ORAL ARGUMENT HELD DECEMBER 10, 2013
DECIDED APRIL 15, 2014

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

White Stallion Energy Center, LLC, et al.,	)	
Petitioners,	)	
v.	)	No. 12-1100
	)	(and consolidated cases)
United States Environmental Protection Agency,	)	
Respondent.	)	

RESPONDENT'S MOTION TO GOVERN FUTURE PROCEEDINGS

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Respondent Environmental Protection Agency ("EPA") hereby requests that this Court remand the Mercury and Air Toxics Standards ("the Rule") to EPA for further proceedings consistent with the Supreme Court's decision in *Michigan v. EPA*, 135 S. Ct. 2699 (June 29, 2015), without vacating the Rule. The *Michigan* decision reversed a portion of this Court's decision in *White Stallion Energy Center, LLC v. EPA*, 748 F.3d 1222 (D.C. Cir. 2014), and remanded to this Court for further proceedings. Specifically, the *Michigan* decision held that EPA misinterpreted Clean Air Act ("CAA") section 112(n)(1)(A), 42 U.S.C. § 7412(n)(1)(A), in declining to consider costs when deciding whether to regulate emissions of hazardous air pollutants from power plants. As discussed below, remand without vacatur will allow EPA to address the Supreme Court's limited holding on an expedited basis, preserve the important public health and environmental benefits achieved by the Rule, and avoid regulatory uncertainty and significant complications for other important EPA programs, without significant disruptive consequences for regulated sources.

BACKGROUND

I. THE CAA AND HAZARDOUS AIR POLLUTION REGULATION

Enacted in 1970, one of the CAA's purposes is to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare." 42 U.S.C. § 7401(b)(1). Frustrated by EPA's slow progress under the original CAA section 112, 42 U.S.C § 7412, Congress substantially amended that section in 1990 to ensure that EPA would regulate hazardous air pollutant emissions quickly. *See White*

Stallion, 748 F.3d at 1230. These amendments included a mandate that EPA identify and list categories of "major sources" and certain "area sources" of over 180 pollutants, *White Stallion*, 748 F.3d at 1230, and that EPA promulgate emission standards under section 112(d), 42 U.S.C. § 7412(d), for new and existing listed source categories, including the requirement that EPA calculate "floor" standards—the average emission limitation achieved by the best performing sources—and determine the need for more stringent "beyond-the-floor" standards. *See* 42 U.S.C. § 7412(d)(3)(A)-(B); *see also White Stallion*, 748 F.3d at 1230; McCabe Decl. ¶¶ 4-5.

Section 7412 treats electric utility steam generating units ("power plants") differently than other sources of hazardous air pollutants. *See Michigan*, 135 S. Ct. at 2707; *White Stallion*, 748 F.3d 1230-31; McCabe Decl. ¶¶ 6-7. In section 7412(n)(1)(A), Congress directed EPA to conduct a study to evaluate the hazards to public health, if any, resulting from emissions of hazardous air pollutants from power plants that would reasonably be anticipated to occur following implementation of the requirements of the Act, and to report the results of such study to Congress by November 15, 1993. 42 U.S.C. § 7412(n)(1)(A). Congress further required EPA to regulate power plants under section 7412 if EPA determined that such regulation is "appropriate and necessary," after considering the study. *Id.*

II. THE FINDING AND EMISSION STANDARDS AT ISSUE

Since the 1990 CAA amendments, EPA has studied extensively the hazards to public health resulting from hazardous air pollutant emissions from power plants and

concluded, pursuant to 42 U.S.C. § 7412(n)(1)(A), that regulation of coal- and oil-fired power plants is "appropriate and necessary."[1] *See* 65 Fed. Reg. 79,825, 79,826 (Dec. 20, 2000) (the "2000 finding"); 77 Fed. Reg. 9304, 9310-11 (Feb. 16, 2012) (Final Rule reaffirming the 2000 finding based on additional analyses); *see also* 76 Fed. Reg. 24,976, 25,015-18 (May 2, 2011) (Proposed Rule); McCabe Decl. ¶¶ 8-9. Among other things, EPA found that power plants are by far the largest anthropogenic source of mercury emissions in the United States, responsible for over 50 percent of emissions. 76 Fed. Reg. 24,976, 25,002, Table 3 (May 3, 2011). Power plants are also the largest source of acid gas hazardous air pollutants, emitting 82 percent of domestic hydrogen chloride emissions and 62 percent of hydrogen fluoride emissions. *Id.* at 25,005, Table 4. Additionally, power plants are a significant source of many hazardous metals, including selenium (83% of domestic emissions), arsenic (62%), nickel (28%), and chromium (22%). *Id.* at 25,006, Table 5.

EPA also found that exposure to hazardous air pollutants from power plants is associated with many serious adverse health effects. For example, mercury, the pollutant of greatest concern,[2] is emitted from power plants, deposits into

[1] A detailed discussion of the Rule's regulatory history can be found in EPA's merits brief. *See* Doc. # 141663 at 11-15; *see also White Stallion*, 748 F.3d at 1231-1233.

[2] *See* 76 Fed. Reg. at 24,994; *see also* 42 U.S.C. § 7412(n)(1)(B), (C) (reflecting Congress's particular concern with mercury emissions from power plants).

waterbodies, and then bioaccumulates[3] in fish in the highly toxic form of methylmercury. *See id.* at 25,000. When people consume these fish, they consume methylmercury, which may cause adverse neurotoxic effects (*i.e.*, damage to the brain and nervous system). Methylmercury exposure is a particular concern for children and fetuses because their developing bodies are more highly sensitive to its effects. 76 Fed. Reg. at 24,977-78; *see also* McCabe Decl. ¶¶ 8, 12.

Additionally, some non-mercury hazardous air pollutants emitted by power plants are associated with chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes, nervous system effects, and kidney damage) and acute health disorders (e.g., lung irritation and congestion, nausea and vomiting, and liver, kidney and nervous system effects). *See* 76 Fed. Reg. at 24,978; McCabe Decl. ¶ 13. Acid gases emitted by power plants also add to environmental degradation due to acidification. *See* 76 Fed. Reg. at 25,016; 77 Fed. Reg. at 9362; McCabe Decl. ¶ 14.

In sum, EPA found that hazardous air pollutant emissions from power plants cause substantial harms to public health and the environment, that these harms would not be addressed by implementation of other CAA requirements, and that effective controls are available to reduce emissions. *See* McCabe Decl. ¶¶ 8-9. Based on this, EPA concluded in 2000 that the regulation of hazardous air pollutant emissions from

[3] Bioaccumulation occurs when an organism absorbs a toxic substance at a rate greater than it is lost.

power plants was "appropriate and necessary" and listed coal- and oil-fired power plants as a source category to be regulated. *See id.* ¶ 8. EPA then reaffirmed this finding in February 2012 upon promulgating final emission standards in the Rule at issue. *See id.* ¶ 9.[4] EPA concluded that section 7412(n)(1)(A) did not call for EPA to consider costs in making an "appropriate and necessary" finding under that section. *See* 77 Fed. Reg. at 9324-27. Specifically, EPA stated that "it is reasonable to make the listing decision, including the appropriate determination, without considering costs." 77 Fed. Reg. at 9327.

In the final Rule, EPA promulgated technology-based emission standards under section 7412(d) for hazardous air pollutants emitted by power plants. *See* 77 Fed. Reg. at 9367-69; McCabe Decl. ¶ 10. With almost no exceptions, EPA declined to exercise its discretion to make these standards more stringent than the "floor"—*i.e.*, the least stringent level allowed by Congress. *See* 77 Fed. Reg. at 9367, Table 3, 9369. Sources were required to comply with the Rule by April 16, 2015, but as discussed further below, some obtained extensions to April 2016, and units that are necessary for reliability and meet certain criteria may seek further flexibility from EPA's Office of Enforcement and Compliance Assurance. *See* Doc. # 736958 at 12-13 (EPA Opp. to Second Tri-State Motion); McCabe Decl. ¶¶ 20, 25.

[4] Once EPA listed power plants as a source category to be regulated in 2000, EPA had a nondiscretionary duty to promulgate emission standards for this source category within two years. 42 U.S.C. § 7412(c)(5). Thus, the emission standards ultimately promulgated in February 2012 were almost ten years overdue.

Notwithstanding EPA's conclusion that costs need not be considered as part of the "appropriate and necessary" determination, EPA otherwise considered costs throughout the process that led to promulgation of final emission standards. EPA estimated the costs and quantifiable benefits of the final standards in a Regulatory Impact Analysis ("RIA"). *See* McCabe Decl. ¶ 15-17, Att. A. EPA projected in the RIA that in 2016, the total monetized benefits of the promulgated standards would be $33 to $90 billion, the total costs (the sum of compliance costs and monitoring, recordkeeping, and reporting costs) would be $9.6 billion, and the quantifiable net benefits would be $24 to $80 billion. *See id.* ¶ 15; *see also* 77 Fed. Reg. at 9306. In the RIA, EPA concluded that implementation of the Rule "is expected, based purely on economic efficiency criteria, to provide society with a significant net gain in social welfare, even given the limited set of health and environmental effects [the agency was] able to quantify." McCabe Decl. ¶ 15, Att. A. at 101. EPA therefore concluded in the Rule that "it remains clear that the benefits of [the Rule], . . . are substantial and far outweigh the costs." 77 Fed. Reg. at 9306. In addition, as discussed *infra*, EPA considered costs in several ways when setting the emission standards.

On consolidated petitions for review before this Court, a number of petitioners challenged, among other things, EPA's interpretation of section 7412(n)(1)(A), arguing that the statute required EPA to consider costs when determining whether regulating power plants is "appropriate and necessary." *See White Stallion*, 748 F.3d at 1236. This Court concluded that section 7412(n)(1)(A)'s terms were ambiguous and

that "EPA reasonably concluded it need not consider costs" for the determination. *Id.* at 1237, 1241.

In *Michigan v. EPA*, however, the Supreme Court disagreed. The Supreme Court explained that "[r]ead naturally in the present context, the phrase 'appropriate and necessary' requires at least some attention to cost," *id.* at 2707, and held that "EPA interpreted § 7412(n)(1)(A) unreasonably when it deemed cost irrelevant to the decision to regulate power plants." *Id.* at 2712. Expressly not constraining EPA's discretion regarding how to consider costs, the Supreme Court remanded the consolidated cases to this Court for further proceedings. *See id.* at 2712. Meanwhile, the Rule remains in effect and, for the reasons explained below, should continue in effect during remand.

STANDARD OF REVIEW

In determining whether to remand a deficient rule without vacatur, the Court considers two factors: (1) "the seriousness of the . . . deficiencies (and thus the extent of doubt whether the agency chose correctly)," and (2) "the disruptive consequences of an interim change that may itself be changed." *Allied Signal, Inc. v. U.S. Nuclear Regulatory Comm'n*, 988 F.2d 146, 150-51 (D.C. Cir. 1993) (declining to vacate a rule because "there [was] at least a serious possibility that the [agency would] be able to substantiate its decision on remand" and "the consequences of vacating [could] be quite disruptive"). Under the first factor, this Court evaluates the likelihood that the agency will be able to cure the rule's deficiency on remand. *NRDC v. EPA*, 571 F.3d

1245, 1276 (D.C. Cir. 2009) (vacating part of CAA rule because "there was little or no [such] prospect," but remanding without vacatur two other parts of the rule); *see also Nat'l Ass'n of Clean Water Agencies v. EPA*, 734 F.3d 1115, 1161 (D.C. Cir. 2013) (remanding without vacatur CAA rule so that EPA could further "elaborate," "clarify," and "explain"); *Sierra Club v. EPA*, 167 F.3d 658, 664 (D.C. Cir. 1999) (remanding where the agency "may be able to explain" its decision).

Under the second factor, this Court's "traditional position" is to remand without vacatur "where vacatur would have serious adverse implications for public health and the environment." *North Carolina v. EPA*, 550 F.3d 1176, 1178 (D.C. Cir. 2008) (Rogers, J., concurring in part) (granting remand without vacatur on rehearing to "at least temporarily preserve the environmental values of [the rule]" notwithstanding the "fundamental flaws" identified by the court.). *See also EME Homer City Generation, L.P. v. EPA,* 795 F.3d 118, 132 (D.C. Cir. 2015) (remanding EPA's Transport Rule without vacatur in light of the "substantial disruption" vacatur would have for emissions trading markets); *Mississippi v. EPA*, 744 F.3d 1334, 1362 (D.C. Cir. 2013) (remanding so as not to "sacrifice" the environmental protection afforded by the CAA rule), *cert. denied*, 135 S. Ct. 53 (2014); *Sierra Club*, 167 F.3d at 664 (choosing to remand a CAA rule "rather than eliminate any federal control at all"). Here, as explained below, both *Allied Signal* factors weigh in favor of remand without vacatur. Thus, EPA's motion for remand without vacatur should be granted.

ARGUMENT

I. BASED ON COST DATA ALREADY IN THE RECORD, EPA CAN ACT QUICKLY TO CURE THE LIMITED DEFICIENCY IDENTIFIED BY THE SUPREME COURT.

As an initial matter, the Supreme Court's holding in *Michigan* is extremely limited in nature. The sole issue on which the Supreme Court granted certiorari was EPA's interpretation that section 7412(n)(1)(A) did not require a consideration of costs for the "appropriate and necessary" finding; the Supreme Court did not otherwise disturb this Court's decision rejecting a host of technical and legal challenges to the Rule. *Compare Michigan*, 135 S. Ct. 2699-2712 *with White Stallion*, 748 F.3d 1234-1258. Nor did the Supreme Court look beyond EPA's interpretation of section 7412(n)(1)(A) to the facts in the record reflecting the Agency's extensive consideration of costs in other parts of the rulemaking. *See Michigan*, 135 S. Ct. at 2711. In fact, the Supreme Court rejected a request to do so and stated that the Court "may uphold agency action only upon the grounds on which the agency acted." *Id.* (acknowledging the request by respondents in support of EPA and Justice Kagan's dissent, both of which relied on the RIA to argue that the benefits of the Rule plainly outweigh the costs). Because the Agency explicitly did not rely on the evaluations of cost that were conducted throughout the rulemaking process, the Supreme Court concluded that it could not uphold the Agency's "appropriate and necessary" finding based on those facts. *See id.* Thus, EPA's *only task* on remand should be to consider cost as part of the "appropriate and necessary" finding in light of the *Michigan*

decision. If EPA reaffirms that finding on remand, there is no reason for EPA to revisit any other portions of the Rule that were already upheld by this Court. As discussed below, EPA believes, based on the cost data that is already in the record, that there is a "serious possibility" that EPA will reaffirm the finding.

Notably, the Supreme Court explicitly declined to limit EPA's discretion as to how to consider costs on remand, explaining that "[i]t will be up to the Agency to decide . . . how to account for cost." *Michigan*, 135 S. Ct. at 2711. Although the Agency has not yet determined the most appropriate means for doing so,[5] the existing record for the Rule contains extensive documentation regarding the costs of compliance with the Rule. In developing the Rule, EPA assembled a vast amount of cost information and employed economic modeling to assess the Rule's cost impacts on industry. The substance of these cost assessments was not questioned by the Supreme Court.

Specifically, the Agency performed a complete cost assessment—including acquisition, installation, and operation—of the various pollution control technologies responsive to the Rule. *See* McCabe Decl., Att. B, Documentation for EPA Base Case v.4.10, Chapter 5 "Emission Control Technologies," Docket No. EPA-HQ-OAR-2009-0234-3049; Att. C, Documentation Supplement, at 8, Docket No. EPA-HQ-

[5] There are several reasonable methodological approaches available to an agency for taking costs into consideration in implementing a particular regulatory provision. *See, e.g., Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 217-218 (2009) (identifying at least three "plausible" approaches).

OAR-2009-0234-19996. EPA then modeled the compliance costs for the power industry, capturing in its analysis the amortized cost of capital investment and ongoing costs of operating additional pollution controls, needed new capacity, and shifts between or among various fuels. *See* McCabe Decl., Att. A at 16-51; 77 Fed. Reg. at 9425. The Agency also determined the Rule's economic impact on employment, fuel prices, and retail electricity prices. *See* McCabe Decl., Att. A at 37-40; 77 Fed. Reg. at 9425-26.

EPA also considered cost in many ways in setting the emission standards. For example, EPA took cost into account in making decisions regarding emissions averaging and in developing additional compliance options that minimize the cost of compliance. *See Michigan*, 135 S. Ct. at 2719-20; 77 Fed. Reg. at 9384-86; 76 Fed. Reg. at 25,053-54. Additionally, EPA took cost into consideration in deciding whether to set "beyond-the-floor" standards (and in all but one case, declined to do so based in part on cost). *See Michigan*, 135 S. Ct. at 2721; 77 Fed. Reg. at 9331, 9393; 76 Fed. Reg. at 25,046-47. Finally, as explained above, EPA conducted a formal cost-benefit analysis in the RIA. *See* McCabe Decl. ¶ 15, Att. A. As mentioned above, the RIA estimated that the quantifiable benefits of the Rule outweigh the costs by tens of billions of dollars.

Given the significant role that cost considerations played in the Rule (although not in the section 7412(n)(1)(A) determination), the significant amount of supporting documentation regarding costs in the existing record, and the conclusions EPA has

already reached regarding costs (none of which were called into question in *Michigan*), the Agency believes it can meet an ambitious schedule on remand and that there is "at least a serious possibility that [EPA will] be able to substantiate its decision on remand." *Allied Signal*, 988 F.2d at 151. Indeed, as detailed in the McCabe Declaration, the Agency intends to complete the required consideration of cost for the "appropriate and necessary" finding as close to April 15, 2016, as possible. *See* McCabe Decl. ¶¶ 18-19. Although EPA cannot predetermine the outcome of the public notice and comment process, and recognizes that the task on remand is not a mere clarification of the record, EPA anticipates that the robust data set amassed during the rulemaking will prevent the need to generate a new analysis out of whole cloth, and that there should be little doubt that the Agency chose correctly from the outset. Accordingly, remand without vacatur is warranted.

II. VACATUR WOULD ERODE THE PUBLIC HEALTH AND ENVIRONMENTAL PROTECTIONS OF THE RULE.

When the Rule was promulgated in 2012, it was already long overdue. As explained above, Congress instructed EPA *twenty-five years ago* to study emissions from power plants within three years, to make an "appropriate and necessary" finding based on that study, and to promulgate emission standards if appropriate and necessary by no later than November 2000, or within two years after power plants were listed. *See* 42 U.S.C. §§ 7412(n)(1)(A), 7412(c)(5). *See also New Jersey v. EPA*, 517 F.3d 574, 584 (D.C. Cir. 2012) (noting that in enacting section 7412 Congress was

"preoccupied with . . . the fact that EPA had failed for decades to regulate [hazardous air pollutants] sufficiently"). EPA made an affirmative "appropriate and necessary" finding in 2000, after a study that concluded in 1998 (almost five years late), yet EPA did not promulgate standards to control emissions until it promulgated the Rule at issue here in 2012. *See White Stallion*, 748 F.3d at 1230-33. Thus, until the Rule was promulgated (*i.e.,* for more than two decades after the 1990 Amendments) hazardous air emissions from power plants were not subject to any federally enforceable hazardous pollutant emission reduction requirements.

Not only is the Rule long overdue, it is also very important. As EPA found when it studied emissions from power plants, hazardous air pollutants emitted from such sources pose serious hazards to public health and the environment; mercury emissions in particular are extremely dangerous to children and developing fetuses. *See* 65 Fed. Reg. 79,827-30; *see also* 76 Fed. Reg. 24,994-97; 25,000-05. In the 2000 finding, EPA found that methylmercury "readily passes through the placenta to the fetus and fetal brain," and that children who were exposed to methylmercury during pregnancy have exhibited a variety of developmental neurological abnormalities. 65 Fed. Reg. at 79,829. For example, children exposed to relatively high levels of methylmercury exhibited delayed developmental milestones and deficits in learning abilities. *Id.; see also* McCabe Decl. ¶ 12.

In the 2000 finding, EPA estimated that 7 percent of American women of childbearing age were being exposed to methylmercury in amounts that exceeded a

health-protective level. *See* 65 Fed. Reg. at 79,829. In reaffirming the finding in 2012, EPA performed a study in which it further found that in 10 percent of modeled watersheds, mercury emissions from power plants alone resulted in projected methylmercury exposures exceeding a health-protective level. *See* 77 Fed. Reg. at 9311. In addition, mercury has been linked to adverse environmental effects, including adverse reproductive effects in numerous species of fish, as well as adverse behavioral, physiological, and reproductive effects in several species of fish-eating birds and mammals. *See* 76 Fed. Reg. at 24,983; *see* also 76 Fed. Reg. at 25,012-3; McCabe Decl. ¶ 12. The delay in issuing mercury regulations under section 7412 has already resulted in hundreds of additional tons of mercury being emitted into the environment, and because it bioaccumulates, that mercury will remain part of the global mercury burden. McCabe Decl. ¶ 27; 76 Fed. Reg. at 25,015-16.

The other hazardous air pollutants regulated by the Rule, including metals and acid gases, also pose risks to public health and the environment. Some are associated with chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes, effects on the nervous system, and damage to the kidneys) and acute health disorders (e.g., lung irritation and congestion, nausea and vomiting, and liver, kidney and nervous system effects). *See* 76 Fed. Reg. at 24,978; McCabe Decl. ¶ 13. Metals regulated by the Rule, including arsenic, chromium, and nickel, cause cancer. *See* 76 Fed. Reg. at 25,003-05; *see also* 77 Fed. Reg. at 9311. Fetuses exposed to lead in the womb may be born prematurely or have lower weights at birth; exposure in the

womb, in infancy, or in early childhood may also slow mental development and cause lower intelligence later in childhood. Exposure to selenium can cause severe respiratory effects. *See* 76 Fed. Reg. at 25,005; *see also* McCabe Decl. ¶ 13.

Acid gases such as hydrogen chloride, hydrogen cyanide, and hydrogen fluoride add to already high atmospheric levels of other chronic respiratory toxicants and to environmental degradation due to acidification. *See* 76 Fed. Reg. at 25,016; *see* also 77 Fed. Reg. at 9362; McCabe Decl. ¶ 14. Many sensitive ecosystems are already experiencing acidification, and recent evidence indicates that hydrogen chloride can be transported long distances and aggravate acidification in locations distant from emission sources. *See* 77 Fed. Reg. at 9362.

Assuming full compliance in 2015, the Rule was projected to result in an 88 percent reduction in hydrogen chloride emissions, a 75 percent reduction in mercury emissions, a 41 percent reduction in sulfur dioxide emissions, and a 19 percent reduction in particulate matter emissions from coal-fired units greater than 25 MW in 2015 alone. *See* 77 Fed. Reg. at 9424.[6] Additionally, the Rule will reduce hazardous air pollutant emissions from oil-fired power plants. *See id.* Based on the projected reductions in fine particulate matter associated with compliance with the Rule, EPA estimated that in 2016 alone the Rule would result in between 4,200 and 11,000 fewer premature deaths from respiratory and cardiovascular illness; 3,100 fewer emergency

[6] Precise figures will not be available until initial emissions data is submitted in October.

room visits for children with asthma; over 250,000 fewer cases of respiratory symptoms and asthma exacerbation in children; and 4,700 fewer non-fatal heart attacks. *See* 77 Fed. Reg. at 9429 (Table 9); *see also* 77 Fed. Reg. at 9305-06 (summarizing health benefits of the Rule); McCabe Decl. ¶ 17, Att. A at 5, 7. Thus, even in the short-term, the Rule has yielded and will yield significant benefits to public health and the environment.

EPA was unable to quantify many of the direct benefits of the Rule. *See* 77 Fed. Reg. at 9430; *see also* McCabe Decl. ¶ 16. As EPA explained in the RIA, there are significant obstacles to successfully quantifying and monetizing the direct public health benefits from reducing emissions of hazardous air pollutants. McCabe Decl. ¶ 16. These obstacles include gaps in toxicological data, uncertainties in extrapolating results from high-dose animal experiments to estimate human effects at lower doses, limited monitoring data, difficulties in tracking diseases such as cancer that have long latency periods, and insufficient economic research to support the valuation of the health impacts often associated with exposure to individual air toxics. *Id.* As a result of these difficulties, the vast majority of benefits associated with the Rule's reductions in hazardous air pollutants were not quantified. Nonetheless, EPA concluded that just the *quantifiable benefits* to public health and the environment of the Rule *far outweigh* (by tens of billions of dollars) the costs. As explained above, EPA estimated the total monetized benefits of the promulgated standards to be $33 to $90 billion, the total

costs to be $9.6 billion, and the quantifiable net benefits to be $24 to $80 billion. *See* 77 Fed. Reg. at 9306.

In addition to the significant public health and environmental benefits of the Rule, states are currently relying on the emission reductions obtained by the Rule for regulatory planning under a number of EPA programs. *See* McCabe Decl. ¶ 30. For example, states have relied on reductions: (1) for purposes of requesting area redesignations from nonattainment to attainment of national ambient air quality standards and for setting enforceable limits in planning for attainment of those standards; (2) for purposes of demonstrating reasonable progress under the CAA's regional haze program (and EPA has relied on those reductions to approve state regional haze plans); and (3) for purposes of calculating total maximum daily loads of mercury in waterbodies under the Clean Water Act. *See id.*

Vacatur would diminish emission reductions that have already started since the Rule's original compliance deadline of April 2015, and would further delay additional reductions that could be achieved once all regulated sources come into compliance, thereby diminishing and further delaying the public health and environmental benefits of the Rule. *See* McCabe Decl. ¶ 28. Vacatur would also significantly complicate state implementation of other EPA programs, especially given the ongoing nature of states' regulatory planning. *See id.* ¶ 30.

Unlike in other cases, there is no prior rule that could be imposed in the interim while EPA acts on remand. *See, e.g., EME Homer City*, 696 F.3d 7, 37 (D.C.

Cir. 2012) (reinstating a prior rule after vacating the rule at issue); *see also* McCabe Decl. ¶ 26 ("The Rule is the only federal standard regulating emissions of hazardous air pollutants from . . . [power plants]."). Power plants would not be required to operate controls to limit hazardous air pollutant emissions, and similarly would have no obligation to report or monitor those emissions. See McCabe Decl. ¶ 28. Given the importance of the Rule for public health and the environment, and the likelihood that the "appropriate and necessary" finding will be reaffirmed upon reconsideration, the Court should not require such a situation. Instead, the Court should continue its "traditional position" of remanding without vacatur where vacating would have serious adverse implications for public health and the environment. *North Carolina*, 550 F.3d at 1178.

III. REMAND WITHOUT VACATUR WOULD NOT HAVE SIGNIFICANT DISRUPTIVE CONSEQUENCES FOR INDUSTRY.

In contrast to the significant disruptive consequences vacatur would have for public health and the environment, and for other EPA programs, remand without vacatur would not have significant disruptive consequences for the regulated industry, and would in fact, maintain the status quo for most affected sources during the short period in which EPA acts on remand.

The Rule provided unprecedented flexibility with respect to the timing of compliance with the Rule. *See* McCabe Decl. ¶ 20, 25. First, the Rule set a three-year compliance deadline for existing sources of April 16, 2015, which is the longest time-

period allowed by the statute. *See* 77 Fed. Reg. at 9407. Second, the Rule also provided guidance addressing how sources could obtain an extension for a fourth year from the relevant permitting authorities under 42 U.S.C. § 7412(i)(3)(B) if such time is needed for the installation of controls. *See id.* at 9409-10. Finally, EPA separately issued an enforcement response policy to provide additional flexibility for certain reliability-critical power plants. *See* McCabe Decl., Att. D (December 2011 EPA Enforcement Response Policy); *see also* 77 Fed. Reg. at 9411.

In the RIA, EPA estimated that approximately 1,400 units at 600 plants were affected by the Rule. *See* McCabe Decl. ¶ 22. A number of these were granted one-year extensions by state permitting authorities, but to the best of EPA's knowledge more than half of all affected units, representing half of domestic coal-fired generation capacity, came into compliance by April 2015.[7] *See id.* ¶¶ 20-23.

Units that have already installed controls would not face any significant disruptive consequences by remand without vacatur because their capital investments have already been made and incorporated into business strategies. *See* McCabe Decl. ¶¶ 20-21, 31. Additionally, owners of such units in capacity markets have already bid into energy markets at prices that reflect the cost of operating the controls. *Id.* ¶ 31. Units that were granted one-year extensions to April 2016 in order to install controls

[7] As with emissions reductions, a precise number of units in compliance will not be available until the initial emissions data is submitted in October.

would also not face any significant disruptive consequences; such sources have likely already complied or made steps towards complying. *See id.* ¶¶ 22-23 (expected installation time for most controls is 9-36 months).[8] Furthermore, reliability-critical sources can seek relief from the April 2016 deadline under EPA's Enforcement Response Policy. *See* McCabe Decl. ¶ 25; Docket No. 736958 at 12-13 (EPA Opposition to Second Tri-State Motion). Keeping the Rule in effect while EPA acts on remand would therefore maintain the status quo for most sources, avoiding any significant disruptive consequences.

CONCLUSION

In summary, because EPA intends to act quickly on remand, and remand without vacatur would preserve important public health and environmental protections, and prevent significant disruption to state implementation of other EPA programs, without significant disruptive consequences for regulated sources, remand without vacatur is warranted.

[8] Vacatur may in fact be significantly disruptive, and even ultimately increase costs of compliance, for sources that have taken steps towards installing controls given the potential confusion and uncertainty associated with potentially unraveling or delaying contractual commitments and construction plans, only to have to reinstate those arrangements if EPA reaffirms the "appropriate and necessary" finding on remand. *See* McCarthy Decl. ¶ 23. *Cf. EME Homer City*, 795 F.3d at 132 (holding that remand without vacatur is appropriate where vacatur of standards could cause substantial disruption to trading markets that have developed around emission budgets).

DATED: September 24, 2015

Respectfully submitted,

/s/ Stephanie J. Talbert

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CERTIFICATE OF SERVICE

I hereby certify that I served a copy of RESPONDENT'S MOTION TO GOVERN FUTURE PROCEEDINGS via Notice of Docket Activity by the Court's CM/ECF system, on September 24, 2015, on all counsel of record.

DATED: September 24, 2015

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IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

White Stallion Energy Center, LLC, et al., Petitioners, v. United States Environmental Protection Agency, Respondent.	No. 12-1100 (and consolidated cases)

DECLARATION OF JANET G. MCCABE

I. Background

1. I, Janet G. McCabe, declare under penalty of perjury under the laws of the United States of America that the following statements are true and correct to the best of my knowledge and belief and that they are based upon my personal knowledge or on information contained in the records of the United States Environmental Protection Agency (EPA) or on information supplied to me by employees under my supervision and employees in other EPA offices.

2. I am the Acting Assistant Administrator for the Office of Air and Radiation (OAR) at the EPA, a position I have held since July 19, 2013. I previously served as the Principal Deputy to the Assistant Administrator for this office from November 2009 to July 18, 2013. OAR is the headquarters-based EPA office that

administers the Clean Air Act and develops national programs, technical policies and regulations for controlling air pollution and protecting public health and welfare. OAR is concerned with preventing and responding to air quality issues including industrial air pollution, pollution from vehicles and engines, toxic air pollutants, acid rain, stratospheric ozone depletion and climate change.

3. Prior to joining the EPA, I served as the Executive Director of Improving Kids' Environment, Inc., and as an adjunct faculty member at the Indiana University School of Medicine, Department of Public Health. From 1993 to 2005, I held several leadership positions in the Indiana Department of Environmental Management's Office of Air Quality and was the office's Assistant Commissioner from 1998 to 2005. Before coming to Indiana in 1993, I served as Assistant Attorney General for environmental protection for the Commonwealth of Massachusetts and Assistant Secretary for Environmental Impact Review. I received an undergraduate degree from Harvard College in 1980 and J.D. from Harvard Law School in 1983.

4. As part of my duties as Acting Assistant Administrator of the Office of Air and Radiation, I oversee the development and implementation of regulations, policy and guidance under section 112 of the Clean Air Act ("CAA" or "Act"), 42 U.S.C. §7412, the national emission standards for hazardous air pollutants ("NESHAP") program, including development of the NESHAP for coal- and oil-fired electric utility steam generating units ("power plants") that is the subject of this litigation. Section 7412(c) of the Act requires EPA to regulate emissions of the

approximately 180 hazardous air pollutants listed in section 7412(b) from stationary industrial sources, referred to as "source categories." 42 U.S.C. § 7412(c). The statute requires EPA to list for regulation all source categories that contain at least one major stationary source.[1] *Id.* The statute also requires EPA to list and regulate area sources[2] of hazardous air pollutants consistent with sections 7412(c)(3) and (c)(6).[3] *Id.* §§ 7412(c)(3), (6). As required under the Act, EPA has developed a list of major and area source categories that must meet section 7412(d) emission standards to control their emissions of hazardous air pollutants.

5. For all hazardous air pollutants emitted by major sources EPA is required to establish emissions standards, commonly known as "maximum achievable control technology floor" or "MACT floor" standards, that require sources in the listed category to control their emissions to the levels of the best performing 12 percent of sources in that category for source categories with 30 or more sources. *See also id.* § 7412(d)(3)(B) (requiring MACT floors to be based on the performance of the

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[1] Section 7412(a)(1) defines a major source as any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit at least 10 tons per year of any single hazardous air pollutant or more than 25 tons per year of any combination of hazardous air pollutants.

[2] Section 7412(a)(2) area sources are stationary sources of hazardous air pollutants that are not major sources.

[3] For specific hazardous air pollutants identified in section 7412(c)(6), EPA is required to identify sources, including area sources, that account for at least 90 percent of the aggregate emissions of the identified pollutants, and regulate those sources based on emissions standards that reflect the best performing sources or with respect to a health threshold under 7412(d)(4).

best 5 sources for source categories with less than 30 sources). EPA must also determine whether to establish MACT standards more stringent than the MACT floor after considering cost, energy requirements and non-air quality health and environmental effects. *Id.* § 7412(d)(2). EPA is specifically authorized to subcategorize a source category by class, type or size of sources. *Id.* § 7412(d)(1). Under the statute, EPA may provide sources up to three years to come into compliance once standards are established, and EPA and title V permitting authorities – usually state agencies – may provide sources an additional year if it necessary "for the installation of controls." *Id.* § 7412(i)(3)(A); 40 C.F.R. § 63.6(i).

6. The 1990 CAA Amendments established a unique provision—section 7412(n)(1)—for EPA to determine whether to list power plants for regulation of hazardous air pollutants. *See* 42 U.S.C. § 7412(n)(1)(A); *see also New Jersey v. EPA*, 517 F.3d 574, 578 (D.C. Cir. 2008). Under section 7412(n)(1)(A), Congress directed EPA to perform a study of the hazards to public health of hazardous air pollutant emissions from power plants ("Utility Study") reasonably anticipated to occur after implementation of the title IV acid rain program and other CAA programs and also determine alternative control strategies for hazardous air pollutant emissions from such sources and report those findings to Congress by November 1993, or within 3 years.[4] *Id.* Section 7412(n)(1)(A) further provides that EPA shall regulate power

[4] EPA completed the Utility Study in 1998.

plants pursuant to section 7412 if the Agency determines that regulation of hazardous air pollutant emissions from power plants is appropriate and necessary, after considering the results of the section 7412(n)(1)(A) Utility Study. *Id.*

7. Section 7412(n)(1)(B) directs the Agency to conduct a study of mercury emissions from power plants, municipal waste combustion units, and other sources, including area sources of mercury ("Mercury Study") and to report the findings of this study to Congress within 4 years after November 15, 1990.[5] *Id.* § 7412(n)(1)(B). In conducting the Mercury Study, Congress instructed EPA to "consider the rate and mass of such emissions, the health and environmental effects of such emissions, technologies which are available to control such emissions, and the costs of such technologies." *Id.* Prior to publication, EPA subjected the Mercury Study to two extensive external peer reviews. *See* 77 Fed. Reg. 9304, 9307 (Feb. 12, 2012). Congress separately tasked the National Institute of Environmental Health Sciences and the National Academy of Sciences to perform additional independent studies to determine the threshold level of mercury exposure below which adverse human health effects are not expected to occur in even the most sensitive members of the population. *Id.* This exposure level is commonly referred to as the reference dose.

[5] EPA completed the Mercury Study in 1997. Notwithstanding the statutory requirement that this study be completed before the Utility Study, EPA completed the Mercury Study first and used many of the results of that study to develop the mercury related information in the Utility Study.

8. In December 2000, after considering the studies required by section 7412(n)(1) and other relevant information, including mercury emissions data from power plants, the EPA made a finding that it is appropriate and necessary to regulate hazardous air pollutants from coal and oil-fired electric generating units and listed those sources pursuant to section 7412(c), making coal- and oil-fired power plants subject to regulation under section 7412(d). 65 Fed. Reg. 79,825, 79,825-31 (Dec. 20, 2000) (2000 finding). Specifically, EPA found that coal- and oil-fired power plants "are the largest domestic source of mercury emissions, and mercury in the environment presents significant hazards to public health and the environment." *Id.* at 79,830. The Agency took note that the National Academy of Sciences study had confirmed EPA's own research concluding that "mercury in the environment presents a significant hazard to public health." *Id.* Moreover, in the 2000 finding, EPA explained that it is appropriate to regulate hazardous air pollutant emissions from coal- and oil-fired units because we identified certain control options that we believed would effectively reduce those emissions from such units. *Id.* The 2000 finding also concluded that it is "necessary" to regulate hazardous air pollutant emissions from power plants under section 7412 "because the implementation of other requirements under the CAA will not adequately address the serious public health and environmental hazards arising from such emissions identified in the Utility [Study] and confirmed by the [National Academy of Sciences] Study, and which section 7412 is intended to address." *Id.*

9. In May 2011, EPA proposed for comment section 7412(d) standards for coal- and oil-fired power plants. 76 Fed. Reg. 24,976 (May 3, 2011). In that action, the EPA confirmed that the 2000 finding and listing of power plants remain valid based on consideration of the information available at the time of that finding, and the Agency reaffirmed that it is appropriate and necessary to regulate hazardous air pollutant emissions from coal- and oil-fired power plants after conducting new peer-reviewed analyses demonstrating that such emissions from power plants continue to pose hazards to public health and the environment and that those hazards will not be addressed through implementation of the other CAA provisions applicable to power plants. EPA revised the new analyses in response to comments by EPA's Science Advisory Board and public comments and confirmed the appropriate and necessary finding and listing of power plants when the Agency issued the final Mercury and Air Toxics Standards (the "Rule"). *See* 77 Fed. Reg. at 9362-64.

10. The final Rule set numeric emission standards to control mercury, other hazardous metals (e.g., arsenic and nickel), and hazardous acid gases (e.g. hydrogen chloride, hydrogen cyanide, and hydrogen fluoride) from power plants. The rule also established work practice standards to control emissions of organic hazardous air pollutants such as dioxins and furans. EPA provided alternative or surrogate standards for non-mercury metal hazardous air pollutants and acid gas hazardous air pollutants. Specifically, for non-mercury metals, EPA established filterable particulate matter and total metals limits as surrogates for the individual non-mercury metal

hazardous air pollutants, and for acid gas hazardous air pollutants, EPA established hydrogen chloride and sulfur dioxide as surrogates. The surrogate standards allow many affected facilities to utilize monitoring devices that are already in place, thus lowering the compliance costs for the affected units. *See* 76 Fed. Reg. at 25,038-39.

11. This declaration is filed in support of the EPA's Motion for Remand without Vacatur in *White Stallion Energy Center, LLC v. EPA*, No. 12-1100 (and consolidated cases) (D.C. Cir.).

II. Public Health and Environmental Benefits of the Rule

12. Hazardous air pollutants emitted from coal- and oil-fired power plants are associated with serious adverse health and environmental effects. Mercury emitted from power plants may be transformed in the environment into methylmercury, a highly toxic persistent pollutant that accumulates in the food chain, especially the tissue of fish. People consuming these methylmercury-contaminated fish also ingest and bioaccumulate the methylmercury, which can cause neurotoxic effects. Children, and even more so developing fetuses, are especially susceptible to methylmercury effects because their developing bodies are more highly sensitive to its effects. 76 Fed. Reg. at 24,977-8. Children who are prenatally exposed to even low concentrations of methylmercury are at increased risk of poor performance on neurobehavioral tests, such as those measuring attention, fine motor function, language skills, visual spatial abilities, and verbal memory. *Id.* at 25,018. According to the National Academy of Sciences, these neurodevelopmental effects from

methylmercury exposure include the ability of children to learn and succeed in school. *Id.* at 25,001.

The population at highest risk are children of women who consume large amounts of fish and other seafood during pregnancy. Some portions of the population, including anglers, Asian-Americans, and members of some Native American Tribes are particularly affected because of increased fish consumption due to cultural and economic reasons. In fact, they may have methylmercury exposures that are twice as high as the average U.S. population. *Id.* at 24,978, 24,984. In addition, mercury has been linked to adverse environmental effects, including adverse reproductive effects on numerous species of fish, as well as adverse behavioral, physiological, and reproductive effects in several species of fish-eating birds and mammals. *Id.* at 24,983, 25,012-13.

13. In addition to mercury, the Rule reduces emissions of several other hazardous air pollutant metals linked to serious health impacts. Adverse noncancer health effects associated with non-mercury hazardous air pollutants include chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes, effects on the nervous system, and damage to the kidneys), and acute health disorders (e.g., lung irritation and congestion, alimentary effects such as nausea and vomiting, and liver, kidney and nervous system effects). *See id.* at 24,978. Hazardous air pollutant metals such as arsenic, nickel, and chromium have been classified as human carcinogens, and cadmium is classified as a probable human carcinogen. Hazardous air pollutant metals

such as lead and selenium also have potentially serious noncancer health effects. Children are more sensitive to the effects of lead than adults and no safe blood level has been determined for children. Fetuses exposed to lead in the womb may be born prematurely or have lower weights at birth; exposure in the womb, in infancy, or in early childhood may also slow mental development and cause lower intelligence later in childhood. Exposure to selenium can cause severe respiratory effects. *Id.* at 25,005.

14. Acid gas hazardous air pollutants such as hydrogen chloride, hydrogen fluoride, and hydrogen cyanide add to already high atmospheric levels of other chronic respiratory toxicants and to environmental degradation due to acidification. *Id.* at 25,016; *see also* 77 Fed. Reg. at 9362. Many sensitive ecosystems are already experiencing acidification, and recent evidence indicates that hydrogen chloride can be transported long distances and aggravate acidification in locations distant from emissions sources. 77 Fed. Reg. at 9362.

15. In conjunction with the final Rule, the EPA conducted a Regulatory Impact Analysis (RIA) pursuant to Executive Orders 12,866 and 13,563. Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, December 2011, Docket No. EPA-HQ-OAR-2009-0234-20131, Att. A. The EPA estimated that the annual monetized benefits of the Rule in 2007 dollars would range between $37 to $90 billion, using a 3 percent discount rate, and $33 billion to $81 billion using a 7 percent discount rate. Att. A at 3 (ES-1). The cost of the Rule, which accounted for

compliance, monitoring, and reporting costs, was estimated at $9.6 billion in 2007 dollars. *Id.* at 46 (3-31). The net annual quantifiable benefits of the Rule, once fully implemented in 2016, would exceed the Rule's total costs by between $27 billion and $80 billion in 2007 dollars at a 3 percent discount rate, or $24 to $71 billion using a 7 percent discount rate. *Id.* at 101 (8-1). We concluded that implementation of the Rule "is expected, based purely on economic efficiency criteria, to provide society with a significant net gain in social welfare, even given the limited set of health and environmental effects we were able to quantify." *Id.*

16. When analyzing the costs and benefits for this Rule, the EPA applied peer-reviewed methods and explained in detail the empirical basis for our conclusions. In keeping with the directives of the Executive Orders, in the RIA EPA characterized in detail the sources of uncertainties affecting our benefits estimates, including the many unquantifiable health and environmental benefits associated with reductions in hazardous air pollutants attributable to the Rule. *See* 77 Fed. Reg. 9432; *see also, e.g.*, Att. A at 11-15 (ES-9 to -13) (listing the many human health benefits that could not be quantified or monetized). There are many obstacles to fully quantifying and monetizing these benefits, including gaps in toxicological data, uncertainties in extrapolating results from high-dose animal experiments to estimate human effects at lower doses, limited ambient and personal exposure monitoring data, difficulties in tracking diseases such as cancer that have long latency periods, and insufficient economic research to support the valuation of the health impacts often associated

with exposure to individual hazardous air pollutants. Att. A at 57-61 (4-62 to -66). For example, EPA could quantify and monetize only one of the benefits attributable to reductions in mercury, and the Agency could not quantify or monetize any of the benefits attributable to reductions in the other hazardous air pollutant emissions from power plants because of unavailable data and uncertainties associated with input parameters. *See* 77 Fed. Reg. at 9305-9306; Att. A. at 52-89 (4-57 to -94). The many unquantifiable benefits of the Rule, e.g., reducing the incidence of cancer or reducing adverse effects on brain development and memory functions aside from IQ loss, are nonetheless important.

17. Hazardous air pollutant emissions from power plants can be controlled effectively with the controls used to reduce emissions of filterable particulate matter and sulfur dioxide. Because of this close relationship between reductions of the criteria pollutants filterable particulate matter (also called fine particulate matter) and sulfur dioxide and reductions of hazardous air pollutant emissions, the standards established in the Rule necessarily yield reductions in emissions of filterable particulate matter and sulfur dioxide (a particulate matter precursor).[6] The Agency has developed metrics to quantify and monetize benefits associated with reductions in those criteria

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[6] In fact, because of the close relationship between reductions of these criteria pollutants and hazardous air pollutants, EPA established filterable particulate matter and sulfur dioxide as surrogates for non-mercury metal hazardous air pollutants and acid gas hazardous air pollutants, respectively. This allows sources to comply with their hazardous air pollutant emission reduction obligations by demonstrating reductions in filterable particulate matter and sulfur dioxide emissions.

pollutants. Based on the projected reductions in ambient levels of fine particulate matter associated with the Rule's compliance, EPA estimated that the Rule would result in significant quantifiable public health benefits, including avoidance of 4,200 to 11,000 premature deaths, 4,700 nonfatal heart attacks, 2,600 hospitalizations for respiratory and cardiovascular diseases, 540,000 lost work days, and 3.2 million days when adults restrict normal activities. Att. A. at 5 (ES-3). *See also id.* at 90-94 (5-3 to -7, tbls. 5-1, 5-2) (summarizing quantified and monetized benefits from improved human health associated with reductions in primary and secondarily formed fine particulate matter).

III. Estimated Timeframe for Completing Analysis of Cost Considerations for a Revised "Appropriate & Necessary" Finding

18. As part of my duties as Acting Assistant Administrator of OAR, I am involved in the prioritization and allocation of resources to meet the legal requirements of the CAA as well as the air quality needs of the country. I am familiar with the processes and time periods allotted for the EPA to take regulatory actions under the CAA. Responding to the Supreme Court's remand in this case is a high priority for OAR and we are fully committed to providing the resources necessary to complete our action on remand quickly.

19. EPA has already begun the process of reviewing available information relevant to cost as part of its CAA section 7412(n)(1)(A) "appropriate and necessary" finding in response to the Supreme Court's decision in *Michigan v. EPA*. Relevant

staff have been assigned to the project, and we have established a detailed internal schedule with the goal of completing the proposed consideration of cost in the next few months. EPA will also provide a public comment period to allow for input from stakeholders. The Agency is committed to completing this process on an expedited basis, and intends to finalize our analysis of cost considerations for the appropriate and necessary finding as close to April 15, 2016 as possible.

IV. Effects of Remand Without Vacatur on Regulated Sources and States

20. Many units affected by the Rule are in compliance with the final standards consistent with the April 16, 2015 compliance date. As discussed above, in the final rule, EPA gave all sources up to three years to comply. EPA also included additional flexibilities to allow some sources an opportunity to obtain further compliance extensions under section 7412. The Rule was upheld and all petitions for review dismissed by the D.C. Circuit in April 2014, a year prior to the compliance date. Although EPA will not have complete emission reporting data for the Rule until after the reporting deadline in October of this year, according to a survey by SNL Energy,[7] those units that have already come into compliance with the Rule represent half of the domestic coal-fired generation capacity. Eric Wolff, *Supreme Court's*

[7] SNL Financial is a subscriber-based service that collects, standardizes and disseminates relevant information – including news and analysis — for a variety of industries, including the energy sector. http://www.snl.com/Sectors/Energy/

Eventual MATS Ruling Will Be (Mostly) Moot, May 14, 2015, https://www.snl.com/InteractiveX/Article.aspx?cdid=A-32620730-13109, (Att. E).

21. The actions the industry have taken or announced in response to the Rule are notable. Pollution controls have been purchased and in most cases installed. The Institute of Clean Air Companies estimates that almost 400 units totaling over 180 gigawatts[8] (GW) of capacity have installed mercury controls. Institute of Clean Air Companies, Mercury Installation List, http://c.ymcdn.com/sites/www.icac.com/resource/resmgr/Mercury/Mercury_Installation_List_-_.pdf, (Att. F). Since 2012, nearly 50 GW of capacity have either updated existing controls or installed new controls that reduce acid gases and sulfur dioxide, and about 19 GW of particulate matter controls were updated or installed.[9] While some controls that have been installed in order to comply with the Rule require lower initial capital investment in relation to operating costs, for many control technologies, a significant portion of the cost of compliance is associated with the initial capital expenditure. Some coal- and oil-fired units, representing almost 2 GW of capacity, have switched to burning natural gas.[10]

22. According to the National Association of Clean Air Agencies (NACAA), which has been surveying states periodically throughout the Rule's compliance period,

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[8] A gigawatt (GW) is equal to 1,000 megawatts (MW).
[9] SNL Financial, http://www.snl.com, Energy Database (subscriber only).
[10] SNL Financial, http://www.snl.com, Energy Database (subscriber only) (last visited March, 23, 2015).

states have granted 189 extensions to power plants for the installation of controls since the Rule was promulgated. National Association of Clean Air Agencies, Survey of MATS Compliance Extension Requests, August 11, 2015, http://www.4cleanair.org/sites/default/files/Documents/MATSextensionrequests-table-August-2015.pdf, (Att. G). The Association's survey did not ask states to specify how many units were covered by each extension, thus some of these extensions may have been for entire plants while others may have been for individual units. For perspective, when the Rule was promulgated, EPA estimated that there were approximately 1,400 units at 600 plants that were affected by the Rule. Att. A at 18 (3-3). The Association also reports that at least some of the extensions were for less than one full year and others were limited to only some of the Rule's requirements. For example, some extensions were granted for a six-week time period in order to honor contractual capacity commitments that had been made to system operators that ran several weeks past the April 2015 compliance deadline and some extensions extended the deadline for complying with the requirements regarding a single hazardous air pollutant or group of pollutants. Att. E.

23. For those units that were approved in accordance with 40 CFR Part 63.6(i) to operate for up to an additional year past the April 16, 2015 compliance deadline, and are planning to install controls by the 2016 deadline, many will have already made significant investments or entered into contractual commitments in order to meet that extended deadline. The controls that are expected to be installed

would include sorbent injection systems, fabric filters, and various types of acid gas controls. Those controls have expected installation times (from design, construction, installation and testing) of 9 to 36 months. *See generally*, Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, prepared by URS for Exelon Corporation, April 2011 (Att. H). In addition, the regulations implementing the extension provisions require extension requests to include, among other things, a description of the controls to be installed and compliance schedule that provides the dates when the necessary construction will begin and end. 40 C.F.R. § 63.6(i)(6)(i). Thus, sources that received extensions in order to install controls will have already taken significant steps to do so. A vacatur rather than remand at this point could ultimately increase costs of compliance with the Rule for these companies, given the confusion of unraveling or delaying contractual commitments and construction plans, only to have to re-instate those arrangements if EPA reaffirms that it is appropriate to regulate power plants under section 7412. In that same vein, vacatur would certainly have negative implications for the companies that design, fabricate, and supply the control technologies required by the Rule.

24. For those units that received an extension and are planning to shut down, remand without vacatur will largely maintain the status quo. As explained above, EPA will act quickly on remand. If EPA concludes that regulation of power plants is appropriate after considering cost, such units could shut down as planned on April 16, 2016. If EPA reaches the opposite conclusion, those sources could continue

to operate. We believe that many of the units that have determined that it is not economically justifiable to install controls are likely to be smaller, older plants that already operate intermittently. *See* Att. A at 50 (3-35); *see also, e.g.*, Tri-State First Emergency Motion, Doc. # 1565685, at 2 (describing small size and infrequent operation of Nucla Station).

25. Existing CAA authorities have allowed compliance with the Rule to proceed while maintaining the stability of the grid, and the Agency is working with sources to address the few circumstances in which potential threats to electric reliability may exist. EPA provided unprecedented flexibilities to power plants to ensure that implementation would occur with limited impact to electric reliability. Specifically, for reliability-critical units, EPA interpreted the phrase "installation of controls" in the CAA section 7412(i)(3)(B) extension provision to apply to units that do not plan to install controls if the units are needed to run while replacement units or transmission upgrades are being constructed to address the potential electric reliability issues. Thus, these units can run without controlling their hazardous air pollutant emissions for up to an additional year pursuant to the statutory extension provision. As noted above, EPA has also been working with reliability critical units that need additional time past April 16, 2016, pursuant to the aforementioned December 2011 EPA Enforcement Response Policy.

V. Disruptive Consequences of Vacatur

26. The Rule is the only federal standard regulating emissions of hazardous air pollutants from coal- and oil-fired power plants. Hazardous air pollutants emitted by power plants include metals (e.g., lead, mercury, arsenic, cadmium, chromium, and nickel), organics (e.g., acetaldehyde, benzene, and formaldehyde), and acid gases (e.g., hydrogen chloride and hydrogen flouride). *See* 76 Fed. Reg. at 25,003-5. The power sector is the largest anthropogenic source of many hazardous air pollutants in the United States, including mercury, hydrogen chloride, hydrogen fluoride, selenium, arsenic, chromium, cadmium, nickel, and others. EPA estimates that in 2005 the power sector emitted 50 percent of total domestic anthropogenic mercury emissions, 62 percent of total domestic arsenic emissions, 39 percent of total domestic cadmium emissions, 22 percent of total domestic chromium emissions, 82 percent of total domestic hydrogen chloride emissions, 62 percent of total domestic hydrogen flouride emissions, 28 percent of total domestic nickel emissions, and 83 percent of total domestic selenium emissions. 77 Fed. Reg. at 9310.

27. As previously discussed, major progress towards compliance with the Rule has already occurred. A vacatur of the Rule now would endanger the emission reductions required by the Rule by eliminating the only federally enforceable requirements for existing coal- and oil-fired power plants to control, monitor, and report their hazardous air pollutant emissions. The emission reductions required by the Rule are significant: the EPA estimated that in 2015, the Rule would reduce

mercury emissions from U.S. coal-fired power plants by 75 percent, hydrogen chloride emissions (as a surrogate for acid gases) by 88 percent, and fine particulate matter emissions (which includes non-mercury metals) by 19 percent. *See* 77 Fed. Reg. at 9424. Moreover, mercury emissions from power plants affect not only deposition, exposures, and risk today, but may also contribute to future deposition, exposure, and risk due to the persistent nature of mercury in the environment. 76 Fed. Reg. at 25,015. As EPA noted in the proposed rule, the delay in issuing mercury regulations under section 7412 has already resulted in hundreds of additional tons of mercury being emitted to the environment, and that mercury will remain part of the global burden of mercury. *Id.* A vacatur now would only compound that impact.

28. Although the Rule's estimated 2015 emission reductions do not account for the approximately 200 plants that received a one-year extension, it is our understanding that only 22 of those plants, representing less than 1% of the coal-fired generating capacity in the country, were granted the additional time—up to one year—to operate without installation of controls in order to provide grid reliability before retiring. *See* Att. E. The majority of the units receiving an extension did so on the basis of needing more time to install controls, and, as noted above, should already be well on their way to compliance. Without a standard in place, plants that have already installed controls could choose not to operate those controls. Plants that have yet to complete construction and installation of controls could halt that activity. In addition, power plants would be under no federal obligation to monitor and report

their hazardous air pollutant emissions. While more than 80 other industrial source categories are currently subject to emissions standards that limit these emissions and require routine monitoring and reporting, existing power plants, representing a major portion of all anthropogenic hazardous air pollutant emissions in the United States, would have no federally mandated requirements to control, monitor, or report those emissions.

