPA, 2011) and are drawn from techniques described in the peer reviewed literature (Fann et al. 2011b) EPA will continue to modify these approaches based on evaluation of the methods.

7.11.3.1 Methodology

The methods used here to describe the distribution of $PM_{2.5}$ mortality impacts are consistent with the approach used in the proposed MATS RIA (U.S. EPA, 2011a) and the final CSAPR RIA (U.S. EPA, 2011b). As a first step, we estimate the level of $PM_{2.5}$-related mortality risk in each county in the continental U.S. based on 2005 air quality levels, which provides a baseline distribution of risk which we use to identify populations with initial higher and lower baseline $PM_{2.5}$-related mortality risk. This portion of the analysis follows an approach described elsewhere (Fann et al. 2011a, Fann et al. 2011b), wherein modeled 2005 $PM_{2.5}$ levels are used to calculate the proportion of all-cause mortality risk attributable to total $PM_{2.5}$ levels in each county in the Continental U.S. Within each county we estimate the level of all-cause $PM_{2.5}$ mortality risks for adult populations as well as the level of $PM_{2.5}$ mortality risk according to the race, income and educational attainment of the population.

Our approach to calculating the distribution of $PM_{2.5}$ mortality risk across the population is generally consistent with the benefits analysis conducted for the modeled scenario described in Appendix 5C with two exceptions: the $PM_{2.5}$ mortality risk coefficients used to quantify impacts and the baseline mortality rates used to calculate mortality impacts (a detailed discussion of how both the mortality risk coefficients and baseline incidence rates are used to estimate the incidence of $PM_{2.5}$-related deaths may be found in the Chapter 5 of the RIA). We

[6] In this analysis we assess the change in risk among populations of different race, income and educational attainment. As we discuss further in the methodology, we consider this last variable because of the availability of education-modified $PM_{2.5}$ mortality risk estimates.

substitute risk estimates drawn from the Krewski et al. (2009) extended analysis of the ACS cohort. In particular, we applied the all-cause mortality risk estimate random effects Cox model that controls for 44 individual and 7 ecological covariates, using average exposure levels for 1999-2000 over 116 U.S. cities (Krewski et al. 2009) (RR=1.06, 95% confidence intervals 1.04—1.08 per 10μg/m^3 increase in $PM_{2.5}$). This mean relative risk estimate is identical to the Pope et al. (2002) risk estimate applied for the benefits analysis (though the standard error around the mean RR estimate is slightly narrower).

Within both this and other analyses of the ACS cohort (see Krewski et al. 2000), educational attainment has been found to be inversely related to the risk of all-cause mortality. That is, populations with lower levels of education (in particular, < grade 12) are more vulnerable to $PM_{2.5}$-related mortality. Krewski and colleagues note that "…the level of education attainment may likely indicate the effects of complex and multifactorial socioeconomic processes on mortality…," factors that we would like to account for in this EJ assessment. When estimating PM mortality impacts among populations according to level of education, we applied $PM_{2.5}$ mortality risk coefficients modified by educational attainment: less than grade 12 (RR = 1.082, 95% confidence intervals 1.024—1.144 per 10 μg/m^3 change), grade 12 (RR = 1.072, 95% confidence intervals 1.020—1.127 per 10 μg/m^3 change), and greater than grade 12 (RR = 1.055, 95% confidence intervals 1.018—1.094 per 10 μg/m^3 change). The Pope et al. (2002) study does not provide education-stratified RR estimates. The principal reason we applied risk estimates from the Krewski et al. (2009) study was to ensure that the risk coefficients used to estimate all-cause mortality risk and education-modified mortality risk were drawn from a consistent modeling framework.

The other key difference between this distributional analysis and the benefits analysis for this rule relates to the baseline mortality rates. As described in Chapter 5 of this RIA, we calculate $PM_{2.5}$-related mortality risk relative to baseline mortality rates in each county. Traditionally, for benefits analysis, we have applied county-level age- and sex-stratified baseline mortality rates when calculating mortality impacts (Abt, 2010). To calculate $PM_{2.5}$ impacts by race, we incorporated race-specific (stratified by White/Black/Asian/Native American) baseline mortality rates. This approach improves our ability to characterize the relationship between race and $PM_{2.5}$-related mortality however, we do not have a differential concentration-response function as we do for education, and as a result, we are not able to capture the full impacts of race in modifying the benefits associated with reductions in PM2.5

The result of this analysis is a distribution of $PM_{2.5}$ mortality risk estimates by county, stratified by each of the three population variables (race, income and educational attainment).