29. When promulgated, the Rule was already decades overdue. A complete vacatur of the Rule would interrupt or delay the implementation of enforceable requirements to control, monitor, and report hazardous air pollutant emissions and could delay those requirements further still by requiring EPA to conduct a rulemaking to re-establish all aspects of the Rule, as opposed to conducting a rulemaking to remedy the sole deficiency identified by the Supreme Court in *Michigan*. For reference, the Rule took almost 4 years to issue after the D.C. Circuit vacated the Section 7412(n) Revision Rule in 2008. *See New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

30. Vacatur would also have significant disruptive consequences for other regulatory programs. For example, when requesting area redesignations from nonattainment to attainment, states are required to provide ten-year projections of maintenance of the national ambient air quality standards ("NAAQS") for criteria pollutants, and some of those recently approved redesignations have already incorporated emission reductions associated with the Rule into those ten-year

maintenance plans. *See, e.g.*, 80 Fed. Reg. 44,873 (July 28, 2015); North Carolina Dept. of Envt. and Natural Resources, Div. of Air Quality, Redesignation Demonstration and Maintenance Plan for the Charlotte-Gastonia-Salisbury, North Carolina 2008 8-Hour Ozone Marginal Nonattainment Area (April 16, 2015) at 32, *available at* http://daq.state.nc.us/planning/metrolina/Charlotte_2008_Ozone_Redesignation_and_Maintenance_SIP_Narrative_Final_04-16-15.pdf (Att. I) (indicating North Carolina's incorporation of the Rule into its future emissions inventory projections). Similarly, under the CAA's regional haze program, states have relied on the Rule for purposes of demonstrating reasonable progress towards natural visibility conditions in national parks and wilderness areas, and EPA has approved a number of regional haze plans based in part on the Rule's emission limits. States are also permitted to rely on reductions under the Rule in creating enforceable limits in the context of attainment planning for the 2010 1-hr SO_2 NAAQS, because of the potential co-benefit reductions of SO_2 in complying with the Rule's acid gas standards. *See* 80 Fed. Reg. 51,051, 51,077-78 (August 21, 2015). In the water quality planning context, states are required under the Clean Water Act to calculate total maximum daily loads (TMDLs), which establish the maximum amount of pollutant that a waterbody can receive and still meet water quality standards. In the case of mercury TMDLs, states rely on national air emission standards to limit mercury in order to reduce deposition into water bodies. *See, e.g.*, Northeast States Regional Mercury TMDL, at xii, 39, 44, available at http://www.epa.gov/region1/eco/tmdl/pdfs/ne/Northeast-Regional-

Mercury-TMDL.pdf (Att. J) ("The Northeast region's ability to achieve the calculated TMDL allocations is dependent on the adoption and effective implementation of national and international programs to achieve necessary reductions in mercury emissions. Given the magnitude of the reductions required to implement the TMDL, the Northeast cannot reduce in-region sources further to compensate for insufficient reductions from out-of-region sources.").

31. Remand without vacatur would not have significant disruptive consequences for regulated sources. In addition to capital investments that sources have already made to comply with the Rule, financial planning decisions, contractual commitments, and bids into the electricity market have also already assumed compliance with the Rule. For example, PJM Interconnection, Midcontinent Independent System Operator (MISO) Energy, and Southwest Power Pool Electric Energy Network[11] all report that the construction to install controls for compliance with the Rule is well underway. In MISO, for example, operators have already

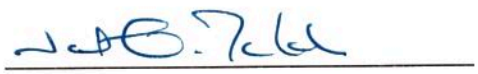
[11] PJM Interconnection, MISO Energy, and Southwest Power Pool Electric Energy Network are regional transmission organizations operating in the United States. Regional transmission organizations coordinate, control, and monitor electric transmission grids. PJM serves all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. MISO serves all or part of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and parts of Montana, Missouri, Kentucky, Arkansas, Texas, Louisiana, and Mississippi. The Southwest Power Pool serves all or part of Kansas, Oklahoma, New Mexico, Texas, Arkansas, Louisiana, Missouri, Mississippi and Nebraska.

entered into contracts for installation of all of the mercury and acid gas controls necessary under the Rule. In addition, the costs of operating controls are typically included in the bids that owners make into capacity market auctions, such as PJM's recent auction to cover the next three years. There are also likely ongoing efforts by utilities to recover costs of compliance, in either the organized markets or state proceedings, such as decisions by state commissions to allow utilities to pass on the costs of the compliance with the Rule to their customers. Vacatur may require untangling the market actions that have taken place in reliance on compliance with the Rule, and doing so would be unnecessarily disruptive given that the Agency expects to complete its cost consideration in approximately seven months.

32. Vacatur of the Rule would have severe disruptive consequences for public health and the environment, and would also interfere with other EPA programs. Remand without vacatur, in contrast, would preserve the benefits provided by the Rule without significant disruptive consequences for regulated sources.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 24th day of September, 2015.



Janet G. McCabe
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Office of Air and Radiation
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Protection Agency

ATTACHMENT A

Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards

EXECUTIVE SUMMARY

This Regulatory Impact Analysis (RIA) presents the health and welfare benefits, costs, and other impacts of the final Mercury and Air Toxics Standards (MATS) in 2016.

ES.1 Key Findings

This rule will reduce emissions of Hazardous Air Pollutants (HAP), including mercury, from the electric power industry. As a co-benefit, the emissions of certain $PM_{2.5}$ precursors such as SO_2 will also decline. EPA estimates that this final rule will yield annual monetized benefits (in 2007$) of between $37 to $90 billion using a 3% discount rate and $33 to $81 billion using a 7% discount rate. The great majority of the estimates are attributable to co-benefits from 4,200 to 11,000 fewer $PM_{2.5}$-related premature mortalities. The monetized benefits from reductions in mercury emissions, calculated only for children exposed to recreationally caught freshwater fish, are expected to be $0.004 to $0.006 billion in 2016 using a 3% discount rate and $0.0005 to $0.001 billion using a 7% discount rate. The annual social costs, approximated by the compliance costs, are $9.6 billion (2007$) and the annual monetized net benefits are $27 to $80 billion using 3% discount rate or $24 to $71 billion using a 7% discount rate.[1] The benefits outweigh costs by between 3 to 1 or 9 to 1 depending on the benefit estimate and discount rate used. There are some costs and important benefits that EPA could not monetize, such as other mercury reduction benefits and those for the HAP other than mercury being reduced by this final rule. Upon considering these limitations and uncertainties, it remains clear that the benefits of the MATS are substantial and far outweigh the costs. Employment impacts associated with the final rule are estimated to be small.

The benefits and costs in 2016 of the final rule are in Table ES-1. The emission reductions from the electricity sector that are expected to result from the rule are reported in Table ES-2.

[1] As discussed in Chapter 3, costs were annualized using a 6.15% discount rate.

Table ES-1. Summary of EPA's Estimates of Annualized[a] Benefits, Costs, and Net Benefits of the Final MATS in 2016[b] (billions of 2007$)

Description	Estimate (3% Discount Rate)	Estimate (7% Discount Rate)
Costs[c]	$9.6	$9.6
Benefits[d,e,f]	$37 to $90 + B	$33 to $81 + B
Net benefits (benefits-costs)[g]	$27 to $80 + B	$24 to $71 + B

[a] All estimates presented in this report represent annualized estimates of the benefits and costs of the final MATS in 2016 rather than the net present value of a stream of benefits and costs in these particular years of analysis.

[b] Estimates rounded to two significant figures and represent annualized benefits and costs anticipated for the year 2016.

[c] Total social costs are approximated by the compliance costs. Compliance costs consist of IPM projections, monitoring/reporting/recordkeeping costs, and oil-fired fleet analysis costs. For a complete discussion of these costs refer to Chapter 3. Costs were annualized using a 6.15% discount rate.

[d] Total benefits are composed primarily of monetized PM-related health benefits. The reduction in premature fatalities each year accounts for over 90% of total monetized benefits. Benefits in this table are nationwide and are associated with directly emitted $PM_{2.5}$ and SO_2 reductions. The estimate of social benefits also includes CO_2-related benefits calculated using the social cost of carbon, discussed further in Chapter 5.

[e] Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Data limitations prevented us from quantifying these endpoints, and as such, these benefits are inherently more uncertain than those benefits that we were able to quantify. Estimates here are subject to uncertainties discussed further in the body of the document. Potential benefit categories that have not been quantified and monetized are listed in Table ES-5.

[f] Mortality risk valuation assumes discounting over the SAB-recommended 20-year segmented lag structure. Results reflect the use of 3% and 7% discount rates consistent with EPA and OMB guidelines for preparing economic analyses (EPA, 2000; OMB, 2003).

[g] Net benefits are rounded to two significant figures. Columnar totals may not sum due to rounding.

Table ES-2: Projected Electricity Generating Unit (EGU) Emissions of SO_2, NO_X, Mercury, Hydrogen Chloride, PM, and CO_2 with the Base Case and with MATS, 2015 [a,b]

		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	1,883

[a] Source: Integrated Planning Model run by EPA, 2011

[b] The year 2016 is the compliance year for MATS, though as we explain in later chapters, we use 2015 as a proxy for compliance in 2016 for IPM emissions and costs due to availability of modeling impacts in that year.

ES.1.1 Health Co-Benefits

The final MATS Rule is expected to yield significant health co-benefits by reducing emissions not only of HAP such as mercury, but also significant co-benefits by reducing to direct fine particles ($PM_{2.5}$) and sulfur dioxide, which contributes to the formation of $PM_{2.5}$.

Our analyses suggest this rule would yield co-benefits in 2016 of $37 to $90 billion (based on a 3% discount rate) and $33 to $81 billion (based on a 7% discount rate). This estimate reflects the economic value of a range of avoided health outcomes including 510 fewer mercury-related IQ points lost as well as avoided $PM_{2.5}$-related impacts, including 4,200 to 11,000 premature deaths, 4,700 nonfatal heart attacks, 2,600 hospitalizations for respiratory and cardiovascular diseases, 540,000 lost work days, and 3.2 million days when adults restrict normal activities because of respiratory symptoms exacerbated by $PM_{2.5}$. We also estimate substantial additional health improvements for children from reductions in upper and lower respiratory illnesses, acute bronchitis, and asthma attacks. See Table ES-3 for a list of the annual reduction in health effects expected in 2016 and Table ES -4 for the estimated value of those reductions. In addition, we include in our monetized co-benefits estimates the effect from the reduction in CO_2 emissions resulting from this rule. We calculate the co-benefits associated with these emission reductions using the interagency estimates of the social cost of carbon (SCC)[1].

It is important to note that the health co-benefits from reduced $PM_{2.5}$ exposure reported here contain uncertainty, including from the following key assumptions:

1. The $PM_{2.5}$-related co-benefits of the regulatory alternatives were derived through a benefit per-ton approach, which does not fully reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors that might lead to an over-estimate or under-estimate of the actual co-benefits of controlling PM precursors. In addition, differences in the distribution of emissions reductions across states between the modeled scenario and the final rule scenario add uncertainty to the final benefits estimates.

[1] Docket ID EPA-HQ-OAR-2009-0472-114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866,* Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at http://www.epa.gov/otaq/climate/regulations.htm

2. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$ produced via transported precursors emitted from EGUs may differ significantly from direct $PM_{2.5}$ released from diesel engines and other industrial sources, but the scientific evidence is not yet sufficient to allow differential effects estimates by particle type.

3. We assume that the health impact function for fine particles is linear within the range of ambient concentrations under consideration. Thus, the estimates include health co-benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both regions that are in attainment with fine particle standard and those that do not meet the standard down to the lowest modeled concentrations.

A large fraction of the $PM_{2.5}$-related benefits associated with this rule occur below the level of the National Ambient Air Quality Standard (NAAQS) for annual $PM_{2.5}$ at 15 $\mu g/m^3$, which was set in 2006. It is important to emphasize that NAAQS are not set at a level of zero risk. Instead, the NAAQS reflect the level determined by the Administrator to be protective of public health within an adequate margin of safety, taking into consideration effects on susceptible populations. While benefits occurring below the standard may be less certain than those occurring above the standard, EPA considers them to be legitimate components of the total benefits estimate.

Based on the modeled interim baseline which is approximately equivalent to the final baseline (see Appendix 5A), 11% and 73% of the estimated avoided premature deaths occur at or above an annual mean $PM_{2.5}$ level of 10 $\mu g/m^3$ (the LML of the Laden et al. 2006 study) and 7.5 $\mu g/m^3$ (the LML of the Pope et al. 2002 study), respectively. These are the source studies for the concentration-response functions used to estimate mortality benefits. As we model avoided premature deaths among populations exposed to levels of $PM_{2.5,}$ we have lower confidence in levels below the LML for each study. However, studies using data from more recent years, during which time PM concentrations have fallen, continue to report strong associations with mortality. EPA briefly describes these uncertainties below and in more detail in the benefits chapter of this RIA.

ES.1.2 Welfare Co-Benefits

The term *welfare co-benefits* covers both environmental and societal benefits of reducing pollution, such as reductions in damage to ecosystems, improved visibility and improvements in recreational and commercial fishing, agricultural yields, and forest

productivity. EPA did not quantify any of the important welfare co-benefits expected from the final MATS, but these are discussed in detail in Chapter 5.

Table ES-3. Estimated Reduction in Incidence of Adverse Health Effects of the Mercury and Air Toxics Standards (95% confidence intervals)[a,b]

Impact	Eastern U.S.[c]	Western U.S.	Total
Mercury-Related Endpoints			
IQ Points Lost			510.8
PM-Related Endpoints			
Premature death			
Pope et al. (2002) (age >30)	4,100 (1,100 – 7,000)	130 (30 – 220)	4,200 (1,200 – 7,200)
Laden et al. (2006) (age >25)	10,000 (4,800 – 16,000)	320 (140 – 510)	11,000 (5,000 – 17,000)
Infant (< 1 year)	19 (-21 – 59)	1 (-1 – 2)	20 (-22 – 61)
Chronic bronchitis	2,700 (89 – 5,400)	100 (-1 – 210)	2,800 (88 – 5,600)
Non-fatal heart attacks (age > 18)	4,600 (1,200 – 8,100)	120 (25 – 210)	4,700 (1,200 – 8,300)
Hospital admissions—respiratory (all ages)	820 (320 – 1,300)	17 (6 – 27)	830 (330 – 1,300)
Hospital admissions—cardiovascular (age > 18)	1,800 (1,200 – 2,100)	42 (27 – 50)	1,800 (1,200 – 2,200)
Emergency room visits for asthma (age < 18)	3,000 (1,500 – 4,500)	110 (52 – 160)	3,100 (1,600 – 4,700)
Acute bronchitis (age 8-12)	6,000 (-1,400 – 13,000)	250 (-69 – 560)	6,300 (-1,400 – 14,000)
Lower respiratory symptoms (age 7-14)	77,000 (30,000 – 120,000)	3,100 (1,100 – 5,200)	80,000 (31,000 – 130,000)
Upper respiratory symptoms (asthmatics age 9-18)	58,000 (11,000 – 110,000)	2,400 (360 – 4,400)	60,000 (11,000 – 110,000)
Asthma exacerbation (asthmatics age 6-18)	130,000 (4,500 – 430,000)	5,200 (-6 – 18,000)	130,000 (4,500 – 450,000)
Lost work days (ages 18-65)	520,000 (440,000 – 600,000)	21,000 (18,000 – 24,000)	540,000 (460,000 – 620,000)
Minor restricted-activity days (ages 18-65)	3,100,000 (2,500,000 – 3,700,000)	120,000 (99,000 – 150,000)	3,200,000 (2,600,000 – 3,800,000)

[a] Estimates rounded to two significant figures; column values will not sum to total value.

[b] The negative estimates for certain endpoints are the result of the weak statistical power of the study used to calculate these health impacts and do not suggest that increases in air pollution exposure result in decreased health impacts.

[c] Includes Texas and those states to the north and east.

Table ES-4. Estimated Economic Value of Health and Welfare Co-Benefits of the Mercury and Air Toxics Standards (95% confidence intervals, billions of 2007$)[a]

Impact	Pollutant	Eastern U.S.[b]	Western U.S.	Total
Avoided IQ loss associated with methylmercury exposure from self-caught fish consumption among recreational anglers				
3% discount rate	Hg			$0.004 – $0.006
7% discount rate	Hg			$0.0005 – $0.001
Adult premature death (Pope et al., 2002 PM mortality estimate)				
3% discount rate	$PM_{2.5}$	$33 ($2.6 - $99)	$1.0 (<$0.01 - $3.1)	$34 ($2.6 - $100)
7% discount rate	$PM_{2.5}$	$30 ($2.3 - $90)	$0.9 (<$0.01 - $2.8)	$30 ($2.4 - $92)
Adult premature death (Laden et al., 2006 PM mortality estimate)				
3% discount rate	$PM_{2.5}$	$84 ($7.4 - $240)	$2.6 ($0.1 - $7.6)	$87 ($7.5 - $250)
7% discount rate	$PM_{2.5}$	$76 ($6.7 - $220)	$2.3 ($0.1 - $6.9)	$78 ($6.8 - $230)
Infant premature death	$PM_{2.5}$	$0.2 ($-0.2 – $0.8)	<$0.01	$0.2 ($-0.2 - $0.8)
Chronic bronchitis	$PM_{2.5}$	$1.3 ($0.1 - $6.1)	$0.1 (<$0.01 - $0.2)	$1.4 ($0.1 - $6.4)
Non-fatal heart attacks				
3% discount rate	$PM_{2.5}$	$0.5 ($0.1 - $1.3)	<$0.01	$0.5 ($0.1 - $1.3)
7% discount rate	$PM_{2.5}$	$0.4 ($0.1 - $1.0)	<$0.01	$0.4 ($0.1 - $1.0)
Hospital admissions—respiratory	$PM_{2.5}$	$0.01 (<$0.01 - $0.02)	<$0.01	$0.01 ($0.01 - $0.02)
Hospital admissions—cardiovascular	$PM_{2.5}$	$0.03 (<$0.01 - $0.05)	<$0.01	$0.03 (<$0.01 - $0.05)
Emergency room visits for asthma	$PM_{2.5}$	<$0.01	<$0.01	<$0.01
Acute bronchitis	$PM_{2.5}$	<$0.01	<$0.01	<$0.01
Lower respiratory symptoms	$PM_{2.5}$	<$0.01	<$0.01	<$0.01
Upper respiratory symptoms	$PM_{2.5}$	<$0.01	<$0.01	<$0.01
Asthma exacerbation	$PM_{2.5}$	<$0.01	<$0.01	<$0.01
Lost work days	$PM_{2.5}$	$0.1 ($0.1 - $0.1)	<$0.01	$0.1 ($0.1 - $0.1)

(continued)

Table ES-4. Estimated Economic Value of Health and Welfare Co-Benefits of the Mercury and Air Toxics Standards (95% confidence intervals, billions of 2007$)[a] (continued)

Impact	Pollutant	Eastern U.S.[b]	Western U.S.	Total
Minor restricted-activity days	$PM_{2.5}$	$0.2 ($0.1 - $0.3)	<$0.01	$0.2 ($0.1 - $0.3)
CO_2-related benefits				
(3% discount rate)	CO_2			$0.36
Monetized total Benefits (Pope et al., 2002 $PM_{2.5}$ mortality estimate)				
3% discount rate		$35+B ($2.8 - $110)	$1.1+B ($0.03 - $3.4)	$37+B ($3.2 - $110)
7% discount rate		$32+B ($2.5 - $98)	$1.0+B ($0.03 - $3.1)	$33+B ($2.9 - $100)
Monetized total Benefits (Laden et al., 2006 $PM_{2.5}$ mortality estimate)				
3% discount rate		$87+B ($7.5 - $250)	$2.7+B ($0.1 - $7.9)	$90+B ($8.0 - $260)
7% discount rate		$78+B ($6.8 - $230)	$2.4+B ($0.1 - $7.2)	$81+B ($7.3 - $240)

[a] Economic value adjusted to 2007$ using GDP deflator. Estimates rounded to two significant figures. The negative estimates for certain endpoints are the result of the weak statistical power of the study used to calculate these health impacts and do not suggest that increases in air pollution exposure result in decreased health impacts. Confidence intervals reflect random sampling error and not the additional uncertainty associated with accounting for differences in air quality baseline forecasts described in Chapter 5. The net present value of reduced CO_2 emissions are calculated differently than other benefits. The same discount rate used to discount the value of damages from future emissions (SCC at 5, 3, 2.5 percent) is used to calculate net present value of SCC for internal consistency. This table shows monetized CO_2 co-benefits at discount rates at 3 and 7 percent that were calculated using the global average SCC estimate at a 3% discount rate because the interagency workgroup on this topic deemed this marginal value to be the central value. In section 5.6 we also report CO_2 co-benefits using discount rates of 5 percent (average), 2.5 percent (average), and 3 percent (95^{th} percentile).

[b] Includes Texas and those states to the north and east.

Figure ES-1 summarizes an array of $PM_{2.5}$-related monetized benefits estimates based on alternative epidemiology and expert-derived PM-mortality estimate.

Figure ES-2 summarizes the estimated net benefits for the final rule by displaying all possible combinations of health and climate co-benefits and costs. Each of the 14 bars in each graph represents a separate point estimate of net benefits under a certain combination of cost and benefit estimation methods. Because it is not a distribution, it is not possible to infer the likelihood of any single net benefit estimate.

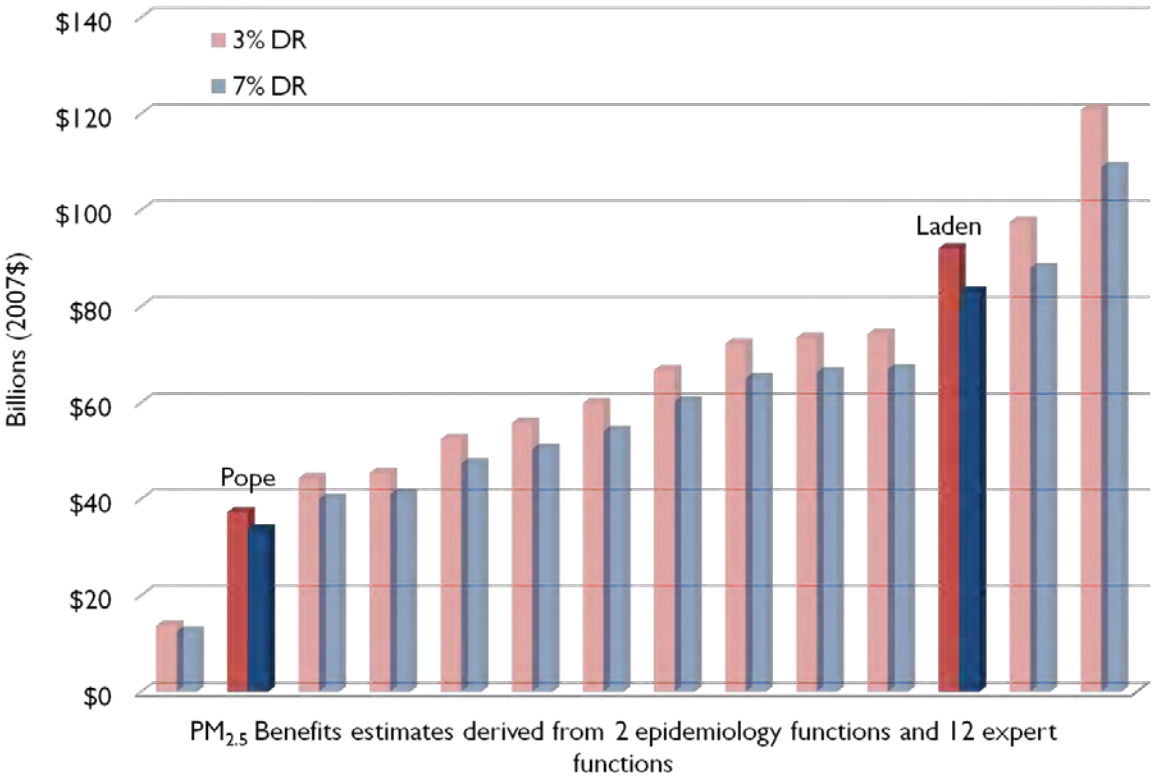

Figure ES-1. Economic Value of Estimated $PM_{2.5}$-Related Health Co-Benefits According to Epidemiology or Expert-Derived PM Mortality Risk Estimate[a,b]

[a] Based on the modeled interim baseline, which is approximately equivalent to the final baseline (see Appendix 5A)

[b] Column total equals sum of $PM_{2.5}$-related mortality and morbidity benefits.

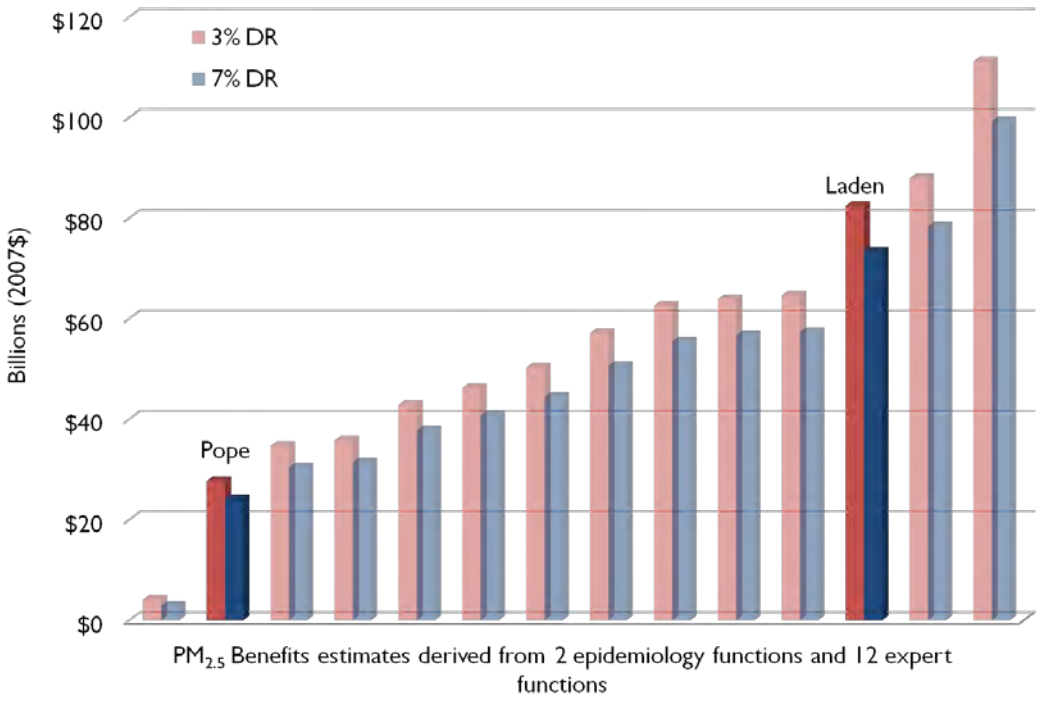

Figure ES-2. Net Benefits of the MATS Rule According to $PM_{2.5}$ Epidemiology or Expert-Derived Mortality Risk Estimate[a,b]

[a] Based on the modeled interim baseline, which is approximately equivalent to the final baseline (see Appendix 5A)

[b] Column total equals sum of $PM_{2.5}$-related mortality and morbidity benefits.

ES.2 Not All Benefits Quantified

EPA was unable to quantify or monetize all of the health and environmental benefits associated with the final MATS Rule. EPA believes these unquantified benefits could be substantial, including the overall value associated with HAP reductions, value of increased agricultural crop and commercial forest yields, visibility improvements, and reductions in nitrogen and acid deposition and the resulting changes in ecosystem functions. Tables ES-5 and ES-6 provide a list of these benefits.

Table ES-5. Human Health Effects of Pollutants Affected by the Mercury and Air Toxics Standards

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information[a]
Improved Human Health				
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	Section 5.4
	Infant mortality (age <1)	✓	✓	Section 5.4
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	✓	✓	Section 5.4
	Hospital admissions—respiratory (all ages)	✓	✓	Section 5.4
	Hospital admissions—cardiovascular (age >18)	✓	✓	Section 5.4
	Emergency room visits for asthma (age <18)	✓	✓	Section 5.4
	Acute bronchitis (age 8–12)	✓	✓	Section 5.4
	Lower respiratory symptoms (age 7–14)	✓	✓	Section 5.4
	Upper respiratory symptoms (asthmatics age 9-11)	✓	✓	Section 5.4
	Asthma exacerbation (asthmatics age 6–18)	✓	✓	Section 5.4
	Lost work days (age 18-65)	✓	✓	Section 5.4
	Minor restricted-activity days (age 18–65)	✓	✓	Section 5.4
	Chronic bronchitis (age >26)	✓	✓	Section 5.4
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[c]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[c]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc)	—	—	PM ISA[c, d]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[c, d]
Reduced incidence of mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	—	—	Ozone CD, Draft Ozone ISA[b]
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone CD, Draft Ozone ISA[b]
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	—	—	Ozone CD, Draft Ozone ISA[b]
	Hospital admissions—respiratory causes (age <2)	—	—	Ozone CD, Draft Ozone ISA[b]
	Emergency room visits for asthma (all ages)	—	—	Ozone CD, Draft Ozone ISA[b]
	Minor restricted-activity days (age 18–65)	—	—	Ozone CD, Draft Ozone ISA[b]

(continued)

Table ES-5. Human Health Effects of Pollutants Affected by the Mercury and Air Toxics Standards (continued)

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
	School absence days (age 5–17)	—	—	Ozone CD, Draft Ozone ISA[b]
	Decreased outdoor worker productivity (age 18-65)	—	—	Ozone CD, Draft Ozone ISA[b]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone CD, Draft Ozone ISA[c]
	Cardiovascular and nervous system effects	—	—	Ozone CD, Draft Ozone ISA[d]
	Reproductive and developmental effects	—	—	Ozone CD, Draft Ozone ISA[d]
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions (all ages)	—	—	NO_2 ISA[b]
	Chronic lung disease hospital admissions (age > 65)	—	—	NO_2 ISA[b]
	Respiratory emergency department visits (all ages)	—	—	NO_2 ISA[b]
	Asthma exacerbation (asthmatics age 4–18)	—	—	NO_2 ISA[b]
	Acute respiratory symptoms (age 7–14)	—	—	NO_2 ISA[b]
	Premature mortality	—	—	NO_2 ISA[c,d]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[c,d]
Reduced incidence of morbidity from exposure to SO_2	Respiratory hospital admissions (age > 65)	—	—	SO_2 ISA[b]
	Asthma emergency room visits (all ages)	—	—	SO_2 ISA[b]
	Asthma exacerbation (asthmatics age 4–12)	—	—	SO_2 ISA[b]
	Acute respiratory symptoms (age 7–14)	—	—	SO_2 ISA[b]
	Premature mortality	—	—	SO_2 ISA[c,d]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	SO_2 ISA[c,d]
Reduced incidence of morbidity from exposure to methyl mercury (through reduced mercury deposition as well as the role of sulfate in methylation)	Neurologic effects—IQ loss	✓	✓	IRIS; NRC, 2000[b]
	Other neurologic effects (e.g., developmental delays, memory, behavior)	—	—	IRIS; NRC, 2000c
	Cardiovascular effects	—	—	IRIS; NRC, 2000[c,d]
	Genotoxic, immunologic, and other toxic effects	—	—	IRIS; NRC, 2000[c,d]

[a] For a complete list of references see Chapter 5.
[b] We assess these benefits qualitatively due to time and resource limitations for this analysis.
[c] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[d] We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

Table ES-6. Environmental Effects of Pollutants Affected by the Mercury and Air Toxics Standards

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information[a]
Improved Environment				
Reduced visibility impairment	Visibility in Class I areas in SE, SW, and CA regions	—	—	PM ISA[b]
	Visibility in Class I areas in other regions	—	—	PM ISA[b]
	Visibility in residential areas	—	—	PM ISA[b]
Reduced climate effects	Global climate impacts from CO_2	—	✓	Section 5.6
	Climate impacts from ozone and PM	—	—	Section 5.6
	Other climate impacts (e.g., other GHGs, other impacts)	—	—	IPCC[c]
Reduced effects on materials	Household soiling	—	—	PM ISA[c]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[c]
Reduced effects from PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[c]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone CD, Draft Ozone ISA[c]
	Reduced vegetation growth and reproduction	—	—	Ozone CD, Draft Ozone ISA[b]
	Yield and quality of commercial forest products and crops	—	—	Ozone CD, Draft Ozone ISA[b,d]
	Damage to urban ornamental plants	—	—	Ozone CD, Draft Ozone ISA[c]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone CD, Draft Ozone ISA[c]
	Recreational demand associated with forest aesthetics	—	—	Ozone CD, Draft Ozone ISA[c]
	Other non-use effects			Ozone CD, Draft Ozone ISA[c]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone CD, Draft Ozone ISA[c]

(continued)

Table ES-6. Environmental Effects of Pollutants Affected by the Mercury and Air Toxics Standards (continued)

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[b]
	Tree mortality and decline	—	—	NO_x SO_x ISA[c]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[c]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[c]
	Other nonuse effects			NO_x SO_x ISA[c]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[c]
Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[c]
	Coastal eutrophication	—	—	NO_x SO_x ISA[c]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[c]
	Other non-use effects			NO_x SO_x ISA[c]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[c]
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[c]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[c]
Reduced incidence of morbidity from exposure to methyl mercury (through reduced mercury deposition as well as the role of sulfate in methylation)	Effects on fish, birds, and mammals (e.g., reproductive effects)	—	—	Mercury Study RTC[c,d]
	Commercial, subsistence and recreational fishing	—	—	Mercury Study RTC[c]

[a] For a complete list of references see Chapter 5.
[b] We assess these benefits qualitatively due to time and resource limitations for this analysis.
[c] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[d] We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

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]

[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.

[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.

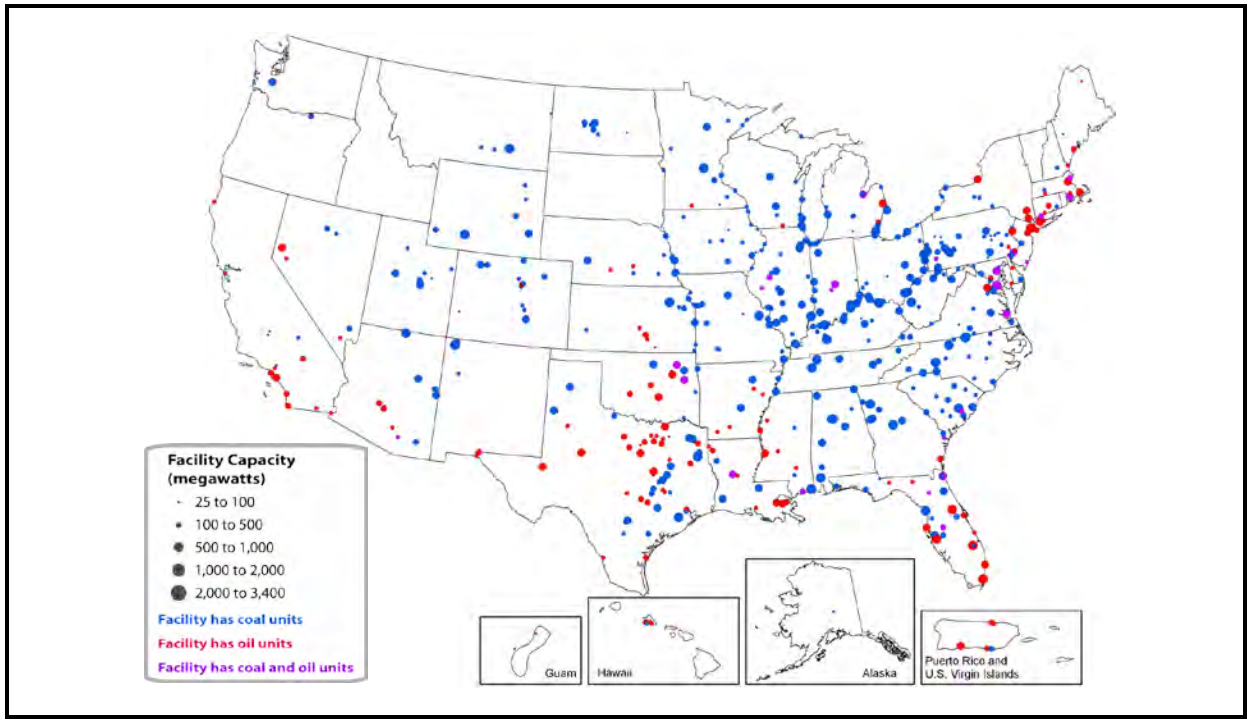

Figure 3-1. Geographic Distribution of Affected Units, by Facility, Size and Fuel Source in 2012

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.

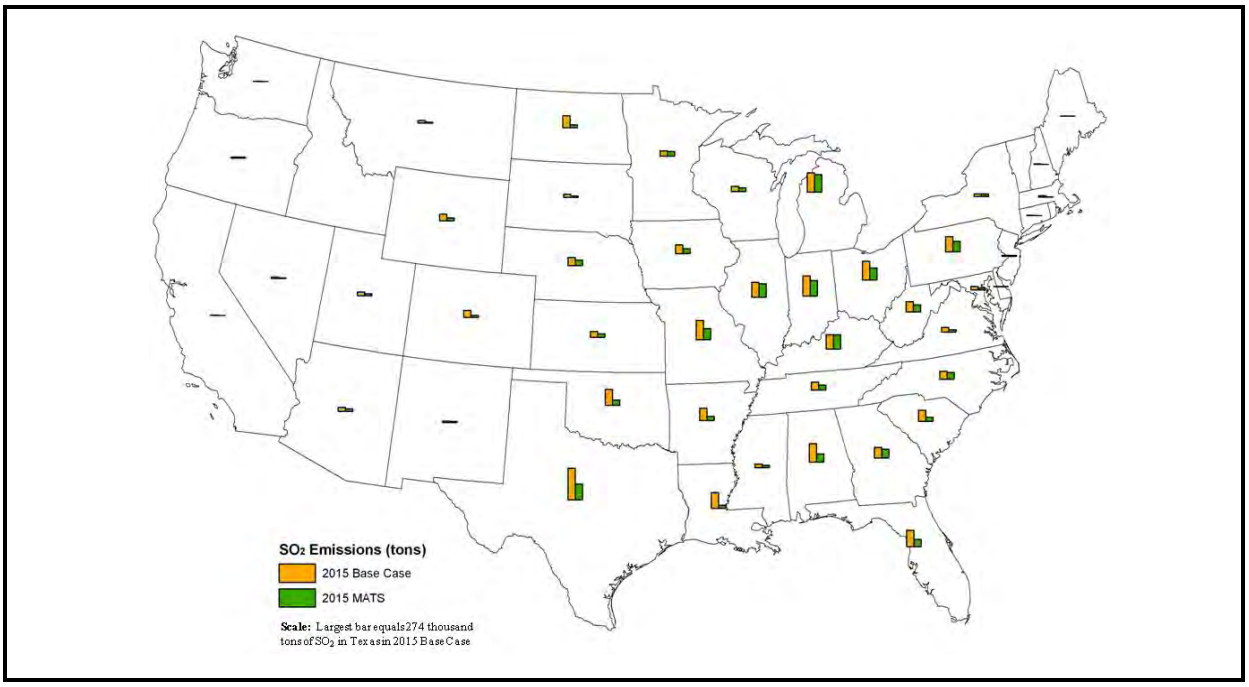

Figure 3-2. SO_2 Emissions from the Power Sector in 2015 with and without MATS

Source: 2015 emissions include coal steam (including IGCC and petroleum coke) units >25 MW from IPM v4.10 base case and control case projections (EPA, February 2011)

Figure 3-3. NO_X Emissions from the Power Sector in 2015 with and without MATS

Source: 2015 emissions include coal steam (including IGCC and petroleum coke) units >25 MW from IPM v4.10_MATS base case and control case projections (EPA, 2011)

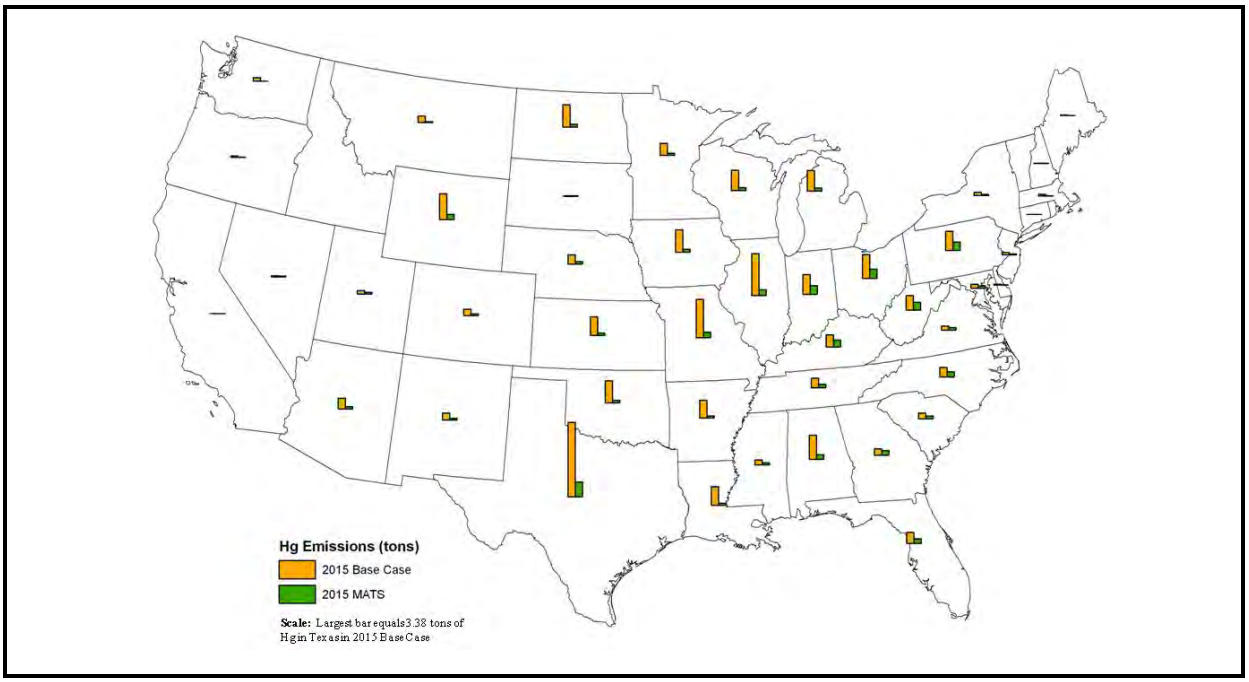

Figure 3-4. Mercury Emissions from the Power Sector in 2015 with and without MATS

Source: 2015 emissions include coal steam (including IGCC and petroleum coke) units >25 MW from IPM v4.10_MATS base case and control case projections (EPA, 2011)

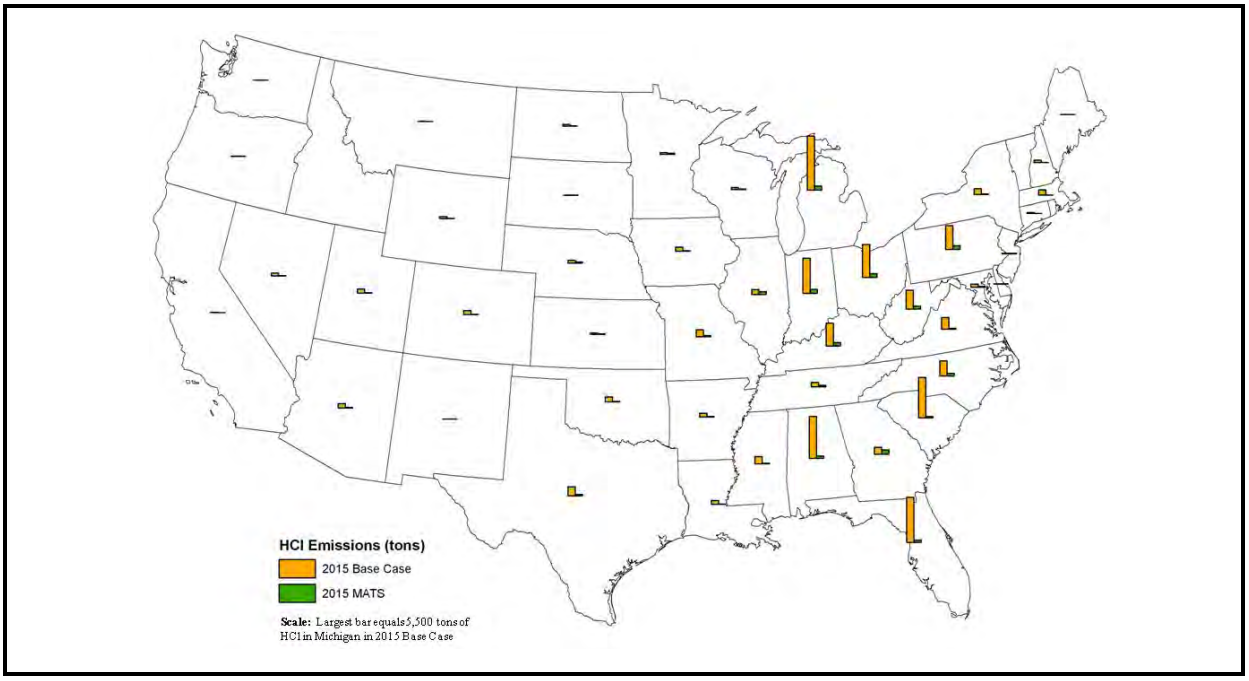

Figure 3-5. Hydrogen Chloride Emissions from the Power Sector in 2015 with and without MATS

Source: 2015 emissions include coal steam (including IGCC and petroleum coke) units >25 MW from IPM v4.10_MATS base case and control case projections (EPA, 2011)

3.3 Projected Compliance Costs

The power industry's "compliance costs" are represented in this analysis as the change in electric power generation costs between the base case and policy case in which the sector pursues pollution control approaches to meet the final HAP emission standards. In simple terms, these costs are the resource costs of what the power industry will directly expend to comply with EPA's requirements.

EPA projects that the annual incremental compliance cost of MATS is $9.4 billion in 2015 ($2007). The annual incremental cost is the projected additional cost of complying with the final rule in the year analyzed, and includes the amortized cost of capital investment (at 6.15%) and the ongoing costs of operating additional pollution controls, investments in new generating sources, shifts between or amongst various fuels, and other actions associated with compliance. This projected cost does not include the compliance calculated outside of IPM modeling, namely the compliance costs for oil-fired EGUs, and monitoring, reporting, and record-keeping costs. See section 3.14 for further details on these costs. EPA believes that the

cost assumptions used for the final rule reflect, as closely as possible, the best information available to the Agency today.

Table 3-5. Annualized Compliance Cost for MATS Requirements on Coal-fired Generation

	2015	2020	2030
Annualized Compliance Cost (billions of 2007$)	$9.4	$8.6	$7.4

Source: Integrated Planning Model run by EPA, 2011.

EPA's projection of $9.4 billion in additional costs in 2015 should be put into context for power sector operations. As shown in section 2.7, the power sector is expected in the base case to expend over $320 billion in 2015 to generate, transmit, and distribute electricity to end-use consumers. Therefore, the projected costs of compliance with MATS amount to less than a 3% increase in the cost to meet electricity demand, while securing public health benefits that are several times more valuable (as described in Chapters 4 and 5).

3.4 Projected Compliance Actions for Emissions Reductions

Fossil fuel-fired electric generating units are projected to achieve HAP emission reductions through a combination of compliance options. These actions include improved operation of existing controls, additional pollution control installations, coal switching (including blending of coals), and generation shifts towards more efficient units and lower-emitting generation technologies (e.g., some reduction of coal-fired generation with an increase of generation from natural gas). In addition, there will be some affected sources that find it uneconomic to invest in new pollution control equipment and will be removed from service. These facilities are generally amongst the oldest and least efficient power plants, and typically run infrequently. In order to ensure that any retirements resulting from MATS do not adversely impact the ability of affected sources and electric utilities from meeting the demand for electricity, EPA has conducted an analysis of the impacts of projected retirements on electric reliability. This analysis is discussed in TSD titled: "Resource Adequacy and Reliability in the IPM Projections for the MATS Rule" which is available in the docket.

The requirements under MATS are largely met through the installation of pollution controls (see Figure 3-6). To a lesser extent, there is a small degree of shifting within and across various ranks and types of coals, and a relatively small shift from coal-fired generation to greater use of natural gas and non-emitting sources of electricity (e.g., hydro and nuclear) (see Table 3-6). The largest share of emissions reductions occur from coal-fired units installing new pollution control devices, such as FGD, ACI, and fabric filters; a smaller share of emission

reductions come from fuel shifts and unit retirements. Mercury emission reductions are largely driven by SCR/FGD combinations and ACI installations. HCl emission reductions are largely driven by FGD and DSI installations, which also incidentally provide substantial SO_2 reductions in the policy case. Mercury, $PM_{2.5}$, and HCl emission reductions are also facilitated by the installation of fabric filters, which boost mercury and HCl removal efficiencies of ACI and DSI, respectively.

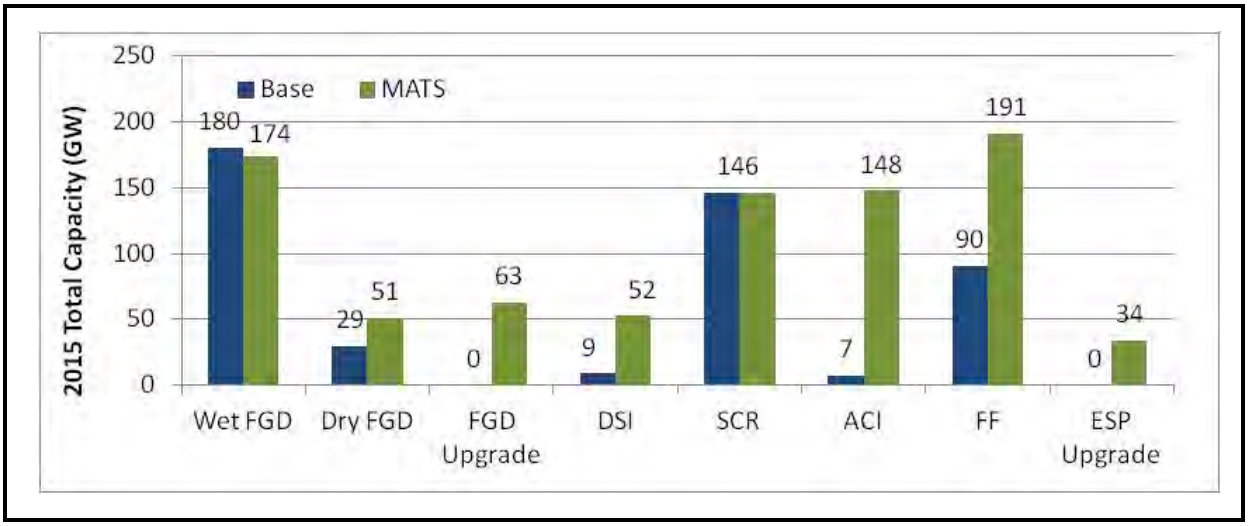

Figure 3-6. Operating Pollution Control Capacity on Coal-fired Capacity (by Technology) with the Base Case and with MATS, 2015 (GW)

Note: The difference between controlled capacity in the base case and under the MATS may not necessarily equal new retrofit construction, since controlled capacity above reflects incremental operation of dispatchable controls in 2015. Additionally, existing ACI installed on those units online before 2008 are not included in the base case to reflect removal of state mercury rules from IPM modeling. For these reasons, and due to rounding, numbers in the text below may not reflect the increments displayed in this figure. See IPM Documentation for more information on dispatchable controls.

Source: Integrated Planning Model run by EPA, 2011.

As shown in Figure 3-6, this analysis projects that by 2015, the final rule will drive the installation of an additional 20 GW of dry FGD (dry scrubbers), 44 GW of DSI, 99 GW of additional ACI, 102 GW of additional fabric filters, 63 GW of scrubber upgrades, and 34 GW of ESP upgrades. Furthermore, the final rule results in a 3 GW decrease in retrofit wet FGD capacity relative to the base, where the SO_2 allowance price under CSAPR provides an incentive for the additional SO_2 reductions achieved by a wet scrubber relative to a dry scrubber.

The difference between operating controlled capacity in the base case and under MATS in Figure 3-6 may not necessarily equal new retrofit construction, since total controlled capacity in the figure reflects incremental operation of existing controls that are projected to operate

under MATS but not under the base case. With respect to the increase in operating ACI, some of this increase represents existing ACI capacity on units built before 2008. EPA's modeling does not reflect the presence of state mercury rules, and EPA assumes that ACI controls on units built before 2008 do not operate in the absence of these rules. In the policy case, these controls are projected to operate and the projected compliance cost thus reflects the operating cost of these controls. Since these controls are in existence, EPA does not count their capacity toward new retrofit construction, nor does EPA's compliance costs projection reflect the capital cost of these controls (new retrofit capacity is reported in the previous paragraph).

3.5 Projected Generation Mix

Table 3-6 and Figure 3-7 show the generation mix in the base case and in MATS. In 2015, coal-fired generation is projected to decline slightly and natural-gas-fired generation is projected to increase slightly relative to the base case. Coal-fired generation is projected to increase above 2009 actual levels. 2015 natural gas-fired generation is projected to be lower than 2009, due in large part to the smaller relative difference in delivered natural gas and coal prices in different areas of the country projected in 2015 than occurred in 2009. The vast majority (over 98%) of base case coal capacity is projected to remain in service under MATS. In addition, the operating costs of complying coal-fired units are not so affected as to result in major changes in the electricity generation mix.

Table 3-6. Generation Mix with the Base Case and the MATS, 2015 (Thousand GWh)

	2009	2015			
				Change from	
	Historical	Base Case	Policy Case	Base	Percent Change
Coal	1,741	1,982	1,957	-25	-1.3%
Oil	36	0.11	0.11	0.00	3.6%
Natural Gas	841	710	731	22	3.1%
Nuclear	799	828	831	3	0.4%
Hydroelectric	267	286	288	2	0.8%
Non-hydro Renewables	116	252	250	-1	-0.6%
Other	10	45	45	0.0	0.0%
Total	3,810	**4,103**	**4,104**	**1**	**0.0%**

Note: Numbers may not add due to rounding.

Source: 2009 data from AEO Annual Energy Review, Table 8.2c Electricity Net Generation: Electric Power Sector by Plant Type, 1989-2010; 2015 projections are from the Integrated Planning Model run by EPA, 2011.

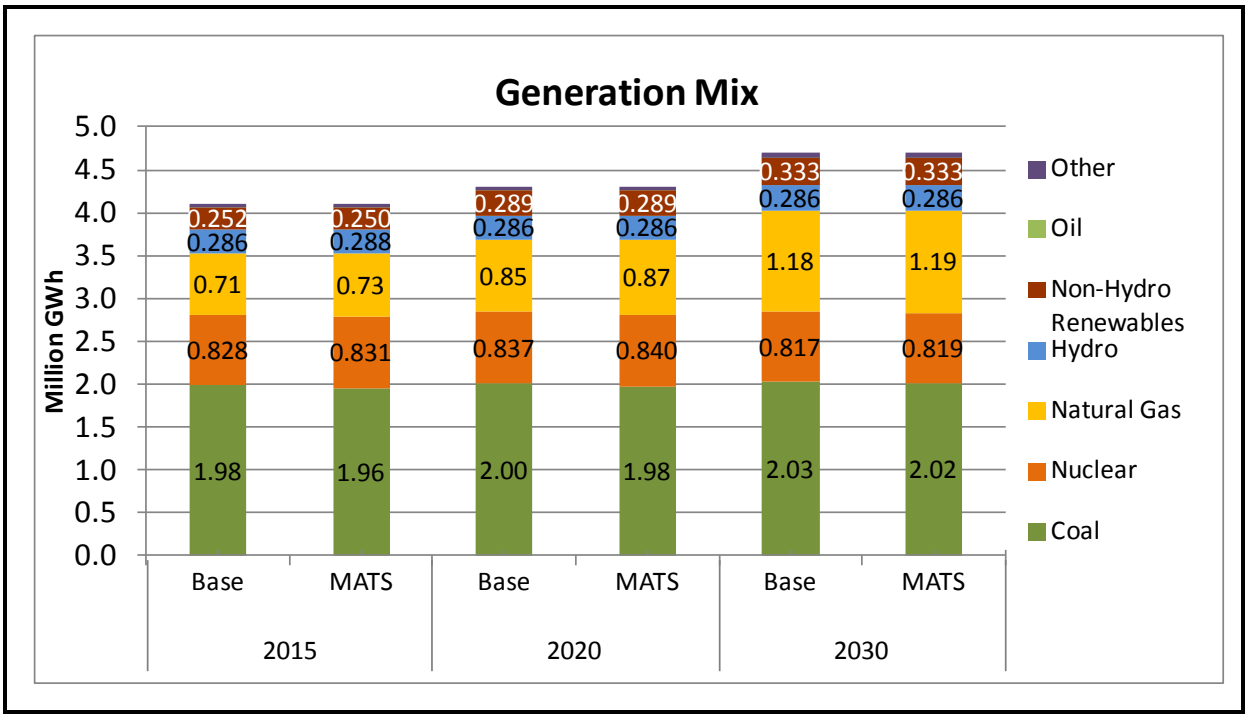

Figure 3-7. Generation Mix with the Base Case and with MATS, 2015-2030

Source: Integrated Planning Model run by EPA, 2011.

3.6 Projected Withdrawals from Service

Relative to the base case, about 4.7 GW (less than 2 percent) of coal-fired capacity is projected to be uneconomic to maintain by 2015. This projection considers various regional factors (e.g., other available capacity and fuel prices) and unit attributes (e.g., efficiency and age). These projected "uneconomic" units, for the most part, are older, smaller, and less frequently used generating units that are dispersed throughout the country (see Table 3-7).

Table 3-7. Characteristics of Covered Operational Coal Units and Additional Coal Units Projected to Withdraw as Uneconomic under MATS, 2015

	Average Age (Years)	Average Capacity	
		MW	Factor in Base
Withdrawn as Uneconomic	52	129	54%
Operational	43	322	71%

Source: Integrated Planning Model run by EPA, 2011.

These results should be considered "potential" closures. There are a variety of local factors that could make plant owners decide to keep one or more units projected to be uneconomic in service. These factors include different costs or demand estimates than what

was included in the IPM modeling, and local operating conditions or requirements that are on a smaller scale than that represented in EPA's IPM modeling. To the extent EPA's modeling does not account for plants that continue to operate due to one or more of these local factors, these results could be overestimating the capacity removed from service as a result of this rule.

For the final rule, EPA has examined whether the IPM-projected closures may adversely impact reserve margins and reliability planning. The IPM model is specifically designed to ensure that generation resource availability is maintained in the projected results subject to reserve margins in 32 modeling regions for the contiguous US, which must be preserved either by using existing resources or through the construction of new resources. IPM also addresses reliable delivery of generation resources by limiting the ability to transfer power between regions using the bulk power transmission system. Within each model region, IPM assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region. The IPM model projects available capacity given certain constraints such as reserve margins and transmission capability but does not constitute a detailed reliability analysis. For example, the IPM model does not examine frequency response. For more detail on IPM's electric load modeling and power system operation, please see IPM documentation (http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html) and the TSD on Resource Adequacy and Reliability in the IPM Projections for the MATS Rule.

Total operational capacity is lower in the policy scenario, primarily as a result of additional coal projected to be uneconomic to maintain. Since most regions are projected to have excess capacity above their target reserve margins, most of these withdrawals from service are absorbed by a reduction in excess reserves. Operational capacity changes from the base case in 2015 are shown in Table 3-8.

Table 3-8. Total Generation Capacity by 2015 (GW)

	2010	Base Case	MATS
Pulverized Coal	317	310	305
Natural Gas Combined Cycle	201	206	206
Other Oil/Gas	253	233	233
Non-Hydro Renewables	31	70	70
Hydro	99	99	99
Nuclear	102	104	105
Other	5	4	4
Total	1,009	1,026	1,021

Source: 2010 data from EPA's NEEDS v.4.10_PTox. Projections from Integrated Planning Model run by EPA.
Note: "Non-Hydro Renewables" include biomass, geothermal, solar, and wind electric generation capacity. 2015 capacity reflects plant closures planned to occur prior to 2015.

The policy case analyzed maintains resource adequacy in each region projected to decrease in coal capacity by using excess reserve capacity within the region, reversing base case withdrawals of non-coal capacity, building new capacity, or by importing excess reserve capacity from other regions. Although any closure of a large generation facility will need to be studied to determine potential local reliability concerns, EPA analysis suggests that projected economic withdrawals from service under the final rule could have little to no overall impact on electric reliability. Not only are projected withdrawals under MATS limited in scope, but the existing state of the power sector is also characterized by substantial excess capacity. The weighted average reserve margin at the national level is projected to be approximately 25% in the base case, while the North American Electric Reliability Corporation (NERC) recommends a margin of 15%. EPA projects that MATS would only reduce total operational capacity by less than one percent in 2015.

Moreover, coal units projected to withdraw as uneconomic are distributed throughout the power grid with limited effect at the regional level, such that any potential impacts should not adversely affect reserve margins and should be manageable through the normal industry processes. For example, in the RFC NERC reliability Region, containing coal-fired generating area in Pennsylvania, West Virginia and the Midwest, there is a decrease of less than 2% in the reserve margin in the policy case and a remaining overall reserve margin of over 20%. Furthermore, subregions may share each other's excess reserves to ensure adequate reserve margins within a larger reliability region. EPA's IPM modeling accommodates such transfers of reserves within the assumed limits of reliability of the inter-regional bulk power system. For

these reasons, the projected closures of coal plants are not expected to raise broad reliability concerns.

3.7 Projected Capacity Additions

Due in part to a low growth rate anticipated for future electricity demand levels in the latest EIA forecast, EPA analysis indicates that there is sufficient excess capacity through 2015 to compensate for capacity that is retired from service under MATS. In the short-term, most new capacity is projected as a mix of wind and natural gas in response to low fuel prices and other energy policies (such as tax credits and state renewable portfolio standards). In addition, future electricity demand expectations have trended downwards in recent forecasts, reducing the need for new capacity in the 2015 timeframe (see Chapter 2 for more discussion on future electricity demand).

Table 3-9. Total Generation Capacity by 2030 (GW)

	2010	Base Case	MATS	Change
Pulverized Coal	317	308	304	-3.9
Natural Gas Combined Cycle	201	275	278	2.9
Other Oil/Gas	253	235	235	0.6
Non-Hydro Renewables	31	79	79	0.1
Hydro	99	99	99	0.0
Nuclear	102	103	103	0.3
Other	5	4	4	0.0
Total	1,009	1,103	1,102	-0.1

Note: "Non-Hydro Renewables" include biomass, geothermal, solar, and wind electric generation capacity.
Source: 2010 data from EPA's NEEDS v.4.10_PTox. Projections from Integrated Planning Model run by EPA.

3.8 Projected Coal Production for the Electric Power Sector

Coal production for electricity generation under MATS is expected to increase from 2009 levels and decline modestly relative to the base case without the rule. The reductions in emissions from the power sector will be met through the installation and operation of pollution controls for HAP removal. Many available pollution controls achieve emissions removal rates of up to 99 percent (e.g., HCl removal by new scrubbers), which allows industry to rely more heavily on local bituminous coal in the eastern and central parts of the country that has higher contents of HCl and sulfur, and it is less expensive to transport than western subbituminous coal. Overall demand for coal is projected to be reduced as a result of MATS, with a slight

reduction in bituminous coal, and more of a reduction in subbituminous coal (see Tables 3-10 and 3-11). The trend reflects the projected reduced demand for lower-sulfur coal under MATS, where nearly all units are operating with a post-combustion emissions control. In this case, because of the additional pollution controls, many of these units no longer find it economic to pay a transportation premium to purchase lower-sulfur subbituminous coals. Instead, EGUs are generally projected to shift consumption towards nearby bituminous coal, which can achieve low emissions when combined with post-combustion emissions controls. This explains the increase from the base case in coal supplied from the Interior region, which is located in relatively close proximity to many coal-fired generators subject to MATS. This continues a trend of increased Interior supply (due to abundant Illinois Basin reserves that are relatively inexpensive to mine) and decreased Central Appalachian supply which is forecasted to occur in the base case from historic levels. The decline in Appalachia is a result of an increase in the relative cost of Central Appalachian extraction due both to rising mining cost (e.g., in 2010 major producers reported mining cost increases up to 15% with this trend continuing into 2011) and shrinking economically recoverable capacity. Growing international demand for Appalachian thermal coal is also contributing to its rising price. The increase in lignite use occurs at units blending subbituminous and lignite coals, and reflects a small shift in blended balance towards a greater use of lignite.

Table 3-10. 2015 Coal Production for the Electric Power Sector with the Base Case and MATS (Million Tons)

Supply Area	2009	2015 Base	2015 MATS	Change in 2015
Appalachia	246	184	172	-6%
Interior	129	216	236	9%
West	553	554	537	-3%
Waste Coal	14	14	13	-5%
Imports		30	30	0%
Total	942	998	989	-1%

Source: Production: U.S. Energy Information Administration (EIA), *Coal Distribution — Annual (Final)*, web site http://www.eia.doe.gov/cneaf/coal/page/coaldistrib/a_distributions.html (posted February 18, 2011); Waste Coal: U.S. EIA, *Monthly Energy Review, January 2011 Edition,* Table 6.1 Coal Overview, web site http://www.eia.doe.gov/emeu/mer/coal.html (posted January 31, 2011). All projections from Integrated Planning Model run by EPA, 2011.

Table 3-11. 2015 Power Sector Coal Use with the Base Case and the MATS, by Coal Rank (TBtu)

Coal Rank	Base	MATS	Change
Bituminous	11,314	11,248	-0.6%
Subbituminous	7,736	7,554	-2%
Lignite	849	895	5%
Total	19,900	19,698	-1%

Source: Integrated Planning Model run by EPA, 2011.

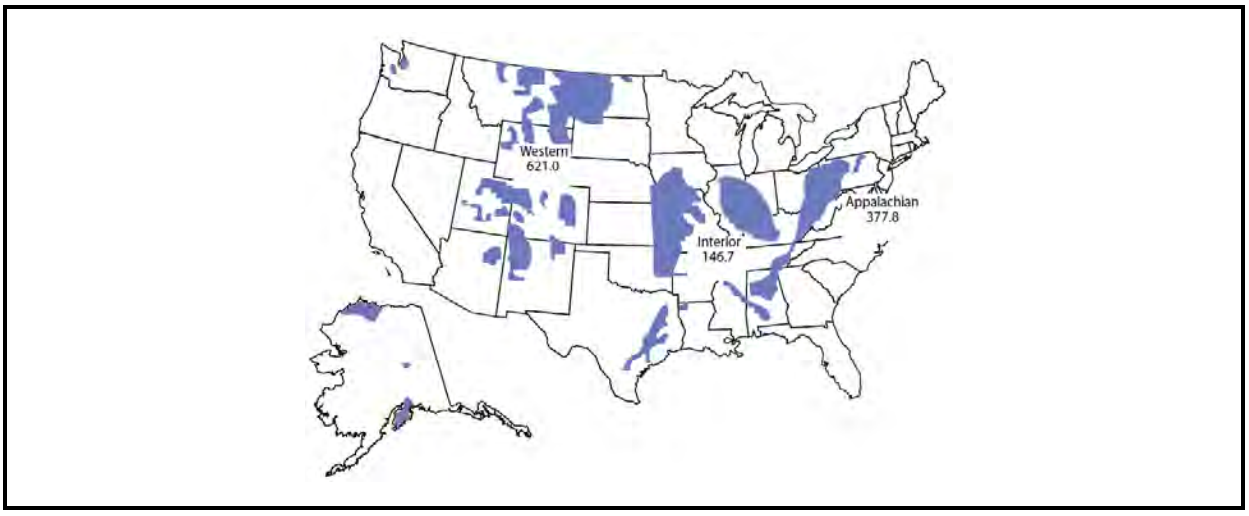

Figure 3-8. Total Coal Production by Coal-Producing Region, 2007 (Million Short Tons)

Note: Regional totals do not include refuse recovery

Source: EIA Annual Coal Report, 2007

3.9 Projected Retail Electricity Prices

EPA's analysis projects a near-term increase in the average retail electricity price of 3.1% in 2015 falling to 2% by 2020 under the final rule in the contiguous U.S. The projected price impacts vary by region and are provided in Table 3-12 (see Figure 3-9 for regional classifications).

Regional retail electricity prices are projected to range from 1 to 6 percent higher with MATS in 2015. The extent of regional retail electricity increases correlates with states that have considerable coal-fired generation in total generation capacity and that coal-fired generation is less well-controlled (such as in the ECAR and SPP regions). Retail electricity prices embody generation, transmission, and distribution costs. IPM modeling projects changes in regional

wholesale power prices, capacity payments, and actual costs of compliance in areas that are "cost of service" regions that are combined with EIA regional transmission and distribution costs to complete the retail price picture.

Table 3-12. Projected Contiguous U.S. and Regional Retail Electricity Prices with the Base Case and with the MATS (2007 cents/kWh)

	Base Case			MATS			Percent Change		
	2015	2020	2030	2015	2020	2030	2015	2020	2030
ECAR	8.2	8.2	9.8	8.5	8.5	9.9	4.5%	2.8%	1.0%
ERCOT	8.9	8.8	11.3	9.2	8.8	11.3	3.3%	0.6%	-0.2%
MAAC	9.5	10.4	12.7	9.8	10.4	12.7	2.8%	0.4%	-0.2%
MAIN	8.1	8.4	9.7	8.3	8.6	9.7	2.8%	2.2%	0.2%
MAPP	8.0	7.9	8.5	8.5	8.3	8.8	5.3%	5.6%	3.4%
NY	13.8	13.4	16.6	14.1	13.5	16.6	2.2%	0.7%	-0.1%
NE	12.3	11.8	13.8	12.6	11.9	13.8	2.0%	0.8%	0.0%
FRCC	10.2	9.7	11.0	10.4	9.8	11.0	2.2%	0.9%	0.4%
STV	7.9	7.8	8.4	8.2	8.0	8.6	3.1%	2.4%	1.6%
SPP	7.7	7.4	8.1	8.1	7.8	8.4	6.3%	6.1%	4.6%
PNW	7.1	6.8	7.6	7.3	7.0	7.6	2.7%	2.6%	1.1%
RM	9.2	9.5	11.0	9.4	9.7	11.1	2.3%	1.9%	1.1%
CALI	13.0	12.5	12.7	13.2	12.6	12.7	1.3%	0.7%	0.0%
Contiguous U.S. Average	9.0	9.0	10.2	9.3	9.2	10.3	3.1%	2.0%	0.9%

Source: EPA's Retail Electricity Price Model, 2011.

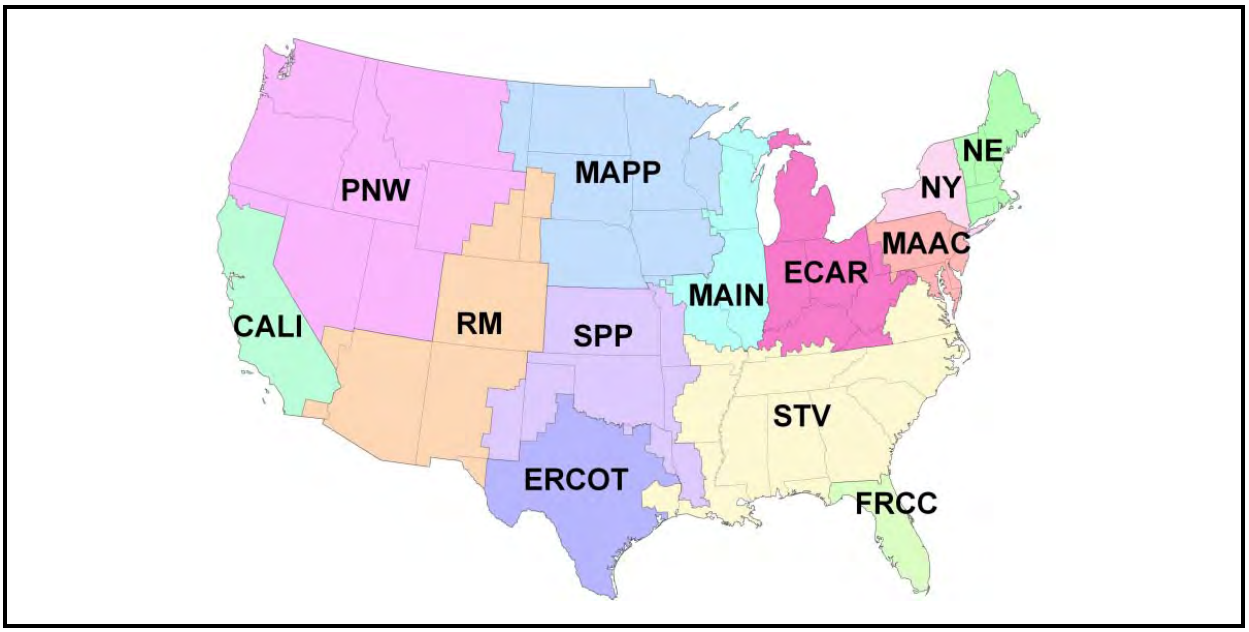

Figure 3-9. Retail Price Model Regions

3.10 Projected Fuel Price Impacts

The impacts of the final Rule on coal and natural gas prices before shipment are shown below in Tables 3-13 and 3-14. Overall, the national average coal price changes are related to changes in demand for a wide variety of coals based upon a number of parameters (e.g., chlorine or mercury content, heat content, proximity to the power plant, etc.), and this national average captures increases and decreases in coal demand and price at the regional level. Generally, total demand for coal decreases slightly under MATS, most notably subbituminous coal, which is by far the least expensive type of coal supplied to the power sector on an MMBtu basis. This is reflected in the projected average minemouth price of coal, which goes up by about 3 percent even though total demand for coal is reduced slightly (1 percent reduction). Notwithstanding the projected "mine-mouth" coal price changes, many units may in fact be realizing overall fuel cost savings by switching to more local coal supplies (which reduces transportation costs) after installing additional pollution control equipment. Gas price changes are directly related the projected increase in natural gas consumption under MATS. This increase in demand is met by producing additional natural gas at some increase in regional costs, resulting over time in a small price increase.

Table 3-13. Average Minemouth and Delivered Coal Prices with the Base Case and with MATS (2007$/MMBtu)

		2015			2030		
	2007	Base Case	MATS	Percent Change from Base	Base Case	MATS	Percent Change from Base
Minemouth	1.27	1.35	1.39	2.8%	1.51	1.56	3.3%
Delivered	1.76	2.11	2.15	1.9%	2.29	2.33	1.7%

Source: Historical data from EIA AEO 2010 Reference Case Table 15 (Coal Supply, Distribution, and Prices); projections from the Integrated Planning Model run by EPA, 2011.

Table 3-14. 2015-2030 Weighted Average Henry Hub (spot) and Delivered Natural Gas Prices with the Base Case and with MATS (2007$/MMBtu)

	Base Case	MATS	Percent Change from Base
Henry Hub	5.29	5.32	0.6%
Delivered - Electric Power	5.56	5.60	0.6%
Delivered - Residential	10.94	10.97	0.3%

Source: Projections from the Integrated Planning Model run by EPA (2011) adjusted to Henry Hub prices using historical data from EIA AEO 2011 reference case to derive residential prices.

IPM modeling of natural gas prices uses both short- and long-term price signals to balance supply of and demand in competitive markets for the fuel across the modeled time horizon. As such, it should be understood that the pattern of IPM natural gas price projections over time is not a forecast of natural gas prices incurred by *end-use consumers* at any particular point in time. The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and even sees major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). These short-term price signals are fundamental for allowing the market to successfully align immediate supply and demand needs; however, end-use consumers are typically shielded from experiencing these rapid fluctuations in natural gas prices by retail rate regulation and by hedging through longer-term fuel supply contracts. IPM assumes these longer-term price arrangements take place "outside of the model" and on top of the "real-time" shorter-term price variation necessary to align supply and demand. Therefore, the model's natural gas price projections should not be mistaken for traditionally experienced consumer price impacts related to natural gas, but a reflection of expected average price changes over the time period 2015 to 2030.

For this analysis, in order to represent a natural gas price evolution that end-use consumers can anticipate under retail rate regulation and/or typical hedging behavior, EPA is displaying the weighted average of IPM's natural gas price projections for the 2015-2030 time horizon (see Table 3-14). In that framework, consumer natural gas price impacts are anticipated to range from 0.3% to 0.6% based on consumer class in response to MATS.

3.11 Key Differences in EPA Model Runs for MATS Modeling

In this analysis, we use the Integrated Planning Model (IPM), which is a multiregional, dynamic, deterministic linear programming model of the U.S. electric power sector.[9] The length of time required to conduct emissions and photochemical modeling precluded the use of IPM version 4.10_MATS. Thus the air quality modeling for MATS relied on EGU emission projections from an interim IPM platform that was subsequently updated during the rulemaking process for the base case and policy scenario summarized in this chapter. The 2015 base case EGU emissions projections of mercury, hydrogen chloride, SO_2, and PM used in air quality modeling were obtained from an earlier version of IPM, 4.10_FTransport. IPM version 4.10_FTransport reflects all state rules and consent decrees adopted through December 2010. 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 allowed in IPM to decide on the basis of economic efficiency whether to operate those controls. Note that this base case includes CSAPR, which was finalized in July 2011. Further details on the EGU emissions inventory used for this proposal can be found in the IPM Documentation.

The results presented in this chapter, from IPM version 4.10_MATS, reflect updates made to the 4.10_FTransport base case. These revisions are fully documented in the IPM 4.10 Supplemental Documentation for MATS and 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. Additionally, IPM v.4.10_MATS does not reflect mercury-specific state regulations (see section 1 above).

[9] http://www.epa.gov/airmarkt/progsregs/epa-ipm/index.html

3.12 Projected Primary PM Emissions from Power Plants

IPM does not endogenously model primary PM emissions from power plants. These emissions are calculated as a function of IPM outputs, emission factors and control configuration. IPM-projected fuel use (heat input) is multiplied by PM emission factors (based in part on the presence of PM-relevant pollution control devices) to determine PM emissions. Primary PM emissions are calculated by adding the filterable PM and condensable PM emissions.

Filterable PM emissions for each unit are based on historical information regarding existing emissions controls and types of fuel burned and ash content of the fuel burned, as well as the projected emission controls (e.g., scrubbers and fabric filters).

Condensable PM emissions are based on plant type, sulfur content of the fuel, and SO_2/HCl and PM control configurations. Although EPA's analysis is based on the best available emission factors, these emission factors do not account for the potential changes in condensable PM emissions due to the installation and operation of SCRs. The formation of additional condensable PM (in the form of SO_3 and H_2SO_4) in units with SCRs depends on a number of factors, including coal sulfur content, combustion conditions and characteristics of the catalyst used in the SCR, and is likely to vary widely from unit to unit. SCRs are generally designed and operated to minimize increases in condensable PM. This limitation means that IPM post-processing is potentially underestimating condensable PM emissions for units with SCRs. In contrast, it is possible that IPM post-processing overestimates condensable PM emissions in a case where the unit is combusting a low-sulfur coal in the presence of a scrubber.

EPA plans to continue improving and updating the PM emission factors and calculation methodologies. For a more complete description of the methodologies used to post-process PM emissions from IPM, see "IPM ORL File Generation Methodology" (March, 2011).

3.13 Illustrative Dry Sorbent Injection Sensitivity

Several commenters believe that EPA's IPM modeling assumptions regarding the efficacy and cost of DSI are based on too little data and are too optimistic. Some commenters believe that in practice there will be a need for many more FGD scrubbers for MATS compliance than projected by EPA for effective acid gas control, and at a corresponding higher cost. EPA disagrees with these opinions for several reasons (see the response to comments document in the docket) and believes that EPA's modeling assumptions regarding DSI cost and performance are reasonable.

However, to examine the potential impacts of limited DSI availability, EPA analyzed a scenario that limited total DSI capacity to 35 GW in 2015. In this scenario, which reduces the capacity of DSI by 18 GW compared to the primary MATS scenario, an additional 14 GW of coal capacity chooses to install scrubbers, and an additional 1.3 GW of capacity is projected to withdraw from service.

Limiting total DSI capacity to 35 GW results in a $1.2 billion (2007$) increase in annualized compliance costs in 2015. Additionally, SO_2 is further reduced in 2015 by an additional 62,000 tons (a 4.7% increase in SO_2 reductions and 4.5% increase in health benefits).

3.14 Additional Compliance Costs Analyzed for Covered Units

3.14.1 Compliance Cost for Oil-Fired Units.

As discussed in section 3.1, EPA used IPM to assess impacts of the MATS emission limitations for coal-fired EGUs but did not use IPM to assess the impacts for oil-fired units. IPM, with its power system and fuel cost assumptions, predicts many dual fuel units switch to natural gas and oil-fired units will not operate because IPM focuses on least cost operation of the power system. However, despite their apparent economic disadvantages, many of these units have run during many of the past five years (2006-2010). Therefore, EPA conducted a separate analysis to assess the impacts of the MATS emission limitations for oil-fired units.[10] EPA limited this analysis to oil-fired units in the contiguous U.S. Although there are several oil-fired units in states and territories outside the contiguous U.S., the final MATS emission limitations (shown in Table 3-2) for non-continental units will likely allow these units to continue firing residual fuel oil without additional air pollution controls.

For the base case, EPA categorized units by modeled fuels as listed in NEEDS 4.10 (EPA, December 2010) and assigned each unit the least-cost fuel among its available fuels. For units with natural gas curtailment provisions that might require the firing of residual fuel oil, EPA assigned a mixed fuel ratio based on each unit's 2008-2010 weighted average natural gas-to-fuel oil ratio. For the policy case, EPA assessed three compliance options: (1) switching to natural gas where available, (2) switching to distillate fuel oil, and (3) installing an electrostatic precipitator (ESP) capable of 90% particulate removal efficiency. These compliance options address particulate emissions only. However, there might be additional emission reductions that result from changes to oil-fired units' generation due to changes in relative generating costs.

[10] Additional details and methodology for the analysis are presented in appendix 3A.

Between the base case and policy case, 12 units convert from residual fuel oil to distillate fuel oil at a cost of approximately $12 million annually (2007$) to meet the MATS emission limitations for oil-fired units. An additional 11 units, eight of which are subject to natural gas curtailment, that do not have existing ESP particulate pollution controls install an ESP at a cost of approximately $44 million annually (2007$) to achieve the MATS emission limitations for oil-fired units (see Table 3-15). EPA believes the emission impacts from these potential actions will be relatively small when compared to the full impacts of the MATS emission limitations because particulate emissions from oil-fired units are a small fraction of the total particulate emissions from EGUs.

Table 3-15. Cost Impacts of Compliance Actions for Oil-Fired Units

Compliance option	Number of units affected	Capacity of units affected	Annual cost (2007$)
Switch to distillate fuel oil	12	2,675 MW	$12 million
Install ESP for residual fuel oil	11	4,015 MW	$44 million
Total	**23**	**6,690 MW**	**$56 million**

3.14.2 Monitoring, Reporting and Record-keeping Costs

The annual monitoring, reporting, and record-keeping 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 record-keeping. 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. See Section 7.3, Paperwork Reduction Act.

3.14.3 Total Costs Projected for Covered Units under MATS

EPA used IPM to analyze the compliance cost, and economic and energy impacts of the MATS rule. IPM estimated the costs for coal-fired electric utility steam generating units that burn coal, coal refuse, or solid-oil derived fuel. EPA did not use IPM, however, estimate compliance costs for most oil/gas steam boilers because IPM projection shows least-cost dispatch in an

environment where oil/gas-fired units are primarily selecting natural gas on an economic basis. In the separate analysis summarized above, EPA estimates compliance costs for oil-fired EGUs in a scenario in which these units continue to burn oil as historically observed and thus take compliance measures to remain on oil. This is a reasonable estimate of compliance costs for these units, but does not represent a re-balancing of electricity dispatch where these units combust oil rather than natural gas. Therefore, the summation of IPM-projected compliance costs for least-cost dispatch with the oil-fired compliance costs and the monitoring, reporting, and record-keeping costs is a reasonable approximation of total compliance costs, but does not represent projected compliance costs under an economically efficient dispatch (see Table 3-16).

Table 3-16. Total Costs Projected for Covered Units under MATS, 2015 (billions of 2007$)

	2015
IPM Projection	$9.4
Monitoring/Reporting/Record-keeping	$0.158
Oil-Fired Fleet	$0.056
Total	$9.6

3.15 Limitations of Analysis

EPA's modeling is based on expert judgment of various input assumptions for variables whose outcomes are in fact uncertain. Assumptions for future fuel supplies and electricity demand growth deserve particular attention because of the importance of these two key model inputs to the power sector. As a general matter, the Agency reviews the best available information from engineering studies of air pollution controls to support a reasonable modeling framework for analyzing the cost, emission changes, and other impacts of regulatory actions.

The IPM-projected annualized cost estimates of private compliance costs provided in this analysis are meant to show the increase in production (generating) costs to the power sector in response to the final rule. To estimate these annualized costs, EPA uses a conventional and widely-accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the cost of capital (private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital. The private compliance costs presented earlier are EPA's best estimate of the direct private compliance costs of MATS.

The annualized cost of the final rule, as quantified here, is EPA's best assessment of the cost of implementing the rule. These costs are generated from rigorous economic modeling of

changes in the power sector due to implementation of MATS. This type of analysis using IPM has undergone peer review, and federal courts have upheld regulations covering the power sector that have relied on IPM's cost analysis.

Cost estimates for MATS are based on results from ICF's Integrated Planning Model. The model minimizes the costs of producing electricity (including abatement costs) while meeting load demand and other constraints (full documentation for IPM can be found at http://www.epa.gov/airmarkets/progsregs/epa-ipm and in the IPM 4.10 Supplemental Documentation for MATS. IPM assumes "perfect foresight" of market conditions over the time horizon modeled; to the extent that utilities and/or energy regulators misjudge future conditions affecting the economics of pollution control, costs may be understated as well.

In the policy case modeling, EPA exogenously determines that a subset of covered units might require a retrofit fabric filter (also known as a baghouse) retrofit, or might need to upgrade existing ESP control in order to meet the PM standard. EPA's methodology for assigning these controls to EGUs in policy case modeling is based on historic PM emission rates and reported control efficiencies, and is explained in the IPM 4.10 Supplemental Documentation for MATS.

Additionally, this modeling analysis does not take into account the potential for advancements in the capabilities of pollution control technologies as well as reductions in their costs over time. In addition, EPA modeling cannot anticipate in advance the full spectrum of compliance strategies that the power sector may innovate to achieve the required emission reductions under MATS, which would potentially reduce overall compliance costs. Where possible, EPA designs regulations to assure environmental performance while preserving flexibility for affected sources to design their own solutions for compliance. Industry will employ an array of responses, some of which regulators may not fully anticipate and will generally lead to lower costs associated with the rule than modeled in this analysis. For example, unit operators may find opportunities to improve or upgrade existing pollution control equipment without requiring as many new retrofit devices (i.e., meeting the PM standard with an existing ESP without requiring installation of a new fabric filter).

With that in mind, MATS establishes emission rates on key HAPs, and although this analysis projects a specific set of technologies and behaviors as EPA's judgment of least-cost compliance, the power sector is free to adopt alternative technologies and behaviors to achieve the same environmental outcome EPA has deemed in the public interest as laid out in the Clean Air Act. Such regulation serves to promote innovation and the development of new and

cheaper technologies. As an example, cost estimates of the Acid Rain SO_2 trading program by Resources for the Future (RFF) and MIT's Center for Energy and Environmental Policy Research (CEEPR) have been as much as 83 percent lower than originally projected by the EPA (see Carlson et al., 2000; Ellerman, 2003). It is important to note that the original analysis for the Acid Rain Program done by EPA also relied on an optimization model like IPM. Ex ante, EPA cost estimates of roughly $2.7 to $6.2 billion[11] in 1989 were an overestimate of the costs of the program in part because of the limitation of economic modeling to perfectly anticipate technological improvement of pollution controls and economic improvement of other compliance options such as fuel switching. Ex post estimates of the annual cost of the Acid Rain SO_2 trading program range from $1.0 to $1.4 billion.

In recognition of this historic pattern of overestimated regulatory cost, EPA's mobile source program uses adjusted engineering cost estimates of pollution control equipment and installation costs.[12] To date, and including this analysis, EPA has not incorporated a similar approach into IPM modeling of EGU compliance with environmental constraints. As a result, this analysis may overstate costs where such cost savings from as-yet untapped improvements to pollution control technologies may occur in the future. Considering the broad and complex suite of generating technologies, fuels, and pollution control strategies available to the power sector, as well as the fundamental role of operating cost in electricity dispatch, it is not possible to apply a single technology-improving "discount" transformation to the cost projections in this analysis. The Agency will consider additional methodologies in the future which may inform the amount by which projected compliance costs could be overstated regarding further technological development in analyses of power sector regulations.

As configured in this application, IPM does not take into account demand response (i.e., consumer reaction to electricity prices). The increased retail electricity prices shown in Table 3-13 would prompt end users to increase investment in energy efficiency and/or curtail (to some extent) their use of electricity and encourage them to use substitutes.[13] Those responses would lessen the demand for electricity, resulting in electricity price increases slightly lower than IPM predicts, which would also reduce generation and emissions. Demand response would yield certain unquantified cost savings from requiring less electricity to meet the quantity demanded. To some degree, these saved resource costs will offset the additional costs

[11] 2010 Phase II cost estimate in $1995.

[12] See regulatory impact analysis for the Tier 2 Regulations for passenger vehicles (1999) and Heavy-Duty Diesel Vehicle Rules (2000).

[13] The degree of substitution/curtailment depends on the costs and performance of the goods that substitute for more energy consuming goods, which is reflected in the demand elasticity.

of pollution controls and fuel switching that EPA anticipates from the final rule, although there could be some increase in social cost resulting from any decrease in electricity consumption. Although the reduction in electricity use is likely to be small, the cost savings from such a large industry[14] are not insignificant. EIA analysis examining multi-pollutant legislation in 2003 indicated that the annualized costs of MATS may be overstated substantially by not considering demand response, depending on the magnitude and coverage of the price increases.[15]

EPA's IPM modeling of MATS reflects the Agency's authority to allow facility-level compliance with the HAP emission standards rather than require each affected unit at a given facility to meet the standards separately. This flexibility would offer important cost savings to facility owners in situations where a subset of affected units at a given facility could be controlled more cost-effectively such that their "overperformance" would compensate for any "underperformance" of the rest of the affected units. EPA's modeling in this analysis required the average emission rate across all affected units at a given facility to meet the standard. This averaging flexibility has the potential to offer further cost savings beyond this analysis if particular units find ways to achieve superior pollution control beyond EPA's assumptions of retrofit technology performance at the modeled costs (which could then reduce the need to control other units at the same facility).

Additionally, EPA has chosen to express most of the control requirements here as engineering performance standards (e.g., lbs/MMBtu of heat input), which provide power plant operators goals to meet as they see fit in choosing coals with various pollutant concentrations and pollutant control technologies that they adopt to meet the requirements. Historically, such an approach encourages industry to engineer cheaper solutions over time to achieve the pollution controls requirements.

EPA's IPM modeling is based on retrofit technology cost assumptions which reflect the best available information on current and foreseeable market conditions for pollution control deployment. In the current economic environment, EPA does not anticipate (and thus this analysis does not reflect) significant near-term price increases in retrofit pollution control supply chains in response to MATS. To the extent that such conditions may develop during the

[14] Investor-owned utilities alone accounted for nearly $300 billion in revenue in 2008 (EIA).

[15] See "Analysis of S. 485, the Clear Skies Act of 2003, and S. 843, the Clean Air Planning Act of 2003." Energy Information Administration. September, 2003. EIA modeling indicated that the Clear Skies Act of 2003 (a nationwide cap and trade program for SO_2, NO_X, and mercury), demand response could lower present value costs by as much as 47% below what it would have been without an emission constraint similar to the Transport Rule.

sector's installation of pollution control technologies under the final rule, this analysis may understate the cost of compliance.

3.16 Significant Energy Impact

MATS would have a significant impact according to *E.O. 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use*. Under the provisions of this rule, EPA projects that approximately 4.7 GW of coal-fired generation (less than 2 percent of all coal-fired capacity and 0.5% of total generation capacity in 2015) may be removed from operation by 2015. These units are predominantly smaller and less frequently-used generating units dispersed throughout the area affected by the rule. If current forecasts of either natural gas prices or electricity demand were revised in the future to be higher, that would create a greater incentive to keep these units operational.

EPA also projects fuel price increases resulting from MATS. Average retail electricity price are shown to increase in the contiguous U.S. by 3.1 percent in 2015. This is generally less of an increase than often occurs with fluctuating fuel prices and other market factors. Related to this, the average delivered coal price increases by less than 2 percent in 2015 as a result of shifts within and across coal types. As discussed above in section 8.10, EPA also projects that electric power sector-delivered natural gas prices will increase by about 0.6% percent over the 2015-2030 timeframe and that natural gas use for electricity generation will increase by less than 200 billion cubic feet (BCF) in 2015. These impacts are well within the range of price variability that is regularly experienced in natural gas markets. Finally, the EPA projects coal production for use by the power sector, a large component of total coal production, will decrease by 10 million tons in 2015 from base case levels, which is about 1 percent of total coal produced for the electric power sector in that year. The EPA does not believe that this rule will have any other impacts (e.g., on oil markets) that exceed the significance criteria.

3.17 References

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same 2016 base case). Relative to the *2005* base case, the benefits of the 2016 Toxics Rule scenario range from $13 million to $20 million (3% discount). Despite growth in the exposed population from 2005 to 2016, the changes from the 2005 base case to the 2016 base case account for 69% of these benefits, while the changes from the 2016 base case to the 2016 Toxics Rule account for 31%.

4.8.5 Discussion of Assumptions, Limitations, and Uncertainties

Uncertainty regarding the model results and estimates reported in Section 4.8 can arise from several sources. Some of the uncertainty can be attributed to model uncertainty. For example, to estimate exposures a number of different modeling approaches have been selected and combined. The separate model components are summarized in Figure 4-4 and equations (4.) to (4.8), each of which simplifies potentially complex processes. The results, therefore, depend importantly on how these models are selected, specified, and combined.

Another important source of uncertainty can be characterized as input or parameter uncertainties. Each of the modeling components discussed in this report requires summary data and estimates of key model parameters. For example, estimating IQ losses associated with consumption of freshwater fish requires estimates of the size of the exposed population of interest, the average mercury concentrations in consumed fish, the freshwater fish consumption rate for the exposed population, and the concentration-response relationship between mercury ingestion and IQ loss. All of these inputs are measured with some degree of uncertainty and can affect, to differing degrees, the confidence range of our summary results. The discussion below identifies and highlights some of the key model parameters, characterizes the source and extent of uncertainties associated with them, and characterizes the potential effects of these uncertainties on the model results.

To organize this discussion, we discuss different components of the modeling framework separately. This section first discusses issues related to estimating the mercury concentrations and then those related to estimating the exposed population. After that, it discusses issues related to matching these two components and then concludes by discussing the estimation of mercury ingestion through fish consumption.

4.8.5.1 Mercury Concentration Estimates

As described in Section 4.2.2, the mercury concentration estimates for the analysis come from several different sources, including fish tissue sample data from the National Listing of Fish Advisories (NLFA) and several other state- and national-level sources. These estimates

were then used to approximate mercury concentrations across the study area. Some of the key assumptions, limitations, and uncertainties associated with these estimates are the following:

- The fish tissue sampling data from various sources are subject to measurement and reporting error and variability. The NLFA is the largest and most detailed source of data on mercury in fish; however, even this system was not centrally designed (e.g., by EPA) using a common set of sampling and analytical methods. Rather, states collected the data primarily to support the development of advisories, and the data are submitted voluntarily to EPA. Each state uses different methods and criteria for sampling and allocates different levels of resources to their monitoring programs. In addition, there are uncertainties regarding the precise locations (lat/long coordinates) of some of the samples. The heterogeneity and potential errors across state sampling programs can bias the results in any direction and contribute to uncertainty.

- The fish tissue sampling data were assigned as either lake or river samples, based on the site name and/or the location coordinates mapped to the nearest type of waterbody. This process also involves measurement error and may have resulted in misclassifications for some of the samples. These errors are not expected to bias results, but they contribute to uncertainty.

- The mercury concentration estimates used in the model were based on simple temporal and spatial averages of reported fish tissue samples. This approach assumes that the mercury samples are representative of "local" conditions (i.e., within the same HUC-12) in similar waterbodies (i.e., rivers or lakes). However, even though states use a variety of approaches to monitor and sample fish tissue contaminants, in some cases, the sampling sites are selected to target areas with high levels of angler activity and/or a high level of pollution potential. To the extent that sample selection procedures favor areas with relatively high mercury, the spatial extrapolation methods used in this report will tend to overstate exposures. These approaches also implicitly assume that mercury concentration estimates are strongly spatially correlated, such that closer sampling sites (i.e., from the same HUC or distance interval) provide more information about mercury concentrations than more distant sites. To the extent that spatial correlation is weaker than assumed, this will increase the degree of uncertainty in the modeling results.

- To generate average mercury fish tissue concentration estimates, all available samples from the three main data sources (1995–2009) and from freshwater fish larger the 7 inches were included in the analysis. Smaller fish were excluded to better approximate concentrations in the types of fish that are more likely to be consumed, and samples from years before 1995 were excluded to better represent more recent conditions. Even with these sample selection procedures, average concentration estimates from the retained samples may still under or overestimate actual concentrations in currently consumed fish.

4.8.5.2 Exposed Population Estimates

The methods described in Section 4.7 to estimate the total exposed population of interest in 2005 and 2016 involve the following key assumptions, limitations, and uncertainties:

- The approach relies on data from the FHWAR to estimate state-level freshwater angler activity levels, including freshwater fishing participation rates and lake-to-river trip ratios. Each of these data elements is measured with some error in the FHWAR, but they are based on a relatively large sample. More importantly the state-level averages are applied to each modeled census tract in the state; therefore, the model fails to capture within-state variation in these factors, which contributes to uncertainty in the model estimates.

- The analysis also uses state-level fertility rate data to approximate the rate of pregnancy among women of childbearing age in angler households for a smaller geographic area. The state-level fertility rates from the National Vital Statistics are estimated with relatively little error; however, applying these rates to specific census tracts (and specifically to women in angler households) does involve considerably more uncertainty.

- The approach assumes that, in each census tract, the percentage of women who live in freshwater angler households (i.e., households with at least one freshwater angler) is equal to the percentage of the state adult population that fishes. Applying the state-level participation rate to approximate the conditions at a block level creates uncertainty. More importantly, however, using individual-based fishing participation rates to approximate household rates is likely to underestimate the percentage of women living in freshwater angler households.[9] Unfortunately, data on household participation levels in freshwater fishing are not readily available.

- Census tract populations are only included in the model if they are matched to distance intervals and waterbody types that have spatial overlap with at least one HUC-12 sub-watershed containing a mercury concentrations estimate for that waterbody type. By design, this approach undercounts the exposed population (by roughly 40 to 45%) and, therefore, leads to underestimates of national aggregate baseline exposures and risks and underestimates of the risk reductions and benefits resulting from mercury emission reductions.

- All of the tract-level population estimates are based on Census 2000 data, which are projected forward to 2005 and 2016 using county-level growth projections for the subpopulations of interest from Woods and Poole (2008). Therefore, the 2005 and 2016 population estimates incorporate uncertainty from both the growth

[9]For example, hypothetically if one out of every three members in each household fished, the population rate would be 33%, but the household rate would be 100%.

projections themselves and from transferring the county-level growth estimates to the tract level.

The purpose of the analysis of potentially high risk subpopulations is not to estimate the size of the exposed population but rather to characterize the distribution of individual-level risks in the subpopulations of interest. Nevertheless, the size and spatial distribution of the total population in each group was used as a proxy for characterizing the spatial distribution of pregnant women in freshwater fishing households in each group.

The main assumption underlying this approach is that the expected proportion of the subgroup's population in each Census tract that consists of pregnant women in fishing households is the same across the selected census tracts. The main limitation of this assumption is that it does not allow or account for spatial variation in (1) the percentage of the subpopulation that are women of childbearing age, (2) the percentage of these women that are pregnant (i.e., fertility rate) and (3) the freshwater angler participation rates for the subgroups of interest. Unfortunately, spatially varying data for the last component (fishing participation rates among the subpopulations of interest) are not readily available. This assumption is not expected to bias the results but it does contribute to uncertainty in the estimated distributions of individual-level risks.

4.8.5.3 Matching of Exposed Populations to Mercury Concentrations

The methods described in Section 4.7 to match the exposed population estimates with the corresponding mercury concentration estimates involve the following key assumptions, limitations, and uncertainties:

- For the aggregate benefits analysis, tract-level exposed populations are assigned to waterbody types based on state-level ratios of lake-to-river fishing days (from the FHWAR). They are further assigned to distance intervals based on observed travel distance patterns in national fishing data (NSRE, 1994). Both of these assignment methods involve uncertainty, but particularly the second method because it is based on much more aggregate data and on a much smaller and more dated sample of anglers. This approach does not take into account the physical characteristics of the area in which the population is located. In particular, the allocation of exposures to lakes or rivers at different distances from each census tract does not take into account the presence or number of these waterbodies in each distance interval. Using these state and national level estimates to represent conditions at a local (i.e., census tract) level increases uncertainty in the model results, but it is not expected to bias the results in either direction.

- For the analysis of potentially high-risk populations, these methods and assumptions were slightly modified. In particular, because these analyses focus on low-income and/or subsistence fishing populations, all trips were assumed to occur within 20 miles of the census tract. Unfortunately, it is difficult to evaluate the accuracy of this restriction due to limited data on travel distances for the subgroups of interest.

One potentially important factor that is not included for matching populations and mercury concentrations is the effect of fish consumption advisories on fishing behavior. Evidence summarized in Jakus, McGuinness, and Krupnick (2002) suggests that awareness of advisories by anglers is relatively low (less than 50%), and even those who are aware do not always alter their fishing behavior. Nonetheless, anglers are less likely to fish in areas with advisories. Unfortunately, we were not able to reliably quantify the reduction and redistribution of fishing trips in either model to account for fish advisories. By excluding these effects, the model estimates are likely to overstate mercury exposures.

4.8.5.4 Fish Consumption Estimates

One of the most influential variables in both modeling approaches is the rate of self-caught freshwater fish consumption. The following key assumptions, limitation, and uncertainties are associated with the methods used:

- For the aggregate analysis we have assumed 8 g/day for the general population in freshwater angler households (based on recommendations in EPA's EFH). Unfortunately, data are not available to reliably vary this rate with respect to characteristics of the population across the entire study area. Uncertainty regarding the true average fish consumption rate has a direct effect on uncertainty for the aggregate exposure and benefit estimates. Because a single consumption rate is applied uniformly across the entire exposed population and because it is a multiplicative factor in the model, the two uncertainties are directly proportional to one another. The recommended 8 g/day rate is based on four studies with mean estimates ranging from 5 g/day (37% less than 8) to 17 g/day (113% more than 8). If it is assumed that this range of estimates represents the uncertainty in the *mean* freshwater fish consumption rate for the study population, then the resulting uncertainty range for the estimated *mean* mercury ingestion level (and resulting IQ loss) will also be between −37% and +113% of the mean mercury ingestion level.

- To analyze the distributions of individual-level risks in potentially high risk subpopulations, we applied empirical distributions of fish consumption rates for specific subpopulations. One of the main limitations of this approach is that these empirical distributions are based on relatively small and localized samples. In particular, the estimated distribution of consumption rates for low-income African American subsistence/recreational fishers in the Southeastern U.S. (see Table 4-3) is based on a very small sample (N=39) drawn from one location (Columbia, SC). The

sample sizes for the other groups, particularly the Hispanic (N= 45) and Laotian (N=54) populations are also small; therefore, there is considerable uncertainty regarding how well these empirical consumption rate distributions reflect actual rates of consumption in the subpopulations of interest.

Another related and potentially influential variable in the modeling approach is the assumed conversion factor for mercury concentrations between uncooked and cooked fish. Studies have found that cooking fish tends to reduce the overall weight of fish by approximately one-third (Great Lakes Sport Fish Advisory Task Force, 1993) without affecting the overall amount of mercury. But these conversion rates depend on cooking practices and types of fish. Uncertainty regarding this conversion factor also has a proportionate effect on the modeling results.

4.8.5.5 Measurement and Valuation of IQ Related Effects

The models for estimating and valuing IQ effects involve three main steps. The first step is translating maternal mercury ingestion rates to mercury levels in hair. The second step is translating differences in hair mercury concentrations during pregnancy to IQ changes in offspring. The third step is translating IQ losses into expected reductions in lifetime earnings. As discussed below, each of these steps also involves the following assumptions, limiations, and uncertainties:.

- The conversion of mercury ingestion rate to mercury concentration in hair is based on uncertainty analysis of a toxicokinetic model for estimating reference dose (Swartout and Rice, 2000). The conversion factor was estimated by considering the variability and uncertainty in various inputs used in deriving the dose including body weight, hair-to-blood mercury ratio, half-life of MeHg in blood, and others. Therefore, there is uncertainty regarding the conversion factor between hair mercury concentration and mercury ingestion rate. Although, the median conversion factor (0.08 µg/kg-day/hair-ppm) is used, the 90% confidence interval is from 0.037 to 0.16 µg/kg day/hair-ppm. Any change in the conversion factor will proportionately affect the benefits results because of the linearity of the model.

- The dose-response model used to estimate neurological effects on children because of maternal mercury body burden is susceptible to various uncertainties. In particular, there are three main concerns. First, there are other cognitive end-points that have stronger association with MeHg than IQ point losses. Therefore, using IQ points as a primary end point in the benefits assessment may underestimate the impacts. Second, blood-to-hair ratio for mercury is uncertain, which can cause the results from analyses based on mercury concentration in blood to be uncertain. Third, uncertainty is associated with the epidemiological studies used in deriving the dose-response models.

- With regard to the relationship between prenatal methylmercury exposure and childhood IQ loss, we expect greater uncertainty in associated estimates of IQ loss as exposure levels increase beyond those observed in the primary studies (i.e., Faroe Islands, New Zealand, Seychelles Islands studies) used to derive the dose-response function. In particular, high-end total exposure estimates for some of the subsistence-level fishing subpopulations included in this assessment likely exceed levels observed in the three primary studies.

- To parameterize the dose-response relationship between maternal hair concentrations and IQ loss for this analysis, we applied the results of an integrative study by Axelrad et al. (2007). The implications of applying this study include the following:

  – This approach may confound potentially positive cognitive effects of fish consumption and, more specifically, omega-3 fatty acids. Results from Rice (2010) offer a reasonable, but highly uncertain, estimate for offsetting the possible downward bias resulting from the positive confounding effects of fatty acids. Rice's high coefficient reflects the central estimate of Axelrad but adjusted upwards by a factor of 1.5 to "acknowledge the recent argument of Budtz-Jorgensen (2007) that the parameter estimates from these three epidemiological studies (Faroe Islands, Seychelles Islands, New Zealand) may be biased downward by a factor of approximately 2 because of failure to adequately control for confounding." A third study, Oken (2008), analyzes a cohort in Massachusetts and also seems to support a higher "Axelrad-plus" coefficient range due to evidence of fatty acid confounding (i.e., positive cognitive effects of fatty acids in fish may have previously led to underestimates of mercury-attributable IQ loss). This study offers further qualitative support for a higher-end estimate but is limited by the fact that it did not control for the children's home environment, which is generally a significant factor in early cognitive development.

  – The dose-response coefficient from the Axelrad et al. study is sensitive to the exclusion of one outlier data point from the Seychelles study. Including the outlier would reduce the effect size by about 25 percent. If this outlier actually reflects the true response for a subset of the populations, then risks (as modeled) could be biased high specifically for this subpopulation

  – Because the dose-response coefficient is applied uniformly across the entire exposed population and is a multiplicative factor in the model, the uncertainty in this parameter has a directly proportional effect on the reported risk and benefit estimates. In other words, adjusting the absolute value of the dose-response coefficient upward by a factor of 1.5 (i.e., based on Rice, 2010) would yield reductions in IQ losses and benefits from mercury emission reductions that are also greater by a factor of 1.5.

- The valuation of IQ losses is based on a unit-value approach developed by EPA, which estimates that the average effect of a 1-point reduction in IQ is to reduce the present value of net future earnings. Three key assumptions of this unit-value approach are that (1) there is a linear relationship between IQ changes and net earnings losses, (2) the unit value applies to even very small changes in IQ, and (3) the unit value will remain constant (in real present value terms) for several years into the future. Each of these assumptions contributes to uncertainty in the result. In particular the unit value estimate is itself subject to two main sources of uncertainty.

  – The first source is directly related to uncertainties regarding the average reductions in future earnings and years in school as a result of IQ changes. The average percentage change estimates are subject to statistical error, modeling uncertainties, and variability across the population. To address these uncertainties we have included in the analysis and reported results a range of values for this parameter, based on statistical analyses by Salkever (1995) and Schwartz (1994).

  – The second main source of uncertainty is the estimates of average lifetime earnings and costs of schooling. Both of these estimates are derived from national statistics from the early 1990s, but they are also subject to statistical error, modeling uncertainties, and variability across the population. It is also worth noting that the lost future earnings estimates do not include present value estimates for nonwage/nonsalary earnings (i.e., fringe benefits) and household (nonmarket) production. Based on the results of Grosse et al. (2009), including these factors would increase the present value of median earnings (both explicit and implicit) by a factor of roughly 1.9. However, it is not known whether IQ changes have a similar effect on these other (implicit) earnings.

4.8.5.6 Unquantified Benefits

In addition to the uncertainties discussed above associated with the benefit analysis of reducing exposures to MeHg from recreational freshwater angling, we are unable to quantify several additional benefits, which adds to the uncertainties in the final estimate of benefits.

Table 4-20 displays the health and ecosystem effects associated with MeHg exposure that are discussed in Section 4.2.2 for which we are currently unable to quantify. We note that specifically with regard to health effects, the NRC (2000) provided the following observation: "Neurodevelopmental effects are the most extensively studied sensitive end point for MeHg exposure, but there remains some uncertainty about the possibility of other health effects at low levels of exposure. In particular, there are indications of immune and cardiovascular effects, as well as neurological effects emerging later in life, that have not been adequately studied."

Table 4-8. Unquantified Health and Ecosystem Effects Associated with Exposure to Mercury

Category of Health or Ecosystem Effect	Potential Health or Ecosystem Outcomes
Neurologic Effects	Impaired cognitive development
	Problems with language
	Abnormal social development
Other Health Effects[a]	Associations with genetic, autoimmune and cardiovascular effects
Ecological Effects[a]	Survival, reproductive, behavioral, and neurological effects in wildlife (birds, fish, and mammals)

[a] These are potential effects and are not quantified because the literature is either contradictory or incomplete.

In addition to the health and ecosystem effects that we are not able to quantify, we are currently unable to quantify exposures to other segments of the U.S. population including consumption of commercial seafood and freshwater fish (produced domestically as well as imported from foreign sources) and consumption of recreationally caught seafood from estuaries, coastal waters, and the deep ocean. These consumption pathways impact additional recreational anglers who are not modeled in our benefits analysis as well as the general U.S. population. Reductions in domestic fish tissue concentrations can also impact the health of foreign consumers (consuming U.S. exports). Because of technical/theoretical limitations in the science, EPA is unable to quantify the benefits associated with several of these fish consumption pathways. For example, reductions in U.S. power plant emissions will result in a lowering of the global burden of elemental mercury, which will likely produce some degree of reduction in mercury concentrations for fish sourced from the open ocean and freshwater and estuarine waterbodies in foreign countries. In the case of mercury reductions for fish in the open ocean, complexities associated with modeling the linkage between changes in air deposition of mercury and reductions in biomagnification and bioaccumulation up the food chain (including open ocean dilution and the extensive migration patterns of certain high-consumption fish such as tuna) prevent the modeling of fish obtained from the open ocean. In the case of commercial fish obtained from foreign freshwater and estuarine waterbodies, although technical challenges are associated with modeling long-range transport of elemental mercury and the subsequent impacts to fish in these distant locations, additional complexities such as accurately modeling patterns of harvesting and their linkages to commercial consumption in the United States prevent inclusion of foreign-sourced freshwater and estuarine fish in the primary benefits analysis.

Finally, with regard to commercially-produced freshwater fish sourced in the United States (i.e., fish from catfish, bass, and trout farms), we are unable to accurately quantify

effects from this consumption pathway because many of the fish farms operating in the United States use feed that is not part of the aquatic food web of the waterbody containing the fish farm (e.g., use of agricultural-based supplemental feed). In addition, many of the farms involve artificial "constructed" waterbody environments that are atypical of aquatic environments found in the regions where those farms are located, thereby limiting the applicability of Mercury Maps' assumption in linking changes to mercury deposition to changes in mercury fish tissue concentrations (e.g., waterbodies may have restricted or absent watersheds and modified aquatic chemistry, which can effect methylation rates and impact time scales for reaching steady-state mercury fish tissue concentrations following reductions in mercury deposition). Some research indicates that the recycling of water at fish farms can magnify the mercury concentration because the system does not remove mercury as it is recycled, while newly deposited mercury is added to the system. Thus, additional research on aquaculture farms is necessary before a benefits analysis can be conducted.

Exclusion of these commercial pathways means that this benefits analysis, although covering an important source of exposure to domestic mercury emissions (recreational freshwater anglers), excludes a large and potentially important group of individuals. Recreational freshwater consumption accounts for approximately 10 to 17% of total U.S. fish consumption, and 90% is derived from commercial sources (domestic seafood, aquaculture, and imports) (EPA, 2005).