We have less confidence in county-level estimates of mortality than the national or even state estimates, however, the modeling down to the county level can be considered reasonable because the estimates are based on 12km air quality modeling estimates of $PM_{2.5}$, county level baseline mortality rates, and a concentration-response function that is derived from county level data. We next identified the counties at or above the median and upper 95th percentile of the $PM_{2.5}$ mortality risk distribution. We selected this percentile cut-off to capture the very highest levels of $PM_{2.5}$ mortality risk. The second step of the analysis was to repeat the sequence above by estimating $PM_{2.5}$ mortality risk in 2016 prior to, and after, the implementation of MATS.

7.11.3.2 Results

We estimated the change in $PM_{2.5}$ mortality risk in 2016 among populations living in those counties at the upper 95th percentile of the mortality risk in 2005. We then compared the change in risk among these populations living in high-risk counties with populations living in all other counties (Tables 7-17 through 7-9).

Table 7-17. Estimated Change in the Percentage of All Deaths Attributable to $PM_{2.5}$ Before and After Implementation of MATS by 2016 for Each Populations, Stratified by Race

	Race			
Year	**Asian**	**Black**	**Native American**	**White**
Among populations at greater risk				
2016 (pre-MATS Rule)	4.3%	4.4%	4.4%	4.5%
2016 (post-MATS Rule)	4.1%	4.1%	4.2%	4.3%
Among all other populations				
2016 (pre-MATS Rule)	3.2%	3.1%	3.1%	3.3%
2016 (post-MATS Rule)	3%	2.9%	2.9%	3.1%

Table 7-8. Estimated Change in the Percentage of All Deaths Attributable to $PM_{2.5}$ Before and After Implementation of MATS by 2016 for Each Population, Stratified by Race and Poverty Level

	Race			
Year	**Asian**	**Black**	**Native American**	**White**
Among populations living in counties with the largest number of individuals living below the poverty line				
2016 (pre-MATS)	3.6%	3.5%	3.6%	3.6%
2016 (post-MATS)	3%	3.4%	3%	3.5%
Among all other populations				
2016 (pre-MATS)	3.2%	3.2%	3.2%	3.3%
2016 (post-MATS)	3%	2.9%	3%	3.1%

Table 7-9. Estimated Change in the Percentage of All Deaths Attributable to $PM_{2.5}$ Before and After the Implementation of MATS by 2016 for Each Population, Stratified by Educational Attainment

	Race		
Year	**< Grade 12**	**= Grade 12**	**> Grade 12**
Among populations at greater risk			
2016 (pre-MATS)	6.2%	5.5%	4.3%
2016 (post-MATS)	5.9%	5.3%	4.1%
Among all other populations			
2016 (pre-MATS)	4.5%	4%	3.1%
2016 (post-MATS)	4.2%	3.8%	2.9%

Table 7-7, shows the estimated level of $PM_{2.5}$ mortality risk among populations of different races according to whether those populations live in counties identified as "greater risk" counties or "all other counties." As described above, we define "greater risk" counties as those at or above the 95th percentile of the estimated $PM_{2.5}$ mortality risk in 2005, and "all other counties" as those with estimated $PM_{2.5}$ mortality risk below this level. The results of this

analysis suggest that the $PM_{2.5}$ mortality risk among these populations at "greater risk" falls with implementation of the 2016 MATS. These results also suggest that all populations, irrespective of race, may receive an estimated reduction in $PM_{2.5}$ mortality risk. However, limits to data resolution prevent us from delineating the $PM_{2.5}$ mortality risk according to population race with confidence.

Table 7-8 illustrates the estimated change in the level of $PM_{2.5}$ mortality risk among populations living in those counties that meet two criteria: (1) the county is at the upper 95th percentile of mortality risk in 2005; (2) the county is at the upper 95th percentile in terms of the number of individuals living below the poverty line. We also estimate the change in $PM_{2.5}$ risk among all other counties. The analysis suggests that people living in the highest mortality risk and poorest counties may experience a larger improvement in $PM_{2.5}$ mortality risk than those living in lower risk counties containing a smaller number of individuals living below the poverty line.

Table 7-9 summarizes the estimated change in $PM_{2.5}$ mortality risk among populations who have attained three alternate levels of education—less than high school, high school and greater than high school. As described above, we apply education-stratified $PM_{2.5}$ mortality risk coefficients for this analysis. These results indicate that populations with less than a high school education are at higher risk of $PM_{2.5}$ mortality, irrespective of whether these populations live in "greater risk" counties, according to the definition described above. We estimate that with the implementation of MATS, all populations see their $PM_{2.5}$ mortality risk fall, regardless of educational attainment.

7.12 Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the Federal Register. A major rule cannot take effect until 60 days after it is published in the Federal Register. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective 60 days after publication.

7.13 References

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