In conclusion, several unquantified benefits associated with this analysis add to the overall uncertainty in estimating total benefits. To the extent that the proposed rule will reduce mercury deposition from power plants over estuarine areas, coastal, and open ocean waters, there would be a subsequent reduction in mercury fish tissue concentrations in these different waterbodies and an associated benefit from avoided decrements in IQ and other known health and ecosystem effects.

4.8.6 Overall Conclusions

4.8.6.1 Total Baseline Incidence of IQ Loss: Self-Caught Fish Consumption among Recreational Freshwater Anglers

- Out of 64,500 census tracts in the continental U.S., 63,978 are located within 100 miles of at least one HUC-12 watershed with freshwater mercury fish tissue sampling data, and therefore were included in the modeling of IQ loss among recreational freshwater anglers.

- Approximately 240,000 prenatally exposed children were modeled, with an average IQ loss of 0.11 and 0.10 IQ points, respectively, from self-caught freshwater fish consumption for the 2005 and 2016 base case scenarios.

- The highest estimated state-specific average IQ loss among children of freshwater recreational anglers is 0.21 IQ points under the 2005 base case scenario, in both California and Rhode Island.

- Total estimated IQ loss from self-caught freshwater fish consumption among children of recreational anglers is estimated at 25,555 and 24,419 IQ points, respectively, for the 2005 and 2016 base case scenarios.

- The present economic value of baseline IQ loss for 2005 ranges from $210 million to $310 million, assuming a 3% discount rate, and from $23 million to $51 million, assuming a 7% discount rate.

- The present economic value of baseline IQ loss for 2016 ranges from $200 million to $300 million, assuming a 3% discount rate, and from $22 million to $49 million, assuming a 7% discount rate.

4.8.6.2 Avoided IQ Loss and Economic Benefits due to Regulatory Action: Self-Caught Fish Consumption among Recreational Freshwater Anglers

- Eliminating all mercury air emissions from U.S. EGUs in 2016 would result in an estimated 0.00893 fewer IQ points lost per prenatally exposed child from self-caught freshwater fish consumption, as compared with the 2005 base case scenario.

- The present economic value of avoided IQ loss from eliminating all mercury air emissions from U.S. EGUs in 2016 is estimated at a range of $5.7 million to $8.5 million, assuming a 3% discount rate, and $0.6 million to $1.4 million, assuming a 7% discount rate.

- Reduced mercury air emissions due to implementation of the Toxics Rule in 2016 would result in an estimated 0.00209 fewer IQ points lost per prenatally exposed child from self-caught freshwater fish consumption, as compared with the 2016 base case scenario.

- The present economic value of avoided IQ loss from reduced mercury air emissions due to implementation of the Toxics Rule in 2016 is estimated at a range of $4.2 million to $6.2 million, assuming a 3% discount rate, and $0.47 million to $1 million, assuming a 7% discount rate.

4.9 Benefits Associated with Reductions in Other HAP than Mercury

Even though emissions of air toxics from all sources in the U.S. declined by approximately 42 percent since 1990, the 2005 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2011d).[10] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, U.S. EPA conducts the NATA. [11] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient and exposure concentrations of air toxics across the United States

3) Estimating population exposures across the United States

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2005 NATA, EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall cancer risks are formaldehyde and benzene.[12,13] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

[10]The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[11]The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2005 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2011) 2005 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2005/

[12]Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2.

[13]Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at http://www.epa.gov/ttn/atw/nata/roy/page16.html.

Noncancer health effects can result from chronic,[14] subchronic,[15] or acute[16] inhalation exposures to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2005 NATA, about three-fourths of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

Figure 4-5and Figure 46 depict the estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions are more than double acrolein emissions on a national basis, according to EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more toxic than acetaldehyde. 17 Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of these rules.. In a few previous analyses of the benefits of reductions in HAPs, EPA has quantified the benefits of potential reductions in the incidences of cancer and non-cancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[18] These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a

[14]Chronic exposure is defined in the glossary of the Integrated Risk Information (IRIS) database (http://www.epa.gov/iris) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10% of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[15]Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10% of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[16]Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

[17]Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at http://cfpub.epa.gov/ncea/iris/compare.cfm.

[18]The unit risk factor is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu g/m^3$ of a pollutant.

reduction in pollution, use of high-end, conservative risk estimates would overestimate the benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates

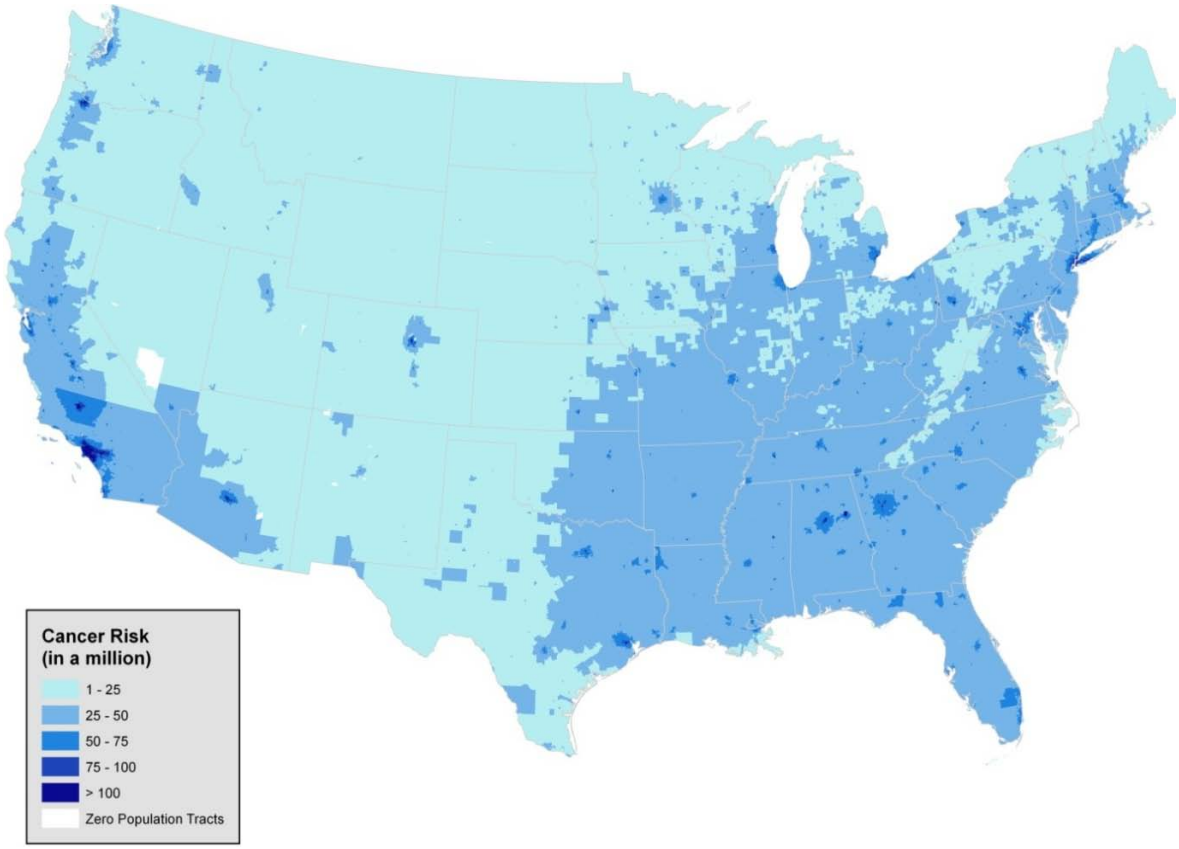

Figure 4-5. Estimated Chronic Census Tract Carcinogenic Risk from HAP Exposure from Outdoor Sources (2005 NATA)

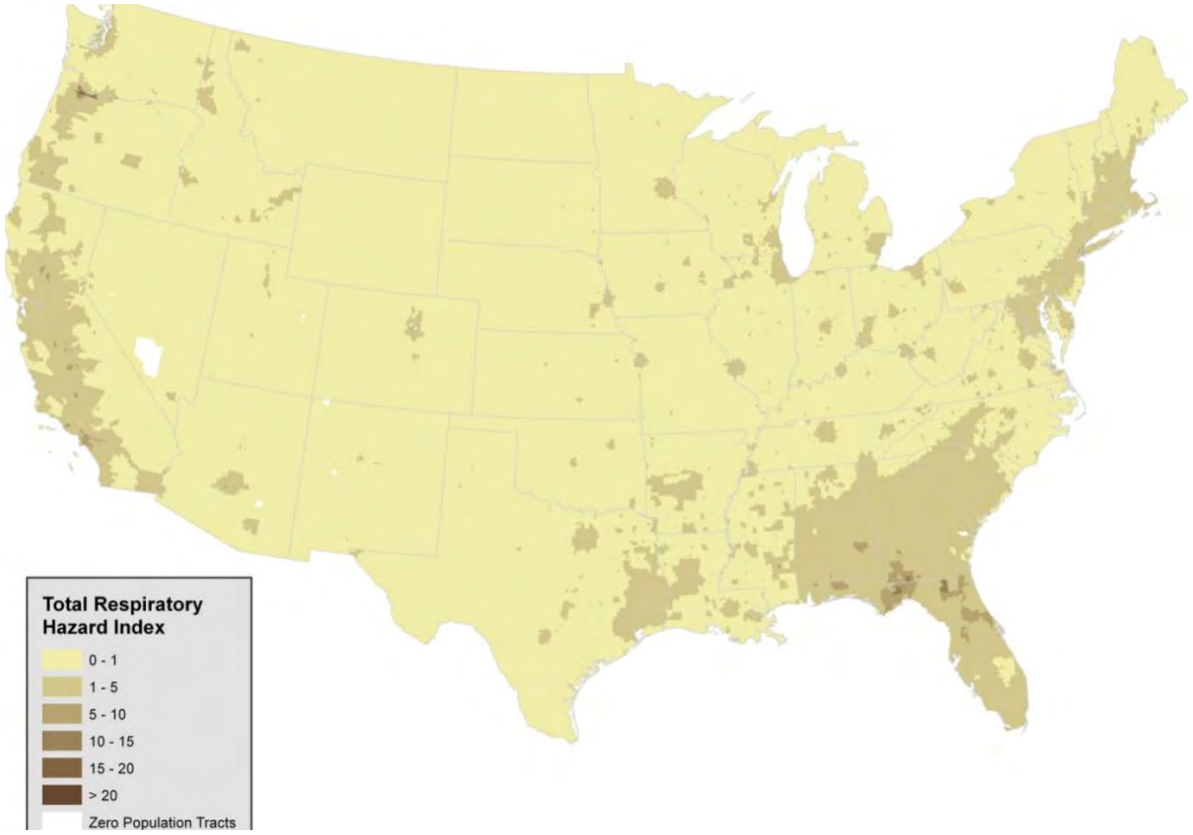

Figure 4-6. Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP Exposure from Outdoor Sources (2005 NATA)

in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAPs.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAPs. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAPs, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAPs in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAPs anticipated to be reduced by these rules and we summarize the results of the residual risk assessment for the Risk and Technology Review (RTR). EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAPs are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAPs make up a large percentage the total HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011a). In the subsequent sections, we describe the health effects associated with the main HAPs of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. These rules combined are anticipated to avoid or reduce 58,000 tons of HAPs per year. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

EPA conducted a residual risk assessment for the NESHAP rule (U.S. EPA, 2011c). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 30 in-a-million for existing sources before and after controls with a cancer incidence of 0.02 before and after controls. For existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with a cancer incidence that decreases from 0.001 before controls to 0.0002 after controls. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. EPA did not conduct a risk assessment for new sources affected by the NSPS. However, it is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are more

than an order of magnitude higher than the HAP emissions reduced from existing sources with the NESHAP.

4.9.1 Hazards

Emissions data collected during development of this proposed rule show that HCl emissions represent the predominant HAP emitted by industrial boilers. Coal- and oil-fired EGUs emit lesser amounts of HF, chlorine, metals (As, Cd, Cr, Hg, Mn, Ni, and Pb), and organic HAP emissions. Although numerous organic HAP may be emitted from coal- and oil-fired EGUs, only a few account for essentially all the mass of organic HAP emissions. These organic HAP are formaldehyde, benzene, and acetaldehyde.

Exposure to high levels of these HAP is associated with a variety of adverse health effects. These adverse health effects include chronic health disorders (e.g., irritation of the lung, skin, and mucus membranes, effects on the central nervous system, and damage to the kidneys), and acute health disorders (e.g., lung irritation and congestion, alimentary effects such as nausea and vomiting, and effects on the kidney and central nervous system). We have classified three of the HAP as human carcinogens and five as probable human carcinogens. The following sections briefly discuss the main health effects information we have regarding the key HAPs emitted by EGUs.

4.9.1.1 Acetaldehyde

Acetaldehyde is classified in EPA's IRIS database as a probable human carcinogen, based on nasal tumors in rats, and is considered toxic by the inhalation, oral, and intravenous routes.[19] Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. Department of Health and Human Services (DHHS) in the 11th Report on Carcinogens and is classified as possibly carcinogenic to humans (Group 2B) by the IARC.[20,21] The primary

[19]U.S. Environmental Protection Agency (U.S. EPA). 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0290.htm.

[20]U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[21]International Agency for Research on Cancer (IARC). 1999. Re-evaluation of some organic chemicals, hydrazine, and hydrogen peroxide. IARC Monographs on the Evaluation of Carcinogenic Risk of Chemical to Humans, Vol 71. Lyon, France.

noncancer effects of exposure to acetaldehyde vapors include irritation of the eyes, skin, and respiratory tract.[22]

4.9.1.2 Arsenic

Arsenic, a naturally occurring element, is found throughout the environment and is considered toxic through the oral, inhalation and dermal routes. Acute (short-term) high-level inhalation exposure to As dust or fumes has resulted in gastrointestinal effects (nausea, diarrhea, abdominal pain, and gastrointestinal hemorrhage); central and peripheral nervous system disorders have occurred in workers acutely exposed to inorganic As. Chronic (long-term) inhalation exposure to inorganic As in humans is associated with irritation of the skin and mucous membranes. Chronic inhalation can also lead to conjunctivitis, irritation of the throat and respiratory tract and perforation of the nasal septum.[23] Chronic oral exposure has resulted in gastrointestinal effects, anemia, peripheral neuropathy, skin lesions, hyperpigmentation, and liver or kidney damage in humans. Inorganic As exposure in humans, by the inhalation route, has been shown to be strongly associated with lung cancer, while ingestion of inorganic As in humans has been linked to a form of skin cancer and also to bladder, liver, and lung cancer. EPA has classified inorganic As as a Group A, human carcinogen.[24]

4.9.1.3 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[25,26,27] EPA states in its IRIS database that data indicate a causal

[22]U.S. Environmental Protection Agency (U.S. EPA). 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0290.htm.

[23]Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Arsenic. Atlanta, GA: U.S. Department of Health and Human Services. Available on the Internet at <http://www.atsdr.cdc.gov/mhmi/mmg168.html#bookmark02>

[24]U.S. Environmental Protection Agency (U.S. EPA). 1998. Integrated Risk Information System File for Arsenic. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0278.htm.

[25]U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[26]International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345–389, 1982.

[27]Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691–3695.

relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The IARC has determined that benzene is a human carcinogen and the DHHS has characterized benzene as a known human carcinogen.[28,29]

A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[30,31]

4.9.1.4 Cadmium

Breathing air with lower levels of Cd over long periods of time (for years) results in a build-up of Cd in the kidney, and if sufficiently high, may result in kidney disease. Lung cancer has been found in some studies of workers exposed to Cd in the air and studies of rats that inhaled Cd. The U.S. DHHS has determined that Cd and Cd compounds are known human carcinogens. The IARC has determined that Cd is carcinogenic to humans. EPA has determined that Cd is a probable human carcinogen.[32]

4.9.1.5 Chlorine

The acute (short term) toxic effects of Cl_2 are primarily due to its corrosive properties. Chlorine is a strong oxidant that upon contact with water moist tissue (e.g., eyes, skin, and upper respiratory tract) can produce major tissue damage.[33] Chronic inhalation exposure to low concentrations of Cl_2 (1 to 10 parts per million, ppm) may cause eye and nasal irritation, sore throat, and coughing. Chronic exposure to Cl_2, usually in the workplace, has been reported to cause corrosion of the teeth. Inhalation of higher concentrations of Cl_2 gas (greater than 15 ppm) can rapidly lead to respiratory distress with airway constriction and accumulation of fluid in the lungs (pulmonary edema). Exposed individuals may have immediate onset of rapid breathing, blue discoloration of the skin, wheezing, rales or hemoptysis (coughing up blood or

[28]International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[29]U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[30]Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193–197.

[31]Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541–554.

[32]Agency for Toxic Substances and Disease Registry (ATSDR). 2008. Public Health Statement for Cadmium. CAS# 1306-19-0. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Available on the Internet at <http://www.atsdr.cdc.gov/PHS/PHS.asp?id=46&tid=15>.

[33]Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Chlorine. Atlanta, GA: U.S. Department of Health and Human Services. http://www.atsdr.cdc.gov/mmg/mmg.asp?id=198&tid=36.

blood-stain sputum). Intoxication with high concentrations of Cl_2 may induce lung collapse. Exposure to Cl_2 can lead to reactive airways dysfunction syndrome (RADS), a chemical irritant-induced type of asthma. Dermal exposure to Cl_2 may cause irritation, burns, inflammation and blisters. EPA has not classified Cl_2 with respect to carcinogenicity.

4.9.1.6 Chromium

Chromium may be emitted in two forms, trivalent Cr (Cr^{+3}) or hexavalent Cr (Cr^{+6}). The respiratory tract is the major target organ for Cr^{+6} toxicity, for acute and chronic inhalation exposures. Shortness of breath, coughing, and wheezing have been reported from acute exposure to Cr^{+6}, while perforations and ulcerations of the septum, bronchitis, decreased pulmonary function, pneumonia, and other respiratory effects have been noted from chronic exposures. Limited human studies suggest that Cr^{+6} inhalation exposure may be associated with complications during pregnancy and childbirth, but there are no supporting data from animal studies reporting reproductive effects from inhalation exposure to Cr^{+6}. Human and animal studies have clearly established the carcinogenic potential of Cr^{+6} by the inhalation route, resulting in an increased risk of lung cancer. EPA has classified Cr^{+6} as a Group A, human carcinogen. Trivalent Cr is less toxic than Cr^{+6}. The respiratory tract is also the major target organ for Cr^{+3} toxicity, similar to Cr^{+6}. EPA has not classified Cr^{+3} with respect to carcinogenicity.

4.9.1.7 Formaldehyde

Since 1987, EPA has classified formaldehyde as a probable human carcinogen based on evidence in humans and in rats, mice, hamsters, and monkeys.[34] EPA is currently reviewing recently published epidemiological data. After reviewing the currently available epidemiological evidence, the IARC (2006) characterized the human evidence for formaldehyde carcinogenicity as "sufficient," based upon the data on nasopharyngeal cancers; the epidemiologic evidence on leukemia was characterized as "strong."[35] EPA is reviewing the recent work cited above from the NCI and NIOSH, as well as the analysis by the CIIT Centers for Health Research and other studies, as part of a reassessment of the human hazard and dose-response associated with formaldehyde.

Formaldehyde exposure also causes a range of noncancer health effects, including irritation of the eyes (burning and watering of the eyes), nose and throat. Effects from repeated exposure in humans include respiratory tract irritation, chronic bronchitis and nasal epithelial

[34]U.S. EPA. 1987. Assessment of Health Risks to Garment Workers and Certain Home Residents from Exposure to Formaldehyde, Office of Pesticides and Toxic Substances, April 1987.

[35]International Agency for Research on Cancer (2006) Formaldehyde, 2-Butoxyethanol and 1-tert-Butoxypropan-2-ol. Monographs Volume 88. World Health Organization, Lyon, France.

lesions such as metaplasia and loss of cilia. Animal studies suggest that formaldehyde may also cause airway inflammation—including eosinophil infiltration into the airways. There are several studies that suggest that formaldehyde may increase the risk of asthma—particularly in the young.[36,37]

4.9.1.8 Hydrogen Chloride

Hydrogen chloride is a corrosive gas that can cause irritation of the mucous membranes of the nose, throat, and respiratory tract. Brief exposure to 35 ppm causes throat irritation, and levels of 50 to 100 ppm are barely tolerable for 1 hour.[38] The greatest impact is on the upper respiratory tract; exposure to high concentrations can rapidly lead to swelling and spasm of the throat and suffocation. Most seriously exposed persons have immediate onset of rapid breathing, blue coloring of the skin, and narrowing of the bronchioles. Exposure to HCl can lead to RADS, a chemically- or irritant-induced type of asthma. Children may be more vulnerable to corrosive agents than adults because of the relatively smaller diameter of their airways. Children may also be more vulnerable to gas exposure because of increased minute ventilation per kg and failure to evacuate an area promptly when exposed. Hydrogen chloride has not been classified for carcinogenic effects.[39]

4.9.1.9 Hydrogen Fluoride

Acute (short-term) inhalation exposure to gaseous HF can cause severe respiratory damage in humans, including severe irritation and pulmonary edema. Chronic (long-term) oral exposure to fluoride at low levels has a beneficial effect of dental cavity prevention and may also be useful for the treatment of osteoporosis. Exposure to higher levels of fluoride may

[36]Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological profile for Formaldehyde. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. http://www.atsdr.cdc.gov/toxprofiles/tp111.html

[37]WHO (2002) Concise International Chemical Assessment Document 40: Formaldehyde. Published under the joint sponsorship of the United Nations Environment Programme, the International Labour Organization, and the World Health Organization, and produced within the framework of the Inter-Organization Programme for the Sound Management of Chemicals. Geneva.

[38]Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Hydrogen Chloride. Atlanta, GA: U.S. Department of Health and Human Services. Available online at http://www.atsdr.cdc.gov/mmg/mmg.asp?id=758&tid=147#bookmark02.

[39]U.S. Environmental Protection Agency (U.S. EPA). 1995. Integrated Risk Information System File of Hydrogen Chloride. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at .http://www.epa.gov/iris/subst/0396.htm.

cause dental fluorosis. One study reported menstrual irregularities in women occupationally exposed to fluoride via inhalation. The EPA has not classified HF for carcinogenicity[40].

4.9.1.10 Lead

The main target for Pb toxicity is the nervous system, both in adults and children. Long-term exposure of adults to Pb at work has resulted in decreased performance in some tests that measure functions of the nervous system. Lead exposure may also cause weakness in fingers, wrists, or ankles. Lead exposure also causes small increases in blood pressure, particularly in middle-aged and older people. Lead exposure may also cause anemia.

Children are more sensitive to the health effects of Pb than adults. No safe blood Pb level in children has been determined. At lower levels of exposure, Pb can affect a child's mental and physical growth. Fetuses exposed to Pb in the womb may be born prematurely and have lower weights at birth. Exposure in the womb, in infancy, or in early childhood also may slow mental development and cause lower intelligence later in childhood. There is evidence that these effects may persist beyond childhood.[41]

There are insufficient data from epidemiologic studies alone to conclude that Pb causes cancer (is carcinogenic) in humans. The DHHS has determined that Pb and Pb compounds are reasonably anticipated to be human carcinogens based on limited evidence from studies in humans and sufficient evidence from animal studies, and the EPA has determined that Pb is a probable human carcinogen.

4.9.1.11 Manganese

Health effects in humans have been associated with both deficiencies and excess intakes of Mn. Chronic exposure to high levels of Mn by inhalation in humans results primarily in central nervous system effects. Visual reaction time, hand steadiness, and eye-hand coordination were affected in chronically-exposed workers. Manganism, characterized by feelings of weakness and lethargy, tremors, a masklike face, and psychological disturbances, may result from chronic exposure to higher levels. Impotence and loss of libido have been

[40]U.S. Environmental Protection Agency. Health Issue Assessment: Summary Review of Health Effects Associated with Hydrogen Fluoride and Related Compounds. EPA/600/8-89/002F. Environmental Criteria and Assessment Office, Office of Health and Environmental Assessment, Office of Research and Development, Cincinnati, OH. 1989.

[41]Agency for Toxic Substances and Disease Registry (ATSDR). 2007. Public Health Statement for Lead. CAS#: 7439-92-1. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. Available on the Internet at < http://www.atsdr.cdc.gov/ToxProfiles/phs13.html>.

noted in male workers afflicted with manganism attributed to inhalation exposures. The EPA has classified Mn in Group D, not classifiable as to carcinogenicity in humans.[42]

4.9.1.12 Nickel

Respiratory effects have been reported in humans from inhalation exposure to Ni. No information is available regarding the reproductive or developmental effects of Ni in humans, but animal studies have reported such effects. Human and animal studies have reported an increased risk of lung and nasal cancers from exposure to Ni refinery dusts and nickel subsulfide. The EPA has classified nickel subsulfide as a human carcinogen and nickel carbonyl as a probable human carcinogen.[43,44] The IARC has classified Ni compounds as carcinogenic to humans.[45]

4.9.1.13 Selenium

Acute exposure to elemental Se, hydrogen selenide, and selenium dioxide (SeO_2) by inhalation results primarily in respiratory effects, such as irritation of the mucous membranes, pulmonary edema, severe bronchitis, and bronchial pneumonia. One Se compound, selenium sulfide, is carcinogenic in animals exposed orally. EPA has classified elemental Se as a Group D, not classifiable as to human carcinogenicity, and selenium sulfide as a Group B2, probable human carcinogen.

4.10 References

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[42]U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Manganese. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.
[43]U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Nickel Subsulfide. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.
[44]U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Nickel Carbonyl. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.
[45]Nickel (IARC Summary & Evaluation , Volume 49, 1990), http://www.inchem.org/documents/iarc/vol49/nickel.html

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Table 5-1 summarizes the total monetized co-benefits of the rule in 2016. This table reflects the economic value of the change in $PM_{2.5}$-related human health impacts and the monetized value of CO_2 reductions occurring as a result of the Mercury and Air Toxics Standards.

Table 5-1. Estimated Monetized Co-benefits of the Mercury and Air Toxics Standards in 2016 (billions of 2007$)[a]

Benefits Estimate	Eastern U.S. [b]	Western U.S.	Total
Pope et al. (2002) $PM_{2.5}$ mortality estimate			
Using a 3% discount rate	$35+B ($2.8 – $110)	$1.1+B ($0.03 – $3.4)	$37+B ($3.2 – $110)
Using a 7% discount rate	$32+B ($2.5 – $98)	$1.0+B ($0.03 – $3.1)	$33+B ($2.9 – $100)
Laden et al. (2006) $PM_{2.5}$ mortality estimate			
Using a 3% discount rate	$87+B ($7.5 – $250)	$2.7+B ($0.1 – $7.9)	$90+B ($8.0 – $260)
Using a 7% discount rate	$78+B ($6.8 – $230)	$2.4+B ($0.1 – $7.2)	$81+B ($7.3 – $240)

[a] For notational purposes, unquantified benefits are indicated with a "B" to represent the sum of additional monetary benefits and disbenefits. Data limitations prevented us from quantifying these endpoints, and as such, these benefits are inherently more uncertain than those benefits that we were able to quantify. A detailed listing of unquantified health and welfare effects is provided in Tables 5-2 and 5-3. Estimates here are subject to uncertainties discussed further in the body of the document. Estimates are rounded to two significant figures. Value of total co-benefits includes CO_2-related co benefits discounted at 3%.

[b] Includes Texas and those states to the north and east.

Tables 5-2 and 5-3 summarize the human health and environmental co-benefits categories contained within the total monetized benefits estimate, and those categories that were unquantified due to limited data or time. It is important to emphasize that the list of unquantified benefit categories is not exhaustive, nor is quantification of each effect complete. In order to identify the most meaningful human health and environmental co-benefits, we excluded effects not identified as having at least a causal, likely causal, or suggestive relationship with the affected pollutants in the most recent comprehensive scientific assessment, such as an Integrated Science Assessment. This does not imply that additional relationships between these and other human health and environmental co-benefits and the affected pollutants do not exist. Due to this decision criterion, some effects that were identified in previous lists of unquantified benefits in other RIAs have been dropped (e.g., UVb exposure). In addition, some quantified effects represent only a partial accounting of likely impacts due to limitations in the currently available data (e.g., climate effects from CO_2, etc).

Table 5-2. Human Health Effects of Pollutants Affected by the Mercury and Air Toxics Standards

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Human Health				
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	Section 5.4
	Infant mortality (age <1)	✓	✓	Section 5.4
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	✓	✓	Section 5.4
	Hospital admissions—respiratory (all ages)	✓	✓	Section 5.4
	Hospital admissions—cardiovascular (age >18)	✓	✓	Section 5.4
	Emergency room visits for asthma (<18)	✓	✓	Section 5.4
	Acute bronchitis (age 8-12)	✓	✓	Section 5.4
	Lower respiratory symptoms (age 7–14)	✓	✓	Section 5.4
	Upper respiratory symptoms (asthmatics age 9–11)	✓	✓	Section 5.4
	Asthma exacerbation (asthmatics age 6–18)	✓	✓	Section 5.4
	Lost work days (age 18–65)	✓	✓	Section 5.4
	Minor restricted-activity days (age 18–65)	✓	✓	Section 5.4
	Chronic Bronchitis (age >26)	✓	✓	Section 5.4
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[b]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[b]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc)	—	—	PM ISA[b,c]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[b,c]
Reduced incidence of mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	—	—	Ozone CD, Draft Ozone ISA[a]
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone CD, Draft Ozone ISA[a]
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	—	—	Ozone CD, Draft Ozone ISA[a]
	Hospital admissions—respiratory causes (age <2)	—	—	Ozone CD, Draft Ozone ISA[a]
	Emergency room visits for asthma (all ages)	—	—	Ozone CD, Draft Ozone ISA[a]
	Minor restricted-activity days (age 18–65)	—	—	Ozone CD, Draft Ozone ISA[a]

(continued)

Table 5-2. Human Health Effects of Pollutants Affected by the Mercury and Air Toxics Standards (continued)

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
	School absence days (age 5–17)	—	—	Ozone CD, Draft Ozone ISA[a]
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone CD, Draft Ozone ISA[a]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone CD, Draft Ozone ISA[b]
	Cardiovascular and nervous system effects	—	—	Ozone CD, Draft Ozone ISA[c]
	Reproductive and developmental effects	—	—	Ozone CD, Draft Ozone ISA[c]
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions (all ages)	—	—	NO_2 ISA[a]
	Chronic lung disease hospital admissions (age > 65)	—	—	NO_2 ISA[a]
	Respiratory emergency department visits (all ages)	—	—	NO_2 ISA[a]
	Asthma exacerbation (asthmatics age 4–18)	—	—	NO_2 ISA[a]
	Acute respiratory symptoms (age 7–14)	—	—	NO_2 ISA[a]
	Premature mortality	—	—	NO_2 ISA[b,c]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[b,c]
Reduced incidence of morbidity from exposure to SO_2	Respiratory hospital admissions (age > 65)	—	—	SO_2 ISA[a]
	Asthma emergency room visits (all ages)	—	—	SO_2 ISA[a]
	Asthma exacerbation (asthmatics age 4–12)	—	—	SO_2 ISA[a]
	Acute respiratory symptoms (age 7–14)	—	—	SO_2 ISA[a]
	Premature mortality	—	—	SO_2 ISA[b,c]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	SO_2 ISA[b,c]
Reduced incidence of morbidity from exposure to methylmercury (through reduced mercury deposition as well as the role of sulfate in methylation)	Neurologic effects - IQ loss	✓	✓	IRIS; NRC, 2000[a]
	Other neurologic effects (e.g., developmental delays, memory, behavior)	—	—	IRIS; NRC, 2000[b]
	Cardiovascular effects	—	—	IRIS; NRC, 2000[b,c]
	Genotoxic, immunologic, and other toxic effects	—	—	IRIS; NRC, 2000[b,c]

[a] We assess these co-benefits qualitatively due to time and resource limitations for this analysis.
[b] We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.
[c] We assess these co-benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

Table 5-3. Environmental Effects of Pollutants Affected by the Mercury and Air Toxics Standards

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced visibility impairment	Visibility in Class I areas in SE, SW, and CA regions	—	—	PM ISA[a]
	Visibility in Class I areas in other regions	—	—	PM ISA[a]
	Visibility in residential areas	—	—	PM ISA[a]
Reduced climate effects	Global climate impacts from CO_2	—	✓	Section 5.6
	Climate impacts from ozone and PM	—	—	Section 5.6
	Other climate impacts (e.g., other GHGs, other impacts)	—	—	IPCC[b]
Reduced effects on materials	Household soiling	—	—	PM ISA[b]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[b]
Reduced effects from PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[b]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone CD, Draft Ozone ISA[b]
	Reduced vegetation growth and reproduction	—	—	Ozone CD, Draft Ozone ISA[a]
	Yield and quality of commercial forest products and crops	—	—	Ozone CD, Draft Ozone ISA[a,c]
	Damage to urban ornamental plants	—	—	Ozone CD, Draft Ozone ISA[b]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone CD, Draft Ozone ISA[b]
	Recreational demand associated with forest aesthetics	—	—	Ozone CD, Draft Ozone ISA[b]
	Other non-use effects			Ozone CD, Draft Ozone ISA[b]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone CD, Draft Ozone ISA[b]

(continued)

Table 5-3. Environmental Effects of Pollutants Affected by the Mercury and Air Toxics Standards (continued)

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Reduced effects from acid deposition	Recreational fishing	—	—	NOx SOx ISA[a]
	Tree mortality and decline	—	—	NOx SOx ISA[b]
	Commercial fishing and forestry effects	—	—	NOx SOx ISA[b]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NOx SOx ISA[b]
	Other non-use effects			NOx SOx ISA[b]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NOx SOx ISA[b]
Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NOx SOx ISA[b]
	Coastal eutrophication	—	—	NOx SOx ISA[b]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NOx SOx ISA[b]
	Other non-use effects			NOx SOx ISA[b]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NOx SOx ISA[b]
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NOx SOx ISA[b]
	Injury to vegetation from NO_x exposure	—	—	NOx SOx ISA[b]
Reduced ecosystem effects from exposure to methylmercury (through reduced mercury deposition as well as the role of sulfate in methylation)	Effects on fish, birds, and mammals (e.g., reproductive effects)	—	—	Mercury Study RTC[b,c]
	Commercial, subsistence and recreational fishing	—	—	Mercury Study RTC[b]

[a] We assess these co-benefits qualitatively due to time and resource limitations for this analysis.

[b] We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.

[c] We assess these co-benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

The co-benefits analysis in this chapter relies on an array of data inputs—including air quality modeling, health impact functions and valuation functions among others—which are themselves subject to uncertainty and may also contribute to the overall uncertainty in this analysis. As a means of characterizing this uncertainty we employ two primary techniques. First,

we use Monte Carlo methods for characterizing random sampling error associated with the concentration response functions from epidemiological studies and economic valuation functions. Second, because this characterization of random statistical error may omit important sources of uncertainty we also employ the results of an expert elicitation on the relationship between premature mortality and ambient $PM_{2.5}$ concentration (Roman et al., 2008). This provides additional insight into the likelihood of different outcomes and about the state of knowledge regarding the co-benefits estimates. Both approaches have different strengths and weaknesses, which are fully described in Chapter 5 of the PM NAAQS RIA (U.S. EPA, 2006a). While the contributions from additional data inputs to uncertainty in the results are not quantified here, this analysis employs best practices in every aspect of its development.

Given that co-benefits of reductions in premature mortality are a dominant share of the overall monetized co-benefits, more focus on uncertainty in mortality-related co-benefits gives us greater confidence in our uncertainty characterization surrounding total $PM_{2.5}$-related co-benefits. Additional sensitivity analyses have been performed for the 2006 PM NAAQS RIA, and were not specifically included here as the results would be similar and would not change the conclusions of the analyses to support this rule. In particular, these analyses characterized the sensitivity of the monetized co-benefits to the specification of alternate cessation lags and income growth adjustment factors. As shown in these RIAs, the estimated co-benefits increased or decreased in proportion to the specification of alternate income growth adjustments and cessation lags. Therefore, readers can infer the sensitivity of the results in this RIA to these parameters by referring to the sensitivity analyses in the PM NAAQS RIA (2006d) and Ozone NAAQS RIA (2008a). For example, based on the results from previous analyses, the use of an alternate lag structure would change the $PM_{2.5}$-related mortality co-benefits discounted at 3% discounted by between 10.4% and –27%; when discounted at 7%, these co-benefits change by between 31% and -49%. When applying higher and lower income growth adjustments, the monetary value of $PM_{2.5}$ -related premature changes between 30% and -10%; the value of chronic endpoints change between 5% and -2% and the value of acute endpoints change between 6% and -7%.

Additionally, in this RIA we binned the estimated population exposed to projected future baseline $PM_{2.5}$ air quality levels for comparison against the “Lowest Measured Level” (LML) of $PM_{2.5}$ air quality in the mortality studies. The purpose of this analysis is to show whether the estimated premature deaths associated with reduced $PM_{2.5}$ exposure occur at or above the range of ambient $PM_{2.5}$ observations studied in Pope et al. (2002) and Laden et al. (2006), which are the two epidemiological studies that EPA uses to estimate $PM_{2.5}$-related

premature mortality co-benefits. We found that a significant proportion of the avoided PM-related premature deaths we estimated in this analysis occurred among populations exposed at or above the LML of each study in the baseline, increasing our confidence in our estimate of the magnitude of the PM-related premature deaths avoided. Approximately 11% of the avoided premature deaths occur at or above an annual mean $PM_{2.5}$ level of 10 $\mu g/m^3$ (the LML of the Laden et al. 2006 study), and about 73% occur at or above an annual mean $PM_{2.5}$ level of 7.5 $\mu g/m^3$ (the LML of the Pope et al. 2002 study). As we model avoided premature deaths among populations exposed to levels of $PM_{2.5}$ that are successively lower than the LML of each study our confidence in the results diminishes.

5.2 Benefits Analysis Methods

We follow a "damage-function" approach in calculating health co-benefits of the modeled changes in environmental quality. This approach estimates changes in individual health and welfare endpoints (specific effects that can be associated with changes in air quality) and estimates values of those changes assuming independence between the values of individual endpoints. Total benefits are calculated simply as the sum of the values for all non-overlapping health and welfare endpoints. The "damage-function" approach is the standard method for assessing costs and benefits of environmental quality programs and has been used in several recent published analyses (Levy et al., 2009; Hubbell et al., 2009; Tagaris et al., 2009).

To assess economic value in a damage-function framework, the changes in environmental quality must be translated into effects on people or on the things that people value. In some cases, the changes in environmental quality can be directly valued, as is the case for changes in visibility. In other cases, such as for changes in ozone and PM, a health and welfare impact analysis must first be conducted to convert air quality changes into effects that can be assigned dollar values.

We note at the outset that EPA rarely has the time or resources to perform extensive new research to measure directly either the health outcomes or their values for regulatory analyses. Thus, similar to Kunzli et al. (2000) and other recent health impact analyses, our estimates are based on the best available methods of benefits transfer. Benefits transfer is a means of adapting primary research from similar contexts to obtain the most accurate measure of benefits for the environmental quality change under analysis. Adjustments are made for the level of environmental quality change, the socio-demographic and economic characteristics of the affected population, and other factors to improve the accuracy and robustness of benefits estimates.

5.2.1 Health Impact Assessment

Health Impact Assessment (HIA) quantifies changes in the incidence of adverse health impacts resulting from changes in human exposure to specific pollutants, such as $PM_{2.5}$. HIAs are a well-established approach for estimating the retrospective or prospective change in adverse health impacts expected to result from population-level changes in exposure to pollutants (Levy et al. 2009). PC-based tools such as the environmental Benefits Mapping and Analysis Program (BenMAP) can systematize health impact analyses by applying a database of key input parameters, including health impact functions and population projections. Analysts have applied the HIA approach to estimate human health impacts resulting from hypothetical changes in pollutant levels (Hubbell et al. 2005; Davidson et al. 2007, Tagaris et al. 2009). EPA and others have relied upon this method to predict future changes in health impacts expected to result from the implementation of regulations affecting air quality (e.g. U.S. EPA, 2008a). For this assessment, the HIAs are limited to those health effects that are directly linked to ambient $PM_{2.5}$ concentrations. There may be other indirect health impacts associated with implementing emissions controls, such as occupational health impacts for coal miners.

The HIA approach used in this analysis involves three basic steps: (1) utilizing CAMx-generated projections of $PM_{2.5}$ and ozone air quality and estimating the change in the spatial distribution of the ambient air quality; (2) determining the subsequent change in population-level exposure; (3) calculating health impacts by applying concentration-response relationships drawn from the epidemiological literature (Hubbell et al. 2009) to this change in population exposure.

A typical health impact function might look as follows:

$$\Delta y = y_o \cdot \left(e^{\beta \cdot \Delta x} - 1\right) \cdot Pop$$

where y_0 is the baseline incidence rate for the health endpoint being quantified (for example, a health impact function quantifying changes in mortality would use the baseline, or background, mortality rate for the given population of interest); *Pop* is the population affected by the change in air quality; Δx is the change in air quality; and β is the effect coefficient drawn from the epidemiological study. Tools such as BenMAP can systematize the HIA calculation process, allowing users to draw upon a library of existing air quality monitoring data, population data and health impact functions.

Figure 5-1 provides a simplified overview of this approach.

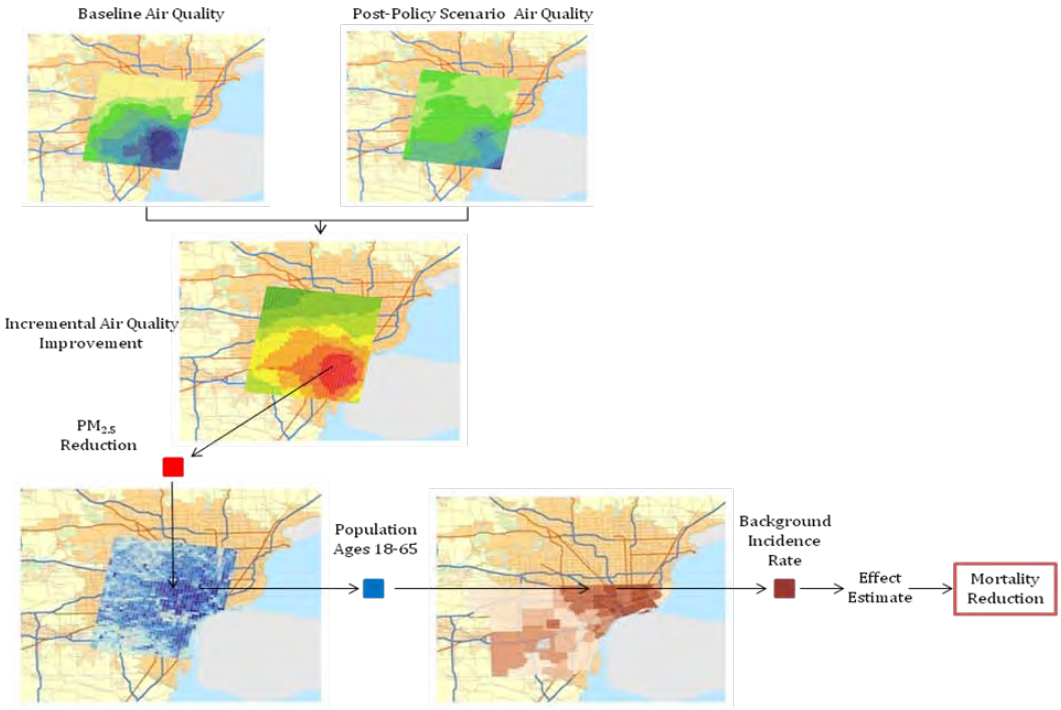

Figure 5-1. Illustration of BenMAP Approach

5.2.2 Economic Valuation of Health Impacts

After quantifying the change in adverse health impacts, the final step is to estimate the economic value of these avoided impacts. The appropriate economic value for a change in a health effect depends on whether the health effect is viewed *ex ante* (before the effect has occurred) or *ex post* (after the effect has occurred). Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects by a small amount for a large population. The appropriate economic measure is therefore *ex ante* Willingness to Pay (WTP) for changes in risk. However, epidemiological studies generally provide estimates of the relative risks of a particular health effect avoided due to a reduction in air pollution. A convenient way to use this data in a consistent framework is to convert probabilities to units of avoided statistical incidences. This measure is calculated by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a measure is able to reduce the risk of premature mortality from 2 in 10,000 to 1 in 10,000 (a reduction of 1 in 10,000). If individual WTP for this risk reduction is $100, then the WTP for an avoided statistical premature mortality amounts to $1 million ($100/0.0001 change in risk). Using this approach, the size of the affected population is automatically taken into account by the number of incidences predicted by epidemiological studies applied to the relevant population. The same type of calculation can produce values for statistical incidences of other health endpoints.

For some health effects, such as hospital admissions, WTP estimates are generally not available. In these cases, we use the cost of treating or mitigating the effect as a primary estimate. For example, for the valuation of hospital admissions we use the avoided medical costs as an estimate of the value of avoiding the health effects causing the admission. These cost of illness (COI) estimates generally (although not in every case) understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect.

We use the BenMAP model version 4 (Abt Associates, 2010) to estimate the health impacts and monetized health co-benefits for the Mercury and Air Toxics Standards. Figure 5-2 shows the data inputs and outputs for the BenMAP model.

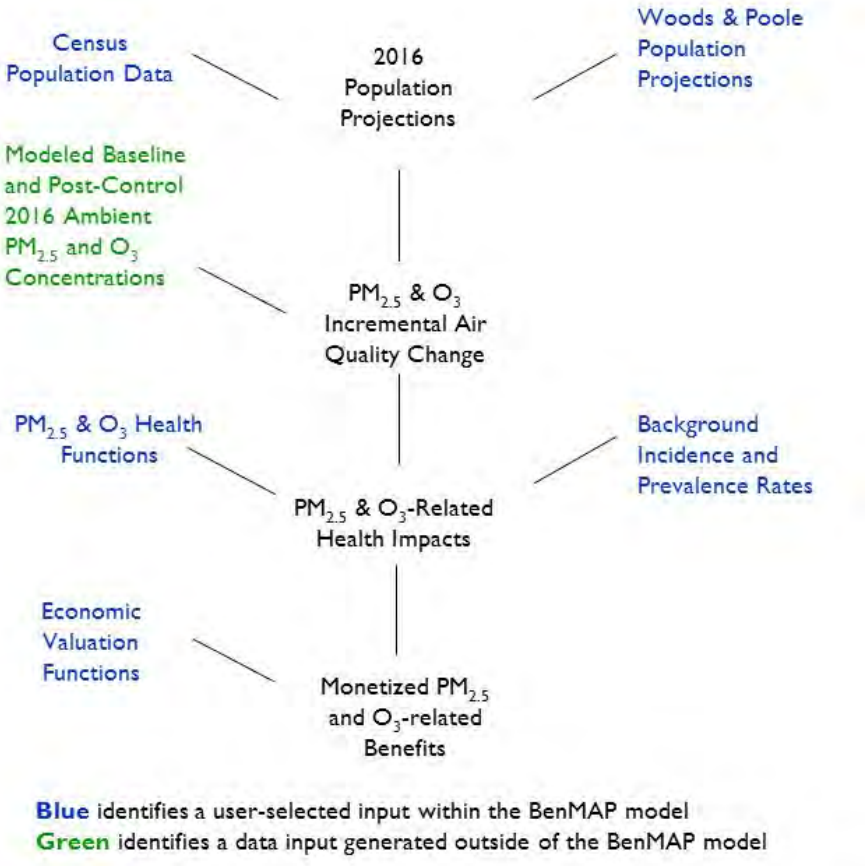

Figure 5-2. Data Inputs and Outputs for the BenMAP Model

5.2.3 Adjusting the Results of the $PM_{2.5}$ co-benefits Analysis to Account for the Emission Reductions in the Final Mercury and Air Toxics Standards

As described in Chapter 3 of this RIA, EPA finalized the rule requirements after the completion of the air quality modeling for this rule. These changes to the rule affected both the overall level and distribution of $PM_{2.5}$ precursor emissions across the U.S., which in turn affect the level of $PM_{2.5}$ co-benefits. We determined that the geographic distribution of emissions reductions resulting from the final rule requirements were sufficiently similar to the modeled interim emissions reductions that we could adjust our co-benefits estimates to reflect these emission changes by applying benefit per-ton estimates generated using the modeled air quality changes.

Benefit per-ton (BPT) estimates quantify the health impacts and monetized human health co-benefits of an incremental change in air pollution precursor emissions. In circumstances where we are unable to perform air quality modeling because of resource or time constraints, this approach can provide a reasonable estimate of the co-benefits of emission reductions. EPA has used the BPT technique in previous RIAs, including the recent Ozone NAAQS RIA (U.S. EPA, 2008a), the NO_2 NAAQS RIA (U.S. EPA, 2010b), the proposed Mercury and Air Toxics Standards RIA (U.S. EPA 2011a), and the Cross-State Air Pollution Rule (U.S. EPA, 2011b).

For this co-benefits analysis we created per-ton estimates of $PM_{2.5}$-related incidence- and monetized co-benefits based on the co-benefits of the air quality modeled scenario. Our approach here is methodologically consistent with the technique reported in Fann, Fulcher & Hubbell (2009), but adjusted for this analysis to better match the spatial distribution of air quality changes expected under the Mercury and Air Toxics Standards. To derive the BPT estimates for this analysis, we:

1. *Quantified the $PM_{2.5}$-related human and monetized health co-benefits of SO_2 and direct $PM_{2.5}$ changes for Eastern and Western states*. We first estimated the health impacts and monetized co-benefits of reductions in directly emitted $PM_{2.5}$ and particulate sulfate.[1] MATS is expected to reduce both SO_2 and NO_x emissions. In general SO_2 is a precursor to particulate sulfate and NO_x is a precursor to particulate nitrate. However, there are also several interactions between the $PM_{2.5}$ precursors which cannot be easily quantified. For example, under conditions in which SO_2 levels are reduced by a substantial margin, "nitrate replacement" may occur. This occurs

[1] Consistent with advice from the Health Effects Subcommittee of the Science Advisory Board (U.S. EPA-SAB, 2010), we assume that each PM species is equally toxic. We quantify the change in incidence for each PM component by applying risk coefficients based on undifferentiated $PM_{2.5}$ mass.

CHAPTER 8
COMPARISON OF BENEFITS AND COSTS

8.1 Comparison of Benefits and Costs

The estimated costs to implement the final MATS Rule, as described earlier in this document, are approximately $9.6 billion annually for 2016 (2007 dollars). Thus, the net benefits (benefits minus costs) of the program in 2016 are approximately $27 to 80 +B billion or $24 to 71 +B billion annually (2007 dollars, based on a discount rate of 3 percent and 7 percent for the benefits, respectively and rounded to two significant figures). (B represents the sum of all unquantified benefits and disbenefits of the regulation.) Therefore, implementation of this rule is expected, based purely on economic efficiency criteria, to provide society with a significant net gain in social welfare, even given the limited set of health and environmental effects we were able to quantify. Addition of health endpoints other than IQ loss to children exposed to mercury from recreationally caught freshwater fish and acidification-, and eutrophication-related impacts would likely increase the net benefits of the rule. Table 8-1 presents a summary of the benefits, costs, and net benefits of the final MATS Rule.

As with any complex analysis of this scope, there are several uncertainties inherent in the final estimate of benefits and costs that are described fully in Chapters 3, 4 and 5.

ATTACHMENT B

5 Emission Control Technologies

EPA Base Case v.4.10 includes a major update of emission control technology assumptions. For this base case EPA contracted with engineering firm Sargent and Lundy to perform a complete bottom-up engineering reassessment of the cost and performance assumptions for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission controls. In addition to the work by Sargent and Lundy, Base Case v.4.10 includes two Activated Carbon Injections (ACI) options (Standard and Modified) for mercury (Hg) control[27]. Capture and storage options for carbon dioxide (CO_2) have also been added in the new base case.

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

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

SO_2 Control Technology Options	NO_X Control Technology Options	Hg Control Technology Options	CO_2 Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Standard Activated Carbon Injection (SPAC-ACI) System	CO_2 Capture and Sequestration
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	Modified Activated Carbon Injection (MPAC-ACI) System	
	Combustion Controls	SO_2 and NO_X Control Technology Removal Cobenefits	

5.1 Sulfur Dioxide Control Technologies

Two commercially available Flue Gas Desulfurization (FGD) technology options for removing the SO_2 produced by coal-fired power plants are offered in EPA Base Case v.4.10: Limestone Forced Oxidation (LSFO) — a wet FGD technology — and Lime Spray Dryer (LSD) — a semi-dry FGD technology which employs a spray dryer absorber (SDA). In wet FGD systems, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose SO_2 content exceeds 3lb SO_2/MMBtu, so this technology is provided only to plants which have the option to burn coals with sulfur content no greater than 3 lbs SO_2/MMBtu. In EPA Base Casev.4.10 when a unit retrofits with an LSD SO_2 scrubber, it loses the option of burning BG, BH, and LG coals due to their high sulfur content.

In EPA Base Case v.4.10 the LSFO and LSD SO_2 emission control technologies are available to existing "unscrubbed" units. They are also available to existing "scrubbed" units with reported removal efficiencies of less than fifty percent. Such units are considered to have an injection technology and classified as “unscrubbed” for modeling purposes in the NEEDS database of

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

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

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

Table 5-2 Summary of Retrofit SO_2 Emission Control Performance Assumptions

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal	98% with a floor of 0.06 lbs/MMBtu	93% with a floor of 0.065 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-4 for examples	Calculated based on characteristics of the unit: See Table 5-4 for examples
Heat Rate Penalty		
Cost (2007$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs SO_2/MMBtu
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, LD, LE, and LG	BA, BB, BD, BE, SA, SB, SD, LD, and LE

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

5.1.1 Methodology for Obtaining SO_2 Controls Costs

The Sargent and Lundy update of SO_2 and NO_x control costs is notable on several counts. First, it brought costs up to levels seen in the marketplace in 2009. Incorporating these costs into EPA's base case carries an implicit assumption, not universally accepted, that the run up in costs seen over the preceding 5 years and largely attributed to international competition, is permanent and will not settle back to pre-2009 levels. Second, a revised methodology, based on Sargent and Lundy's expert experience, was used to build up the capital, fixed and variable operating and maintenance components of cost. That methodology, which employed an engineering build up of each component of cost, is described here and in the following sections. Detailed example cost calculation spreadsheets for both SO_2 and NO_x controls are included in Appendices 5-1 and 5-2 respectively. The Sargent and Lundy reports in which these spreadsheets appeared can be downloaded via links to the Appendices 5-1A, 5-1B, 5-2A, and 5-2B links found at www.epa.gov/airmarkets/progsregs/epaipm/BaseCasev410.html.

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

The governing cost variables for each module are indicated in Table 5-3. The major variables affecting capital cost are unit size and the SO_2 content of the fuel with the latter having the greatest impact on the reagent and waste handling facilities. In addition, heat rate affects the amount of flue gas produced and consequently the size of each of the modules. The quantity of flue gas is also a function of coal rank since different coals have different typical heating values.

Table 5-3 Capital Cost Modules and Their Governing Variables for SO_2 and NO_x Emission Controls

Module	Retrofit Difficulty (1 = average)	Coal Rank Factor (Bi_t = 1, PRB = 1.05, Lignite = 1.07)	Heat Rate (Btu/kWh)	SO_2 Rate (lb/MMBtu)	NO_x Rate (lb/MMBtu)[5]	Unit Size (MW)
SO_2 Emission Controls – Wet FGD and SDA FGD						
Absorber Island	X	X	X	X		X
Reagent Preparation	X		X	X		X
Waste Handling	X		X	X		X
Balance of Plant[1]	X	X	X			X
NO_x Emission Controls – SCR and SNCR						
SCR/SNCR Island[2]	X	X	X		X[3]	X
Reagent Preparation[3]					X	
Air Heater Modification[4]	X	X	X	X		X
Balance of Plant[5] – SCR	X	X	X			X
Balance of Plant[1] – SNCR					X	X

Notes:
[1]"Balance of plant" costs include such cost items as ID and booster fans, new wet chimneys, piping, ductwork, minor waste water treatment, auxiliary power modifications, and other electrical and site upgrades.
[2]The SCR island module includes the cost of inlet ductwork, reactor, and bypass. The SNCR island module includes cost of injectors, blowers, distributed control system (DCS), and reagent system.
[3]Only applies to SCR.
[4]On generating units that burn bituminous coal whose SO_2 and content exceeds 3 lbs/MMBtu, air heater modifications used to control SO_3 are needed in conjunction with the operation of SCR and SNCR.
[5]For SCR, the NO_x rate is frequently expressed through the calculated NO_x removal efficiency.

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

Variable Operating and Maintenance Costs (VOM): These are the costs incurred in running the emission control device. They are proportional to the electrical energy produced and are expressed in units of $ per MWh. For FGD, Sargent and Lundy identified four components of VOM: (a) costs for reagent usage, (b) costs for waste generation, (c) make up water costs, and (d) cost of additional power required to run the control (often called the "parasitic load"). For a given coal rank and a pre-specified SO_2 removal efficiency, each of these components of VOM cost is a function of the generating unit's heat rate (Btu/kWh) and the sulfur content (lb SO_2/MMBtu) of the coal (also referred to as the SO_2 feed rate). For purposes of modeling, the total VOM includes the first three of these component costs. The last component – cost of additional power – is factored into IPM, not in the VOM value, but through a capacity and heat rate penalty as described in the next paragraph. Due to the differences in the removal processes, the per MWh cost for waste handling, makeup water, and auxiliary power tend to be higher for LSFO while reagent usage cost and total VOM (excluding parasitic load) are higher for LSD.

Capacity and Heat Rate Penalty: The amount of electrical power required to operate the FGD device is represented through a reduction in the amount of electricity that is available for sale to the grid. For example, if 1.6% of the unit's electrical generation is needed to operate the scrubber, the generating unit's capacity is reduced by 1.6%. This is the "capacity penalty." At the same time, to capture the total fuel used in generation both for sale to the grid and for internal load (i.e., for operating the FGD device), the unit's heat rate is scaled up such that a comparable reduction (1.6% in the previous example) in the new higher heat rate yields the original heat rate[28]. The factor used to scale up the original heat rate is called "heat rate penalty." It is a modeling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency). Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

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

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

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

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

Table 5-4 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalty for the two SO_2 emission control technologies (LSFO and LSD) included in EPA Base Case v.4.10 for an illustrative set of generating units with a representative range of capacities and heat rates.

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

Scrubber Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
LSFO														
Minimum Cutoff: ≥ 25 MW	9,000	-1.5	1.53	1.66	747	22.5	547	10.5	473	7.8	430	7.2	388	5.9
Maximum Cutoff: None	10,000	-1.67	1.7	1.84	783	22.8	573	10.8	496	8.0	451	7.4	407	6.1
Assuming 3 lb/MMBtu SO_2 Content Bituminous Coal	11,000	-1.84	1.87	2.03	817	23.2	598	11.0	517	8.2	470	7.6	425	6.3
LSD														
Minimum Cutoff: ≥ 25 MW	9,000	-1.18	1.2	2.13	641	16.4	469	8.1	406	6.1	385	5.3	385	4.9
Maximum Cutoff: None	10,000	-1.32	1.33	2.36	670	16.7	491	8.3	424	6.3	403	5.5	403	5.1
Assuming 2 lb/MMBtu SO_2 Content Bituminous Coal	11,000	-1.45	1.47	2.60	698	17.0	511	8.5	442	6.5	420	5.7	420	5.2

5.2 Nitrogen Oxides Control Technology

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

5.2.1 Combustion Controls

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

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

Boiler Type	Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
Dry Bottom Wall-Fired	Low NO_x Burner without Overfire Air (LNB without OFA)	45	0.3	0.07
	Low NO_x Burner with Overfire Air (LNB with OFA)	61	0.4	0.09
Tangentially-Fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	24	0.2	0.00
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	33	0.2	0.03
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	38	0.3	0.03
Vertically-Fired	NO_x Combustion Control	29	0.2	0.06

Scaling Factor

The following scaling factor is used to obtain the capital and fixed operating and maintenance costs applicable to the capacity (in MW) of the unit taking on combustion controls. No scaling factor is applied in calculating the variable operating and maintenance cost.

LNB without OFA & LNB with OFA = ($ for *X* MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.359}$

LNC1, LNC2 and LNC3 = ($ for *X* MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.359}$

Vertically-Fired = ($ for *X* MW Unit) = ($ for 300 MW Unit) x $(300/X)^{0.553}$

where

($ for 300 MW Unit) is the value obtained using the factors shown in the above table and *X* is the capacity (in MW) of the unit taking on combustion controls.

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

Boiler Type	Existing NO_x Combustion Control	Incremental Combustional Control
Cell	LNB	OFA
	NGR	LNB AND OFA
Cyclone	--	OFA
Stoker/SPR	--	OFA
Tangential	--	LNC3
	LA	LNC3
	LNB	CONVERSION FROM LNC1 TO LNC3
	LNB + OFA	CONVERSION FROM LNC1 TO LNC3
	LNC1	CONVERSION FROM LNC1 TO LNC3
	LNC2	CONVERSION FROM LNC2 TO LNC3
	OFA	LNC1
	ROFA	LNB
Vertical	--	NO_x Combustion Control - Vertically Fired Units
Wall	--	LNB AND OFA
	LA	LNB AND OFA
	LNB	OFA
	LNF	OFA
	OFA	LNB

5.2.2 Post-combustion Controls

The EPA Base Case v.4.10 includes two post-combustion retrofit control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Base Case v.4.10 oil/gas steam units are eligible for SCR only. NO_x reduction in an SCR system takes place by injecting ammonia (NH_3) vapor into the flue gas stream where the NO_x is reduced to nitrogen (N2) and water H_2O abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten. As its name implies, SNCR operates without a catalyst. In SNCR a nitrogenous reducing agent (reagent), typically ammonia or urea, is injected into, and mixed with, hot flue gas where it reacts with the NO_x in the gas stream reducing it to nitrogen gas and water vapor. Due to the presence of a catalyst, SCR can achieve greater NO_x reductions than SNCR. However, SCR costs are higher.

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

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

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

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

5.2.3 Methodology for Obtaining SCR Costs for Coal Units

As with the update of SO_2 control costs, Sargent and Lundy employed an engineering build-up of the capital, fixed and variable operating and maintenance components of cost to update post-combustion NO_x control costs. This section describes the approach used for SCR. The next section treats SNCR. Detailed example cost calculation spreadsheets for both technologies can be found in Appendix 5-2.

For cost calculation purposes the Sargent and Lundy methodology calculates plant specific NO_x removal efficiencies, i.e., the percent difference between the uncontrolled NO_x rate[29] for a model plant and the cost calculation floor NO_x rate corresponding to the predominant coal rank used at the plant (0.07 lb/MMBtu for bituminous and 0.05 lb/MMBtu for subbitumionus and lignite coals). For example, a plant that burns subbitumionus coal with an uncontrolled NO_x rate of 0.1667 lb/MMBtu, and a cost calculation floor NO_x rate of 0.05 lb/MMBtu would have a removal efficiency of 70%, i.e., (0.1667 – 0.05)/0.1667 = 0.1167/0.1667 = .70. The NO_x removal efficiency so obtained figures in the capital, VOM, and FOM components of SCR cost.

Capital Costs: In building up SCR capital costs, four separate cost modules were included: SCR island (e.g., inlet ductwork, reactor, and bypass), reagent preparation, air pre-heater modification, and balance of plan (e.g., ID or booster fans, piping, and auxiliary power modification). Air pre-heater modification cost only applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater, where SO_3 control is necessary. Otherwise, there is no air pre-heat cost. For each of the four modules the cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. All four capital cost modules, except reagent preparation, are functions of retrofit difficulty, coal rank, heat rate, and unit size. NO_x rate (expressed via the NO_x removal efficiency) affects the SCR and reagent preparation cost modules. Not shown in Table 5-3, heat input (in Btu/hr) also impacts reagent preparation costs. As noted above, the SO_2 rate becomes a factor in SCR cost for plants that combust bituminous coal with 3 lbs SO_2/MMBtu or greater, where air pre-heater modifications are needed for SO_3 control.

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

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

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

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

Capacity and Heat Rate Penalty:
Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific SCR heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

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

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

Table 5-8 presents the SCR and SNCR capital, VOM, and FOM costs and capacity and heat rate penalties for an illustrative set of coal generating units with a representative range of capacities, heat rates, and NO_x removal efficiencies. The illustrations include and identify plants that do and do not burn bituminous coal with 3 lbs SO_2/MMBtu or greater.

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

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
SCR														
Minimum Cutoff: ≥ 25 MW	9,000	-0.54	0.54	1.15	221	2.5	177	0.8	163	0.7	155	0.5	147	0.4
Maximum Cutoff: None														
Assuming Bituminous Coal	10,000	-0.56	0.56	1.24	240	2.5	193	0.8	178	0.7	169	0.5	162	0.4
NO_x rate: 0.5 lb/MMBtu														
SO_2 rate: 2.0 lb/MMBtu	11,000	-0.58	0.59	1.33	258	2.5	209	0.8	193	0.7	184	0.5	176	0.4
SNCR - Non-FBC														
Minimum Cutoff: ≥ 25 MW	9,000			0.88	45	1	Size Not Modeled							
Maximum Cutoff: None														
Assuming Bituminous Coal	10,000	-0.05	0.05	0.98	47	1								
NO_x rate: 0.5 lb/MMBtu														
SO_2 rate: 2.0 lb/MMBtu	11,000			1.08	48	1								
SNCR - Fluidized Bed														
Minimum Cutoff: ≥ 25 MW	9,000			0.88	34	0.9	18	0.4	14	0.2	11	0.2	9	0.1
Maximum Cutoff: None														
Assuming Bituminous Coal	10,000	-0.05	0.05	0.98	35	0.9	19	0.4	14	0.2	12	0.2	10	0.1
NO_x rate: 0.5 lb/MMBtu														
SO_2 rate: 2.0 lb/MMBtu	11,000			1.08	36	0.9	19	0.4	14	0.2	12	0.2	10	0.1

Note:

If a coal plant burns bituminous coal with a SO_2 content above 3.0 lb/MMBtu then the capital costs will increase due to the required air preheater modification. For example, a 100 MW coal boiler with an SCR burning bituminous coal at a heat rate of 11,000 Btu/kWh and an SO_2 rate of 4.0 lb/MMBtu will have a capital cost of 296 $/kW, a 36 $/kW increase in capital costs from an identical boiler burning coal with an SO_2 rate of 2.0 lb/MMBtu.

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

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

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

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

Notes:

The "Coefficients" in the table above are multiplied by the terms below to determine costs.

"MW" in the terms below is the unit's capacity in megawatts.

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

[1] SCR Cost Equations:

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

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

Example for 275 MW unit:

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

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

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

Reference:

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

5.2.5 Methodology for Obtaining SNCR Costs

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

Capital Costs: Due to the absence of a catalyst and, with it, the elimination of the need for more extensive reagent preparation, the Sargent and Lundy engineering build up of SNCR capital costs includes three rather than four separate cost modules: SNCR (injectors, blowers, distributive control system, reagent system), air pre-heater modification, and balance of plan (e.g., ID or booster fans, piping, and auxiliary power modification). For CFB units, the SNCR and balance of plan module costs are 75% of what they are on other boiler types. The air pre-heater modification cost module is the same as for SCR and there is no cost difference between CFB and other boiler types. As with SCR the air heater modification cost only applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater, where SO_3 control is necessary. Otherwise, there is no air pre-heat cost. For each of the three modules the cost of foundations, buildings, electrical equipment, installation, and average retrofit difficulty were taken into account.

The governing cost variables for each module are indicated in Table 5-3. Unit size affects all three modules. Retrofit difficulty, coal rank, and heat rate impact the SNCR and air heater modification modules. The SO_2 rate impacts the air pre-heater modification module. NO_X rate

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

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

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

Capacity and Heat Rate Penalty:
Unlike previous base cases, which assumed a generic heat rate and capacity penalties for all installations, in EPA Base Case v.4.10 specific SNCR heat rate and capacity penalties are calculated for each installation based on equations developed by Sargent and Lundy that take into account the rank of coal burned, its SO_2 rate, and the heat rate of the model plant.

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

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

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

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

5.2.6 SO_2 and NO_x Controls for Units with Capacities from 25 MW to 100 MW (25 M ≤ capacity < 100 MW)

In EPA Base Case v.4.10 coal units with capacities between 25 MW and 100 MW are offered the same SO_2 and NO_x emission control options as larger units. However, for purposes of modeling, the costs of controls for these units are assumed to be equivalent to that of a 100 MW unit. This assumption is based on several considerations. First, to achieve economies of scale, several units in this size range are likely to be ducted to share a single common control, so the 100 MW cost equivalency assumption, though generic, would be technically plausible. Second, single units in this size range that are not grouped to achieve economies of scale are likely to have the option of hybrid multi-pollutant controls currently under development.[30] These hybrid controls achieve cost economies by combining SO_2, NO_X and particulate controls into a single control unit. Singly, the costs of the individual control would be higher for units below 100 MW than for a 100 MW unit,

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

but when combined in the Multi-Pollutant Technologies (MPTs) their costs would be roughly equivalent to the cost of individual controls on a 100 MW unit. While MPTs are not explicitly represented in EPA Base Case v.4.10, single units in the 25-100 MW range that take on combinations of SO_2 and NO_X controls in a model run can be thought of as being retrofit with an MPT.

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

5.3 Biomass Co-firing

Under most climate policies currently being discussed, biomass is treated as "carbon neutral," i.e., a zero contributor of CO_2 to the atmosphere. The reasoning is that the CO_2 emitted in the combustion of biomass will be reabsorbed via photosynthesis in plants grown to replace the biomass that was combusted. Consequently, if a power plant can co-fire biomass and thereby replace a portion of fossil fuel, it reduces its CO_2 emissions by approximately the same proportion, although combustion efficiency losses may somewhat diminish the proportion of CO_2 reduction. Roughly speaking, by co-firing enough biomass to produce 10% of a coal plant's power output, a co-fired plant can realize close to an effective 10% reduction in CO_2 emitted.

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

In EPA Base Case v.4.10 the limit on biomass co-firing is expressed as the percentage of the facility level power output that is produced from biomass. Based on analysis by EPA's power sector engineering staff, a maximum of 10% of the facility level power output (not to exceed 50 MW) can be fired by biomass. In EPA Base Case v.4.10 "facility level" is defined as the set of generating units which share the same ORIS code[31] in NEEDS v.4.10.

The capital and FOM costs associated with biomass co-firing are summarized in Table 5-10. Developed by EPA's power sector engineering staff[32], they are on the same cost basis as the

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

[32] Among the studies consulted in developing these costs were:

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

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

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

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

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

Table 5-10 Biomass Cofiring for Coal Plants

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

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

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

5.4 Mercury Control Technologies

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

For any power plant, mercury emissions depend on the mercury content of the fuel used, the combustion and physical characteristics of the unit, and the emission control technologies deployed. In the absence of emission policies that would require the installation of mercury emission controls, mercury emission reductions below the mercury content of the fuel are strictly due to characteristics of the combustion process and incidental removal resulting from non-mercury control technologies, i.e., the SO_2, NO_X, and particulate controls. While the base case itself does not include any federal mercury control policies, it does include some State mercury reduction requirements. IPM has the capability to model mercury controls that might be installed in response to such State mercury control policies. These same controls come into play in model runs that analyze possible federal mercury policies relative to the base case. The technology specifically designated for mercury control in such policy runs is Activated Carbon Injection (ACI) downstream of the combustion process.

Burners, PowerGen 2000 - Orlando, FL, www.fwc.com/publications/tech_papers/powgen/pdfs/clrw_bio.pdf.
Tillman, D. A., *Cofiring Biomass for Greenhouse Gas Mitigation*, presented at Power-Gen 99, New Orleans, LA, November 30 – December 1, 1999.
(e) Tillman, D. A. and P. Hus, *Blending Opportunity Fuels with Coal for Efficiency and Environmental Benefit*, presented at 25th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., March 6 – 9, 2000

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

5.4.1 Mercury Content of Fuels

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

The ICR second component resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content and other characteristics of coal burned at coal-fired utility units greater than 25 MW. To make this data usable in EPA Base Case v.4.10, these data points were first grouped by IPM coal types and IPM coal supply regions. (IPM coal types divide bituminous, sub-bituminous, and lignite coal into different grades based on sulfur content. See Table 5-11.) Next, a clustering analysis was performed on the data using the SAS statistical software package. Clustering analysis places objects into groups or clusters, such that data in a given cluster tend to be similar to each other and dissimilar to data in other clusters. The clustering analysis involved two steps. First, the number of clusters of mercury concentrations for each IPM coal type was determined based on the range of mercury and SO_2 concentrations for that coal type. Each coal type used one, two or three clusters. To the greatest extent possible the total number of clusters for each coal type was limited to keep the model size and run time within feasible limits. Second, the clustering procedure was used to group each coal type within each IPM coal supply region into the previously determined number of clusters and show the resulting mercury concentration for each cluster. The average of each cluster is the mercury content of coal finally used in EPA Base Case v.4.10 for estimating mercury emissions. IPM input files retain the mapping between different coal type-supply region combinations and the mercury clusters. Table 5-11 below provides a summary by coal type of the number of clusters and their mercury concentrations.

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

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

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

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

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

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

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

5.4.2 Mercury Emission Modification Factors

Emission Modification Factors (EMFs) represent the mercury reductions attributable to the specific burner type and configuration of SO_2, NO_X, and particulate matter control devices at an electric generating unit. An EMF is the ratio of outlet mercury concentration to inlet mercury concentration, and depends on the unit's burner type, particulate control device, post-combustion NO_X control and SO_2 scrubber control. In other words, the mercury reduction achieved (relative to

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

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

Deriving EMFs involves obtaining mercury inlet data by coal sampling and mercury emission data by stack testing at a representation set of coal units. As noted above, EPA's EMFs were initially based on 1999 mercury ICR emission test data. More recent testing conducted by the EPA, DOE, and industry participants[35] has provided a better understanding of mercury emissions from electric generating units and mercury capture in pollution control devices. Overall the 1999 ICR data revealed higher levels of mercury capture for bituminous coal-fired plants than for subbitumionus and lignite coal-fired plants, and significant capture of ionic Hg in wet-FGD scrubbers. Additional mercury testing indicates that for bituminous coals, SCR systems have the ability to convert elemental Hg into ionic Hg and thus allow easier capture in a downstream wet-FGD scrubber. This improved understanding of mercury capture with SCRs was incorporated in EPA Base Case v.4.10 mercury EMFs for unit configurations with SCR and wet scrubbers.

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

5.4.3 Mercury Control Capabilities

EPA Base Case v.4.10 offers two options for meeting mercury reduction requirements: (1) combinations of SO_2, NO_X, and particulate controls which deliver mercury reductions as a co-benefit and (2) Activated Carbon Injection (ACI), a retrofit option specifically designed for mercury control. These two options are discussed below.

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

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

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Cyclone	Cold Side ESP	SNCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP	SNCR	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	SCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.58
Cyclone	Cold Side ESP	SCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	None	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP	None	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP	None	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FF	SNCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	SCR	None	0.11	0.27	1
Cyclone	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FF	None	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FF	None	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FF	None	None	0.11	0.27	1
Cyclone	Cold Side ESP + FGC	SNCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC	SNCR	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	SCR	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.58
Cyclone	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	None	Wet FGD	0.46	0.84	0.58
Cyclone	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	0.93
Cyclone	Cold Side ESP + FGC	None	None	0.64	0.97	0.93
Cyclone	Cold Side ESP + FGC + FF	SCR	None	0.11	0.27	1
Cyclone	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FGC + FF	None	Wet FGD	0.1	0.27	0.58
Cyclone	Cold Side ESP + FGC + FF	None	Dry FGD	0.4	0.95	0.91
Cyclone	Cold Side ESP + FGC + FF	None	None	0.11	0.27	1
Cyclone	Fabric Filter	SNCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.58
Cyclone	Fabric Filter	SNCR	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	SCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.58
Cyclone	Fabric Filter	SCR	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	None	Wet FGD	0.1	0.27	0.58
Cyclone	Fabric Filter	None	Dry FGD	0.4	0.95	0.91
Cyclone	Fabric Filter	None	None	0.11	0.27	1
Cyclone	Hot Side ESP	SNCR	None	0.9	1	1
Cyclone	Hot Side ESP	SNCR	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP	SNCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP	SCR	None	0.9	1	1
Cyclone	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP	SCR	Dry FGD	0.9	1	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Cyclone	Hot Side ESP	None	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP	None	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP	None	None	0.9	1	1
Cyclone	Hot Side ESP + FF	None	None	0.11	0.27	1
Cyclone	Hot Side ESP + FGC	SNCR	None	0.9	1	1
Cyclone	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP + FGC	SNCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	SCR	None	0.9	1	1
Cyclone	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP + FGC	SCR	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	None	Wet FGD	0.58	0.6	1
Cyclone	Hot Side ESP + FGC	None	Dry FGD	0.9	1	1
Cyclone	Hot Side ESP + FGC	None	None	0.9	1	1
Cyclone	No Control	SNCR	None	1	1	1
Cyclone	No Control	SNCR	Wet FGD	0.45	0.6	1
Cyclone	No Control	SNCR	Dry FGD	1	1	1
Cyclone	No Control	SCR	None	1	1	1
Cyclone	No Control	SCR	Wet FGD	0.1	0.7	1
Cyclone	No Control	SCR	Dry FGD	1	1	1
Cyclone	No Control	None	Wet FGD	0.45	0.6	1
Cyclone	No Control	None	Dry FGD	1	1	1
Cyclone	No Control	None	None	1	1	1
Cyclone	PM Scrubber	None	None	0.8	1	1
FBC	Cold Side ESP	SNCR	None	0.65	0.65	0.62
FBC	Cold Side ESP	SNCR	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.62
FBC	Cold Side ESP	None	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP	None	Dry FGD	0.45	0.45	1
FBC	Cold Side ESP	None	None	0.65	0.65	0.62
FBC	Cold Side ESP + FF	SNCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FF	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FF	None	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FF	None	None	0.05	0.43	0.43
FBC	Cold Side ESP + FGC	SNCR	None	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	SNCR	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.62
FBC	Cold Side ESP + FGC	None	Wet FGD	0.65	0.65	0.62
FBC	Cold Side ESP + FGC	None	Dry FGD	0.45	0.45	1
FBC	Cold Side ESP + FGC	None	None	0.65	0.65	0.62
FBC	Cold Side ESP + FGC + FF	SNCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	None	Dry FGD	0.05	0.43	0.43
FBC	Cold Side ESP + FGC + FF	None	None	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	None	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	Wet FGD	0.05	0.43	0.43
FBC	Fabric Filter	SNCR	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	SCR	None	0.05	0.43	0.43

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
FBC	Fabric Filter	SCR	Wet FGD	0.05	0.27	0.43
FBC	Fabric Filter	SCR	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	None	Wet FGD	0.1	0.43	0.43
FBC	Fabric Filter	None	Dry FGD	0.05	0.43	0.43
FBC	Fabric Filter	None	None	0.05	0.43	0.43
FBC	Hot Side ESP	SNCR	None	1	1	1
FBC	Hot Side ESP	SNCR	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP	None	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP	None	None	1	1	1
FBC	Hot Side ESP + FGC	SNCR	None	1	1	1
FBC	Hot Side ESP + FGC	SNCR	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP + FGC	None	Dry FGD	0.45	0.45	1
FBC	Hot Side ESP + FGC	None	None	1	1	1
FBC	No Control	SNCR	None	1	1	1
FBC	No Control	SNCR	Wet FGD	1	1	1
FBC	No Control	SNCR	Dry FGD	0.45	0.45	1
FBC	No Control	SCR	None	1	1	1
FBC	No Control	SCR	Wet FGD	0.1	0.7	1
FBC	No Control	SCR	Dry FGD	0.45	0.45	1
FBC	No Control	None	Wet FGD	1	1	1
FBC	No Control	None	Dry FGD	0.45	0.45	1
FBC	No Control	None	None	1	1	1
PC	Cold Side ESP	SNCR	None	0.64	0.97	1
PC	Cold Side ESP	SNCR	Wet FGD	0.34	0.65	0.56
PC	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	SCR	None	0.64	0.97	1
PC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
PC	Cold Side ESP	None	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	None	None	0.64	0.97	1
PC	Cold Side ESP + FF	SNCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SNCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	None	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FF	None	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	None	None	0.2	0.75	1
PC	Cold Side ESP + FGC	SNCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.65	0.56
PC	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
PC	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	None	None	0.64	0.97	1
PC	Cold Side ESP + FGC + FF	SNCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SNCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	None	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FGC + FF	None	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	None	None	0.2	0.75	1
PC	Fabric Filter	SNCR	None	0.11	0.27	1
PC	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
PC	Fabric Filter	SNCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	SCR	None	0.11	0.27	1
PC	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	None	Dry FGD	0.05	0.75	1
PC	Fabric Filter	None	None	0.11	0.27	1
PC	Hot Side ESP	SNCR	None	0.9	0.9	1
PC	Hot Side ESP	SNCR	Wet FGD	0.58	0.75	1
PC	Hot Side ESP	SNCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	SCR	None	0.9	0.9	1
PC	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	None	Wet FGD	0.58	0.8	1
PC	Hot Side ESP	None	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	None	None	0.9	0.94	1
PC	Hot Side ESP + FF	SNCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SNCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	None	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	None	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FF	None	None	0.11	0.27	1
PC	Hot Side ESP + FGC	SNCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	0.75	1
PC	Hot Side ESP + FGC	SNCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	SCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	None	Wet FGD	0.58	0.8	1
PC	Hot Side ESP + FGC	None	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	None	None	0.9	0.94	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
PC	Hot Side ESP + FGC + FF	SNCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	SNCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FGC + FF	SNCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	None	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FGC + FF	None	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	None	None	0.11	0.27	1
PC	No Control	SNCR	None	1	1	1
PC	No Control	SNCR	Wet FGD	0.58	0.7	1
PC	No Control	SNCR	Dry FGD	0.6	0.85	1
PC	No Control	SCR	None	1	1	1
PC	No Control	SCR	Wet FGD	0.1	0.7	1
PC	No Control	SCR	Dry FGD	0.6	0.85	1
PC	No Control	None	Wet FGD	0.58	0.7	1
PC	No Control	None	Dry FGD	0.6	0.85	1
PC	No Control	None	None	1	1	1
PC	PM Scrubber	SNCR	None	0.9	0.91	1
PC	PM Scrubber	SCR	None	0.9	1	1
PC	PM Scrubber	None	None	0.9	0.91	1
Stoker	Cold Side ESP	SNCR	None	0.65	0.97	1
Stoker	Cold Side ESP	SNCR	Wet FGD	0.34	0.73	0.56
Stoker	Cold Side ESP	SNCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	SCR	None	0.65	0.97	1
Stoker	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Stoker	Cold Side ESP	SCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
Stoker	Cold Side ESP	None	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP	None	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SNCR	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.73	0.56
Stoker	Cold Side ESP + FGC	SNCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	SCR	None	0.65	0.97	1
Stoker	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Stoker	Cold Side ESP + FGC	SCR	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56
Stoker	Cold Side ESP + FGC	None	Dry FGD	0.65	0.65	1
Stoker	Cold Side ESP + FGC	None	None	0.65	0.97	1
Stoker	Fabric Filter	SNCR	None	0.11	0.27	1
Stoker	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
Stoker	Fabric Filter	SNCR	Dry FGD	0.1	0.75	1
Stoker	Fabric Filter	SCR	None	0.11	0.27	1
Stoker	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Stoker	Fabric Filter	SCR	Dry FGD	0.1	0.75	1
Stoker	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
Stoker	Fabric Filter	None	Dry FGD	0.1	0.75	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Stoker	Fabric Filter	None	None	0.11	0.27	1
Stoker	Hot Side ESP	SNCR	None	1	1	1
Stoker	Hot Side ESP	SNCR	Wet FGD	0.58	1	1
Stoker	Hot Side ESP	SNCR	Dry FGD	1	1	1
Stoker	Hot Side ESP	SCR	None	1	1	1
Stoker	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Stoker	Hot Side ESP	SCR	Dry FGD	1	1	1
Stoker	Hot Side ESP	None	Wet FGD	0.58	1	1
Stoker	Hot Side ESP	None	Dry FGD	1	1	1
Stoker	Hot Side ESP	None	None	1	1	1
Stoker	Hot Side ESP + FGC	SNCR	None	1	1	1
Stoker	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	1	1
Stoker	Hot Side ESP + FGC	SNCR	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	SCR	None	1	1	1
Stoker	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Stoker	Hot Side ESP + FGC	SCR	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	None	Wet FGD	0.58	1	1
Stoker	Hot Side ESP + FGC	None	Dry FGD	1	1	1
Stoker	Hot Side ESP + FGC	None	None	1	1	1
Stoker	No Control	SNCR	None	1	1	1
Stoker	No Control	SNCR	Wet FGD	0.58	1	1
Stoker	No Control	SNCR	Dry FGD	1	1	1
Stoker	No Control	SCR	None	1	1	1
Stoker	No Control	SCR	Wet FGD	0.1	0.7	1
Stoker	No Control	SCR	Dry FGD	1	1	1
Stoker	No Control	None	Wet FGD	0.58	1	1
Stoker	No Control	None	Dry FGD	1	1	1
Stoker	No Control	None	None	1	1	1
Stoker	PM Scrubber	None	None	1	1	1
Other	Cold Side ESP	SNCR	None	0.64	0.97	1
Other	Cold Side ESP	SNCR	Wet FGD	0.34	0.73	0.56
Other	Cold Side ESP	SNCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	SCR	None	0.64	0.97	1
Other	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Other	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	None	Wet FGD	0.34	0.84	0.56
Other	Cold Side ESP	None	Dry FGD	0.64	0.65	1
Other	Cold Side ESP	None	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SNCR	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SNCR	Wet FGD	0.34	0.73	0.56
Other	Cold Side ESP + FGC	SNCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
Other	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Other	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	None	Wet FGD	0.34	0.84	0.56
Other	Cold Side ESP + FGC	None	Dry FGD	0.64	0.65	1
Other	Cold Side ESP + FGC	None	None	0.64	0.97	1

Burner Type	Particulate Control	Post Combustion Control – NO_X	Post Combustion Control - SO_2	Bituminous EMF	Subbitumionus EMF	Lignite EMF
Other	Fabric Filter	SNCR	None	0.45	0.75	1
Other	Fabric Filter	SNCR	Wet FGD	0.03	0.27	0.56
Other	Fabric Filter	SNCR	Dry FGD	0.4	0.75	1
Other	Fabric Filter	SCR	None	0.11	0.27	1
Other	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Other	Fabric Filter	SCR	Dry FGD	0.4	0.75	1
Other	Fabric Filter	None	Wet FGD	0.1	0.27	0.56
Other	Fabric Filter	None	Dry FGD	0.4	0.75	1
Other	Fabric Filter	None	None	0.11	0.27	1
Other	Hot Side ESP	SNCR	None	1	1	1
Other	Hot Side ESP	SNCR	Wet FGD	0.58	1	1
Other	Hot Side ESP	SNCR	Dry FGD	1	1	1
Other	Hot Side ESP	SCR	None	1	1	1
Other	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Other	Hot Side ESP	SCR	Dry FGD	1	1	1
Other	Hot Side ESP	None	Wet FGD	0.58	1	1
Other	Hot Side ESP	None	Dry FGD	1	1	1
Other	Hot Side ESP	None	None	1	1	1
Other	Hot Side ESP + FF	None	None	0.11	0.27	1
Other	Hot Side ESP + FGC	SNCR	None	1	1	1
Other	Hot Side ESP + FGC	SNCR	Wet FGD	0.58	1	1
Other	Hot Side ESP + FGC	SNCR	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	SCR	None	1	1	1
Other	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Other	Hot Side ESP + FGC	SCR	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	None	Wet FGD	0.58	1	1
Other	Hot Side ESP + FGC	None	Dry FGD	1	1	1
Other	Hot Side ESP + FGC	None	None	1	1	1
Other	Hot Side ESP + FGC + FF	None	None	0.11	0.27	1
Other	No Control	SNCR	None	1	1	1
Other	No Control	SNCR	Wet FGD	0.58	0.7	1
Other	No Control	SNCR	Dry FGD	1	1	1
Other	No Control	SCR	None	1	1	1
Other	No Control	SCR	Wet FGD	0.1	0.7	1
Other	No Control	SCR	Dry FGD	1	1	1
Other	No Control	None	Wet FGD	0.58	0.7	1
Other	No Control	None	Dry FGD	1	1	1
Other	No Control	None	None	1	1	1
Other	PM Scrubber	None	None	0.9	0.91	1

Table 5-14 Definition of Acronyms for Existing Controls

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

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

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

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

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

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

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

Mercury Control through SO_2 and NO_X Retrofits

In EPA Base Case v.4.10, units that install SO_2, NO_X, and particulate controls, reduce mercury emissions as a byproduct of these retrofits. Section 5.4.2 described how EMFs are used in the base case to capture the unregulated mercury emissions depending on the rank of coal burned, the generating unit's combustion characteristics, and the specific configuration of SO_2, NO_X, and particulate controls (i.e., hot and cold-side electrostatic precipitators (ESPs), fabric filters (also called "baghouses") and particulate matter (PM) scrubbers). These same EMFs would be available in mercury policy runs to characterize the mercury reductions that can be achieved by retrofitting a unit with SCR, SNCR, SO_2 scrubbers and particulate controls. The absence of a federal mercury emission reduction policy means that these controls appear in the base case in response to SO_2, NO_X, or particulate limits or state-level mercury emission requirements. However, in future model runs where mercury limits are present these same SO_2 and NO_X controls could be deliberately installed for mercury control if they provide the least cost option for meeting mercury policy limits.

Activated Carbon Injection (ACI)

The technology specifically designated for mercury control is Activated Carbon Injection (ACI) downstream of the combustion process in coal fired units. A comprehensive ACI update, which will incorporate the latest field experience through 2010, is being prepared by Sargent and Lundy (the same engineering firm that developed the SO_2 and NO_X control assumptions used in EPA Base Case v.4.10). It will be incorporated in a future EPA base case. The ACI assumptions in the current base case release are the result of a 2007 internal EPA engineering study.

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

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

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

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

The applicable ACI option depends on the coal type burned, its SO_2 content, the boiler and particulate control type and, in some instances, consideration of whether an SO_2 scrubber (FGD) system or SCR NO_x post-combustion control are present. Table 5-17 shows the ACI assignment scheme used in EPA Base Case v.4.10 to achieve 90% mercury removal.

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

Applicability of Activated Carbon Injection

Coal Type	SO_2 in Coal (lb/MMBtu)	Boiler Type	Particulate Control Type	FGD System	SCR System	Toxecon Required?	ACI Type With 90% Hg Reduction
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	CS-ESP or BH (no FGC)	--	No	No	MPAC
Bit/Sub-bit/ Lig	--	Non-CFB	CS-ESP or BH (no FGC)	LSD	--	No	MPAC
Bit/Sub-bit/Lig	--	CFB	CS-ESP or BH (no FGC)	--	--	No	MPAC
Bit	< 1.6	Non-CFB	CS-ESP	Non-LSD	Yes	No	SPAC
Bit	≥ 1.6	Non-CFB	CS-ESP or BH	--	--	No	SPAC
Sub-bit/Lig	≥ 1.6	Non-CFB	CS-ESP	--	--	Yes	SPAC
Sub-bit/Lig	≥ 1.6	Non-CFB	BH	--	--	No	SPAC
Bit/Sub-bit/ Lig	--	Non-CFB	HESP	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	--	--	HESP or CS-ESP (with FGC)	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	BH	No	Yes	No	MPAC
Bit/Sub-bit/ Lig	< 1.6	Non-CFB	CS-ESP (no FGC)	No	Yes	No	MPAC
Bit/Sub-bit/ Lig	--	--	No Control	--	--	Yes	SPAC
Bit/Sub-bit/ Lig	< 1.6	--	BH	Non-LSD	Yes	No	SPAC
Sub-bit/ Lig	< 1.6	--	CS-ESP (no FGC)	Non-LSD	Yes	Yes	SPAC
Bit/Sub-bit/Lig	--	--	Cyclone	--	--	Yes	SPAC

Notes:

Legends:

ACI	Activated carbon injection
BH	Baghouse
Bit	Bituminous coal
CFB	Circulating fluidized-bed boiler
CS-ESP	Cold side electrostatic precipitator
FGC	Flue gas conditioning
HESP	Hot electrostatic precipitator
Lig	Lignite
MPAC	Modified powdered activated carbon
SPAC	Standard powdered activated carbon
Sub-bit	Subbituminous coal

If the existing equipment provides 90% Hg removal, no ACI system is required.

"--" means that the category type has no effect on the ACI application.

Appendix 5-1 Example Cost Calculation Worksheets for SO_2 Control Technologies in EPA Base Case v.4.10

Sargent & Lundy LLC

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
August 20, 2010

Wet FGD Cost Development Methodology – Final

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

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<— User Input (Greater than 100 MW)
Retrofit Factor	B		1	<— User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<— User Input
SO2 Rate	D	(lb/MMBtu)	3	<— User Input
Type of Coal	E		Bituminous	<— User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.911*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		**Example**	**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty			
BMR ($) =	550000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$ 46,024,000	Base absorber island cost
BMF ($) =	190000*(B)*((D*G)^0.3)*(A^0.716)	$ 22,267,000	Base reagent preparation cost
BMW ($) =	100000*(B)*((D*G)^0.45)*(A^0.716)	$ 13,713,000	Base waste handling cost
BMB ($) =	1010000*(B)*((F*G)^0.4)*(A^0.716)	$ 84,698,000	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc.
BMWW ($) =		$ -	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$ 166,702,000	Total base cost including retrofit factor
BM ($/KW) =		333	Base cost per kW
Total Project Cost			
A1 = 10% of BM		$ 16,670,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 16,670,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.
A3 = 10% of BM		$ 16,670,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 216,712,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**433**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$ 10,830,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 227,548,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**455**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 22,755,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 250,303,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**501**	Total project cost per kW

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IPM Model – Revisions to Cost and Performance for APC Technologies

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Wet FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Wastewater Treatment			Minor physical/chemical	
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

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

Variable O&M Cost

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

SDA FGD Cost Development Methodology – Final

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

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		**Example**		**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$	33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$	20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$	47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc...
BM ($) =	BMR + BMF + BMW + BMB	$	102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =			341	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$	10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM		$	10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**512**	Total project cost per kW

SDA FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<---- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<---- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<---- User Input
SO2 Rate	D	(lb/MMBtu)	2	<---- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<---- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

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

Variable O&M Cost

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

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

Sargent & Lundy LLC

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
August 20, 2010

SCR Cost Development Methodology – Final

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

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	600	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9880	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.21	<--- User Input
SO2 Rate	E	(lb/MMBtu)	1.71	
Type of Coal	F		PRB	<--- User Input
Coal Factor	G		1.05	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.988	C/10000
Heat Input	I	(Btu/hr)	5.93E+09	A*C*1000
Capacity Factor	J	(%)	85	<--- User Input
Nox Removal Efficiency	K	%	70	
Nox Removal Factor	L		0.875	I/J
Nox Removed	M	lb/h	8.71E+02	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	609	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	689	N*1.13
Aux Power	P	(%)	0.57	0.56*(G*H)^0.43; Auxiliary Power is not used in the Variable O&M Costs.
Urea Cost 50% wt solution	R	($/ton)	310	
Catalyst Cost	S	($/m3)	8000	
Aux Power Cost	T	($/kWh)	0.06	
Steam Cost	U	($/klb)	4	
Operating Labor Rate	V	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty.				
BMR ($) =	180000*(B)*(L)^0.2*(A*G*H)^0.92	$	65,199,000	SCR (Inlet Ductwork, Reactor, Bypass) Island Cost
BMF ($) =	410000*(M)^0.25	$	2,228,000	Base Reagent Preparation Cost
BMA ($) =	IF E ≥ 3 THEN 65000*(B)*(A*G*H)^0.78; ELSE 0	$	-	Air Heater Modification / SO3 Control (Bituminous only & > 3lb/mmBtu)
BMB ($) =	380000*(B)*(A*G*H)^0.42	$	5,666,000	ID or booster fans & Auxiliary Power Modification Costs
BM ($) =	BMR + BMF + BMA + BMB	$	73,093,000	Total bare module cost including retrofit factor
BM ($/KW) =			122	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	7,309,000	Engineering and Construction Management costs
A2 = 10% of BM		$	7,309,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	7,309,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		$	95,020,000	Capital, engineering and construciton cost subtotal
CECC ($/kW) =			158	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	4,751,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
B2 = 6% of CECC + B1		$	5,986,000	AFUDC (Based on approximately 3% per year for a 2 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		$	105,757,000	Total project cost
TPC ($/kW) =			176	Total project cost per kW

SCR Cost Development Methodology – Final

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

Variable	Designation	Units	Value	Calculation
Unit Size	A	(MW)	600	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9880	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.21	<--- User Input
SO2 Rate	E	(lb/MMBtu)	1.71	
Type of Coal	F		PRB	<--- User Input
Coal Factor	G		1.05	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.988	C/10000
Heat Input	I	(Btu/hr)	5.93E+09	A*C*1000
Capacity Factor	J	(%)	85	<--- User Input
Nox Removal Efficiency	K	%	70	
Nox Removal Factor	L		0.875	I/J
Nox Removed	M	lb/h	8.71E+02	D*I/10^6*K/100
Urea Rate (100%)	N	(lb/hr)	609	M*0.525*60/46*1.01/0.99
Steam Required	O	(lb/hr)	689	N*1.13
Aux Power	P	(%)	0.57	0.56*(G*H)^0.43; Auxiliary Power is not used in the Variable O&M Costs.
Urea Cost 50% wt solution	R	($/ton)	310	
Catalyst Cost	S	($/m3)	8000	
Aux Power Cost	T	($/kWh)	0.06	
Steam Cost	U	($/klb)	4	
Operating Labor Rate	V	($/hr)	60	Labor cost including all benefits

Costs are all based on 2009 dollars			
Fixed O&M Cost			
FOMO ($/kW yr) = (1/2 operator time assumed)*2080**V/(A*1000)	$	0.10	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = IF A < 500 then $200,00 ELSE $300,000	$	0.50	Fixed O&M additional maintenance material and labor costs
FOM ($/kW yr) = FOMO + FOMM	**$**	**0.60**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = N*R/A/1000	$	0.31	Variable O&M costs for Urea
VOMW ($/MWh) = discrete function of A, G, J, K, S	$	0.35	Variable O&M costs for catalyst: replacement & disposal
VOMM ($/MWh) = O*U/A/1000	$	0.01	Variable O&M costs for steam
VOM ($/MWh) = VOMR + VOMW + VOMM	**$**	**0.66**	

Sargent & Lundy LLC

IPM Model – Revisions to Cost and Performance for APC Technologies

Project No. 12301-007
August 20, 2010

SNCR Cost Development Methodology – Final

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

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

Costs are all based on 2009 dollars

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

SNCR Cost Development Methodology – Final

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

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

Costs are all based on 2009 dollars			
Fixed O&M Cost			
FOMO ($/kW yr) = (1/2 operator time assumed)*2080*S/(A*1000)	$	0.21	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = 0.012*BM/A/1000	$	0.21	Fixed O&M additional maintenance material and labor costs
FOM ($/kW yr) = FOMO + FOMM	**$**	**0.42**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = L*P/A/1000	$	0.74	Variable O&M costs for Urea
VOMM ($/MWh) = O*R/A	$	0.00	Variable O&M costs for dilution water
VOM ($/MWh) = VOMR + VOMM	**$**	**0.74**	

ATTACHMENT C

United States Environmental Protection Agency | Air and Radiation (6204J) | EPA # 430-F-11-066 December 2011

Documentation Supplement for EPA Base Case v.4.10_MATS – Updates for Final Mercury and Air Toxics Standards (MATS) Rule

This report is the third of three supplements to the August 2010 documentation for EPA Base Case v.4.10[1]. The previous two supplements presented the enhancements and updates that were made to the Base Case for the Proposed Toxics Rule (March 2011)[2] and the Cross-State Air Pollution Rule or CSAPR (June 2011)[3]. The current supplement presents the enhancements and updates that were made for the final Toxics Rule, now designated the Mercury and Air Toxics Standards (MATS).

The 3 documentation supplements are cumulative in nature. Previous documented features not addressed here were retained in the MATS Base Case as described in the most recent previous documentation. Figure 1 attempts to provide a graphical representation of the cumulative structure. The March 2011 documentation supplement for the Proposed Toxics Rule is highlighted in Figure 1 because the Base Case for MATS represents an extension of the Base Case for the Proposed Toxics Rule.

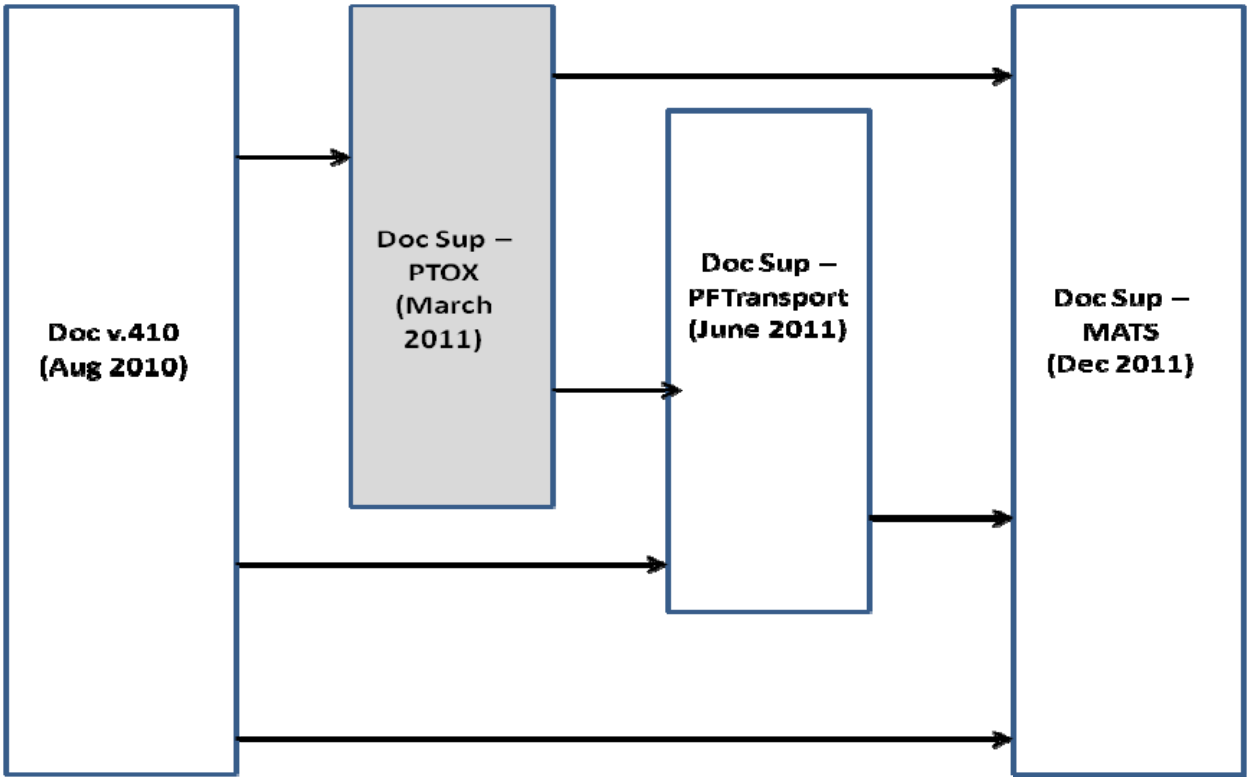

Figure 1. Relationship of Current Report to Previous Documentation for EPA Base Case v.4.10 Variants

The current report consists of two parts: Part A briefly summarizes the changes found in the EPA Base

[1] The formal title of the August 2010 documentation report is *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model* (EPA #430-R-10-010), August 2010. It is available for viewing and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.

2 The formal title of the March 2011 documentation supplement is *Documentation Supplement for EPA Base Case v4.10_PTox − Updates for Proposed Toxics Rule* (EPA #430-R-11-006), March 2011. It is available for viewing and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf

[3] The formal title of the June 2011 documentation supplement is *Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule* (EPA #430-K-11-004). June 2011. It is available for viewing and downloading at www.epa.gov/airmarkets/progsregs/epa-ipm/CSAPR/docs/DocSuppv410_FTransport.pdf.

Case v.4.10 for the MATS. To facilitate cross-references to the previous documentation reports, the topics in Part A are covered in the same categories and in the same order as covered in the previous documentation reports. At the end of Part A there a listing of corrections to errors in previous documentation and enhancements to previous documentation items. The items in this section of Part A do not represent changes in the base case itself but in the documentation describing features included in the base case.

Part B of this report gives detailed information on these changes and takes the form of a supplement to the previous documentation, using redline and strike-out highlights to show provisions that changed and building upon the section numbering in the previous documentation to show where new enhancements fit into the modeling structure.

Part A

Summary of Key Changes in the EPA Base Case v.4.10 for the MATS

Power System Operations Assumptions

(Chapter 3 in previous documentation)

Cross-State Air Pollution Rule (CSAPR): Since issuing the *Documentation Supplement for the Proposed Toxics Rule* in March of 2011, the EPA Administrator on July 6, 2011 signed a Notice of Final Rulemaking for the Cross-State Air Pollution Rule (CSAPR). As a result of this regulatory action, the SO2 and NOx provisions of CSAPR were incorporated in the EPA Base Case v.4.10_MATS. Part B Cross-Reference: For an indication of previous provisions removed and details of the representation of CASAPR provisions in the final MATS base case (including tables of key CSAPR provisions, state budgets, and a map of affected states), see the new redlined text in Section 3.9 in Part B.

Colorado RPS: Part B Cross-Reference: For a summary of the Colorado RPS included see the redlined additions to Section 3.9.3 in Part B.)

Colorado Clean Air – Clean Jobs Act: Due to timing, previous versions of EPA Base Case v.4.10 did not include this state regulation, which was enacted in April 2011. Part B Cross-Reference: For a summary of the modeled provisions of the Colorado Clean Air – Clean Jobs Act, see the new redlined additions to Section 3.9.4 in Part B.)

Handling of State Mercury Regulations in MATS Base and Policy Cases: State mercury regulations (as shown in Appendix 3-2 in the Documentation Supplement for Proposed Toxics Rule) were not modeled in the MATS base or policy cases. Part B Cross-Reference: For an explanation of reasons why state mercury regulations were not included in the MATS base or policy cases, see the new text that appears at the end of Section 3.9.4 ("State Specific Environmental Regulations") in Part B.

NIPSCO and TVA NSR Settlements: Between the last previously released EPA Base Case v.4.10 (for CSAPR) and the base case for MATS, provisions of the NSR settlements with Northern Indiana Public Service Company (NIPSCO) and Tennessee Valley Authority (TVA) were announced. See www.epa.gov/compliance/resources/cases/civil/caa/nipsco.html and www.epa.gov/compliance/resources/cases/civil/caa/tvacoalfired. The NIPSCO settlement and the system-wide TVA SO2 limit, which were not previously included, are now represented in the Base Case v.4.10_MATS. Part B Cross-Reference: For a summary of the modeled provisions of the NIPSCO and TVA NSR settlements see the appropriate entries in the updated version of Appendix 3-3 ("New Source Review (NSR) Settlements in EPA Base Case v.4.10_MATS.

Handling of Existing ACI Controls in MATS Base and Policy Cases: Certain existing ACI controls (shown in the NEEDS database) were not included in EPA Base Case v.4.10_MATS but were included in the MATS policy case. Part B Cross-Reference: For an explanation of reasons and a listing of existing ACI controls that were not included in the MATS Base Case but were included in the MATS policy case see new sub-section 3.9.7 ("Unit-Level Control Assumptions") and 3.9.7.1 ("Existing ACI Controls in MATS Base and Policy Cases") in Part B.

Unit-Specific Assumptions on Emissions, Emission Controls, and Fuels:
Unit specific assumptions were adopted for

- Big Sandy Units 1 and 2,
- Monroe Units 1 and 2
- Dunkirk Units 3 and 4,
- C R Huntley Units 7 and 8
- Coal Units in Washington State, including the retirements at
  - Centralia
  - Boardman
- D B Wilson plant
- Revised coal assignments at various plants to improve consistency with EIA Form 923

Part B Cross-Reference: For details of these changes, see new documentation sub-section 3.9.7 ("Unit-Level Control, Emission and Fuel Assumptions") in Part B.

Generation Resources

(Chapter 4 in previous documentation)

Revised Capital Cost Structure for New Nuclear Units: The capital cost for new nuclear capacity was updated to $5,000/kW from $4,621 (in 2007$). The life extension costs for existing nuclear units were revised to be consistent with the new nuclear plant capital costs.

Part B Cross-Reference: The changes noted here are shown in Table 4-13 in Part B.

Emission Control Technologies

(Chapter 5 in previous documentation)

Filterable Particulate Matter (PM) Compliance Technologies for Existing Units: In the MATS policy case all coal units with a capacity greater than 25 MW must meet the filterable PM compliance requirement. Units that have an existing fabric filter are assumed to meet the requirement. Depending on the incremental filterable PM reduction needed to bring a unit into compliance, uncontrolled units and units with electrostatic precipitators (ESPs) for PM control that do not currently meet their compliance requirement are assigned either a fabric filter or one of three tiered ESP upgrades to bring them into compliance. The determination of the appropriate option is an off-line calculation and the assignment of that option is performed in setting up a run, not in the course of the run. Part B Cross-Reference: See new section 5.6 for details of the procedure used to determine the appropriate compliance technology.

Updated FGD Removal Rate Assumptions for Petroleum Coke: Based on the performance capabilities indicated in the 2010 ICR, a 93% mercury removal rate is assumed when FGD is present on units that burn petroleum coke. Part B Cross-Reference: The previous sentence should be appended as a note under Table 5-13 ("Mercury Emission Modification Factors Used in EPA Base Case v.4.10_MATS") in section 5.4.3 ("Mercury Control Capabilities") of the August 2010 documentation for EPA Base Case v.4.10. (This is not reproduced in Part B.)

Revised ACI VOM Cost for Units with Certain Particulate Control Configurations: For certain particulate control configurations the variable operating and maintenance (VOM) cost of activated carbon injection (ACI) retrofits is assumed to be 81 percent lower due the presence of pre-existing particulate controls. Part B Cross-Reference: See the redlined addition to section 5.4.3 ("Mercury Control Capabilities") for the specific configurations affected by this VOM cost revision.

Revised HCl Emissions from Lignite and Subbituminous Coals Reflecting Impact of Ash Chemistry: To account for the effect of ash chemistry on HCl emissions, the HCl content of lignite and subbituminous coals is reduced by 75%. Part B Cross-Reference: For a fuller explanation of these changes see additional redlined text at end of Section 5.5.1 ("Chlorine Content of Fuels") in Part B

FGD Upgrade Assumptions in MATS Policy Case: In setting up the MATS policy runs, it is assumed that the most cost effective approach for units with pre-existing FGD that do not meet the 94% HCl removal requirement is to upgrade their FGD to bring the unit into compliance. Part B Cross-Reference: For the specifics of the FGD upgrade see the new redlined text in Section 5.5.3.1 ("Wet and Dry FGD") in Part B.

Dry Scrubber Removal Assumptions for Waste Coal and Petroleum Coke Units in MATS Policy Case: In setting up the Base Case v.4.10_MATS, waste coal and petroleum coke fired FBC units without an existing FGD were mistakenly not provided with a scrubber retrofit option. To make up for this oversight, in run year 2015 a dry scrubber and its associated capital cost (applied through and FOM adder) are assigned to these units when setting up the MATS policy case. Part B Cross-Reference: For further details on these revisions see new redlined text in Section 5.5.3.1 ("Wet and Dry FGD").

Revisions to DSI cost and performance assumptions in the Base Case for MATS: A number of additional assumptions were made regarding DSI in the Base Case v.4.10_MATS. Part B Cross-Reference: : See the redlined addition to section 5.5.3.2 ("Dry Sorbent Injection") in Part 2 for a discussion of the specific assumptions.

Assumed Air-to-Cloth Ratio in the Cost Equations for the DSI + Fabric Filter Retrofit Option: Based on public comments and engineering assessments, an air-to-cloth ratio of 4.0, rather than 6.0, was used in MATS to provide a conservative projection of the requirements and cost of sorbent removal. Part B Cross-Reference: New redlined text was added to the "Capital Cost" write-up in Section 5.5.4 ("Fabric Filter (Baghouse) Cost Development") to reflect this assumption. This addition is shown in Part B.

Other Fuels and Fuel Emission Factor Assumptions

(Chapter 11 in previous documentation)

Correction of Error in Mercury Emission Factor (EMF) for Petroleum Coke: A previous computational error in the mercury emission factor for petroleum coke as presented in Table 6-3 of the EPA report titled *Control of Mercury Emissions from Coal-fired Electric Utility Boilers: Interim Report Including Errata,* 3-21-02 was corrected (from 23.18 lbs/TBtu to 2.66 lb/TBtu) based on re-examination of the 1999 ICR data for petroleum coke and implementation of a procedure for flagging and excluding outlier values above the 95 percentile value. Part B Cross-Reference: This correction is reflected in the update of Table 11-4 that appears in Part B.

Mercury Removal Assumption for Waste Coal Units: Based on 2010 ICR data waste coal units in the Base Case for MATS were assumed to achieve 99% mercury removal. Part B Cross-Reference: This revision is reflected in new footnote under Table 11-4 that appears in Part B.

Errata and Enhancements of Previous Documentation

Below is a listing of corrections to errors in previous documentation and enhancements to previous documentation items. The items below do not represent changes in the base case itself but in the documentation describing features included in the base case.

SCR Cost Equations: The following editorial corrections should be made to the Sargent & Lundy paper, SCR Cost Development Methodology (at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix52A.pdf :

a) on pages 5 and 6, change the formula text for "NOx Removal Factor" (L) to: K/80

b) on page 6, add the following formula text for "Variable O&M costs for catalyst replacement & disposal" (VOMW):

VOMW ($/MWh) = 0.3*(G)^2.9*(L)^0.71/8760/J*100*S

Fabric Filter (FF) Costs Include Ash Handling: The following clarifying text should be added to the Sargent & Lundy paper, Particulate Control Cost Development Methodology (at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_5.pdf):

a) on page 4, to the list of capital cost items included, add: “interconnecting piping, etc, to existing fly ash handling system”

SNCR Removal Rates in Table 5-7: The removal rates in the last column of Table 5-7 did not correctly reflect the implementation in EPA Base Case v.4.10_MATS. Table 5-7 (“Summary of Retrofit NOx Emission Control Performance Assumptions”) is located in section 5.2 (“Nitrogen Oxides Control Technology”) of the previous documentation. Part B Cross-Reference: Using redline and strike-out highlights, the corrections to Table 5-7 are shown in Part B.

ACI Cost Equations: The following editorial corrections should be made to the Sargent & Lundy paper, Mercury Control Cost Development Methodology (at www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_3.pdf) :

a) on pages 12 – 16 change the formula text for capital cost component “BMB” to:

if(J = Not Added then 0, J = 6.0 Air-to-Cloth then 422, J = 4.0 Air-to-Cloth then 476)*B*L^0.81

Part B

Detailed Information on Changes in EPA Base Case v.4.10_MATS (Using Mark-Up of Previous Documentation Reports)

3.9 Existing Environmental Regulations

This section describes the existing federal, regional, and state SO_2, NO_x, mercury, and CO_2 emissions regulations that are represented in the EPA Base Case v.4.10_MATS. The first three subsections discuss national and regional regulations. The next two subsections describe state level environmental regulations and a variety of legal settlements. The last subsection presents emission assumptions for potential units.

~~**Note on Clean Air Interstate Rule (CAIR):** In December 2008 the U.S. Court of Appeals for the District of Columbia Circuit remanded CAIR to EPA to correct legal flaws in the proposed regulations as cited in the Court's July 2008 ruling. Until EPA's work was completed, CAIR, which includes a cap-and-trade system for SO_2 and NO_x emissions, was temporarily reinstated. However, although CAIR's provisions were still in effect when EPA Base Case v.4.10 was released, it is not included in the base case to allow EPA Base Case v.4.10 to be used to analyze the regulations proposed to replace CAIR.~~

Note on Cross-State Air Pollution Rule (CSAPR): Since issuing the *Documentation Supplement for the Proposed Toxics Rule* in March of 2011, the EPA Administrator on July 6, 2011 signed a Notice of Final Rulemaking for the Cross-State Air Pollution Rule (CSAPR). As a result of this regulatory action, the SO2 and NOx provisions of CSAPR were incorporated in the EPA Base Case v.4.10_MATS. Below are a map of affected states and state budget tables listing the key CSAPR provisions.

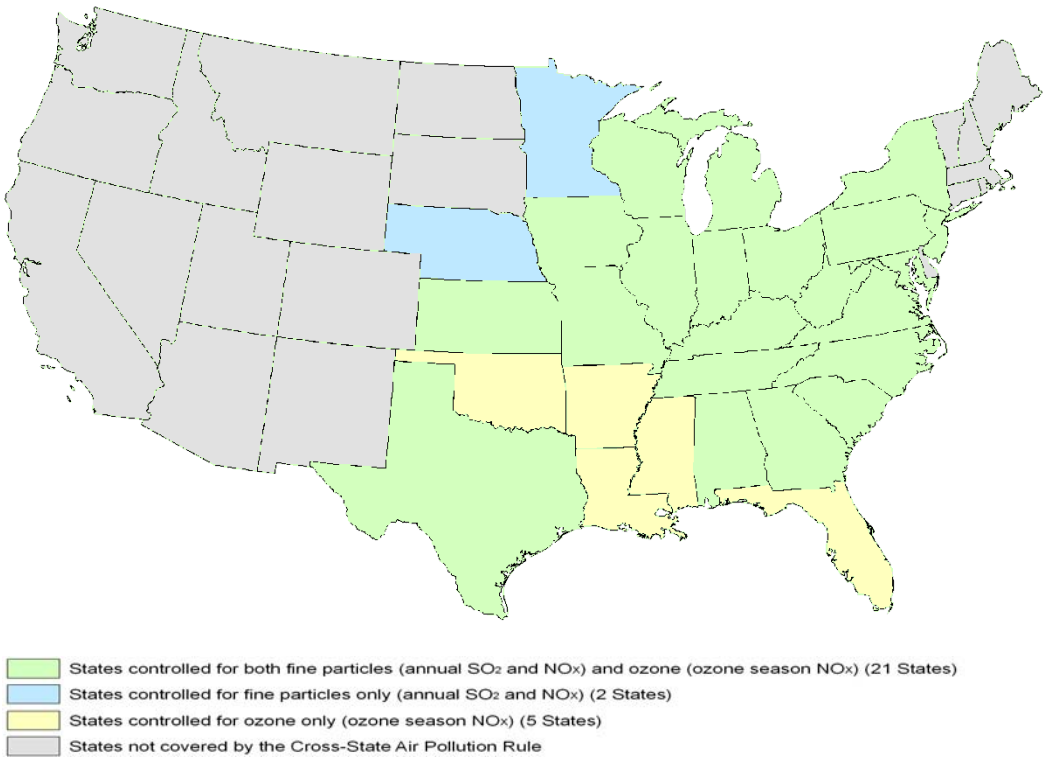

Figure 3.1. CSAPR States

Table 3. 1. a) SO2

Emissions	Budget		Variability Limit	
In 1000 tons	2012	2014	2012	2014
Alabama	216.033	213.258	38.886	38.386
Georgia	158.527	95.231	28.535	17.142
Illinois	234.889	124.123	42.28	22.342
Indiana	285.424	161.111	51.376	29
Iowa	107.085	75.184	19.275	13.533
Kansas	41.528	41.528	7.475	7.475
Kentucky	232.662	106.284	41.879	19.131
Maryland	30.12	28.203	5.422	5.077
Michigan	229.303	143.995	41.275	25.919
Minnesota	41.981	41.981	7.557	7.557
Missouri	207.466	165.941	37.344	29.869
Nebraska	65.052	65.052	11.709	11.709
New Jersey	5.574	5.574	1.003	1.003
New York	27.325	18.585	4.919	3.345
North Carolina	136.881	57.62	24.639	10.372
Ohio	310.23	137.077	55.841	24.674
Pennsylvania	278.651	112.021	50.157	20.164
South Carolina	88.62	88.62	15.952	15.952
Tennessee	148.15	58.833	26.667	10.59
Texas	243.954	243.954	43.912	43.912
Virginia	70.82	35.057	12.748	6.31
West Virginia	146.174	75.668	26.311	13.62
Wisconsin	79.48	40.126	14.306	7.223

Table 3.1. b) Ozone Season NOx

Emissions	Budget		Variability Limit	
In 1000 tons	2012	2014	2012	2014
Alabama	31.746	31.499	6.667	6.615
Arkansas	15.037	15.037	3.158	3.158
Florida	27.825	27.825	5.843	5.843
Georgia	27.944	18.279	5.868	3.839
Illinois	21.208	21.208	4.454	4.454
Indiana	46.876	46.175	9.844	9.697
Iowa	16.532	16.207	3.472	3.403
Kansas	13.536	10.998	2.843	2.31
Kentucky	36.167	32.674	7.595	6.862
Louisiana	13.432	13.432	2.821	2.821
Maryland	7.179	7.179	1.508	1.508

Michigan	25.752	24.727	5.408	5.193
Mississippi	10.16	10.16	2.134	2.134
Missouri	22.762	21.073	4.78	4.425
New Jersey	3.382	3.382	0.71	0.71
New York	8.331	8.331	1.75	1.75
North Carolina	22.168	18.455	4.655	3.876
Ohio	40.063	37.792	8.413	7.936
Oklahoma	21.835	21.835	4.585	4.585
Pennsylvania	52.201	51.912	10.962	10.902
South Carolina	13.909	13.909	2.921	2.921
Tennessee	14.908	8.016	3.131	1.683
Texas	63.043	63.043	13.239	13.239
Virginia	14.452	14.452	3.035	3.035
West Virginia	25.283	23.291	5.309	4.891
Wisconsin	13.704	13.216	2.878	2.775

Table 3.1. c) Annual NOx

Emissions	Budget		Variability Limit	
In 1000 tons	2012	2014	2012	2014
Alabama	72.691	71.962	13.084	12.953
Georgia	62.01	40.54	11.162	7.297
Illinois	47.872	47.872	8.617	8.617
Indiana	109.726	108.424	19.751	19.516
Iowa	38.335	37.498	6.9	6.75
Kansas	30.714	25.56	5.529	4.601
Kentucky	85.086	77.238	15.315	13.903
Maryland	16.633	16.574	2.994	2.983
Michigan	60.193	57.812	10.835	10.406
Minnesota	29.572	29.572	5.323	5.323
Missouri	52.374	48.717	9.427	8.769
Nebraska	26.44	26.44	4.759	4.759
New Jersey	7.266	7.266	1.308	1.308
New York	17.543	17.543	3.158	3.158
North Carolina	50.587	41.553	9.106	7.48
Ohio	92.703	87.493	16.687	15.749
Pennsylvania	119.986	119.194	21.597	21.455
South Carolina	32.498	32.498	5.85	5.85
Tennessee	35.703	19.337	6.427	3.481
Texas	133.595	133.595	24.047	24.047
Virginia	33.242	33.242	5.984	5.984
West Virginia	59.472	54.582	10.705	9.825

Wisconsin	31.628	30.398	5.693	5.472

"Dispatchable" Controls Operate in CSAPR Covered States: After the Clean Air Interstate Rule (CAIR) was remanded to EPA by the Court for revision, existing emission controls for SO2 and NOx that had been installed in anticipation of CAIR were modeled as "dispatchable." (see *Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule* (EPA #430-K-11-004). June 2011, page 54, available at www.epa.gov/airmarkets/progsregs/epa-ipm/CSAPR/docs/DocSuppv410_FTransport.pdf.)
Since Base Case v.4.10_MATS includes CASPR, which EPA recently promulgated to replace CAIR, "dispatchable" controls in states covered by CASPR are operated in this scenario.

Table 3.2.a) List of Units Operating "Dispatchable" FGD Retrofits in Base Case v4.10 for MATS

Plant Name	UniqueID	Unit ID	State Name	Capacity (MW)
Cayuga	1001_B_2	2	Indiana	473
E W Brown	1355_B_1	1	Kentucky	94.0
E W Brown	1355_B_2	2	Kentucky	160
Ghent	1356_B_1	1	Kentucky	475
Ghent	1356_B_2	2	Kentucky	469
Ghent	1356_B_3	3	Kentucky	478
Ghent	1356_B_4	4	Kentucky	478
Elmer Smith	1374_B_1	1	Kentucky	132
Elmer Smith	1374_B_2	2	Kentucky	261
Paradise	1378_B_3	3	Kentucky	977
Kenneth C Coleman	1381_B_C1	C1	Kentucky	150
Kenneth C Coleman	1381_B_C2	C2	Kentucky	150
Kenneth C Coleman	1381_B_C3	C3	Kentucky	155
HMP&L Station Two Henderson	1382_B_H1	H1	Kentucky	153
HMP&L Station Two Henderson	1382_B_H2	H2	Kentucky	159
Dickerson	1572_B_1	1	Maryland	182
Dickerson	1572_B_2	2	Maryland	182
Dickerson	1572_B_3	3	Maryland	182
Monroe	1733_B_1	1	Michigan	770
Monroe	1733_B_2	2	Michigan	785
Monroe	1733_B_3	3	Michigan	795
Monroe	1733_B_4	4	Michigan	775
Sioux	2107_B_1	1	Missouri	497
Sioux	2107_B_2	2	Missouri	497
B L England	2378_B_1	1	New Jersey	129
B L England	2378_B_2	2	New Jersey	155
AES Cayuga	2535_B_1	1	New York	152
AES Cayuga	2535_B_2	2	New York	153
C R Huntley Generating Station	2549_B_67	67	New York	190

C R Huntley Generating Station	2549_B_68	68	New York	190
Dunkirk Generating Station	2554_B_3	3	New York	185
Dunkirk Generating Station	2554_B_4	4	New York	185
E C Gaston	26_B_5	5	Alabama	861
Miami Fort	2832_B_7	7	Ohio	500
Miami Fort	2832_B_8	8	Ohio	500
Niles	2861_B_1	1	Ohio	109
Hamilton	2917_B_9	9	Ohio	51.0
Barry	3_B_5	5	Alabama	750
Homer City Station	3122_B_3	3	Pennsylvania	650
Keystone	3136_B_1	1	Pennsylvania	850
Keystone	3136_B_2	2	Pennsylvania	850
PPL Brunner Island	3140_B_1	1	Pennsylvania	335
PPL Brunner Island	3140_B_2	2	Pennsylvania	387
PPL Brunner Island	3140_B_3	3	Pennsylvania	754
PPL Montour	3149_B_1	1	Pennsylvania	761
PPL Montour	3149_B_2	2	Pennsylvania	757
Hatfields Ferry Power Station	3179_B_1	1	Pennsylvania	530
Hatfields Ferry Power Station	3179_B_2	2	Pennsylvania	530
Hatfields Ferry Power Station	3179_B_3	3	Pennsylvania	530
W S Lee	3264_B_3	3	South Carolina	170
Wateree	3297_B_WAT1	WAT1	South Carolina	350
Wateree	3297_B_WAT2	WAT2	South Carolina	350
Williams	3298_B_WIL1	WIL1	South Carolina	615
W A Parish	3470_B_WAP6	WAP6	Texas	650
Yorktown	3809_B_1	1	Virginia	159
Fort Martin Power Station	3943_B_1	1	West Virginia	552
Fort Martin Power Station	3943_B_2	2	West Virginia	555
Harrison Power Station	3944_B_1	1	West Virginia	652
Harrison Power Station	3944_B_2	2	West Virginia	642
Harrison Power Station	3944_B_3	3	West Virginia	651
Genoa	4143_B_1	1	Wisconsin	356
Charles R Lowman	56_B_1	1	Alabama	86.0
James H Miller Jr	6002_B_1	1	Alabama	684
Brandon Shores	602_B_1	1	Maryland	643
Killen Station	6031_B_2	2	Ohio	615
Gibson	6113_B_1	1	Indiana	630
Gibson	6113_B_2	2	Indiana	628

Gibson	6113_B_3	3	Indiana	628
Fayette Power Project	6179_B_1	1	Texas	598
Fayette Power Project	6179_B_2	2	Texas	598
Gorgas	8_B_10	10	Alabama	690
Gorgas	8_B_8	8	Alabama	165
Gorgas	8_B_9	9	Alabama	175
Cheswick	8226_B_1	1	Pennsylvania	580
Coffeen	861_B_01	01	Illinois	340
Coffeen	861_B_02	02	Illinois	560
Havana	891_B_9	9	Illinois	487
Harding Street	990_B_70	70	Indiana	435
Petersburg	994_B_3	3	Indiana	540

Table 3.2.b) List of Units Operating "Dispatchable" SCR Retrofits in Base Case v4.10 for MATS

Plant Name	UniqueID	Unit ID	State Name	Capacity (MW)
Lansing	1047_B_4	4	Iowa	261
AES Deepwater	10670_B_AAB001	AAB001	Texas	140
Seminole	136_B_1	1	Florida	658
Seminole	136_B_2	2	Florida	658
St Johns River Power Park	207_B_1	1	Florida	626
St Johns River Power Park	207_B_2	2	Florida	626
W A Parish	3470_B_WAP5	WAP5	Texas	645
W A Parish	3470_B_WAP6	WAP6	Texas	650
W A Parish	3470_B_WAP7	WAP7	Texas	565
W A Parish	3470_B_WAP8	WAP8	Texas	600
Edgewater	4050_B_5	5	Wisconsin	414
John P Madgett	4271_B_B1	B1	Wisconsin	398
Crystal River	628_B_4	4	Florida	722
Crystal River	628_B_5	5	Florida	721
Deerhaven Generating Station	663_B_B2	B2	Florida	228
Sandow	6648_B_4	4	Texas	545
C D McIntosh Jr	676_B_3	3	Florida	342

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3.9.3 CO_2 Regulations and Renewable Portfolio Standards

The Regional Greenhouse Gas Initiative (RGGI) is a year-round CO_2 cap and trade program affecting fossil fired electric power plants 25 MW or larger in Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, Vermont, Rhode Island, Massachusetts, and Maryland.

EPA Base Case v.4.10_MATS incorporated the following updated targets to reflect Colorado RPS:
- 12% of its retail electricity sales in Colorado for the years 2011-2014;
- 20% of its retail electricity sales in Colorado for the years 2015-2019; and

- 30% of its retail electricity sales in Colorado for the years 2020 and later.

Renewable Portfolio Standards (RPS) generally refer to various state-level policies that require the addition of renewable generation to meet a specified share of state-wide generation In EPA Base Case v.4.10 the state RPS requirements are represented at a regional level utilizing the aggregate regional representation of RPS requirements that is implemented in AEO 2010[4] as shown in Appendix 3-6. This appendix shows the RPS requirements that apply to the NEMS (National Energy Modeling System) regions used in AEO. The RPS requirement for a particular NEMS region applies to all IPM regions that are predominantly contained in that NEMS region.

3.9.4 State Specific Environmental Regulations

EPA Base Case v.4.10 represents laws and regulations in 25 states affecting emissions from the electricity sector. The laws and regulations had to either be on the books or expected to come into force. Appendix 3-2 summarizes the provisions of state laws and regulations that are represented in EPA Base Case 4.10.

EPA Base Case v.4.10_MATS incorporated the following provisions of the Colorado Clean Air-Clean Jobs Act (HB 1365, passed in April 2010):

Table 3-9-4. Changes Incorporated in EPA Base Case v.4.10_MATS in Response to Provisions of the Colorado Clean Air-Clean Jobs Act (HB 1365, passed in April 2010)

Plant Name	UniqueID	ORIS Plant Code	Unit ID	Modeled In v.4.10_FMATS
Arapahoe	465_B_3	465	3	Unit retired, effective in 2015 run year
Arapahoe	465_B_4	465	4	Unit forced to convert to natural gas, effective in 2015 run year
Cameo	468_B_1	468	1	Retired in NEEDS
Cameo	468_B_2	468	2	Retired in NEEDS
Cherokee	469_B_1	469	1	Unit retired, effective in 2012 run year
Cherokee	469_B_2	469	2	Unit retired, effective in 2012 run year
Cherokee	469_B_3	469	3	Unit retired, effective in 2020 run year
Cherokee	469_B_4	469	4	Unit forced to convert to natural gas, effective in 2020 run year
Valmont	477_B_5	477	5	Unit retired, effective in 2020 run year
W N Clark	462_B_55	462	55	Unit retired, effective in 2015 run year
W N Clark	462_B_59	462	59	Unit retired, effective in 2015 run year

State Mercury Regulations in MATS Base and Policy Cases: Consistent with the mercury risk deposition modeling for MATS, EPA did not model non-federally enforceable mercury-specific emissions reduction rules (as shown in Appendix 3-2 in the Documentation Supplement for Proposed Toxics Rule) in the base case or MATS policy case (see preamble section III.A)

3.9.5 New Source Review (NSR) Settlements

The New Source Review, (NSR) settlements refer to legal agreements with companies resulting from the

[4]Energy Information Administration, U.S. Department of Energy, *Assumptions to Annual Energy Outlook 2010: Renewable Fuels Module* (DOE/EIA-0554(2010)), April 9, 2010, Table 13.4 "Aggregate Regional RPS Requirements, www.eia.doe.gov/oiaf/aeo/assumption/renewable.html and www.eia.doe.gov/oiaf/aeo/assumption/pdf/renewable_tbls.pdf

permitting process under the CAAA which requires industry to undergo an EPA pre-construction review of proposed environmental controls either on new facilities or as modifications to existing facilities where there would result a "significant increase" in a regulated pollutant. EPA Base Case v.4.10_MATS includes more than 20 NSR settlements with electric power companies. EPA Base Case v.4.10_MATS includes provisions of the recently announced NSR settlements with Northern Indiana Public Service Company (NIPSCO) and Tennessee Valley Authority (TVA). See www.epa.gov/compliance/resources/cases/civil/caa/nipsco.html and www.epa.gov/compliance/resources/cases/civil/caa/tvacoalfired. An updated summary of ~~the units affected and how the settlements were~~ all the NSR settlements that are modeled in Base Case v.4.10_MATS can be found in Appendix 3-3.

Seven state settlements and five citizen settlements are also represented in EPA Base Case v.4.10. These are summarized in Appendices 3-4 and 3-5 respectively.

3.9.7 Unit-Level Control, Emission and Fuel Assumptions (new)
The following unit specific assumptions were adopted in EPA Base Case v.4.10 for MATS:

3.9.7.1 Existing ACI Controls in MATS Base and Policy Cases: As **indicated above in section 3.9.4,** EPA did not model non-federally enforceable mercury-specific emissions reduction rules. Units which were online before 2008 with existing ACI controls installed were therefore assumed not to operate those controls in EPA Base Case v.4.10_MATS, but were assumed to operate the existing ACI in the MATS policy case. Units that commenced operation after 2007 were assumed to operate existing ACI because these units are required under section 112(g) to meet HAP limitations (including Hg) for new units.

3.9.7.2 Monroe Units 1 and 2 and Big Sandy Units 1 and 2: The flue gas desulfurization (FGD) for SO2 control at Monroe units 1 and 2 are assumed not to run in 2012. This restriction was not imposed after 2012. Big Sandy Units 1 and 2 had dispatchable controls in the Proposed MATS. This flexibility was not offered in Final MATS, the controls were implemented as non-dispatchable.

3.9.7.3 Dunkirk Units 3 and 4, C R Huntley Units 7 and 8: The SO2 removal rates were adjusted to reflect DSI technology instead of FGD that was assumed in the previous versions.

	DSI	FGD
Dunkirk Units 3 and 4	70%	95.9%
CR Huntley Units 7 and 8	70%	92.3%

3.9.7.4 Coal Units in Washington State (including retirement of Centralia Units 1 and 2 and the Boardman Units: Due to the approval of the Washington State Senate bill (formally known as Senate Bill 5769), new base load coal generation in Washington is subjected to 1,100 lbs/MWh CO2 rate limit and Centralia Units 1 and 2 and the Boardman units are retired in 2021, 2026 and 2021 years respectively.

3.9.7.5 D B Wilson plant: Based on a comment received bituminous coal in addition to petroleum coke was provided as a fuel option for D B Wilson (unique ID 6823_B_W1). In previous base cases its fuel choice had been exclusively petroleum coke. To make the additional fuel choice possible, this plant was assigned to coal demand region IBB3 instead of PCOK

3.9.7.6 Revised Coal Assignments to Improve Consistency with EIA Form 923: The following table shows revisions in coal assignments that were made to improve the consistency between the coal assignments in EPA Base Case v.4.10_MATS and the coal consumption reported in EIA Form 923 for 2008.

Table 3-9-7-5. Changes in Coal Assignments in EPA Base Case v.4.10_MATS to Improve Consistency with Information Reported in EIA Form 923 (2008)

Plant Name	UniqueID	ORIS Plant Code	Unit ID	Modeled Fuels In v.4.10_FTransport	Modeled Fuels In v.4.10_MATS	Notes
C P Crane	1552_B_1	1552	1	Subbituminous	Subbituminous, Bituminous	
C P Crane	1552_B_2	1552	2	Subbituminous	Subbituminous, Bituminous	
Herbert A Wagner	1554_B_2	1554	2	Subbituminous	Subbituminous, Bituminous	
Herbert A Wagner	1554_B_3	1554	3	Subbituminous	Subbituminous, Bituminous	
PSEG Hudson Generating Station	2403_B_2	2403	2	Bituminous	Subbituminous, Bituminous	Coal demand region changed from NE2 to PE1 to provide both coal ranks.
R E Burger	2864_B_5	2864	5	Bituminous	Subbituminous, Bituminous	
R E Burger	2864_B_6	2864	6	Bituminous	Subbituminous, Bituminous	
Willow Island	3946_B_1	3946	1	Bituminous	Subbituminous	
Willow Island	3946_B_2	3946	2	Bituminous	Subbituminous	

Appendix 3-3 New Source Review (NSR) Settlements in EPA Base Case v.4.10_MATS

Company and Plant	State	Unit	Settlement Actions														Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	
Alabama Power																	
James H. Miller	Alabama	Units 3 & 4			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06	With 45 days of settlement entry, APC must retire 7,538 SO_2 emission allowances.	APC shall not sell, trade, or otherwise exchange any Plant Miller excess SO_2 emission allowances outside of the APC system	1/1/21	http://www.epa.gov/compliance/resources/cases/civil/caa/alabamapower.html
Minnkota Power Cooperative																	
Beginning 1/01/2006, Minnkota shall not emit more than 31,000 tons of SO_2/year, no more than 26,000 tons beginning 2011, no more than 11,500 tons beginning 1/01/2012. If Unit 3 is not operational by 12/31/2015, then beginning 1/01/2014, the plant wide emission shall not exceed 8,500.																	
Milton R. Young	Minnesota	Unit 1			Install and continuously operate FGD	95% if wet FGD, 90% if dry	12/31/11	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/09		0.03 if wet FGD, .015 if dry FGD		Plant will surrender 4,346 allowances for each year 2012 – 2015, 8,693 allowances for years 2016 – 2018, 12,170 allowances for year 2019, and 14,886 allowances/ year thereafter if Units 1 – 3 are operational by 12/31/2015. If only Units 1 and 2 are operational by12/31/2015, the plant shall retire 17,886 units in 2020 and thereafter.	Minnkota shall not sell or trade NO_x allowances allocated to Units 1, 2, or 3 that would otherwise be available for sale or trade as a result of the actions taken by the settling defendants to comply with the requirements		http://www.epa.gov/compliance/resources/cases/civil/caa/minnkota.html
		Unit 2			Design, upgrade, and continuously operate FGD	90%	12/31/10	Install and continuously operate over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/07		0.03	Before 2008				

SIGECO															
FB Culley	Indiana	Unit 1	Repower to natural gas (or retire)	12/31/06									The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.		http://www.epa.gov/compliance/resources/cases/civil/caa/sigecofb.html
		Unit 2			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04								
		Unit 3			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04	Operate Existing SCR Continuously	0.1	09/01/03	Install and continuously operate a Baghouse	0.015	06/30/07			
PSEG FOSSIL															
Bergen	New Jersey	Unit 2	Repower to combined cycle	12/31/02									The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.		http://www.epa.gov/compliance/resources/cases/civil/caa/psegllc.html
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/06	Install SCR (or approved tech) and continually operate	0.1	05/01/07	Install Baghouse (or approved technology)	0.015	12/31/06			

Mercer	New Jersey	Units 1 & 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.13	05/01/06				
TECO														
Big Bend	Florida	Units 1 & 2			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.1	05/01/09		The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.		http://www.epa.gov/compliance/resources/cases/civil/caa/teco.html
		Unit 3			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	2000 (01/01/10)	Install SCR	0.1	05/01/09				
		Unit 4			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	06/22/05	Install SCR	0.1	07/01/07				
Gannon	Florida	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/04										
WEPCO														
WEPCO shall comply with the following system wide average NO_x emission rates and total NO_x tonnage permissible: by 1/1/2005 an emission rate of 0.27 and 31,500 tons, by 1/1/2007 an emission rate of 0.19 and 23,400 tons, and by 1/1/2013 an emission rate of 0.17 and 17, 400 tons. For SO_2 emissions, WEPCO will comply with: by 1/1/2005 an emission rate of 0.76 and 86,900 tons, by 1/1/2007 an emission rate of 0.61 and 74,400 tons, by 1/1/2008 an emission rate of 0.45 and 55,400 tons, and by 1/1/2013 an emission rate of 0.32 and 33,300 tons.													http://www.epa.gov/compliance/resources/cases/civil/caa/wepco.html
Presque Isle	Wisconsin	Units 1 – 4	Retire or install SO_2 and NO_x controls	12/31/12	Install and continuously operate FGD (or approved equiv. tech)	95% or 0.1	12/31/12	Install SCR (or approved tech) and continually operate	0.1	12/31/12				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.
		Units 5 & 6						Install and operate low NO_x burners		12/31/03				
		Units 7 & 8						Operate existing low NO_x burners		12/31/05	Install Baghouse			
		Unit 9						Operate existing low NO_x burners		12/31/06	Install Baghouse			
Pleasant Prairie	Wisconsin	1			Install and continuously operate FGD (or	95% or 0.1	12/31/06	Install and continuously operate SCR (or	0.1	12/31/06				

					approved control tech)			approved tech)								
		2			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/07	Install and continuously operate SCR (or approved tech)	0.1	12/31/03						
Oak Creek	Wisconsin	Units 5 & 6			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12						
		Unit 7			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12						
		Unit 8			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12						
Port Washington	Wisconsin	Units 1 – 4	Retire	12/31/04 for Units 1 – 3. Unit 4 by entry of consent decree												
Valley	Wisconsin	Boilers 1 – 4						Operate existing low NO_x burner		30 days after entry of consent decree						
VEPCO																
The Total Permissible NOx Emissions (in tons) from VEPCO system are: 104,000 in 2003, 95,000 in 2004, 90,000 in 2005, 83,000 in 2006, 81,000 in 2007, 63,000 in 2008 – 2010, 54,000 in 2011, 50,000 in 2012, and 30,250 each year there after. Beginning 1/1/2013 they will have a system wide emission rate no greater then 0.15 lb/MMBtu.													http://www.epa.gov/compliance/resources/cases/civil/caa/vepco.html			
Mount Storm	West Virginia	Units 1 – 3			Construct or improve FGD	95% or 0.15	01/01/05	Install and continuously operate SCR	0.11	01/01/08				On or before March 31 of every year beginning in 2013 and continuing thereafter, VEPCO shall surrender 45,000 SO_2 allowances.		
Chesterfield	Virginia	Unit 4						Install and continuously operate SCR	0.1	01/01/13						
		Unit 5			Construct or improve FGD	95% or 0.13	10/12/12	Install and continuously operate SCR	0.1	01/01/12						
		Unit 6			Construct or improve FGD	95% or 0.13	01/01/10	Install and continuously operate SCR	0.1	01/01/11						

Chesapeake Energy	Virginia	Units 3 & 4						Install and continuously operate SCR	0.1	01/01/13							
Clover	Virginia	Units 1 & 2			Improve FGD	95% or 0.13	09/01/03										
Possum Point	Virginia	Units 3 & 4	Retire and repower to natural gas	05/02/03													
Santee Cooper	Santee Cooper shall comply with the following system wide averages for NO_x emission rates and combined tons for emission of: by 1/01/2005 facility shall comply with an emission rate of 0.3 and 30,000 tons, by 1/1/2007 an emission rate of 0.18 and 25,000 tons, by 1/1/2010 and emission rate of 0.15 and 20,000 tons. For SO_2 emission the company shall comply with system wide averages of: by 1/1/2005 an emission rate of 0.92 and 95,000 tons, by 1/1/2007 and emission rate of 0.75 and 85,000 tons, by 1/1/2009 an emission rate of 0.53 and 70 tons, and by 1/1/2011 and emission rate of 0.5 and 65 tons.															http://www.epa.gov/compliance/resources/cases/civil/caa/santeecooper.html
Cross	South Carolina	Unit 1			Upgrade and continuously operate FGD	95%	06/30/06	Install and continuously operate SCR	0.1	05/31/04				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.			
		Unit 2			Upgrade and continuously operate FGD	87%	06/30/06	Install and Continuously operate SCR	0.11/0.1	05/31/04 and 05/31/07							
Winyah	South Carolina	Unit 1			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.11/0.1	11/30/04 and 11/30/04							
		Unit 2			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.12	11/30/04							
		Unit 3			Upgrade and continuously operate existing FGD	90%	12/31/08	Install and continuously operate SCR	0.14/0.12	11/30/2005 and 11/30/08							
		Unit 4			Upgrade and continuously operate existing FGD	90%	12/31/07	Install and continuously operate SCR	0.13/0.12	11/30/05 and 11/30/08							
Grainger	South Carolina	Unit 1						Operate low NO_x burner or more stringent technology		06/25/04							
		Unit 2						Operate low NO_x burner or more stringent technology		05/01/04							
Jeffries	South Carolina	Units 3, 4						Operate low NO_x burner or more stringent technology		06/25/04							
Ohio Edison																	

Ohio Edison shall achieve reductions of 2,483 tons NO_x between 7/1/2005 and 12/31/2010 using any combination of: 1) low sulfur coal at Burger Units 4 and 5, 2) operating SCRs currently installed at Mansfield Units 1 – 3 during the months of October through April, and/or 3) emitting fewer tons than the Plant-Wide Annual Cap for NO_x required for the Sammis Plant. Ohio Edison must reduce 24,600 tons system-wide of SO_2 by 12/31/2010.													http://www.epa.gov/compliance/resources/cases/civil/caa/ohioedison.html				
No later than 8/11/2005, Ohio Edison shall install and operate low NO_x burners on Sammis Units 1 - 7 and overfired air on Sammis Units 1,2,3,6, and 7. No later than 12/1/2005, Ohio Edison shall install advanced combustion control optimization with software to minimize NO_x emissions from Sammis Units 1 – 5.																	
W.H. Sammis Plant	Ohio	Unit 1			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/MMBtu	12/31/08	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07				Beginning on 1/1/2006, Ohio Edison may use, sell or transfer any restricted SO_2 only to satisfy the Operational Needs at the Sammis, Burger and Mansfield Plant, or new units within the FirstEnergy System that comply with a 96% removal for SO_2. For calendar year 2006 through 2017, Ohio Edison may accumulate SO_2 allowances for use at the Sammis, Burger, and Mansfield plants, or FirstEnergy units equipped with SO_2 Emission Control Standards. Beginning in 2018, Ohio Edison shall surrender unused restricted SO_2 allowances.			
		Unit 2			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/MMBtu	12/31/08	Operate existing SNCR continuously	0.25	02/15/06							
		Unit 3			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/MMBtu	12/31/08	Operate low NO_x burners and overfire air by 12/1/05; install SNCR (or approved alt. tech) & operate continuously by 12/31/07	0.25	12/01/05 and 10/31/07							
		Unit 4			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lb/MMBtu	06/30/09	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07							
		Unit 5			Install Flash Dryer Absorber or ECO[2] (or approved equiv. control tech) & operate continuously	50% removal or 1.1 lb/MMBtu	06/29/09	Install SNCR (or approved alt. tech) & Operate Continuously	0.29	03/31/08							
		Unit 6			Install FGD[3] (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lb/MMBtu	06/30/11	Install SNCR (or approved alt. tech) & operate continuously	"Minimum Extent Practicable"	06/30/05	Operate Existing ESP Continuously	0.03	01/01/10				
		Unit 7			Install FGD (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lb/MMBtu	06/30/11	Operate existing SNCR Continuously	"Minimum Extent Practicable"	08/11/05	Operate Existing ESP Continuously	0.03	01/01/10				
Mansfield Plant	Pennsylvania	Unit 1			Upgrade existing FGD	95%	12/31/05										

		Unit 2			Upgrade existing FGD	95%	12/31/06									
		Unit 3			Upgrade existing FGD	95%	10/31/07									
Eastlake	Ohio	Unit 5						Install low NO_x burners, over-fired air and SNCR & operate continuously	"Minimize Emissions to the Extent Practicable"	12/31/06						
Burger	Ohio	Unit 4	Repower with at least 80% biomass fuel, up to 20% low sulfur coal.	12/31/11												
		Unit 5		12/31/11												
Mirant[1,6]																
System-wide NO_x Emission Annual Caps: 36,500 tons 2004; 33,840 tons 2005; 33,090 tons 2006; 28,920 tons 2007; 22,000 tons 2008; 19,650 tons 2009; 16,000 tons 2010 onward. System-wide NO_x Emission Ozone Season Caps: 14,700 tons 2004; 13,340 tons 2005; 12,590 tons 2006; 10,190 tons 2007; 6,150 tons 2008 – 2009; 5,200 tons 2010 thereafter. Beginning on 5/1/2008, and continuing for each and every Ozone Season thereafter, the Mirant System shall not exceed a System-wide Ozone Season Emission Rate of 0.150 lb/MMBtu NO_x.															http://www.epa.gov/compliance/resources/cases/civil/caa/mirant.html
Potomac River Plant	Virginia	Unit 1														
		Unit 2														
		Unit 3						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04						
		Unit 4						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04						
		Unit 5						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04						
Morgantown Plant	Maryland	Unit 1						Install SCR (or approved alt. tech) & operate continuously	0.1	05/01/07						

		Unit 2						Install SCR (or approved alt. tech) & operate continuously	0.1	05/01/08							
Chalk Point	Maryland	Unit 1			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10							For each year after Mirant commences FGD operation at Chalk Point, Mirant shall surrender the number of SO_2 Allowances equal to the amount by which the SO_2 Allowances allocated to the Units at the Chalk Point Plant are greater than the total amount of SO_2 emissions allowed under this Section XVIII.			
		Unit 2			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10										
Illinois Power																	
System-wide NOx Emission Annual Caps: 15,000 tons 2005; 14,000 tons 2006; 13,800 tons 2007 onward. System-wide SO2 Emission Annual Caps: 66,300 tons 2005 – 2006; 65,000 tons 2007; 62,000 tons 2008 – 2010; 57,000 tons 2011; 49,500 tons 2012; 29,000 tons 2013 onward.														http://www.epa.gov/compliance/resources/cases/civil/caa/illinois power.html			
Baldwin	Illinois	Units 1 & 2			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA & existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse	0.015	12/31/10	By year end 2008, Dynergy will surrender 12,000 SO_2 emission allowances, by year end 2009 it will surrender 18,000, by year end 2010 it will surrender 24,000, any by year end 2011 and each year thereafter it will surrender 30,000 allowances. If the surrendered allowances result in insufficient remaining allowances allocated to the units comprising the DMG system, DMG can request to surrender fewer SO_2 allowances.			
		Unit 3			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA and/or low NO_x burners	0.12 until 12/30/12; 0.1 from 12/31/12	08/11/05 and 12/31/12	Install & continuously operate Baghouse	0.015	12/31/10				
Havana	Illinois	Unit 6			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	1.2 lb/MMBtu until 12/30/2012; 0.1 lb/MMBtu from 12/31/2012 onward	08/11/05 and 12/31/12	Operate OFA and/or low NO_x burners & operate existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse, then install ESP or alt. PM equip	For Baghouse: 0.015 lb/MMBtu; For ESP: 0.03 lb/MMBtu	For Baghouse: 12/31/12; For ESP: 12/31/05				
Hennepin	Illinois	Unit 1				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously	0.03	12/31/06				

											operate ESPs						
		Unit 2				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06				
Vermilion	Illinois	Units 1 & 2				1.2	01/31/07	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10				
Wood River	Illinois	Units 4 & 5				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05				
Kentucky Utilities Company																	
EW Brown Generating Station	Kentucky	Unit 3			Install FGD	97% or 0.100	12/31/10	Install and continuously operate SCR by 12/31/2012, continuously operate low NO_x boiler and OFA.	0.07	12/31/12	Continuously operate ESP	0.03	12/31/10	KU must surrender 53,000 SO_2 allowances of 2008 or earlier vintage by March 1, 2009. All surplus NO_x allowances must be surrendered through 2020.	SO_2 and NO_x allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		http://www.epa.gov/compliance/resources/cases/civil/caa/kucompany.html
Salt River Project Agricultural Improvement and Power District (SRP)																	
Coronado Generating Station	Arizona	Unit 1 or Unit 2			Immediately begin continuous operation of existing FGDs on both units, install new FGD.	95% or 0.08	New FGD installed by 1/1/2012	Install and continuously operate low NO_x burner and SCR	0.32 prior to SCR installation, 0.080 after	LNB by 06/01/2009, SCR by 06/01/2014	Optimization and continuous operation of existing ESPs.	0.03	Optimization begins immediately, rate limit begins 01/01/12 (date of new FGD installation)	Beginning in 2012, all surplus SO_2 allowances for both Coronado and Springerville Unit 4 must be surrendered through 2020. The allowances limited by this condition may, however, be used for compliance at a prospective future plant using BACT and otherwise specified in par. 54 of the	SO_2 and NO_x allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		http://www.epa.gov/compliance/resources/cases/civil/caa/srp.html
		Unit 1 or Unit 2			Install new FGD	95% or 0.08	01/01/13	Install and continuously operate low NO_x burner	0.32	06/01/11			Optimization begins immediately, rate limit begins 01/01/13 (date of				

													new FGD installation)	consent decree.			
American Electric Power																	
Eastern System-Wide						Annual Cap (tons)	Year		Annual Cap (tons)	Year				NO_x and SO_2 allowances that would have been made available by emission reductions pursuant to the Consent Decree must be surrendered.	NO_x and SO_2 allowances may not be used to comply with any of the limits imposed by the Consent Decree. The Consent Decree includes a formula for calculating excess NO_x allowances relative to the CAIR Allocations, and restricts the use of some. See par. 74-79 for details. Reducing emissions below the Eastern System-Wide Annual Tonnage Limitations for NO_x and SO_2 earns super compliance allowances.		http://www.epa.gov/compliance/resources/cases/civil/caa/americanelectricpower1007.html
						450,000	2010		96,000	2009							
						450,000	2011		92,500	2010							
						420,000	2012		92,500	2011							
						350,000	2013		85,000	2012							
						340,000	2014		85,000	2013							
						275,000	2015		85,000	2014							
						260,000	2016		75,000	2015							
						235,000	2017		72,000	2016 and thereafter							
						184,000	2018										
						174,000	2019 and thereafter										
At least 600MW from various units	West Virginia	Sporn 1 – 4	Retire, retrofit, or re-power	12/31/18													
	Virginia	Clinch River 1 – 3															
	Indiana	Tanners Creek 1 – 3															
	West Virginia	Kammer 1 – 3															
Amos	West Virginia	Unit 1			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08							-

		Unit 2			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		01/01/09							-
		Unit 3			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08							-
Big Sandy	Kentucky	Unit 1			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							-
		Unit 2			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/09							-
Cardinal	Ohio	Unit 1			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09				-
		Unit 2			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09				-
		Unit 3			Install and continuously operate FGD		12/31/12	Install and continuously operate SCR		01/01/09							-
Clinch River	Virginia	Units 1 – 3				Plant-wide annual cap: 21,700 tons from 2010 to 2014, then 16,300 after 1/1/2015	2010 – 2014, 2015 and thereafter	Continuously operate low NO_x burners		Date of entry							-
Conesville	Ohio	Unit 1	Retire, retrofit, or re-power	Date of entry													-
		Unit 2	Retire, retrofit, or re-power	Date of entry													-

		Unit 3	Retire, retrofit, or re-power	12/31/12													-
		Unit 4			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		12/31/10							-
		Unit 5			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_x burners		Date of entry							-
		Unit 6			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_x burners		Date of entry							-
Gavin	Ohio	Unit 1			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09							-
		Unit 2			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09							-
Glen Lyn	Virginia	Units 1 – 3															-
		Units 5, 6			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							-
Kammer	West Virginia	Units 1 – 3				Plant-wide annual cap: 35,000	01/01/10	Continuously operate over-fire air		Date of entry							-
Kanawha River	West Virginia	Units 1, 2			Burn only coal with no more than 1.75 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							-
Mitchell	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09							-
		Unit 2			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09							-
Mountaineer	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/08							-
Muskingum River	Ohio	Units 1 – 4	Retire, retrofit, or re-power	12/31/15													-

		Unit 5			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/08	Continuously operate ESP	0.03	12/31/02				-
Picway	Ohio	Unit 9						Continuously operate low NO_x burners		Date of entry							-
Rockport	Indiana	Unit 1			Install and continuously operate FGD		12/31/17	Install and continuously operate SCR		12/31/17							-
		Unit 2			Install and continuously operate FGD		12/31/19	Install and continuously operate SCR		12/31/19							-
Sporn	West Virginia	Unit 5	Retire, retrofit, or re-power	12/31/13													-
Tanners Creek	Indiana	Units 1 – 3			Burn only coal with no more than 1.2 lb/MMBtu annual average		Date of entry	Continuously operate low NO_x burners		Date of entry							-
		Unit 4			Burn only coal with no more than 1.2% sulfur content annual average		Date of entry	Continuously operate over-fire air		Date of entry							-
East Kentucky Power Cooperative Inc.																	
By 12/31/2009, EKPC shall choose whether to: 1) install and continuously operate NO_x controls at Cooper 2 by 12/31/2012 and SO_2 controls by 6/30/2012 or 2) retire Dale 3 and Dale 4 by 12/31/2012.																	
System-wide					System-wide 12-month rolling tonnage limits apply	12-month rolling limit (tons)	Start of 12-month cycle	All units must operate low NO_x boilers	12-month rolling limit (tons)	Start of 12-month cycle	PM control devices must be operated continuously system-wide, ESPs must be optimized within 270 days of entry date, or	0.03	1 year from entry date	All surplus SO_2 allowances must be surrendered each year, beginning in 2008.	SO_2 and NO_x allowances may not be used to comply with the Consent Decree. NO_x allowances that would become available as a result of		http://www.epa.gov/compliance/resources/cases/civil/caa/nevadapower.html
						57,000	10/01/08		11,500	01/01/08							
						40,000	07/01/11		8,500	01/01/13							

						28,000	01/01/13		8,000	01/01/15	EKPC may choose to submit a PM Pollution Control Upgrade Analysis.				compliance with the Consent Decree may not be sold or traded. SO_2 and NO_x allowances allocated to EKPC must be used within the EKPC system. Allowances made available due to super compliance may be sold or traded.		
Spurlock	Kentucky	Unit 1			Install and continuously operate FGD	95% or 0.1	6/30/2011	Continuously operate SCR	0.12 for Unit 1 until 01/01/2013, at which point the unit limit drops to 0.1. Prior to 01/01/2013, the combined average when both units are operating must be no more than 0.1	60 days after entry							

		Unit 2			Install and continuously operate FGD by 10/1/2008	95% or 0.1	1/1/2009	Continuously operate SCR and OFA	0.1 for Unit 2, 0.1 combined average when both units are operating	60 days after entry							
Dale Plant	Kentucky	Unit 1						Install and continuously operate low NO_x burners by 10/31/2007	0.46	01/01/08				EKPC must surrender 1,000 NO_x allowances immediately under the ARP, and 3,107 under the NO_x SIP Call. EKPC must also surrender 15,311 SO_2 allowances.		Date of entry	http://www.epa.gov/compliance/resources/cases/civil/caa/eastkentuckypower-dale0907.html
		Unit 2						Install and continuously operate low NO_x burners by 10/31/2007	0.46	01/01/08							
		Unit 3	EKPC may choose to retire Dale 3 and 4 in lieu of installing controls in Cooper 2	12/31/2012													
		Unit 4															
Cooper	Kentucky	Unit 1															
		Unit 2			If EKPC opts to install controls rather than retiring Dale, it must install and continuously operate FGD or equiv. technology	95% or 0.10		If EKPC elects to install controls, it must continuously operate SCR or install equiv. technology	0.08 (or 90% if non-SCR technology is used)	12/31/12							
Nevada Power Company																	
Beginning 1/1/2010, combined NO_x emissions from Units 5,6,7, and 8 must be no more than 360 tons per year.																	
Clark Generating Station	Nevada	Unit 5	Units may only fire natural					Increase water injection immediately,	5ppm 1-hour average	12/31/08 (ULNB installation),					Allowances may not be used to comply with the		http://www.epa.gov/compliance/resources

			gas					then install and operate ultra-low NO_x burners (ULNBs) or equivalent technology. In 2009, Units 5 and 8 may not emit more than 180 tons combined		01/30/09 (1-hour average)					Consent Decree, and no allowances made available due to compliance with the Consent Decree may be traded or sold.		/cases/civil/caa/nevadapower.html
		Unit 6							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)							
		Unit 7							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)							
		Unit 8							5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)							
Dayton Power & Light																	
Non-EPA Settlement of 10/23/2008																	
Stuart Generating Station	Ohio	Station-wide			Complete installation of FGDs on each unit.	96% or 0.10	07/31/09	Owners may not purchase any new catalyst with SO_2 to SO_3 conversion rate greater than 0.5%	0.17 station-wide	30 days after entry		0.030 lb per unit	07/31/09		NO_x and SO_2 allowances may not be used to comply with the monthly rates specified in the Consent Decree.		Courtlink document provided by EPA in email
									0.17 station-wide	60 days after entry date							
						82% including data from periods of malfunctions	7/31/09 through 7/30/11	Install control technology on one unit	0.10 on any single unit	12/31/12		Install rigid-type electro-des in each unit's ESP	12/31/15			
						82% including data from periods of malfunctions	after 7/31/11		0.15 station-wide	07/01/12						
									0.10 station-wide	12/31/14						
PSEG FOSSIL, Amended Consent Decree of November 2006																	
Kearny	New Jersey	Unit 7	Retire unit	01/01/07										Allowances allocated to Kearny, Hudson, and Mercer may only be used for the operational			http://www.epa.gov/compliance/resources/decrees/amended/psegfossil-

														needs of those units, and all surplus allowances must be surrendered. Within 90 days of amended Consent Decree, PSEG must surrender 1,230 NO_x Allowances and 8,568 SO_2 Allowances not already allocated to or generated by the units listed here. Kearny allowances must be surrendered with the shutdown of those units.			amended-cd.pdf
		Unit 8	Retire unit	01/01/07													
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	12/31/10	Install Baghouse (or approved technology)	0.015	12/31/10				
						Annual Cap (tons)	Year		Annual Cap (tons)	Year							
						5,547	2007		3,486	2007							
						5,270	2008		3,486	2008							
						5,270	2009		3,486	2009							
						5,270	2010		3,486	2010							
Mercer	New Jersey	Units 1 &2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10				
Westar Energy																	
Jeffrey Energy Center	Kansas	All units			Units 1, 2, and 3 have a total annual limit of 6,600 tons of SO2 and an annual rate limit of 0.07 lbs/MMBtu starting 2012 Units 1, 2, and 3 must all install FGDs by 2011 and operate them continuously. FGDs must maintain a 30-Day Rolling Average Unit Removal Efficiency for SO2 of at least 97% or a 30-Day Rolling Average Unit Emission Rate for SO2 of no greater than 0.070 lb/MMBtu.			Units 1-3 must continuously operate Low NOx Combustion Systems by 2012 and achieve and maintain a 30-Day Rolling Average Unit Emission Rate for NOx of no greater than 0.180 lb/MMBtu. One of the three units must install an SCR by 2015 and operate it continuously to maintain a 30-Day Rolling Average Unit Emission Rate for NOx of no greater than 0.080 lb/MMBtu. By 2013 Westar shall elect to either (a) install a second SCR on one of the other JEC Units by 2017 or (b) meet a 0.100 lb/MMBtu Plant-Wide 12-Month Rolling Average Emission Rate and 9.6 MTons annual cap for NOx by 2015			Units 1, 2, and 3 must operate each ESP and FGD system continuously by 2011 and maintain a 0.030 lb/MMBtu PM Emissions Rate. Units 1 and 2's ESPs must be rebuilt by 2014 in order to meet a 0.030 lb/MMBtu PM Emissions Rate						
Duke Energy																	
Gallagher	Indiana	Units 1 & 3	Retire or repower as natural gas	1/1/2012													

		Units 2 & 4		Install Dry sorbent injection technology	80%	1/1/2012									
American Municipal Power															
Gorsuch Station	Ohio	Units 2 & 3 Units 1 & 4	Elected to Retire Dec 15, 2010 (must retire by Dec 31, 2012)												http://amppartners.org/newsroom/amp-to-retire-gorsuch-generating-station/
Hoosier Energy Rural Electric Cooperative															
Ratts	Indiana	Units 1 & 2					Install & continually operate SNCRS	0.25	12/31/2011	Continuously operate ESP	Annually surrender any NOx and SO2 allowances that Hoosier does not need in order to meet its regulatory obligations				http://www.epa.gov/compliance/resources/cases/civil/caa/hoosier.html
Merom	Indiana	Unit 1		Continually run current FGD for 90% removal and update FGD for 98% removal by 2012	98%	2012	Continuously operate existing SCRs	0.12		Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/12					
		Unit 2		Continually run current FGD for 90% removal and update FGD for 98% removal by 2014	98%	2014				Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/13					
Northern Indiana Public Service Co.															
System-wide NO_x Emission Caps in Tons: 15,537 in 2012, if NIPSCO chooses NOx Option 1: 15,247 in 2013, 14,959 in 2014, 14,365 in 2015, 11,704 in 2016 - 2018, if NIPSCO chooses NOx option A: 11,704 in 2019 & onwards, if NIPSCO chooses NOx option B: 10,300 in 2019 & onwards; if NIPSCO chooses NOx Option 2: 13,752 in 2013, 13,464 in 2014, 12,870 in 2015 - 2018, if NIPSCO chooses NOx option A: 12,870 in 2019 & onwards, if NIPSCO chooses NOx option B: 11,470 in 2019 & onwards. System-wide SO2 Emission Caps in Tons: 50,200 in 2012 - 2013,10,200 35,900 in 2014 & 2015, 25,300 in 2016-2018, if NIPSCO chooses SO2 option 1: 10,200 in 2019 & onwards, if NIPSCO chooses SO2 option 2: 11,600 in 2019 & onwards.															
Bailly	Indiana	Units 7 & 8			Upgrade existing FGD	95% by 01/01/11 97% by 01/01/14 (95% if low sulfur coal only is burned)		OFA & SCR	0.15 lb/MMBtu by 12/31/10 0.13 lb/MMBtu by 12/31/13 0.12 lb/MMBtu by 12/31/15		0.3 lb/MMBtu (0.015 if a baghouse is installed)	12/31/2010				
Michigan City	Indiana	Unit 12			FGD	0.1 lb/MMBtu	12/31/2018	OFA & SCR	0.14 lb/MMBtu by 12/31/10 0.12 lb/MMBtu by 12/31/11 0.10 lb/MMBtu by 12/31/13		0.3 lb/MMBtu (0.015 if a baghouse is installed)	12/31/2018				

Schahfer	Indiana	Unit 14			FGD	0.08 lb/MMBtu	12/31/2013	OFA & SCR	0.14 lb/MMBtu by 12/31/10 0.12 lb/MMBtu by 12/31/12 0.10 lb/MMBtu by 12/31/14			0.3 lb/MMBtu (0.015 if a baghouse is installed)	12/31/2013				
	Indiana	Unit 15			FGD	0.08 lb/MMBtu	12/31/2015	LNB/OFA	0.16	3/31/2011		0.3 lb/MMBtu (0.015 if a baghouse is installed)	12/31/2015				
								SCR	0.08	12/31/2015							
	Indiana	Units 17 & 18			Upgrade existing FGD	97%	1/31/2011	LNB/OFA	0.2	3/31/2011		0.3 lb/MMBtu (0.015 if a baghouse is installed)	12/31/2010				
Dean H Mitchell	Indiana	Units 4, 5, 6, & 11	Retire	12/31/2010													
Tennessee Valley Authority																	
System-wide NOx Emission Caps in Tons: 100,600 in 2012, 90,791 in 2013, 86,842 in 2014, 83,042 in 2015, 70,667 in 2016, 64,951 in 2017, 52,000 in 2018 & onwards. System-wide SO2 Emission Caps in Tons: 285,000 in 2012, 235,518 in 2013, 228,107 in 2014, 220,631 in 2015, 175,626 in 2016, 164,257 in 2017, 121,699 in 2018, 100,000 in 2019 & onwards.																	
Colbert	Alabama	Units 1- 4			FGD		6/30/2016	SCR		6/30/2016				Shall surrender all calendar year NOx and SO2 Allowances allocated to TVA that are not needed for compliance with its own CAA reqts. Allocated allowances may be used for TVA's own compliance with CAA reqts.	Shall not use NOx or SO2 Allowances to comply with any requirement of the Consent Decree, Nothing prevents TVA from purchasing or otherwise obtaining NOx and SO2 allowances from other sources for its compliance with CAA reqts. TVA may sell, bank, use, trade, or transfer any NOx and SO2 "Super-Compliance" Allowances resulting from	2011	http://www.epa.gov/compliance/resources/cases/civil/caa/tvacoal-fired.html
		Unit 5			FGD		12/31/15	SCR		Effective Date							
Widows Creek	Alabama	Units 1 - 6	Retire 2 units 7/31/13 Retire 2 units 7/31/14 Retire 2 units 7/31/15														
		Unit 7						SCR		Effective Date							
		Unit 8						SCR		Effective Date							
Paradise	Kentucky	Units 1 & 2			Upgrade FGD	93%	12/31/12	SCR		Effective Date							
		Unit 3			Wet FGD		Effective Date	SCR		Effective Date							
Shawnee	Kentucky	Units 1 & 4			FGD	1.2	12/31/17	SCR		12/31/17							
		Units 5 - 10				1.2	Effective Date										
Allen	Tennessee	Units 1 - 3			FGD		12/31/18					0.3	12/31/18				
Bull Run	Tennessee	Unit 1			Wet FGD		Effective Date					0.3	Effective Date				

Cumberland	Tennessee	Units 1 & 2			Wet FGD		Effective Date							meeting System-wide limits. Except that reductions used to support new CC/CT will not be Super Allowances in that year and thereafter.		
Gallatin	Tennessee	Units 1 - 4			FGD		12/31/17	SCR		12/31/17		0.3	12/31/17			
John Sevier	Tennessee	Units 1 & 2	Retire 2 Units 12/31/12 and 12/31/15													
		Units 3 & 4			FGD		12/31/15	SCR		12/31/15						
Johnsonville	Tennessee	Units 1 - 10	Retire 6 Units 12/31/15 Retire 4 Units 12/31/17													
Kingston	Tennessee	Units 1 - 9			FGD		Effective Date	SCR		Effective Date		0.3	Effective Date			

Notes:

1) Updates to the EPA Base Case 4.10 Final from EPA Base Case 4.10 include the additions of the American Municipal Power settlement, the Hoosier Energy Rural Electric Cooperative settlement, a modification to the control requirements on the Mercer plant under the PSEG Fossil settlement, and an update to the SO_2 emission modeling on Jeffrey Energy Center as part of the Westar settlement.

2) This summary table describes New Source Review settlement actions as they are represented in EPA Base Case. The settlement actions are simplified for representation in the model. This table is not intended to be a comprehensive description of all elements of the actual settlement agreements.

3) Settlement actions for which the required emission limits will be effective by the time of the first mapped run year (before 1/1/2012) are built into the database of units used in EPA Base Case ("hardwired"). However, future actions are generally modeled as individual constraints on emission rates in EPA Base Case, allowing the modeled economic situation to dictate whether and when a unit would opt to install controls versus retire.

4) Some control installations that are required by these NSR settlements have already been taken by the affected companies, even if deadlines specified in their settlement haven't occurred yet. Any controls that are already in place are built into EPA Base Case

5) If a settlement agreement requires installation of PM controls, then the controls are shown in this table and reflected in EPA Base Case. If settlement requires optimization or upgrade of existing PM controls, those actions are not included in EPA Base Case.

6) For units for which an FGD is modeled as an emissions constraint in EPA Base Case, EPA used the assumptions on removal efficiencies that are shown in the latest emission control technologies documentation

7) For units for which an FGD is hardwired in EPA Base Case, unless the type of FGD is specified in the settlement, EPA modeling assumes the most cost effective FGD (wet or dry) and a corresponding 95% removal efficiency for wet and 90% for dry.

8) For units for which an SCR is modeled as an emissions constraint or is hardwired in EPA Base Case, EPA assumed an emissions rate equal to 10% of the unit's uncontrolled rate, with a floor of .06 lb/MMBtu or used the emission limit if provided.

9) The applicable low NOx burner reduction efficiencies are shown in Table A 3-1:3 in the Base Case documentation materials.

10) EPA included in EPA Base Case the requirements of the settlements as they existed on January 1, 2011.

11) Some of the NSR settlements require the retirement of SO2 allowances. For Base Case, EPA estimates the amount of allowances to be retired from these settlements and adjusted the total Title IV allowances accordingly.

Table 4-13. Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Base Case v4.10_MATS

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Integrated Gasification Combined Cycle – Bituminous	Integrated Gasification Combined Cycle – Subbituminous	Advanced Coal with Carbon Capture-Bituminous[1]	Advanced Coal with Carbon Capture – Subbituminous[1]	Supercritical Pulverized Coal - Wet Bituminous	Supercritical Pulverized Coal - Dry Sub-Bituminous
Size (MW)	560	170	1350	600	600	500	500	600	600
First Year Available	2015	2012	2017	2013	2013	2015	2015	2013	2013
Lead Time (Years)	3	2	6	4	4	4	4	4	4
Vintage #1 (years covered)	2012 - 2054	2012 - 2054	2012 - 2054	2012 - 2054	2012 - 2054	2012 - 2054	2015 - 2054	2012 - 2054	2012 - 2054
Availability	87%	92%	90%	85%	85%	85%	85%	85%	85%
Vintage #1									
Heat Rate (Btu/kWh)	6,810	10,720	10,400	8,424	8,062	10,149	9,713	8,874	8,937
Capital[2] (2007$/kW)	976	698	~~4,621~~ 5,000	3,265	3,310	4,720	4,785	2,918	3,008
Fixed O&M (2007$/kW/yr)	14.4	12.3	92.4	47.9	48.2	60.5	61.0	28.9	28.6
Variable O&M (2007$/MWh)	2.57	3.59	0.77	1.32	1.15	1.67	1.46	3.43	2.27

Notes:
[1]For The term “Advanced Coal with Carbon Capture” is used here and in the output files for EPA Base Case v.4.10_MATS to represent a variety of technologies that are expected to provide carbon capture capabilities. These include both supercritical steam generators with carbon capture and integrated gasification combined cycle (IGCC) with carbon capture. Although IGCC with carbon capture was used to define the cost and performance parameters that are implemented in EPA Base Case v.4.10_MATS, projections of “Advanced Coal with Carbon Capture” in EPA Base Case v.4.10_MATS are not limited to this technology.
[2]Capital cost represents overnight capital cost.

Chapter 5: Emission Control Technologies

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5.2 Nitrogen Oxides Control Technology

Table 5-7. Summary of Retrofit NOx Emission Control Performance Assumptions

Control Performance Assumptions	Selective Catalytic Reduction (SCR)		Selective Non-Catalytic Reduction (SNCR)
Unit Type	Coal	Oil/Gas	Coal
Percent Removal	90% down to 0.06 lb/MMBtu	80%	Pulverized Coal: ~~35%~~ 25% with a NOx rate floor of 0.1 lbs/MMBtu Fluidized Bed: 50% with a NOx rate floor of 0.08lbs/MMBtu
Size Applicability	Units ≥ 25 MW	Units ≥ 25 MW	Units ≥ 25 MW
Costs (2007$)	See Table 5-8*	Table 5-9*	Table 5-8*

* Tables in *EPA Base Case v.4.10* (EPA #430-R-10-010), August 2010 at www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.

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5.4.3 Mercury Control Capabilities

[Insert the following text at the end of section 5.4.3 as it appears in the *Documentation Supplement for the Proposed Toxics Rule* (March 2011)]

Revisions to ACI VOM Cost in Base Case v.4.10_MATS: For coal units that have a FF embedded in LSD or DSI+FF retrofits, the variable operating and maintenance (VOM) cost of activated carbon injection (ACI) retrofits is assumed to be 81 percent lower due to the presence of pre-existing particulate controls.

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5.5.1 Chlorine Content of Fuels

HCl emissions from the power sector result from the chlorine content of the coal that is combusted by electric generating units. Data on chlorine content of coals had been collected as part EPA's 1999 "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR 1999) described above in section 5.4.1 To provide the capability for EPA Base Case v4.10_MATS to account for HCl emissions, this data had to be incorporated into the model. The procedures used for this are presented in the updated text in section 9.1.3 below.

To account for the effect of ash chemistry on HCl emissions, the HCl content of lignite and subbituminous coals is reduced by 75%.

In the IPM modeling runs done in support of the proposed MATS, 100 % of the coal chlorine was assumed to convert to HCl and be present in the flue gas at the point of injection of the dry sorbent. This was the assumption for all coal ranks and types. After MATS proposal a team of EPA and DOE engineers and control technology specialists met regularly to further evaluate the application of DSI. One of the outcomes of that collaboration was recognition that western sub-bituminous coal (such as that mined in

the Powder River Basin) and lignites contain natural alkalinity in the form of non-glassy calcium oxide (CaO) and other alkaline and alkaline earth oxides. This fly ash (classified as 'Class C' fly ash) has a natural pH of 9 and higher and the natural alkalinity can effectively neutralize much of the HCl in the flue gas stream prior to the primary control device.

Eastern bituminous coals, by contrast, tend to produce fly ash with lower natural alkalinity. Though bituminous fly ash (classified as 'Class F' fly ash) may contain calcium, it tends to be present in a glassy matrix and unavailable for acid-base neutralization reactions.

In order to assess the extent of expected natural neutralization, the 2010 ICR data was examined. It was observed that some of the subbituminous coals contained chlorine levels in such low quantities that users should expect to meet the HCl emission limit with no additional controls. It was also noted that some other units burning subbituminous or lignite coals with higher levels of Cl were achieving 50-85 % HCl control with only cold-side ESP (i.e., with no flue gas desulfurization or other acid gas control technology). We examined the Cl content of the sub-bituminous coals that are modeled in IPM and compared those to the ICR results. From that analysis we believe that those coals can expect to achieve approximately 75 % natural HCl neutralization from the alkaline fly ash.

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5.5.3 HCl Retrofit Emission Control Options

Table 5-20 Summary of HCl Emission Control Technology Assumptions in EPA Base Case v4.10_PTox (Proposed Toxics Rule)

HCl Control Technology Options	Applicability
Limestone Forced Oxidation (LSFO) Scrubber	Base case and policy case
Lime Spray Dryer (LSD)	Base case and policy case
Dry Sorbent Injection (DSI)	Base case and policy case
Scrubber upgrade adjustment	To existing coal steam units with FGD in policy cases analyzed for MATS Rulemaking

All the retrofit options for HCl emission control are summarized in Table 5-20. The scrubber upgrade adjustment was discussed above in 5.5.2. The other options are discussed in detail in the following sections.

5.5.3.1 Wet and Dry FGD

In addition to providing SO_2 reductions, wet scrubbers (Limestone Forced Oxidation, LSFO) and dry scrubbers (Lime Spray Dryer, LSD) reduce HCl as well. For both LSFO and LSD the HCl removal rate is assumed to be 99% with a floor of 0.0001 lbs/MMBtu. This is summarized in columns 2-5 of Table 5-21.

FGD Upgrade Assumptions in MATS Policy Case: In setting up the MATS policy case, all scrubbed unit that do not currently achieve an SO2 removal rate of 94% are assigned a capital cost of $100/kW (2009$) for an FGD upgrade that will improve their HCl removal rates to 99% and bring any unit whose SO2 removal rate was below 90% up to 90%.

Dry Scrubber Removal Assumptions for Waste Coal and Petroleum Coke Units in MATS Policy Case: In setting up the Base Case v.4.10_MATS, waste coal and petroleum coke units without an existing FGD were mistakenly not provided with a scrubber retrofit option. To make up for this oversight, in run year 2015 a dry scrubber and an associated capital cost of $748/kW (applied through and FOM adder) are assigned to these units when setting up the MATS policy case. (The $748/kW capital cost was calculated using the procedures described in section 5.1.1 and, illustrated in Appendix 5-1 for a 100 MW unit with an average heat rate of the waste coal units.) The removal rates obtained by the dry FGD (92% for SO2 and 99% for HCl) are incremental to existing FBC removals. In addition, petroleum coke units with dry FGD are assigned a mercury emission modification factor (EMF) of 0.07.]

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5.5.3.2 Dry Sorbent Injection

[Insert the following text at the end of section 5.5.3.2 as it appears in the *Documentation Supplement for the Proposed Toxics Rule* (March 2011)]

Revisions to DSI Cost and Performance Assumptions in Base Case v.4.10_MATS: The following additional assumptions were made with respect to DSI in the Base Case v.4.10_MATS

(a) Since fabric filters are a pre-requisite for a DSI retrofit, the DSI retrofit VOM cost incurred by units with no pre-existing fabric filter is reduced by 35% to reflect the non-contamination of fly ash and the resulting savings in fly ash disposal costs from the forced installation of a fabric filter.

(b) The cost of the pre-requisite fabric filter is implemented as adders to the FOM and capital cost of the DSI installation.

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5.5.4 Fabric Filter (Baghouse) Cost Development

Fabric filters are not endogenously modeled as a separate retrofit option in EPA Base Case v4.10_PTox, but are accounted for as a cost adder where they are required for particulate matter (PM), mercury, or HCl emission control. In EPA Base Case v4.10_PTox, an existing or new fabric filter particulate control device is a pre-condition for installing a DSI retrofit. In the v4.10_PTox policy case any unit that was retrofit by the model with DSI and did not have an existing fabric filter incurred the cost of installing a fabric filter. This cost was added to the DSI costs discussed in section 5.5.3.2. This section describes the methodology used by Sargent & Lundy to derive the cost of a fabric filter.

The engineering cost analysis is based on a pulse-jet fabric filter which collects particulate matter on a fabric bag and uses air pulses to dislodge the particulate from the bag surface and collect it in hoppers for removal via an ash handling system to a silo. This is a mature technology that has been operating commercially for more than 25 years. “Baghouse” and “fabric filters” are used interchangeably to refer to such installations.

Capital Cost: Two governing variables are used to derive the bare module capital cost of a fabric filter. The first of these is the “air-to-cloth” (A/C) ratio. The major driver of fabric filter capital cost, the A/C ratio is defined as the volumetric flow, (typically expressed in Actual Cubic Feet per Minute, ACFM) of flue gas entering the baghouse divided by the areas (typically in square feet) of fabric filter cloth in the baghouse. The lower the A/C ratio, e.g., A/C = 4.0 compared to A/C = 6.0, the greater the area of the cloth required and the higher the cost for a given volumetric flow.

Note: Based on public comments and engineering assessments, an air-to-cloth ratio or 4.0, rather than 6.0, was used in modeling for MATS to provide a conservative projection of the requirements and cost of sorbent removal.

The other determinant of capital cost is the flue gas volumetric flow rate (in ACFM) which is a function of the type of coal burned and the unit's size and heat rate.

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5.6 Filterable Particulate Matter (PM) Compliance

When the MATS policy case is modeled off the v.4.10_MATS Base Case, it is assumed that all coal burning generating units with a capacity of 25 MW or greater will comply with the filterable PM requirements through the operation of either electrostatic precipitator (ESP) or fabric filter (FF) particulate controls. The decision of whether an upgrade of existing controls will be needed to meet the requirement is not modeled endogenously but supplied as an input when setting up the run.

Units with existing fabric filters are assumed to be able to meet the filterable PM compliance requirement. For units with existing ESPs the following procedure is used to determine if they already meet the filterable PM requirement, can meet it by one of three possible ESP upgrades, or can only meet it by installing a FF.

First, PM emission rate data derived either from 2005 EIA Form 767 or (where available) from EPA's 2010 Information Collection Request5 are compared to the applicable filterable PM compliance requirement. If the unit's emission rate is equal to or less than the compliance requirement, adequate controls are assumed already to be in place and no additional upgrade costs are imposed. For units that do not meet the filterable PM compliance requirement, the incremental reduction needed (in lbs/mmBtu) is calculated by subtracting the filterable PM compliance standard from the reported emission rate. Depending on the magnitude of the incremental reduction needed, the unit is assigned one of three ESP upgrade costs (designated ESP1, ESP2, and ESP3) or the cost of a FF installation (designated ESP4), if the required incremental reduction cannot be achieved by an ESP upgrade. Table 5-25 shows the four levels of ESP upgrades (column 1), the key technologies included in each upgrade (column 2), trigger points for the upgrades (column 3), the capital cost of each upgrade (column 4), and the percent increase in collection efficiency provided by the upgrade, differentiated according to the rank (subbituminous, bituminous, or lignite) of coal burned.

When setting up a model run, the capital costs for the ESP upgrades that are shown in Table 5-25 are converted into annual fixed operating and maintenance (FOM) charges which are added to the other FOM costs incurred by a particular generating unit. To obtain the FOM adder for the ESP upgrades, the values shown in Table 5-25 are multiplied by 11.3%, the capital charge rate for environmental retrofits. (For a discussion of all the capital charge rates in the model runs built upon the EPA base case v.4.10_MATS, see Chapter 8 ("Financial Assumptions") in *Documentation for EPA Base Case v.4.10_MATS Using the Integrated Planning Model*, August 2010, EPA #430-R-10-010.) To prevent double counting of PM control costs, the FOM adder described here is removed if a represented generating unit had previously had an ESP4 fabric filter upgrade, or if, in the course of a model run, was retrofit with dry flue gas desulfurization (FGD), DSI, or ACI plus TOXECON --- each of which includes particulate controls in its capital cost.

The percentage improvements in collection efficiency shown in column 5 in Table 5-25 are additive in the sense that the values shown in this column are added to the pre-upgrade collection efficiency to obtain the after-upgrade collection efficiency.

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5 2005 EIA Form 767 is the last year where the data was reported in the format of lb/MMBtu, which is compatible with this analysis. Since any changes to facilities since 2005 would likely have improved (reduced) emissions, the use of this data is conservative. More recent 2010 ICR test data is used where available.

Table 5-25. Electrostatic Precipitator (ESP) Upgrades as Implemented in EPA Base Case for MATS --- Characteristics, Trigger Points, Associated Costs, and Performance Improvements

Upgrade Level	Key Technologies Employed in Upgrade	Trigger Points for ESP Upgrade (Expressed in terms of incremental reduction needed (lbs/mmBtu) to meet the filterable PM Compliance Standard)	Capital Cost	Additive Percent Improvement[5] in Collection Efficiency as a Result of the Upgrade (differentiated by the rank of coal combusted)
1	High Frequency transformer-rectifier (TR) sets	> 0.0 to ≤ 0.005	$55/kW[1]	0.12 for subbituminous 0.05 for bituminous 0.01 for lignite
2	High frequency transformer-rectifier (TR) sets + New internals (rigid electrodes, increased plate spacing, increased plate height)	> 0.005 to ≤ 0.01	$80/kW[2]	0.25 for subbituminous 0.10 for bituminous 0.02 for lignite
3	High frequency transformer-rectifier (TR) sets + New internals (rigid electrodes, increased plate spacing, increased plate height) + Additional field	> 0.01 to ≤ 0.02	$100/kW[3]	0.50 for subbituminous 0.20 for bituminous 0.05 for lignite
4	Replacement with fabric filter (baghouse)	> 0.02	Use capital cost equations for a fabric filter[4]	(Not Applicable)

[1]Assumes upgrading the specific collection area (SCA) to 250 square-feet/1000 afm (actual feet per minute).

[2]Assumes upgrading the specific collection area (SCA) to 300 square-feet/1000 afm (actual feet per minute).

[3]Assumes upgrading the existing specific collection area (SCA) by 100 square-feet/1000 afm (actual feet per minute), a 20% height increase, and additional field.

[4]The cost equations for fabric filters are described in Section 5.5.4 ("Fabric Filter (Baghouse) Cost Development") with calculations illustrated in Tables 1 and 2 in Appendix 5-5 ("Example Cost Calculation Worksheets for Fabric Filters") in *Documentation Supplement for EPA Base Case v4.10_PTox − Updates for Proposed Toxics Rule* (EPA # 430-R-11-006). This documentation supplement is available on the web at ww.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf.

[5]The percentage improvement due to the ESP upgrade as shown in this column is added to the pre-upgrade collection efficiency to obtain the after-upgrade collection removal efficiency.

Appendix 5-6 contains a complete listing of coal generating units with either cold- or hot-side ESPs but no fabric filters. For each generating unit the table in Appendix 5-6 shows the incremental reductions needed to meet the PM filterable compliance requirement and the corresponding ESP upgrade (if any) assigned to the unit to enable it to meet that requirement. A filterable PM limit of 0.279 lb/mmBtu was used in this analysis. This value is roughly 10% below the limit in the final MATS rule, therefore resulting in a conservative estimate of the need to upgrade existing ESPs

Appendix 5-6. ESP Upgrade Provided to Existing Units without Fabric Filters so that They Meet Their Filterable PM Compliance Requirement

Plant Name	Unit ID	State Name	UniqueID	Capacity (MW)	OnLineYear	Firing	Bottom	Dry Scrubber Installed	Current Filterable PM Emission (lbs/MMBtu)	Filterable PM Limit (lbs/MMBtu)	Compliance with the Filterable PM Limit?	Final Filterable Emission (lb/MMBtu)	Incremental Filterable Reduction Needed (lb/MMBtu)	Level of ESP Upgrade Required to Meet Filterable PM Requirement
A B Brown	2	Indiana	6137_B_2	245	1986	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
AES Beaver Valley Partners Beaver Valley	2	Pennsylvania	10676_B_2	43	1943	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
AES Beaver Valley Partners Beaver Valley	3	Pennsylvania	10676_B_3	43	1943	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
AES Beaver Valley Partners Beaver Valley	4	Pennsylvania	10676_B_4	43	1943	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
AES Cayuga	1	New York	2535_B_1	150	1955	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
AES Cayuga	2	New York	2535_B_2	151	1958	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
AES Deepwater	AAB001	Texas	10670_B_AAB001	139	1986	vertical	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
AES Somerset LLC	1	New York	6082_B_1	681	1984	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Albright	1	West Virginia	3942_B_1	73	1952	wall	dry	0	0.0696	0.0279	No	0.0279	0.0417	ESP-4
Albright	2	West Virginia	3942_B_2	73	1952	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Albright	3	West Virginia	3942_B_3	137	1954	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Allen Steam Plant	1	Tennessee	3393_B_1	245	1959	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Allen Steam Plant	2	Tennessee	3393_B_2	245	1959	cyclone	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Allen Steam Plant	3	Tennessee	3393_B_3	245	1959	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Alloy Steam Station	BLR4	West Virginia	50012_B_BLR4	38	1950	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Alma	B4	Wisconsin	4140_B_B4	51	1957	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Alma	B5	Wisconsin	4140_B_B5	77	1960	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Ames Electric Services Power Plant	7	Iowa	1122_B_7	33	1968	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Ames Electric Services Power Plant	8	Iowa	1122_B_8	70	1982	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Apache Station	2	Arizona	160_B_2	175	1979	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Apache Station	3	Arizona	160_B_3	175	1979	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---

Armstrong Power Station	1	Pennsylvania	3178_B_1	172	1958	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Armstrong Power Station	2	Pennsylvania	3178_B_2	171	1959	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Asbury	1	Missouri	2076_B_1	213	1970	cyclone	wet	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
Asheville	1	North Carolina	2706_B_1	191	1964	wall	dry	0	0.0030	0.0279	Yes	0.0030	0.0000	---
Asheville	2	North Carolina	2706_B_2	185	1971	wall	dry	0	0.0036	0.0279	Yes	0.0036	0.0000	---
Ashtabula	7	Ohio	2835_B_7	244	1958	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Austin Northeast	NEPP	Minnesota	1961_B_NEPP	29	1971	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Avon Lake	10	Ohio	2836_B_10	93	1949	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Avon Lake	12	Ohio	2836_B_12	616	1970	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
B C Cobb	4	Michigan	1695_B_4	156	1956	tangential	dry	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
B C Cobb	5	Michigan	1695_B_5	156	1957	tangential	dry	0	0.0620	0.0279	No	0.0279	0.0341	ESP-4
B L England	1	New Jersey	2378_B_1	126	1962	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
B L England	2	New Jersey	2378_B_2	152	1964	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Bailly	7	Indiana	995_B_7	160	1962	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Bailly	8	Indiana	995_B_8	320	1968	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Barry	1	Alabama	3_B_1	138	1954	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Barry	2	Alabama	3_B_2	137	1954	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Barry	3	Alabama	3_B_3	249	1959	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Barry	4	Alabama	3_B_4	362	1969	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Barry	5	Alabama	3_B_5	740	1971	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Bay Shore	2	Ohio	2878_B_2	138	1959	vertical	wet	0	0.3200	0.0279	No	0.0279	0.2921	ESP-4
Bay Shore	3	Ohio	2878_B_3	142	1963	wall	dry	0	0.3200	0.0279	No	0.0279	0.2921	ESP-4
Bay Shore	4	Ohio	2878_B_4	215	1968	wall	dry	0	0.3200	0.0279	No	0.0279	0.2921	ESP-4
Belews Creek	1	North Carolina	8042_B_1	1115	1974	cell	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Belews Creek	2	North Carolina	8042_B_2	1115	1975	cell	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Belle River	1	Michigan	6034_B_1	698	1984	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1

Belle River	2	Michigan	6034_B_2	698	1985	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Big Bend	BB01	Florida	645_B_BB01	391	1970	wall	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Big Bend	BB02	Florida	645_B_BB02	391	1973	wall	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Big Bend	BB03	Florida	645_B_BB03	364	1976	wall	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Big Bend	BB04	Florida	645_B_BB04	447	1985	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Big Cajun 2	2B1	Louisiana	6055_B_2B1	580	1981	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Big Cajun 2	2B2	Louisiana	6055_B_2B2	575	1982	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Big Cajun 2	2B3	Louisiana	6055_B_2B3	588	1983	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Big Sandy	BSU1	Kentucky	1353_B_BSU1	259	1963	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Big Sandy	BSU2	Kentucky	1353_B_BSU2	789	1969	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Black Dog	3	Minnesota	1904_B_3	94	1955	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Black Dog	4	Minnesota	1904_B_4	165	1960	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Blount Street	8	Wisconsin	3992_B_8	49	1957	wall	dry	0	0.1200	0.0279	No	0.0279	0.0921	ESP-4
Blount Street	9	Wisconsin	3992_B_9	48	1961	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Blue Valley	3	Missouri	2132_B_3	51	1965	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Boardman	1SG	Oregon	6106_B_1SG	585	1980	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Bowen	1BLR	Georgia	703_B_1BLR	713	1971	tangential	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Bowen	2BLR	Georgia	703_B_2BLR	718	1972	tangential	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Bowen	3BLR	Georgia	703_B_3BLR	902	1974	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Bowen	4BLR	Georgia	703_B_4BLR	929	1975	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Brayton Point	3	Massachusetts	1619_B_3	607	1969	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Bremo Bluff	3	Virginia	3796_B_3	71	1950	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Bremo Bluff	4	Virginia	3796_B_4	156	1958	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Bruce Mansfield	3	Pennsylvania	6094_B_3	830	1979	wall	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Buck	5	North Carolina	2720_B_5	38	1941	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Buck	6	North Carolina	2720_B_6	38	1941	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---

Buck	7	North Carolina	2720_B_7	38	1942	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Buck	8	North Carolina	2720_B_8	128	1953	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Buck	9	North Carolina	2720_B_9	128	1953	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Bull Run	1	Tennessee	3396_B_1	881	1967	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Burlington	1	Iowa	1104_B_1	209	1968	tangential	dry	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
C D McIntosh Jr	3	Florida	676_B_3	340	1982	wall	dry	0	0.0736	0.0279	No	0.0279	0.0457	ESP-4
Canadys Steam	CAN1	South Carolina	3280_B_CAN1	105	1962	tangential	dry	0	0.2600	0.0279	No	0.0279	0.2321	ESP-4
Canadys Steam	CAN2	South Carolina	3280_B_CAN2	116	1964	tangential	dry	0	0.0140	0.0279	Yes	0.0140	0.0000	---
Cane Run	4	Kentucky	1363_B_4	155	1962	wall	dry	0	0.0257	0.0279	Yes	0.0257	0.0000	---
Cane Run	5	Kentucky	1363_B_5	168	1966	wall	dry	0	0.0113	0.0279	Yes	0.0113	0.0000	---
Cane Run	6	Kentucky	1363_B_6	240	1969	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Cape Fear	5	North Carolina	2708_B_5	144	1956	tangential	dry	1	0.0700	0.0279	No	0.0279	0.0421	---
Cape Fear	6	North Carolina	2708_B_6	172	1958	tangential	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Carbon	1	Utah	3644_B_1	67	1954	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Carbon	2	Utah	3644_B_2	105	1957	tangential	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Cardinal	1	Ohio	2828_B_1	600	1967	cell	dry	0	0.0114	0.0279	Yes	0.0114	0.0000	---
Cardinal	2	Ohio	2828_B_2	600	1967	cell	dry	0	0.0114	0.0279	Yes	0.0114	0.0000	---
Cardinal	3	Ohio	2828_B_3	621	1977	wall	dry	0	0.0114	0.0279	Yes	0.0114	0.0000	---
Cayuga	1	Indiana	1001_B_1	479	1970	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Cayuga	2	Indiana	1001_B_2	466	1972	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Chalk Point LLC	1	Maryland	1571_B_1	341	1964	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Chalk Point LLC	2	Maryland	1571_B_2	342	1965	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Chamois	2	Missouri	2169_B_2	49	1960	cyclone	wet	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Charles R Lowman	1	Alabama	56_B_1	85	1969	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Charles R Lowman	2	Alabama	56_B_2	238	1979	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Charles R Lowman	3	Alabama	56_B_3	238	1980	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1

Chesapeake	1	Virginia	3803_B_1	111	1953	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Chesapeake	2	Virginia	3803_B_2	111	1954	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Chesapeake	3	Virginia	3803_B_3	155	1959	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Chesapeake	4	Virginia	3803_B_4	216	1962	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Chesterfield	3	Virginia	3797_B_3	98	1952	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Chesterfield	4	Virginia	3797_B_4	164	1960	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Chesterfield	5	Virginia	3797_B_5	310	1964	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Cliffside	5	North Carolina	2721_B_5	550	1972	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Cliffside	6	North Carolina	2721_B_6	800	2011	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Clifty Creek	1	Indiana	983_B_1	214	1955	wall	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Clifty Creek	2	Indiana	983_B_2	214	1955	wall	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Clifty Creek	3	Indiana	983_B_3	214	1955	wall	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Clifty Creek	4	Indiana	983_B_4	214	1955	wall	wet	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Clifty Creek	5	Indiana	983_B_5	214	1955	wall	wet	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Clifty Creek	6	Indiana	983_B_6	214	1956	wall	wet	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Clinch River	1	Virginia	3775_B_1	234	1958	vertical	dry	0	0.0531	0.0279	No	0.0279	0.0252	ESP-4
Clinch River	2	Virginia	3775_B_2	234	1958	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Clinch River	3	Virginia	3775_B_3	234	1961	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Coal Creek	1	North Dakota	6030_B_1	554	1979	tangential	dry	0	0.0047	0.0279	Yes	0.0047	0.0000	---
Coal Creek	2	North Dakota	6030_B_2	560	1981	tangential	dry	0	0.0035	0.0279	Yes	0.0035	0.0000	---
Coffeen	01	Illinois	861_B_01	335	1965	cyclone	wet	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Coffeen	02	Illinois	861_B_02	551	1972	cyclone	wet	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Colbert	1	Alabama	47_B_1	177	1955	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Colbert	2	Alabama	47_B_2	177	1955	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Colbert	3	Alabama	47_B_3	177	1955	wall	dry	0	0.0114	0.0279	Yes	0.0114	0.0000	---
Colbert	4	Alabama	47_B_4	173	1955	wall	dry	0	0.0240	0.0279	Yes	0.0240	0.0000	---

Colbert	5	Alabama	47_B_5	459	1965	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Columbia	1	Wisconsin	8023_B_1	546	1975	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Columbia	2	Wisconsin	8023_B_2	551	1978	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Conemaugh	1	Pennsylvania	3118_B_1	850	1970	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Conemaugh	2	Pennsylvania	3118_B_2	850	1971	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Conesville	3	Ohio	2840_B_3	165	1962	wall	dry	0	0.0491	0.0279	No	0.0279	0.0212	ESP-4
Conesville	4	Ohio	2840_B_4	780	1973	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Conesville	5	Ohio	2840_B_5	375	1976	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Conesville	6	Ohio	2840_B_6	375	1978	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Cooper	1	Kentucky	1384_B_1	116	1965	wall	dry	0	0.1700	0.0279	No	0.0279	0.1421	ESP-4
Cooper	2	Kentucky	1384_B_2	221	1969	wall	dry	0	0.1700	0.0279	No	0.0279	0.1421	ESP-4
Coronado	U1B	Arizona	6177_B_U1B	395	1979	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Coronado	U2B	Arizona	6177_B_U2B	388	1980	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Crawford	7	Illinois	867_B_7	212	1958	tangential	dry	0	0.0570	0.0279	No	0.0279	0.0291	ESP-4
Crawford	8	Illinois	867_B_8	318	1961	tangential	dry	0	0.0560	0.0279	No	0.0279	0.0281	ESP-4
Crist	4	Florida	641_B_4	78	1959	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Crist	5	Florida	641_B_5	78	1961	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Crist	6	Florida	641_B_6	300	1970	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Crist	7	Florida	641_B_7	472	1973	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Cross	1	South Carolina	130_B_1	620	1995	wall	dry	0	0.0140	0.0279	Yes	0.0140	0.0000	---
Cross	2	South Carolina	130_B_2	540	1984	tangential	dry	0	0.0160	0.0279	Yes	0.0160	0.0000	---
Cross	3	South Carolina	130_B_3	580	2007	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Cross	4	South Carolina	130_B_4	600	2009	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Crystal River	1	Florida	628_B_1	379	1966	tangential	dry	0	0.1470	0.0279	No	0.0279	0.1191	ESP-4
Crystal River	2	Florida	628_B_2	491	1969	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Crystal River	4	Florida	628_B_4	718	1982	wall	dry	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4

Crystal River	5	Florida	628_B_5	717	1984	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Cumberland	1	Tennessee	3399_B_1	1232	1973	cell	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Cumberland	2	Tennessee	3399_B_2	1233	1973	cell	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
D B Wilson	W1	Kentucky	6823_B_W1	420	1986	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Dale	1	Kentucky	1385_B_1	27	1954	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Dale	2	Kentucky	1385_B_2	27	1954	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Dale	3	Kentucky	1385_B_3	75	1957	wall	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
Dale	4	Kentucky	1385_B_4	75	1960	wall	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
Dallman	31	Illinois	963_B_31	86	1968	cyclone	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Dallman	32	Illinois	963_B_32	87	1972	cyclone	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Dallman	33	Illinois	963_B_33	199	1978	tangential	wet	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
Dan E Karn	1	Michigan	1702_B_1	255	1959	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Dan E Karn	2	Michigan	1702_B_2	260	1961	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Danskammer Generating Station	3	New York	2480_B_3	133	1987	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Danskammer Generating Station	4	New York	2480_B_4	236	1987	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Dave Johnston	BW41	Wyoming	4158_B_BW41	106	1959	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Dave Johnston	BW42	Wyoming	4158_B_BW42	106	1961	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Dolet Hills	1	Louisiana	51_B_1	650	1986	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Dolphus M Grainger	1	South Carolina	3317_B_1	85	1966	wall	dry	0	0.3600	0.0279	No	0.0279	0.3321	ESP-4
Dolphus M Grainger	2	South Carolina	3317_B_2	85	1966	wall	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
Dubuque	1	Iowa	1046_B_1	35	1959	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Dubuque	5	Iowa	1046_B_5	30	1952	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Duck Creek	1	Illinois	6016_B_1	335	1976	wall	dry	0	0.0033	0.0279	Yes	0.0033	0.0000	---
E C Gaston	1	Alabama	26_B_1	254	1960	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
E C Gaston	4	Alabama	26_B_4	256	1962	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
E C Gaston	5	Alabama	26_B_5	849	1974	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1

E D Edwards	1	Illinois	856_B_1	112	1960	wall	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
E D Edwards	2	Illinois	856_B_2	273	1968	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
E D Edwards	3	Illinois	856_B_3	364	1972	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
E W Brown	1	Kentucky	1355_B_1	92	1957	wall	dry	0	0.1400	0.0279	No	0.0279	0.1121	ESP-4
E W Brown	2	Kentucky	1355_B_2	158	1963	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
E W Brown	3	Kentucky	1355_B_3	420	1971	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Eagle Valley	3	Indiana	991_B_3	43	1951	tangential	wet	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Eagle Valley	4	Indiana	991_B_4	56	1953	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Eagle Valley	5	Indiana	991_B_5	62	1953	tangential	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Eagle Valley	6	Indiana	991_B_6	99	1956	tangential	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Earl F Wisdom	1	Iowa	1217_B_1	38	1960	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
East Bend	2	Kentucky	6018_B_2	600	1981	wall	dry	0	0.0087	0.0279	Yes	0.0087	0.0000	---
Eastlake	1	Ohio	2837_B_1	132	1953	tangential	dry	0	0.0057	0.0279	Yes	0.0057	0.0000	---
Eastlake	2	Ohio	2837_B_2	132	1953	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Eastlake	3	Ohio	2837_B_3	132	1954	tangential	dry	0	0.0056	0.0279	Yes	0.0056	0.0000	---
Eastlake	4	Ohio	2837_B_4	240	1956	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Eastlake	5	Ohio	2837_B_5	597	1972	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Eckert Station	1	Michigan	1831_B_1	40	1954	wall	dry	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
Eckert Station	2	Michigan	1831_B_2	42	1958	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Eckert Station	3	Michigan	1831_B_3	41	1961	tangential	dry	0	0.1400	0.0279	No	0.0279	0.1121	ESP-4
Eckert Station	4	Michigan	1831_B_4	69	1964	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Eckert Station	5	Michigan	1831_B_5	69	1968	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Eckert Station	6	Michigan	1831_B_6	67	1970	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Edge Moor	3	Delaware	593_B_3	86	1957	tangential	dry	1	0.0500	0.0279	No	0.0279	0.0221	---
Edge Moor	4	Delaware	593_B_4	174	1966	tangential	dry	1	0.0500	0.0279	No	0.0279	0.0221	---
Edgewater	3	Wisconsin	4050_B_3	76	1951	cyclone	wet	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Edgewater	4	Wisconsin	4050_B_4	321	1969	cyclone	wet	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3

Edgewater	5	Wisconsin	4050_B_5	412	1985	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Elmer Smith	1	Kentucky	1374_B_1	130	1964	cyclone	wet	0	0.0147	0.0279	Yes	0.0147	0.0000	---
Elmer Smith	2	Kentucky	1374_B_2	257	1974	tangential	dry	0	0.0147	0.0279	Yes	0.0147	0.0000	---
Elrama	1	Pennsylvania	3098_B_1	93	1952	vertical	dry	0	0.0184	0.0279	Yes	0.0184	0.0000	---
Elrama	2	Pennsylvania	3098_B_2	93	1953	vertical	dry	0	0.0184	0.0279	Yes	0.0184	0.0000	---
Elrama	3	Pennsylvania	3098_B_3	103	1952	vertical	dry	0	0.0184	0.0279	Yes	0.0184	0.0000	---
Elrama	4	Pennsylvania	3098_B_4	171	1952	wall	dry	0	0.0184	0.0279	Yes	0.0184	0.0000	---
Endicott Station	1	Michigan	4259_B_1	55	1982	wall	dry	0	1.7300	0.0279	No	0.0279	1.7021	ESP-4
Erickson Station	1	Michigan	1832_B_1	152	1973	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Fair Station	2	Iowa	1218_B_2	41	1967	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Fayette Power Project	1	Texas	6179_B_1	590	1979	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Fayette Power Project	2	Texas	6179_B_2	590	1980	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Fayette Power Project	3	Texas	6179_B_3	445	1988	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Fisk Street	19	Illinois	886_B_19	325	1959	tangential	dry	0	0.0780	0.0279	No	0.0279	0.0501	ESP-4
Flint Creek	1	Arkansas	6138_B_1	528	1978	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Fort Martin Power Station	1	West Virginia	3943_B_1	545	1967	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Fort Martin Power Station	2	West Virginia	3943_B_2	547	1968	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Frank E Ratts	1SG1	Indiana	1043_B_1SG1	122	1970	wall	dry	0	0.3400	0.0279	No	0.0279	0.3121	ESP-4
Frank E Ratts	2SG1	Indiana	1043_B_2SG1	121	1970	wall	dry	0	0.3000	0.0279	No	0.0279	0.2721	ESP-4
G F Weaton Power Station	BLR1	Pennsylvania	50130_B_BLR1	56	1957	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
G F Weaton Power Station	BLR2	Pennsylvania	50130_B_BLR2	56	1957	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
G G Allen	1	North Carolina	2718_B_1	162	1957	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
G G Allen	2	North Carolina	2718_B_2	162	1957	tangential	dry	0	0.1400	0.0279	No	0.0279	0.1121	ESP-4
G G Allen	3	North Carolina	2718_B_3	260	1959	tangential	dry	0	0.0041	0.0279	Yes	0.0041	0.0000	---
G G Allen	4	North Carolina	2718_B_4	275	1960	tangential	dry	0	0.0041	0.0279	Yes	0.0041	0.0000	---

G G Allen	5	North Carolina	2718_B_5	265	1961	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Gadsden	1	Alabama	7_B_1	64	1949	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Gadsden	2	Alabama	7_B_2	66	1949	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Gallatin	1	Tennessee	3403_B_1	222	1956	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Gallatin	2	Tennessee	3403_B_2	222	1957	tangential	dry	0	0.0393	0.0279	No	0.0279	0.0114	ESP-3
Gallatin	3	Tennessee	3403_B_3	260	1959	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Gallatin	4	Tennessee	3403_B_4	260	1959	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
General James M Gavin	1	Ohio	8102_B_1	1310	1974	cell	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
General James M Gavin	2	Ohio	8102_B_2	1300	1975	cell	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
George Neal North	1	Iowa	1091_B_1	135	1964	cyclone	wet	0	0.1700	0.0279	No	0.0279	0.1421	ESP-4
George Neal North	2	Iowa	1091_B_2	300	1972	wall	dry	0	0.2300	0.0279	No	0.0279	0.2021	ESP-4
George Neal North	3	Iowa	1091_B_3	515	1975	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
George Neal South	4	Iowa	7343_B_4	632	1979	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Ghent	1	Kentucky	1356_B_1	468	1973	tangential	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Ghent	2	Kentucky	1356_B_2	463	1977	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Ghent	3	Kentucky	1356_B_3	472	1981	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Ghent	4	Kentucky	1356_B_4	472	1984	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Gibbons Creek	1	Texas	6136_B_1	462	1983	tangential	dry	0	0.3000	0.0279	No	0.0279	0.2721	ESP-4
Gibson	1	Indiana	6113_B_1	621	1975	wall	dry	0	0.0067	0.0279	Yes	0.0067	0.0000	---
Gibson	2	Indiana	6113_B_2	619	1975	wall	dry	0	0.0038	0.0279	Yes	0.0038	0.0000	---
Gibson	3	Indiana	6113_B_3	619	1978	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Gibson	4	Indiana	6113_B_4	622	1979	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Gibson	5	Indiana	6113_B_5	620	1982	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Glen Lyn	51	Virginia	3776_B_51	45	1944	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Glen Lyn	52	Virginia	3776_B_52	45	1944	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Glen Lyn	6	Virginia	3776_B_6	235	1957	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Gorgas	10	Alabama	8_B_10	681	1972	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---

Gorgas	6	Alabama	8_B_6	108	1951	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Gorgas	7	Alabama	8_B_7	109	1952	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Gorgas	8	Alabama	8_B_8	163	1956	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Gorgas	9	Alabama	8_B_9	173	1958	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
GRDA	1	Oklahoma	165_B_1	490	1982	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
GRDA	2	Oklahoma	165_B_2	520	1986	wall	dry	1	0.0200	0.0279	Yes	0.0200	0.0000	---
Green River	4	Kentucky	1357_B_4	68	1954	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Green River	5	Kentucky	1357_B_5	95	1959	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Greene County	1	Alabama	10_B_1	254	1965	wall	dry	0	0.0140	0.0279	Yes	0.0140	0.0000	---
Greene County	2	Alabama	10_B_2	243	1966	wall	dry	0	0.0160	0.0279	Yes	0.0160	0.0000	---
H B Robinson	1	South Carolina	3251_B_1	176	1960	tangential	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
H L Spurlock	1	Kentucky	6041_B_1	315	1977	wall	dry	0	0.0065	0.0279	Yes	0.0065	0.0000	---
H L Spurlock	2	Kentucky	6041_B_2	509	1981	tangential	dry	0	0.0065	0.0279	Yes	0.0065	0.0000	---
Hamilton	8	Ohio	2917_B_8	33	1964	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Hammond	1	Georgia	708_B_1	112	1954	wall	dry	0	0.0430	0.0279	No	0.0279	0.0151	ESP-3
Hammond	2	Georgia	708_B_2	112	1954	wall	dry	0	0.0430	0.0279	No	0.0279	0.0151	ESP-3
Hammond	3	Georgia	708_B_3	112	1955	wall	dry	0	0.0430	0.0279	No	0.0279	0.0151	ESP-3
Hammond	4	Georgia	708_B_4	510	1970	wall	dry	0	0.0190	0.0279	Yes	0.0190	0.0000	---
Harbor Beach	1	Michigan	1731_B_1	103	1968	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Harding Street	50	Indiana	990_B_50	109	1958	tangential	dry	0	0.0049	0.0279	Yes	0.0049	0.0000	---
Harding Street	60	Indiana	990_B_60	109	1961	tangential	dry	0	0.0021	0.0279	Yes	0.0021	0.0000	---
Harding Street	70	Indiana	990_B_70	429	1973	tangential	dry	0	0.0168	0.0279	Yes	0.0168	0.0000	---
Harllee Branch	1	Georgia	709_B_1	261	1965	cell	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Harllee Branch	2	Georgia	709_B_2	319	1967	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Harllee Branch	3	Georgia	709_B_3	499	1968	cell	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Harllee Branch	4	Georgia	709_B_4	497	1969	cell	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Harrington	061B	Texas	6193_B_061B	347	1976	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3

Harrison Power Station	1	West Virginia	3944_B_1	643	1972	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Harrison Power Station	2	West Virginia	3944_B_2	633	1973	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Harrison Power Station	3	West Virginia	3944_B_3	642	1974	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Hatfields Ferry Power Station	1	Pennsylvania	3179_B_1	523	1969	cell	dry	0	0.0323	0.0279	No	0.0279	0.0044	ESP-1
Hatfields Ferry Power Station	2	Pennsylvania	3179_B_2	523	1970	cell	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Hatfields Ferry Power Station	3	Pennsylvania	3179_B_3	523	1971	cell	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Herbert A Wagner	2	Maryland	1554_B_2	135	1959	wall	dry	0	0.0017	0.0279	Yes	0.0017	0.0000	---
Herbert A Wagner	3	Maryland	1554_B_3	324	1966	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
HMP&L Station Two Henderson	H1	Kentucky	1382_B_H1	151	1973	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
HMP&L Station Two Henderson	H2	Kentucky	1382_B_H2	157	1974	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Homer City Station	1	Pennsylvania	3122_B_1	612	1969	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Homer City Station	2	Pennsylvania	3122_B_2	606	1970	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Homer City Station	3	Pennsylvania	3122_B_3	641	1977	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Hoot Lake	2	Minnesota	1943_B_2	60	1959	tangential	dry	0	0.0812	0.0279	No	0.0279	0.0533	ESP-4
Hoot Lake	3	Minnesota	1943_B_3	84	1964	wall	dry	0	0.0812	0.0279	No	0.0279	0.0533	ESP-4
Hugo	1	Oklahoma	6772_B_1	440	1982	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Hunter	1	Utah	6165_B_1	430	1978	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Hunter	2	Utah	6165_B_2	430	1980	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Hutsonville	05	Illinois	863_B_05	76	1953	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Hutsonville	06	Illinois	863_B_06	77	1954	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Independence	1	Arkansas	6641_B_1	836	1983	tangential	wet	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Independence	2	Arkansas	6641_B_2	842	1985	tangential	wet	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
J B Sims	3	Michigan	1825_B_3	73	1983	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
J C Weadock	7	Michigan	1720_B_7	151	1955	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
J C Weadock	8	Michigan	1720_B_8	151	1958	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3

J E Corette Plant	2	Montana	2187_B_2	158	1968	tangential	dry	0	0.2700	0.0279	No	0.0279	0.2421	ESP-4
J H Campbell	1	Michigan	1710_B_1	260	1962	tangential	dry	0	0.0111	0.0279	Yes	0.0111	0.0000	---
J H Campbell	2	Michigan	1710_B_2	353	1967	wall	dry	0	0.0111	0.0279	Yes	0.0111	0.0000	---
J H Campbell	3	Michigan	1710_B_3	822	1980	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
J M Stuart	1	Ohio	2850_B_1	597	1971	cell	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
J M Stuart	2	Ohio	2850_B_2	597	1970	cell	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
J M Stuart	3	Ohio	2850_B_3	597	1972	cell	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
J M Stuart	4	Ohio	2850_B_4	597	1974	cell	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
J R Whiting	1	Michigan	1723_B_1	102	1952	wall	dry	0	0.1600	0.0279	No	0.0279	0.1321	ESP-4
J R Whiting	2	Michigan	1723_B_2	102	1952	wall	dry	0	0.1400	0.0279	No	0.0279	0.1121	ESP-4
J R Whiting	3	Michigan	1723_B_3	124	1953	wall	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
Jack Watson	4	Mississippi	2049_B_4	230	1968	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Jack Watson	5	Mississippi	2049_B_5	476	1973	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
James De Young	5	Michigan	1830_B_5	27	1969	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
James H Miller Jr	1	Alabama	6002_B_1	674	1978	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
James H Miller Jr	2	Alabama	6002_B_2	687	1985	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
James H Miller Jr	3	Alabama	6002_B_3	687	1989	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
James H Miller Jr	4	Alabama	6002_B_4	688	1991	wall	dry	0	0.0040	0.0279	Yes	0.0040	0.0000	---
James River Power Station	3	Missouri	2161_B_3	41	1960	wall	dry	0	0.1100	0.0279	No	0.0279	0.0821	ESP-4
James River Power Station	4	Missouri	2161_B_4	56	1964	wall	dry	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
James River Power Station	5	Missouri	2161_B_5	97	1970	wall	dry	0	0.0113	0.0279	Yes	0.0113	0.0000	---
Jefferies	3	South Carolina	3319_B_3	153	1970	wall	dry	0	0.0000	0.0279	Yes	0.0000	0.0000	---
Jefferies	4	South Carolina	3319_B_4	153	1970	wall	dry	0	0.0000	0.0279	Yes	0.0000	0.0000	---
Jeffrey Energy Center	1	Kansas	6068_B_1	726	1978	tangential	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Jeffrey Energy Center	2	Kansas	6068_B_2	727	1980	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Jeffrey Energy Center	3	Kansas	6068_B_3	727	1983	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---

Jim Bridger	BW71	Wyoming	8066_B_BW71	530	1974	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Jim Bridger	BW72	Wyoming	8066_B_BW72	530	1975	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Jim Bridger	BW73	Wyoming	8066_B_BW73	530	1976	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Jim Bridger	BW74	Wyoming	8066_B_BW74	530	1979	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
John E Amos	1	West Virginia	3935_B_1	800	1971	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
John E Amos	2	West Virginia	3935_B_2	789	1972	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
John E Amos	3	West Virginia	3935_B_3	1282	1973	cell	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
John Sevier	2	Tennessee	3405_B_2	176	1955	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
John Sevier	3	Tennessee	3405_B_3	176	1956	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
John Sevier	4	Tennessee	3405_B_4	176	1957	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Johnsonville	1	Tennessee	3406_B_1	106	1951	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	10	Tennessee	3406_B_10	141	1959	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	2	Tennessee	3406_B_2	106	1951	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	3	Tennessee	3406_B_3	106	1952	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	4	Tennessee	3406_B_4	106	1952	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	5	Tennessee	3406_B_5	106	1952	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	6	Tennessee	3406_B_6	106	1953	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	7	Tennessee	3406_B_7	141	1958	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	8	Tennessee	3406_B_8	141	1959	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Johnsonville	9	Tennessee	3406_B_9	141	1959	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Joliet 29	71	Illinois	384_B_71	258	1965	tangential	dry	0	0.0650	0.0279	No	0.0279	0.0371	ESP-4
Joliet 29	72	Illinois	384_B_72	258	1965	tangential	dry	0	0.0650	0.0279	No	0.0279	0.0371	ESP-4
Joliet 29	81	Illinois	384_B_81	258	1965	tangential	dry	0	0.0490	0.0279	No	0.0279	0.0211	ESP-4
Joliet 29	82	Illinois	384_B_82	258	1965	tangential	dry	0	0.0490	0.0279	No	0.0279	0.0211	ESP-4
Joliet 9	5	Illinois	874_B_5	311	1959	cyclone	wet	0	0.0588	0.0279	No	0.0279	0.0309	ESP-4
Joppa Steam	1	Illinois	887_B_1	167	1953	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Joppa Steam	2	Illinois	887_B_2	167	1953	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---

Joppa Steam	3	Illinois	887_B_3	167	1954	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Joppa Steam	4	Illinois	887_B_4	167	1954	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Joppa Steam	5	Illinois	887_B_5	167	1955	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Joppa Steam	6	Illinois	887_B_6	167	1955	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Kammer	1	West Virginia	3947_B_1	206	1958	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Kammer	2	West Virginia	3947_B_2	206	1958	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Kammer	3	West Virginia	3947_B_3	206	1959	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Kanawha River	1	West Virginia	3936_B_1	204	1953	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Kanawha River	2	West Virginia	3936_B_2	204	1953	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Kenneth C Coleman	C1	Kentucky	1381_B_C1	148	1969	wall	dry	0	0.1400	0.0279	No	0.0279	0.1121	ESP-4
Kenneth C Coleman	C2	Kentucky	1381_B_C2	148	1970	wall	dry	0	0.1900	0.0279	No	0.0279	0.1621	ESP-4
Kenneth C Coleman	C3	Kentucky	1381_B_C3	153	1971	wall	dry	0	0.1200	0.0279	No	0.0279	0.0921	ESP-4
Keystone	1	Pennsylvania	3136_B_1	839	1967	tangential	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Keystone	2	Pennsylvania	3136_B_2	839	1968	tangential	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Killen Station	2	Ohio	6031_B_2	608	1982	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Kincaid Generation LLC	1	Illinois	876_B_1	584	1967	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Kincaid Generation LLC	2	Illinois	876_B_2	584	1968	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Kingston	1	Tennessee	3407_B_1	134	1954	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Kingston	2	Tennessee	3407_B_2	134	1954	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Kingston	3	Tennessee	3407_B_3	134	1954	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Kingston	4	Tennessee	3407_B_4	134	1954	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Kingston	5	Tennessee	3407_B_5	175	1955	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Kingston	6	Tennessee	3407_B_6	175	1955	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Kingston	7	Tennessee	3407_B_7	175	1955	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Kingston	8	Tennessee	3407_B_8	175	1955	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Kingston	9	Tennessee	3407_B_9	175	1955	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---

Kraft	1	Georgia	733_B_1	48	1958	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Kraft	2	Georgia	733_B_2	52	1961	tangential	dry	0	0.0170	0.0279	Yes	0.0170	0.0000	---
Kraft	3	Georgia	733_B_3	102	1965	tangential	dry	0	0.0430	0.0279	No	0.0279	0.0151	ESP-3
KUCC	1	Utah	56163_B_1	30	1944	wall	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
KUCC	2	Utah	56163_B_2	30	1945	wall	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
KUCC	3	Utah	56163_B_3	30	1945	wall	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
KUCC	4	Utah	56163_B_4	65	1959	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Kyger Creek	1	Ohio	2876_B_1	214	1955	wall	wet	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Kyger Creek	2	Ohio	2876_B_2	214	1955	wall	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Kyger Creek	3	Ohio	2876_B_3	214	1955	wall	wet	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Kyger Creek	4	Ohio	2876_B_4	214	1955	wall	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Kyger Creek	5	Ohio	2876_B_5	214	1955	wall	wet	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
La Cygne	2	Kansas	1241_B_2	682	1977	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Labadie	1	Missouri	2103_B_1	597	1970	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Labadie	2	Missouri	2103_B_2	594	1971	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Labadie	3	Missouri	2103_B_3	612	1972	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Labadie	4	Missouri	2103_B_4	612	1973	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Lake Road	6	Missouri	2098_B_6	97	1967	cyclone	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Lake Shore	18	Ohio	2838_B_18	245	1962	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Lansing	4	Iowa	1047_B_4	260	1977	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Lansing Smith	1	Florida	643_B_1	162	1965	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Lansing Smith	2	Florida	643_B_2	195	1967	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Laramie River Station	1	Wyoming	6204_B_1	565	1980	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Laramie River Station	2	Wyoming	6204_B_2	570	1981	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Laramie River Station	3	Wyoming	6204_B_3	570	1982	wall	dry	1	0.0100	0.0279	Yes	0.0100	0.0000	---
Lawrence Energy Center	3	Kansas	1250_B_3	48	1955	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Leland Olds	1	North Dakota	2817_B_1	221	1966	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---

Leland Olds	2	North Dakota	2817_B_2	448	1975	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Limestone	LIM1	Texas	298_B_LIM1	830	1985	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Limestone	LIM2	Texas	298_B_LIM2	857	1986	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Lon Wright	8	Nebraska	2240_B_8	85	1976	wall	dry	0	0.1200	0.0279	No	0.0279	0.0921	ESP-4
Marion	4	Illinois	976_B_4	170	1978	cyclone	wet	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Marshall	1	North Carolina	2727_B_1	378	1965	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Marshall	2	North Carolina	2727_B_2	378	1966	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Marshall	3	North Carolina	2727_B_3	657	1969	tangential	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Marshall	4	North Carolina	2727_B_4	657	1970	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Martin Lake	1	Texas	6146_B_1	750	1977	tangential	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Martin Lake	2	Texas	6146_B_2	750	1978	tangential	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Martin Lake	3	Texas	6146_B_3	750	1979	tangential	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Mayo	1A	North Carolina	6250_B_1A	371	1983	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Mayo	1B	North Carolina	6250_B_1B	371	1983	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
McIntosh	1	Georgia	6124_B_1	157	1979	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Meramec	1	Missouri	2104_B_1	122	1953	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Meramec	2	Missouri	2104_B_2	120	1954	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Meramec	3	Missouri	2104_B_3	269	1959	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Meramec	4	Missouri	2104_B_4	347	1961	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Meredosia	05	Illinois	864_B_05	203	1960	tangential	dry	0	0.0319	0.0279	No	0.0279	0.0040	ESP-1
Merom	1SG1	Indiana	6213_B_1SG1	507	1983	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Merom	2SG1	Indiana	6213_B_2SG1	493	1982	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Merrimack	1	New Hampshire	2364_B_1	111	1960	wall	wet	0	0.0332	0.0279	No	0.0279	0.0053	ESP-2
Merrimack	2	New Hampshire	2364_B_2	315	1968	cyclone	wet	0	0.0332	0.0279	No	0.0279	0.0053	ESP-2
Miami Fort	6	Ohio	2832_B_6	162	1960	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3

Miami Fort	7	Ohio	2832_B_7	493	1975	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Miami Fort	8	Ohio	2832_B_8	493	1978	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Michigan City	12	Indiana	997_B_12	469	1974	cyclone	wet	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Mill Creek	1	Kentucky	1364_B_1	303	1972	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Mill Creek	2	Kentucky	1364_B_2	301	1974	tangential	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Mill Creek	3	Kentucky	1364_B_3	391	1978	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Mill Creek	4	Kentucky	1364_B_4	477	1982	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Milton L Kapp	2	Iowa	1048_B_2	211	1967	tangential	dry	0	0.1420	0.0279	No	0.0279	0.1141	ESP-4
Milton R Young	B1	North Dakota	2823_B_B1	250	1970	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Milton R Young	B2	North Dakota	2823_B_B2	455	1977	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Mitchell	1	West Virginia	3948_B_1	800	1971	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Mitchell	2	West Virginia	3948_B_2	800	1971	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Mitchell Power Station	33	Pennsylvania	3181_B_33	277	1963	tangential	dry	0	0.1800	0.0279	No	0.0279	0.1521	ESP-4
Monroe	1	Michigan	1733_B_1	760	1972	cell	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Monroe	2	Michigan	1733_B_2	775	1973	cell	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Monroe	3	Michigan	1733_B_3	785	1973	cell	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Monroe	4	Michigan	1733_B_4	765	1974	cell	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Monticello	3	Texas	6147_B_3	750	1978	wall	wet	0	0.0453	0.0279	No	0.0279	0.0174	ESP-3
Montrose	1	Missouri	2080_B_1	170	1958	tangential	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
Montrose	2	Missouri	2080_B_2	164	1960	tangential	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
Montrose	3	Missouri	2080_B_3	176	1964	tangential	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
Morgantown Generating Plant	1	Maryland	1573_B_1	624	1970	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Morgantown Generating Plant	2	Maryland	1573_B_2	620	1971	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Mountaineer	1	West Virginia	6264_B_1	1300	1980	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Mt Storm	1	West Virginia	3954_B_1	524	1965	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---

Mt Storm	2	West Virginia	3954_B_2	524	1966	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Mt Storm	3	West Virginia	3954_B_3	521	1973	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Muscatine Plant #1	8	Iowa	1167_B_8	35	1969	cyclone	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Muscatine Plant #1	9	Iowa	1167_B_9	147	1983	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Muskingum River	1	Ohio	2872_B_1	190	1953	wall	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Muskingum River	2	Ohio	2872_B_2	190	1954	wall	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Muskingum River	3	Ohio	2872_B_3	205	1957	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Muskingum River	4	Ohio	2872_B_4	205	1958	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Muskingum River	5	Ohio	2872_B_5	578	1968	cell	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Muskogee	4	Oklahoma	2952_B_4	511	1977	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Muskogee	5	Oklahoma	2952_B_5	522	1978	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Muskogee	6	Oklahoma	2952_B_6	515	1984	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Naughton	1	Wyoming	4162_B_1	158	1963	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Naughton	2	Wyoming	4162_B_2	207	1968	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Naughton	3	Wyoming	4162_B_3	330	1971	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Navajo	1	Arizona	4941_B_1	750	1974	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Navajo	2	Arizona	4941_B_2	750	1975	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Navajo	3	Arizona	4941_B_3	750	1976	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Nearman Creek	N1	Kansas	6064_B_N1	229	1981	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Nebraska City	1	Nebraska	6096_B_1	646	1979	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Neil Simpson II	2	Wyoming	7504_B_2	80	1995	wall	dry	1	0.0300	0.0279	No	0.0279	0.0021	---
Nelson Dewey	1	Wisconsin	4054_B_1	107	1959	cyclone	wet	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
Nelson Dewey	2	Wisconsin	4054_B_2	111	1962	cyclone	wet	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
New Castle	3	Pennsylvania	3138_B_3	95	1952	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
New Castle	4	Pennsylvania	3138_B_4	96	1958	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
New Castle	5	Pennsylvania	3138_B_5	138	1964	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4

New Madrid	1	Missouri	2167_B_1	580	1972	cyclone	wet	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
New Madrid	2	Missouri	2167_B_2	580	1977	cyclone	wet	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Newton	1	Illinois	6017_B_1	555	1977	tangential	dry	0	0.0091	0.0279	Yes	0.0091	0.0000	---
Newton	2	Illinois	6017_B_2	567	1982	tangential	dry	0	0.0091	0.0279	Yes	0.0091	0.0000	---
Niles	1	Ohio	2861_B_1	107	1954	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Niles	2	Ohio	2861_B_2	111	1954	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
North Omaha	1	Nebraska	2291_B_1	79	1954	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
North Omaha	2	Nebraska	2291_B_2	111	1957	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
North Omaha	3	Nebraska	2291_B_3	111	1959	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
North Omaha	4	Nebraska	2291_B_4	138	1963	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
North Omaha	5	Nebraska	2291_B_5	224	1968	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Northeastern	3313	Oklahoma	2963_B_3313	450	1979	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Northeastern	3314	Oklahoma	2963_B_3314	450	1980	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
O H Hutchings	H-1	Ohio	2848_B_H-1	58	1948	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
O H Hutchings	H-2	Ohio	2848_B_H-2	55	1949	tangential	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
O H Hutchings	H-3	Ohio	2848_B_H-3	63	1950	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
O H Hutchings	H-4	Ohio	2848_B_H-4	63	1951	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
O H Hutchings	H-5	Ohio	2848_B_H-5	63	1952	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
O H Hutchings	H-6	Ohio	2848_B_H-6	63	1953	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Oklaunion	1	Texas	127_B_1	690	1986	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Ottumwa	1	Iowa	6254_B_1	673	1981	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
P H Glatfelter	5PB036	Pennsylvania	50397_B_5PB036	36	1989	FBC	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Paradise	3	Kentucky	1378_B_3	963	1970	cyclone	wet	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Petersburg	1	Indiana	994_B_1	232	1967	tangential	dry	0	0.0520	0.0279	No	0.0279	0.0241	ESP-4
Petersburg	2	Indiana	994_B_2	435	1969	tangential	dry	0	66.0000	0.0279	No	0.0279	65.9721	ESP-4
Petersburg	3	Indiana	994_B_3	532	1977	tangential	dry	0	0.0270	0.0279	Yes	0.0270	0.0000	---
Petersburg	4	Indiana	994_B_4	545	1986	tangential	dry	0	0.0250	0.0279	Yes	0.0250	0.0000	---

Philip Sporn	11	West Virginia	3938_B_11	150	1950	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Philip Sporn	21	West Virginia	3938_B_21	150	1950	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Philip Sporn	31	West Virginia	3938_B_31	150	1951	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Philip Sporn	41	West Virginia	3938_B_41	150	1952	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Picway	9	Ohio	2843_B_9	95	1955	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Pirkey	1	Texas	7902_B_1	674	1985	wall	dry	0	0.2500	0.0279	No	0.0279	0.2221	ESP-4
Platte	1	Nebraska	59_B_1	100	1982	tangential	dry	0	0.0280	0.0279	No	0.0279	0.0001	ESP-1
Pleasant Prairie	1	Wisconsin	6170_B_1	617	1980	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Pleasant Prairie	2	Wisconsin	6170_B_2	617	1985	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Pleasants Power Station	1	West Virginia	6004_B_1	639	1979	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Pleasants Power Station	2	West Virginia	6004_B_2	639	1980	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Portland	1	Pennsylvania	3113_B_1	157	1958	tangential	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Portland	2	Pennsylvania	3113_B_2	242	1962	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Potomac River	1	Virginia	3788_B_1	88	1949	tangential	dry	1	0.0200	0.0279	Yes	0.0200	0.0000	---
Potomac River	2	Virginia	3788_B_2	88	1950	tangential	dry	1	0.0300	0.0279	No	0.0279	0.0021	---
Potomac River	3	Virginia	3788_B_3	102	1954	tangential	dry	1	0.0500	0.0279	No	0.0279	0.0221	---
Potomac River	4	Virginia	3788_B_4	102	1956	tangential	dry	1	0.0100	0.0279	Yes	0.0100	0.0000	---
Potomac River	5	Virginia	3788_B_5	102	1957	tangential	dry	1	0.0200	0.0279	Yes	0.0200	0.0000	---
Powerton	51	Illinois	879_B_51	382	1972	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Powerton	52	Illinois	879_B_52	383	1972	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Powerton	61	Illinois	879_B_61	382	1975	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Powerton	62	Illinois	879_B_62	383	1975	cyclone	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
PPL Brunner Island	2	Pennsylvania	3140_B_2	382	1965	tangential	dry	0	0.0256	0.0279	Yes	0.0256	0.0000	---
PPL Brunner Island	3	Pennsylvania	3140_B_3	744	1981	tangential	dry	0	0.0256	0.0279	Yes	0.0256	0.0000	---
PPL Montour	1	Pennsylvania	3149_B_1	751	1971	tangential	dry	0	0.0107	0.0279	Yes	0.0107	0.0000	---

PPL Montour	2	Pennsylvania	3149_B_2	747	1973	tangential	dry	0	0.0166	0.0279	Yes	0.0166	0.0000	---
Prairie Creek	3	Iowa	1073_B_3	42	1958	wall	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Prairie Creek	4	Iowa	1073_B_4	125	1967	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Pulliam	5	Wisconsin	4072_B_5	49	1949	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Pulliam	6	Wisconsin	4072_B_6	72	1951	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Pulliam	7	Wisconsin	4072_B_7	88	1958	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Pulliam	8	Wisconsin	4072_B_8	133	1964	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Quindaro	1	Kansas	1295_B_1	72	1965	cyclone	wet	0	0.0284	0.0279	No	0.0279	0.0005	ESP-1
Quindaro	2	Kansas	1295_B_2	111	1971	wall	dry	0	0.0284	0.0279	No	0.0279	0.0005	ESP-1
R D Green	G1	Kentucky	6639_B_G1	231	1979	wall	dry	0	0.0469	0.0279	No	0.0279	0.0190	ESP-3
R D Green	G2	Kentucky	6639_B_G2	233	1981	wall	dry	0	0.0469	0.0279	No	0.0279	0.0190	ESP-3
R D Morrow	1	Mississippi	6061_B_1	180	1978	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
R D Morrow	2	Mississippi	6061_B_2	180	1978	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
R E Burger	5	Ohio	2864_B_5	47	1955	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
R E Burger	6	Ohio	2864_B_6	47	1955	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
R M Heskett	B1	North Dakota	2790_B_B1	29	1954	stoker/SPR	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
R M Heskett	B2	North Dakota	2790_B_B2	76	1963	FBC	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
R M Schahfer	14	Indiana	6085_B_14	424	1976	cyclone	wet	0	0.0152	0.0279	Yes	0.0152	0.0000	---
R M Schahfer	15	Indiana	6085_B_15	472	1979	wall	dry	0	0.0152	0.0279	Yes	0.0152	0.0000	---
R M Schahfer	17	Indiana	6085_B_17	361	1983	tangential	dry	0	0.0152	0.0279	Yes	0.0152	0.0000	---
R M Schahfer	18	Indiana	6085_B_18	361	1986	tangential	dry	0	0.0152	0.0279	Yes	0.0152	0.0000	---
R Paul Smith Power Station	9	Maryland	1570_B_9	28	1947	wall	dry	0	0.1700	0.0279	No	0.0279	0.1421	ESP-4
R S Nelson	6	Louisiana	1393_B_6	550	1982	tangential	wet	0	0.0113	0.0279	Yes	0.0113	0.0000	---
River Rouge	2	Michigan	1740_B_2	241	1957	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
River Rouge	3	Michigan	1740_B_3	272	1958	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Riverbend	10	North Carolina	2732_B_10	133	1954	tangential	dry	0	0.0284	0.0279	No	0.0279	0.0005	ESP-1

Riverbend	7	North Carolina	2732_B_7	94	1952	tangential	dry	0	0.0284	0.0279	No	0.0279	0.0005	ESP-1
Riverbend	8	North Carolina	2732_B_8	94	1952	tangential	dry	0	0.1050	0.0279	No	0.0279	0.0771	ESP-4
Riverbend	9	North Carolina	2732_B_9	133	1954	tangential	dry	0	0.1050	0.0279	No	0.0279	0.0771	ESP-4
Riverside	9	Iowa	1081_B_9	130	1961	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Riverton	39	Kansas	1239_B_39	38	1950	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Riverton	40	Kansas	1239_B_40	54	1954	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Rivesville	7	West Virginia	3945_B_7	46	1943	vertical	wet	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Rivesville	8	West Virginia	3945_B_8	91	1951	vertical	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Rockport	MB1	Indiana	6166_B_MB1	1280	1984	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Rockport	MB2	Indiana	6166_B_MB2	1280	1989	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Rodemacher	2	Louisiana	6190_B_2	523	1982	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Roxboro	1	North Carolina	2712_B_1	369	1966	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Roxboro	2	North Carolina	2712_B_2	671	1968	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Roxboro	3A	North Carolina	2712_B_3A	353	1973	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Roxboro	3B	North Carolina	2712_B_3B	353	1973	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Roxboro	4A	North Carolina	2712_B_4A	349	1980	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Roxboro	4B	North Carolina	2712_B_4B	349	1980	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Rumford Cogeneration	6	Maine	10495_B_6	43	1990	FBC	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Rumford Cogeneration	7	Maine	10495_B_7	43	1990	FBC	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Rush Island	1	Missouri	6155_B_1	604	1976	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Rush Island	2	Missouri	6155_B_2	604	1977	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Salem Harbor	1	Massachusetts	1626_B_1	82	1951	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Salem Harbor	2	Massachusetts	1626_B_2	80	1952	wall	dry	0	0.0005	0.0279	Yes	0.0005	0.0000	---
Salem Harbor	3	Massachusetts	1626_B_3	149	1958	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1

San Miguel	SM-1	Texas	6183_B_SM-1	391	1982	wall	dry	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
Sandow	4	Texas	6648_B_4	542	1981	tangential	wet	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Schiller	4	New Hampshire	2367_B_4	48	1952	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Scholz	1	Florida	642_B_1	49	1953	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Scholz	2	Florida	642_B_2	49	1953	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Seminole	1	Florida	136_B_1	654	1984	wall	dry	0	0.0210	0.0279	Yes	0.0210	0.0000	---
Seminole	2	Florida	136_B_2	654	1984	wall	dry	0	0.0160	0.0279	Yes	0.0160	0.0000	---
Shawville	1	Pennsylvania	3131_B_1	122	1954	wall	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Shawville	2	Pennsylvania	3131_B_2	125	1954	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Shawville	3	Pennsylvania	3131_B_3	175	1959	tangential	dry	0	0.0133	0.0279	Yes	0.0133	0.0000	---
Shawville	4	Pennsylvania	3131_B_4	175	1960	tangential	dry	0	0.0133	0.0279	Yes	0.0133	0.0000	---
Sherburne County	1	Minnesota	6090_B_1	762	1976	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Sherburne County	2	Minnesota	6090_B_2	752	1977	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Sibley	1	Missouri	2094_B_1	54	1960	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Sibley	2	Missouri	2094_B_2	54	1962	cyclone	wet	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Sibley	3	Missouri	2094_B_3	401	1969	cyclone	wet	0	0.0092	0.0279	Yes	0.0092	0.0000	---
Sikeston Power Station	1	Missouri	6768_B_1	233	1981	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Sioux	1	Missouri	2107_B_1	490	1967	cyclone	wet	0	0.0034	0.0279	Yes	0.0034	0.0000	---
Sioux	2	Missouri	2107_B_2	490	1968	cyclone	wet	0	0.0034	0.0279	Yes	0.0034	0.0000	---
Sooner	1	Oklahoma	6095_B_1	535	1979	tangential	dry	0	0.0320	0.0279	No	0.0279	0.0041	ESP-1
Sooner	2	Oklahoma	6095_B_2	540	1980	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
South Oak Creek	5	Wisconsin	4041_B_5	257	1959	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
South Oak Creek	6	Wisconsin	4041_B_6	260	1961	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
South Oak Creek	7	Wisconsin	4041_B_7	292	1965	tangential	dry	0	0.0015	0.0279	Yes	0.0015	0.0000	---
South Oak Creek	8	Wisconsin	4041_B_8	306	1967	tangential	dry	0	0.0117	0.0279	Yes	0.0117	0.0000	---
Southwest Power Station	1	Missouri	6195_B_1	178	1976	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3

St Clair	1	Michigan	1743_B_1	151	1953	wall	dry	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
St Clair	2	Michigan	1743_B_2	154	1953	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
St Clair	3	Michigan	1743_B_3	160	1954	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
St Clair	4	Michigan	1743_B_4	151	1954	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
St Clair	6	Michigan	1743_B_6	312	1961	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
St Clair	7	Michigan	1743_B_7	440	1969	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
St Johns River Power Park	1	Florida	207_B_1	623	1987	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
St Johns River Power Park	2	Florida	207_B_2	622	1988	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Stanton	1	North Dakota	2824_B_1	130	1967	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Stanton Energy Center	1	Florida	564_B_1	440	1987	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Stanton Energy Center	2	Florida	564_B_2	446	1996	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Stone Container Florence Mill	PB4	South Carolina	50806_B_PB4	75	1987	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Streeter Station	7	Iowa	1131_B_7	36	1973	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Sunbury Generation LP	3	Pennsylvania	3152_B_3	94	1951	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Sunbury Generation LP	4	Pennsylvania	3152_B_4	128	1953	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Sutherland	3	Iowa	1077_B_3	82	1961	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Taconite Harbor Energy Center	1	Minnesota	10075_B_1	65	1957	tangential	dry	1	0.0055	0.0279	Yes	0.0055	0.0000	---
Taconite Harbor Energy Center	2	Minnesota	10075_B_2	67	1957	tangential	dry	1	0.0201	0.0279	Yes	0.0201	0.0000	---
Taconite Harbor Energy Center	3	Minnesota	10075_B_3	68	1967	tangential	dry	1	0.0201	0.0279	Yes	0.0201	0.0000	---
Tanners Creek	U1	Indiana	988_B_U1	145	1951	vertical	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Tanners Creek	U2	Indiana	988_B_U2	145	1952	vertical	dry	0	0.0053	0.0279	Yes	0.0053	0.0000	---
Tanners Creek	U3	Indiana	988_B_U3	200	1954	vertical	dry	0	0.0053	0.0279	Yes	0.0053	0.0000	---
Tanners Creek	U4	Indiana	988_B_U4	500	1964	cyclone	wet	0	0.0053	0.0279	Yes	0.0053	0.0000	---
Tecumseh Energy Center	10	Kansas	1252_B_10	129	1962	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Tecumseh Energy Center	9	Kansas	1252_B_9	74	1957	tangential	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4

Thomas Hill	MB1	Missouri	2168_B_MB1	175	1966	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Thomas Hill	MB2	Missouri	2168_B_MB2	275	1969	cyclone	wet	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Thomas Hill	MB3	Missouri	2168_B_MB3	670	1982	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Titus	1	Pennsylvania	3115_B_1	81	1951	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Titus	2	Pennsylvania	3115_B_2	81	1951	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Titus	3	Pennsylvania	3115_B_3	81	1953	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Transalta Centralia Generation	BW21	Washington	3845_B_BW21	703	1972	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Transalta Centralia Generation	BW22	Washington	3845_B_BW22	703	1973	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Trenton Channel	16	Michigan	1745_B_16	53	1949	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Trenton Channel	17	Michigan	1745_B_17	53	1949	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Trenton Channel	18	Michigan	1745_B_18	53	1949	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Trenton Channel	19	Michigan	1745_B_19	53	1950	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Trenton Channel	9A	Michigan	1745_B_9A	536	1968	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Trimble County	1	Kentucky	6071_B_1	383	1990	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Tyrone	5	Kentucky	1361_B_5	71	1953	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Urquhart	URQ3	South Carolina	3295_B_URQ3	94	1955	tangential	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Victor J Daniel Jr	1	Mississippi	6073_B_1	507	1977	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Victor J Daniel Jr	2	Mississippi	6073_B_2	507	1981	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
W H Sammis	5	Ohio	2866_B_5	300	1967	wall	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
W H Sammis	6	Ohio	2866_B_6	597	1969	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
W H Sammis	7	Ohio	2866_B_7	600	1971	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
W H Weatherspoon	1	North Carolina	2716_B_1	48	1949	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
W H Weatherspoon	2	North Carolina	2716_B_2	49	1950	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
W H Weatherspoon	3	North Carolina	2716_B_3	76	1952	tangential	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
W H Zimmer	1	Ohio	6019_B_1	1300	1991	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---

W S Lee	1	South Carolina	3264_B_1	98	1951	tangential	dry	0	0.1300	0.0279	No	0.0279	0.1021	ESP-4
W S Lee	2	South Carolina	3264_B_2	98	1951	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
W S Lee	3	South Carolina	3264_B_3	168	1958	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Wabash River	2	Indiana	1010_B_2	43	1953	wall	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Wabash River	4	Indiana	1010_B_4	43	1955	wall	dry	0	0.1100	0.0279	No	0.0279	0.0821	ESP-4
Wabash River	6	Indiana	1010_B_6	318	1968	tangential	dry	0	0.1100	0.0279	No	0.0279	0.0821	ESP-4
Walter C Beckjord	1	Ohio	2830_B_1	94	1952	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Walter C Beckjord	2	Ohio	2830_B_2	94	1953	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Walter C Beckjord	3	Ohio	2830_B_3	128	1954	wall	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Walter C Beckjord	4	Ohio	2830_B_4	150	1958	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Walter C Beckjord	5	Ohio	2830_B_5	238	1962	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Walter C Beckjord	6	Ohio	2830_B_6	409	1969	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Walter Scott Jr. Energy Center	1	Iowa	1082_B_1	45	1954	wall	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Walter Scott Jr. Energy Center	2	Iowa	1082_B_2	88	1958	tangential	dry	0	0.0500	0.0279	No	0.0279	0.0221	ESP-4
Wansley	1	Georgia	6052_B_1	891	1976	tangential	dry	0	0.0620	0.0279	No	0.0279	0.0341	ESP-4
Wansley	2	Georgia	6052_B_2	892	1978	tangential	dry	0	0.0600	0.0279	No	0.0279	0.0321	ESP-4
Warrick	1	Indiana	6705_B_1	136	1960	wall	dry	0	0.1000	0.0279	No	0.0279	0.0721	ESP-4
Warrick	2	Indiana	6705_B_2	136	1964	wall	dry	0	0.0900	0.0279	No	0.0279	0.0621	ESP-4
Warrick	3	Indiana	6705_B_3	136	1965	wall	dry	0	0.1500	0.0279	No	0.0279	0.1221	ESP-4
Warrick	4	Indiana	6705_B_4	300	1970	cell	dry	0	0.1400	0.0279	No	0.0279	0.1121	ESP-4
Waukegan	17	Illinois	883_B_17	100	1952	cyclone	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Waukegan	7	Illinois	883_B_7	327	1958	tangential	dry	0	0.0517	0.0279	No	0.0279	0.0238	ESP-4
Waukegan	8	Illinois	883_B_8	359	1962	tangential	dry	0	0.0517	0.0279	No	0.0279	0.0238	ESP-4
Welsh	1	Texas	6139_B_1	527	1977	wall	dry	0	0.0075	0.0279	Yes	0.0075	0.0000	---
Welsh	2	Texas	6139_B_2	524	1980	wall	dry	0	0.0075	0.0279	Yes	0.0075	0.0000	---
Welsh	3	Texas	6139_B_3	524	1982	wall	dry	0	0.0075	0.0279	Yes	0.0075	0.0000	---

Weston	1	Wisconsin	4078_B_1	62	1954	wall	dry	0	0.0021	0.0279	Yes	0.0021	0.0000	---
Weston	2	Wisconsin	4078_B_2	86	1960	wall	dry	0	0.0021	0.0279	Yes	0.0021	0.0000	---
Whelan Energy Center	1	Nebraska	60_B_1	76	1981	tangential	dry	0	0.0042	0.0279	Yes	0.0042	0.0000	---
White Bluff	1	Arkansas	6009_B_1	815	1980	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
White Bluff	2	Arkansas	6009_B_2	825	1981	tangential	dry	0	0.0070	0.0279	Yes	0.0070	0.0000	---
Widows Creek	7	Alabama	50_B_7	473	1961	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Will County	3	Illinois	884_B_3	250	1957	tangential	dry	0	0.0288	0.0279	No	0.0279	0.0009	ESP-1
Will County	4	Illinois	884_B_4	503	1963	tangential	dry	0	0.0288	0.0279	No	0.0279	0.0009	ESP-1
Williams	WIL1	South Carolina	3298_B_WIL1	606	1973	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Willow Island	1	West Virginia	3946_B_1	54	1949	vertical	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Willow Island	2	West Virginia	3946_B_2	181	1960	cyclone	wet	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Winyah	1	South Carolina	6249_B_1	295	1975	wall	dry	0	0.0800	0.0279	No	0.0279	0.0521	ESP-4
Winyah	2	South Carolina	6249_B_2	295	1977	wall	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Winyah	3	South Carolina	6249_B_3	295	1980	wall	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Winyah	4	South Carolina	6249_B_4	270	1981	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Wood River	4	Illinois	898_B_4	105	1954	tangential	dry	0	0.0400	0.0279	No	0.0279	0.0121	ESP-3
Wood River	5	Illinois	898_B_5	383	1964	tangential	dry	0	0.0100	0.0279	Yes	0.0100	0.0000	---
Wyandotte	7	Michigan	1866_B_7	35	1948	wall	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Yates	Y1BR	Georgia	728_B_Y1BR	99	1950	tangential	dry	0	0.2000	0.0279	No	0.0279	0.1721	ESP-4
Yates	Y2BR	Georgia	728_B_Y2BR	105	1950	tangential	dry	0	0.2000	0.0279	No	0.0279	0.1721	ESP-4
Yates	Y3BR	Georgia	728_B_Y3BR	112	1952	tangential	dry	0	0.2000	0.0279	No	0.0279	0.1721	ESP-4
Yates	Y4BR	Georgia	728_B_Y4BR	135	1957	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Yates	Y5BR	Georgia	728_B_Y5BR	137	1958	tangential	dry	0	0.0700	0.0279	No	0.0279	0.0421	ESP-4
Yates	Y6BR	Georgia	728_B_Y6BR	346	1974	tangential	dry	0	0.0300	0.0279	No	0.0279	0.0021	ESP-1
Yates	Y7BR	Georgia	728_B_Y7BR	349	1974	tangential	dry	0	0.0200	0.0279	Yes	0.0200	0.0000	---
Yorktown	1	Virginia	3809_B_1	157	1957	tangential	dry	0	0.0518	0.0279	No	0.0279	0.0239	ESP-4

Yorktown	2	Virginia	3809_B_2	164	1959	tangential	dry	0	0.0518	0.0279	No	0.0279	0.0239	ESP-4

Gibsons Creek Power Plant: This unit is listed as only having access to subbituminious coal in NEEDS. However, since it the unit was originally designed to burn lignite, as evidenced by historic consumption, in MATS policy runs it is subjected to the Hg limit for low Btu virgin coal in the policy case.

Treatment of DSI in Emissions Calculations: DSI is considered when calculating condensable PM for air quality modeling but not when assigning mercury EMFs in the power sector modeling.

Accounting for Presence of Fabric Filters in Deriving Mercury Emission Modification Factors (EMFs) and Calculating Filterable Particulate Matter (PM): When fabric filters are added to generating units, the mercury EMFs are recalculated to account for their presence. This is applied in both the base and policy case v.4.10_MATS runs and in the v.4.10_MATS runs used in air quality modeling. In addition, since the calculation of filterable PM for air quality modeling is a function of filter efficiency, the post-processing procedure, used to prepare model output of air quality modeling, was also updated to account for the presence of FFs

Chapter 7: Set-Up Parameters and Rules

7.5 MATS Specific Set-Up Rules" (new)
The following set-up features apply in the v.4.10 base and policy cases for MATS:

7.5.1 New Builds and Retrofits in 2012: Given the short lead time, EPA's policy analysis has disabled incremental new capacity and retrofit construction in the 2012 model year. The results presented for the 2012 model year reflect the model's enactment of investment decisions already underway (as opposed to any investment decisions driven by new policies).

7.5.2 SCR Retrofits in the MATS Policy Scenario: SCR is an advanced post-combustion technology for NO_X control. While SCR can yield mercury control cobenefits, IPM results demonstrate that MATS alone is insufficient to drive new SCR retrofitting by 2015; the results show that other control technologies, such as ACI, are generally more cost-effective compliance options in the near term for MATS implementation. It is possible that certain units may elect to 'accelerate' the installation of SCR that they may otherwise have considered installing in the 2020-2050 timeframe, depending on future NO_X control requirements. In light of the inherent long-run uncertainty in this type of decision, and the focus of this analysis on quantifying the incremental impacts of MATS in 2015, EPA conservatively constrained IPM to prevent the model from "re-locating" (i.e., accelerating) long-term base case SCR installations from 2020-2050 to the 2015 model year for MATS.

11.5 Fuel Emission Factors

Table 11-4 brings together all the fuel emission factor assumptions as implemented in EPA Base Case v.4.10_MATS. For sulfur dioxide and mercury in coal, where emission factors vary widely based on the rank, grade, and supply seam source of the coal, cross references are given to tables that provide more detailed treatment of the topic. Nitrogen oxides (NO_X) are not included in Table 11-4 because NO_X levels are not primarily fuel based but are a factor of the combustion process.

Table 11-4 Fuel Emission Factor Assumptions in EPA Base Case v.4.10_MATS

Fuel Type	Heat Content (Btu/lb)[1]	Carbon Dioxide (lbs/MMBtu)[2]	Sulfur Dioxide (lbs/MMBtu)[3]	Mercury (lbs/TBtu)[3]
Coal				
Bituminous	>10,260 - 13,000	205.2 - 206.6	0.67 - 6.43	1.82 - 34.71
Subbituminous	> 7,500 - 10,260	212.7 - 213.1	0.58 - 1.41	4.24 - 6.44
Lignite	< 7,500	213.5 - 217.0	1.46 - 3.91	7.51 - 14.88
Natural Gas	--	117.08	0	0.00014
Fuel Oil				
Distillate	--	161.4	0	0.48
Residual	--	161.4 - 173.9	0.3 - 2.65	0.48
Biomass	--	0	0.08	0.57
Waste Fuels				
Waste Coal[4]	6,175	205.7	5.36	63.9
Petroleum Coke	14,150	225.1	7.27	~~23.18~~2.66
Fossil Waste	--	321.1	0.08	0
Non-Fossil Waste	--	0	0	0
Tires	--	189.5	1.65	3.58
Municipal Solid Waste	--	91.9	0.35	71.85

Notes:

[1]Distillate and Residual Oils, Biomass, Fossil Waste, Non-Fossil Waste, Tires, and Municipal Solid Waste (MSW) are priced at a $/MMBtu basis and hence heat content is not required for modeling.

[2]Also see Table 9-9 in *EPA Base Case v.4.10* (EPA #430-R-10-010), August 2010 at www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.

[3]Also see Table 9-6 and Table 9-7 in *EPA Base Case v.4.10* (EPA #430-R-10-010), August 2010 at www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html.
Biomass fuel is considered to have a net zero impact on atmospheric carbon dioxide levels since the emissions released are equivalent in carbon content to the carbon absorbed during fuel crop growth. (See, for example, Hughes, E., Role of Renewables in Greenhouse Gas Reduction, Electric Power Research Institute (EPRI): November, 1998. Report TR-111883, p. 28.)
"Biomass Co-firing," Chapter 2 in *Renewable Energy Technology Characterizations*, U.S. Department of Energy and Electric Power Research Institute (EPRI), 1997.
Analysis of Emissions Reduction Option for the Electric Power Industry, Office of Air and Radiation, U.S. Environmental Protection Agency, March 1999.

[4]In EPA Base Case v.4.10_MATS waste coal units are assumed to achieve 99% mercury removal.

ATTACHMENT D

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
ENFORCEMENT AND
COMPLIANCE ASSURANCE

December 16, 2011

MEMORANDUM

SUBJECT: **The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard**

FROM: **Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance**

TO: **Regional Administrators (EPA Regions I-X)**
Regional Counsel (EPA Regions I-X)
Regional Enforcement Division Directors (EPA Regions I-X)
Air Division Directors (EPA Headquarters and Regions I-X)

I. STATEMENT OF POLICY

It is the EPA's obligation to ensure compliance with environmental laws designed to protect public health and welfare. Where there is a conflict between timely compliance with a particular requirement and electric reliability, the EPA intends to carefully exercise its authorities to ensure compliance with environmental standards while addressing genuine risks to reliability in a manner that protects public health and welfare.

Pursuant to Section 112 of the Clean Air Act ("CAA"), the EPA finalized national emission standards for hazardous air pollutants ("NESHAP") from electric generating units ("EGUs") in December 2011. These standards, commonly known as the "Mercury and Air Toxics Standards" ("MATS"), adopt emission limits on mercury, acid gases and other toxic pollutants for affected coal and oil-fired EGUs. Many existing sources will comply with the MATS by controlling their emissions, while others (typically older, smaller, less efficient units) may choose to cease operations rather than install control technologies.

The EPA believes that all affected sources will be able to comply with the MATS within the compliance period specified by Section 112(i)(3) of the CAA (including, as applicable, any

extensions permitted under Section 112(i)(3)(B)) (the "MATS Compliance Date"). The EPA's analysis projects only a modest level of retirements, and the Agency does not anticipate that such retirements will lead to resource constraints that would adversely affect electric reliability.

Nonetheless, the EPA acknowledges that there may be isolated instances in which the deactivation or retirement of a unit or a delay in installation of controls due to factors beyond the owner's/operator's control could have an adverse, localized impact on electric reliability that cannot be predicted or planned for with specificity at the present time. In such instances, sources could find themselves in the position of either operating in noncompliance with the MATS or halting operations and thereby potentially impacting electric reliability.

The EPA is issuing this policy memorandum to describe its intended approach regarding the use of Section 113(a) administrative orders ("AOs") with respect to sources that must operate in noncompliance with the MATS for up to a year to address a specific and documented reliability concern. This enforcement policy is limited in application to units that are critical for reliability purposes. Some sources will be able obtain a broadly available one-year extension pursuant to Section 112(i)(3)(B). A source that qualifies for a one year extension from its permitting authority may also qualify for an AO at the end of its extension, provided that it falls within the terms of this policy. The EPA believes that there are likely to be few, if any, cases in which it is not possible to mitigate a reliability issue within four years, and that there are likely to be fewer, if any, cases in which it is not possible to mitigate a reliability issue within the further year contemplated under this policy.

This policy does not address situations where a reliability critical unit needs more than one year to come into compliance after the MATS Compliance Date. The policy also does not address delays in installations of controls and/or other instances of noncompliance with the MATS for units that are not reliability critical. The EPA intends to handle such scenarios as it has in the past, by assessing each situation on a case-by-case basis, at the appropriate time, to determine the appropriate enforcement response and resolution.

As set forth below, in light of the complexity of the electric system and the local nature of many reliability issues, the EPA will, for purposes of using its Section 113(a) AO authority in this context, rely for identification and/or analysis of reliability risks upon the advice and counsel of reliability experts, including, but not limited to, the Federal Energy Regulatory Commission ("FERC"), Regional Transmission Operators ("RTOs"), Independent System Operators ("ISOs") and other Planning Authorities as identified herein, the North American Electric Reliability Corporation ("NERC") and affiliated regional entities, and state public service commissions ("PSCs") and public utility commissions ("PUCs"). The EPA will work with these and other organizations, as appropriate, to ensure that any claims of reliability risks are properly characterized and evaluated.

The EPA is committed to achieving compliance with the MATS while ensuring electric reliability.

The policies established in this document supplement other applicable policies, and are intended to assist government personnel in determining the appropriate response to noncompliance. These policies and procedures are not intended to, nor do they, constitute a rulemaking by the EPA. These policies and procedures do not create a right or a benefit, substantive or procedural, that is enforceable at law or in equity by any person. The EPA reserves the right to act at variance with these policies and to change them at any time without public notice. Further, nothing in this document should be construed to affect the EPA's analysis of, or reaction to, an imminent and substantial endangerment to human health.

II. SUMMARY OF LEGAL REQUIREMENTS AND AUTHORITIES

Section 112 of the CAA establishes compliance deadlines for existing sources to meet standards promulgated under that provision, such as those included in the MATS rule.[1] Specifically, Section 112(i)(3)(A) provides:

> After the effective date of any emissions standard, limitation or regulation promulgated under this section and applicable to a source, no person may operate such source in violation of such standard, limitation or regulation except, in the case of an existing source, the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard.
>
> *See, also* 40 CFR 63.9984.

The CAA and its implementing regulations provide specific conditions under which extensions may be granted to this three year compliance period and under which other compliance time periods may apply. *See, e.g.,* Section 112(i)(3)(B), (4)-(6). In particular, Section 112(i)(3)(B) provides:

> The Administrator (or a State with a program approved under subchapter V of this chapter) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) of this section if such additional period is necessary for the installation of controls.

Section 113 of the CAA authorizes the Administrator to bring enforcement actions against sources in violation of CAA requirements, seeking injunctive relief, civil penalties and, in certain circumstances, other appropriate relief. The EPA also has the discretion to agree to negotiated

[1] Except as otherwise provided under Section 112(i)(3)(B), the MATS requires compliance within three years of the effective date, the statutory maximum.

resolutions including, for example, expeditious compliance schedules with enforceable compliance milestones.

III. THE EPA'S ENFORCEMENT RESPONSE TO BRING RELIABILITY-CRITICAL UNITS INTO COMPLIANCE

The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly years in advance of the date when a violation may occur. The Agency is doing so now with respect to the MATS to provide confidence with respect to electric reliability. EGUs may be needed to operate to maintain the reliability of the electric grid when they would prefer, or could be required, to halt operations temporarily (until controls can be installed) or indefinitely (through deactivation of a unit). This policy describes the EPA's intended enforcement response in such instances. The policy is informed, as are our enforcement actions in general, by the need to find an appropriate balance between critical public interests, bearing in mind the resources and process time required for any enforcement response.

Some sources may take all steps necessary to comply with the MATS, but may nevertheless be needed to operate in noncompliance with the MATS to address concerns with electric reliability. In the event that such sources are interested in receiving a schedule to come into compliance while operating, the EPA intends, where necessary to avoid a serious risk to electric reliability, and provided the criteria set forth herein are met, to issue an expeditious case-specific AO to bring a source into compliance within one year. *See* Section 113(a). Any such AOs would be issued on or after (not before) the MATS Compliance Date and would be limited to units that are required to run for reliability purposes that (A) would otherwise be deactivated, or (B) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay.[2]

The Agency is cognizant that early planning will play a key role in allowing for the identification, and timely mitigation, of any potential reliability issues. The EPA expects that owners/operators will begin compliance planning early, and will provide early notice of their compliance plans to the appropriate reliability entities. We further expect that entities with responsibility for reliability planning and coordination will develop and maintain system-wide reliability plans for the units within their purview, and that this regional reliability planning will provide early identification of units that are critical for reliability purposes. Early notice and planning can discourage delays in coming into compliance, encourage timely action to avoid or mitigate reliability concerns, and minimize the need for issuance of AOs of the type described herein.

[2] The EPA does not intend to seek civil penalties for violations of the MATS that occur as a result of operation for up to one year in conformity with an AO issued in connection with this policy, unless there are misrepresentations in the materials submitted in a request for an AO.

The EPA also recognizes the need for advance planning with regard to the future availability of any reliability critical EGUs to operate as needed to maintain electric reliability. Accordingly, although an AO cannot be issued under Section 113(a) prior to the MATS Compliance Date, the EPA intends – where the owner/operator has timely submitted a complete request and has provided appropriate cooperation – to give the owner/operator as much advance written notice as practicable of the Agency's plans with regard to such an AO.

To qualify for an AO in connection with this policy, an owner/operator should, at a minimum, take the following steps.[3, 4]

A. Provide early notice of compliance plans. Within one year after the effective date of the MATS, an owner/operator should provide written notice of its compliance plans, with regard to each EGU it owns or operates, that identifies (a) the units it plans to deactivate and the anticipated dates of deactivation and (b) the units for which it intends to install pollution control equipment or otherwise retrofit and the anticipated schedule for completion of that work, to the Planning Authority for the area in which the relevant EGU or EGUs are located.[5]

B. Timely request an AO for a unit that may affect reliability due to deactivation. In addition to the elements identified in III(A) above, for a unit that is required to run for reliability purposes that would otherwise be deactivated:

1. An owner/operator should, no less than 180 days prior to the MATS Compliance Date, submit electronically to (a) the Director of the Air Enforcement Division in the EPA's Office of Enforcement and Compliance Assurance, and (b) the Regional Administrator of the EPA Region in which the EGU is located, with a copy to FERC, at an office of its designation, (collectively, "AO Request Recipients") a written request for an enforceable compliance schedule in an AO for the unit, which includes information responsive to each of the elements specified in III(D) below.

2. At the same time the unit owner/operator submits its request for an AO, an owner/operator should also provide notice that it is seeking such an AO to (a) the Planning Authority, (b) any state PUCs/PSCs with regulatory jurisdiction with

[3] The EPA will evaluate each request for an AO for a unit that is required to run for reliability purposes on a case-by-case basis.

[4] Any notice, request or other submission discussed in this memorandum should conform to the standard business practice of the receiving entity for the submission of information, including any requirements governing submission of Confidential Business Information and/or other confidential information.

[5] Planning Authority is the entity defined as such in the "Glossary of Terms Used in NERC Reliability Standards," available at: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf, or any successor term thereto approved by FERC, and includes, in relevant jurisdictions, RTOs and ISOs.

regard to the relevant EGU,[6] (c) any state, tribal or local environmental agency with permitting authority under Titles I and V of the CAA, and any tribal environmental agency that does not have such authority, with jurisdiction over the area in which the EGU is located (collectively, "AO Notice Recipients").

C. Timely request an AO for a unit that may affect reliability due to delays related to the installation of controls. In addition to the elements identified in III(A) above, for a unit that that is required to run for reliability purposes that, due to factors beyond the control of the owner/operator, has a delay in installation of controls or needs to operate because another unit has had such a delay:

1. An owner/operator should, within a reasonable time of learning of a delay that it believes may result in a unit being unable to comply by the MATS Compliance Date, provide to the Planning Authority for the area in which the relevant EGU or EGUs are located, written notice of the units impacted by the delay, the cause of the delay, an estimate of the length of time of the delay, and the timeframe during which it contemplates operation in noncompliance with the MATS.

2. An owner/operator should, within a reasonable time of learning that it is critical to reliability to operate a unit described in the preceding paragraph in noncompliance with the MATS after the MATS Compliance Date, submit electronically to the AO Request Recipients a written request for an enforceable compliance schedule in an AO for the unit, which includes information responsive to as many of the elements specified in III(D) below as it is possible to provide at that time.

3. At the same time the unit owner/operator submits its request for an AO, an owner/operator should also provide notice that it is seeking such an AO to the AO Notice Recipients.

D. Submit a complete request for an AO. The following elements should be included in a request for an AO in connection with this policy:[7]

1. Copies of the early notice provided to the Planning Authority pursuant to III(A) or an explanation of why it was not practicable to have provided such notice and a demonstration that such notice was provided as soon as it was practicable.

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[6] PUCs/PSCs may also wish to obtain the information identified in III(A), either by requesting that an owner/operator over which the PUC/PSC has jurisdiction provide such information directly, or by requesting such information from the relevant Planning Authority.

[7] The EPA may request additional information from the unit owner/operator. The speed with which the EPA evaluates a request and its ultimate response will be related to the timeliness, completeness, and quality of the submittal.

2. Written analysis of the reliability risk if the unit were not in operation, which demonstrates that operation of the unit after the MATS Compliance Date is critical to maintaining electric reliability, and that failure to operate the unit would: (a) result in the violation of at least one of the reliability criteria required to be filed with FERC, and, in the case of the Electric Reliability Council of Texas ("ERCOT"), with the Texas PUC,[8] or (b) cause reserves to fall below the required system reserve margin.

3. Written concurrence with the analysis in III(D)(2) by, or a separate and equivalent analysis by, the Planning Authority for the area in which the relevant EGU or EGUs are located, or, in the alternative, a written explanation of why such concurrence or separate and equivalent analysis cannot be provided, and, where practicable, any related system wide analysis by such entity.

4. Copies of any written comments from third parties directed to, and received by, the owner/operator in favor of, or opposed to, operation of the unit after the MATS Compliance Date.

5. A plan to achieve compliance with the MATS no later than one year after the MATS Compliance Date, and, where practicable, a written demonstration of the plan to resolve the underlying reliability problem and the steps and timeframe for implementing it, which demonstrates that such resolution cannot be effected on or before the MATS Compliance Date.

6. An identification of the level of operation of the unit that is required to avoid the documented reliability risk in III(D)(2) and, consistent with that level, a proposal for operational limits and/or work practices to minimize or mitigate any HAP emissions to the extent practicable during any operation not in full compliance with the MATS.

In evaluating a request for an AO submitted in contemplation of this policy, although the EPA's issuance of an AO is not conditioned upon the approval or concurrence of any entity, the EPA intends to consult, as necessary or appropriate on a case-by-case basis, with FERC and/or other entities with relevant reliability expertise.

[8] Because ERCOT oversees intrastate transmission of electricity solely within Texas and does not provide for interstate transmission, ERCOT files reliability criteria with the Texas PUC.

ATTACHMENT E

Thursday, May 14, 2015 8:30 AM ET Exclusive

Supreme Court's eventual MATS ruling will be (mostly) moot

By Eric Wolff

A ruling by the U.S. Supreme Court on the U.S. EPA's Mercury and Air Toxics Standards rule will be, from a practical grid perspective, largely moot, according to an SNL Energy analysis of power plants given more time to comply with the rule.

The court's ruling will have legal ramifications for future EPA rules, however. But since the MATS rule's initial compliance date fell in April, most plant owners had to make decisions years ago about how to comply with that rule even though the lengthy legal process of challenging the rule was still playing out.

Moreover, 200 plants, comprising about 20% of U.S. power capacity, were given up to an extra year to comply with the MATS, mostly in order to finish installing mercury controls. Of those, 22 plants, representing less than 1% of U.S. power capacity and 1% of U.S. energy production in 2013, remained in operation without MATS controls to provide grid reliability. It is just these 22 plants, along with perhaps a few others, that the court could save from retirement by striking down the rule.

"It is fair to say that MATS has already largely done what it's going to do," said Jeff Holmstead, an industry attorney for Bracewell & Giuliani.

While nearly every EPA rule incites court challenges from environmental and public health groups or the regulated industry, MATS inspired particular consternation in the industry when it was finalized in 2012. Along with the rule's estimated $9.6 billion in annual compliance costs, the fear was that expensive controls required by the rule would drive up the cost of producing power for older, smaller power plants that already existed on the edge of profitability.

Operating metrics for units receiving MATS extensions

	Number of units	Current operating capacity (MW)	2013 operating capacity (MW)	2013 net generation (MWh)	2013 average capacity factor (%)
Reasons for receiving MATS extension					
Install controls or fuel switch	385	139,500	139,040	740,107,103	67.45
Grid reliability	60	10,282	10,282	44,339,714	57.45
Capacity commitment	22	4,607	4,607	9,115,554	33.37
Extensions received, retired before needed	9	0	2,536	10,185,627	56.87
All US generation					
Total US coal	1,182	300,309	313,465	1,600,531,473	67.24
Total US oil	3,885	44,225	46,871	15,947,618	35.00
Total US, all fuel types	**21,684**	**1,115,498**	**1,116,315**	**4,083,561,578**	**65.22**

2013 operating capacity only includes units for which net generation is available.
Number of units and current operating capacity includes operating, out-of-service and mothballed units, except for retired MATS units.
As of May 8, 2015.
Sources: SNL Energy, state filings

In April 2014, a divided U.S. Court of Appeals for the District of Columbia Circuit upheld the rule, with the majority reasoning that the EPA did not have to account for the cost of compliance in writing the rule. However, the U.S. Supreme Court in March took a closer look at the issue, hearing oral arguments on whether the agency should have and did consider costs in writing the rule. Observers expect a decision in June.

Most plants installing controls

In order to assess the potential grid effects of the ruling, SNL Energy contacted every state environment or clean air agency listed on a National Association of Clean Air Agencies survey as having granted generation owners extensions to comply with MATS, and a few states that were not included in the survey. In total, 80% of U.S. generation capacity, including half of coal-fired capacity, was in compliance with MATS by April 2015.

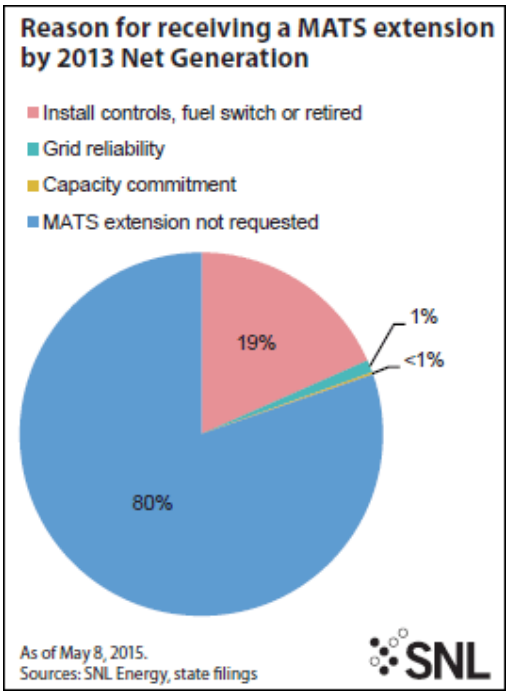
The vast majority, or 89%, of the capacity needing more time to comply needed that extra time to install controls or to complete a conversion to natural gas. Many of the coal-fired plants needing extensions are fairly new and large, like the 536-MW Trenton Channel Unit 9, run by DTE Energy Co., which can operate profitably even with controls. The time consuming process to test and then install mercury controls must now be well underway for these units if they are to meet their 2016 compliance deadline.

Approximately 3% of power capacity, or 22 units, needed six-week extensions to solve the "6-week problem," i.e., they had contractual capacity commitments to the Midcontinent Independent System Operator Inc., PJM Interconnection LLC, or another operator that ran several weeks past the April compliance deadline.

Those plants, like the 60-year-old Philip Sporn plant in West Virginia run by American Electric Power Co. Inc., are running without mercury controls, and unless the court rules before June 1, they will retire. If the court strikes down MATS, they could potentially come back online, but that may be difficult.

"For those slated to retire this spring, they're on a path toward doing that," Ray Dotter, a PJM spokesman, said. "Whether they can arrest that or not, that's a plant by plant, owner by owner decision."

Plants that retired earlier face even steeper hurdles to returning. "You've shut the plant down, given up the permits, laid off your workers — it would be challenging to bring it back," Dotter explained.



The plants that could be saved

The remaining 22 power plants to receive extensions largely received either the full year or at least until the end of 2015 to come into compliance. They make up 1% of all energy produced in 2013, and less than 0.9% of all power capacity.

The operators of those plants all asked for more time to allow nearby reliability projects to be completed, including new natural gas plants, or, as in the case with Dominion Resources Inc.'s Yorktown Power Station, a new transmission line. FERC has essentially recommended that two plants on this list, Grand River Energy owned by the Grand River Dam Authority and Kansas City Board of Public Utilities' Nearman Creek, be given an additional year beyond April 2016 to comply.

The court could potentially save all of these "grid reliability" plants slated for retirement because they are still operating and therefore still have a workforce and working equipment. And yet, some observers are skeptical that operators would halt their retirement plans even if the court should overturn MATS.

"There are so many factors going into the decision whether to invest in controls that go into the MATS rule — they need to make investments for ozone, for [the Cross-State Air Pollution Rule], SO2, startup and shutdowns in some cases," said Pat Gallagher, director of the Environmental Law Program at the Sierra Club. "The number of plants where a decision will be dictated by the outcome of the Supreme Court case is close to nil."

Plants could turn off controls

While very few plants could be saved by the court, a ruling vacating MATS would have potential emissions implications. For instance, operators could decide not to run their controls, something that is not without precedent. A September 2014 draft analysis from the Ozone Transport Commission found data indicating that some units choose, at times, not to operate their nitrogen oxide controls.

Whether it makes financial sense to do so is another question. Most of the money spent on mercury controls is done so up front. Testing is particularly expensive, because mercury emissions vary throughout a plant run. An operator can run at high capacity for a week or low capacity for a day and come up with substantially different emissions rates, said Steve Feeney, mercury and wastewater treatment product manager for Babcock & Wilcox Power Generation Group Inc., a subsidiary of The Babcock & Wilcox Co. and a supplier and engineer of control equipment.

"To understand what their emissions are, that's a multi-million dollar endeavor," he said. "For some of the biggest utilities in the U.S., I would not be surprised if they spent tens of millions on testing."

After testing is complete, installation and equipment can cost approximately another $1 million per stack, though it varies greatly depending on a plant's technology and other characteristics. The controls have relatively little parasitic load — about 75 kW to 150 kW, Feeney said — but the material that absorbs the mercury in the stack can run up a high price, somewhere between $500,000 and $1.5 million annually. Operators could potentially shave some of their costs if they did not have to buy this material.

Holmstead, who represents some large investor-owned utilities, said he believes regulated operators working outside of markets will run their controls regardless.

Top owners of capacity receiving MATS extensions (MW)

Company	Install controls or fuel switch	Grid reliability	Capacity commitment	Total
Southern Co.	12,650	1,482	-	14,132
Duke Energy Corp.	10,894	668	163	11,725
NRG Energy Inc.	10,254	-	-	10,254
Tennessee Valley Authority	7,398	2,472	-	9,870
American Electric Power Co. Inc.	3,601	1,983	4,190	9,774
FirstEnergy Corp.	9,248	-	-	9,248
DTE Energy Co.	6,869	-	-	6,869
PPL Corp.	6,580	171	-	6,751
Texas Energy Future Holdings LP	6,218	-	-	6,218
South Carolina Public Service Authority	3,525	-	-	3,525

Capacity includes operating, out-of-service and mothballed units.
A hyphen indicates a zero value.
As of May 8, 2015.
Sources: SNL Energy, state filings
SNL

"I sit in lots of meetings with utility folks, and my impression is that even if the rule were to be vacated for the most part people would operate these controls that have been installed," he said. "I know that's the case in areas that have regulated utilities, because that's already been accepted as reasonable and appropriate. I think in areas with regulated utilities, there's no question."

But the actions of unregulated merchant generators might be different. A spokesman for NRG Energy Inc., which operates merchant power plants in multiple power markets, was noncommittal about what his company would do if MATS was vacated.

"We will always run our controls to the extent they are needed to comply with laws and regulations as well as permit limits," said NRG's David Gaier. "Our corporate philosophy is always safety over production and environment over production."

The legal weight of a decision

While a Supreme Court decision against the MATS rule would have minimal effect on the grid, the court's words would have legal impact. A decision requiring the agency to consider compliance cost in developing its rules could force it to reconsider other future rules, especially if Chief Justice John Roberts opines for the majority and invalidates the benefits of co-pollutants in justifying new rules.

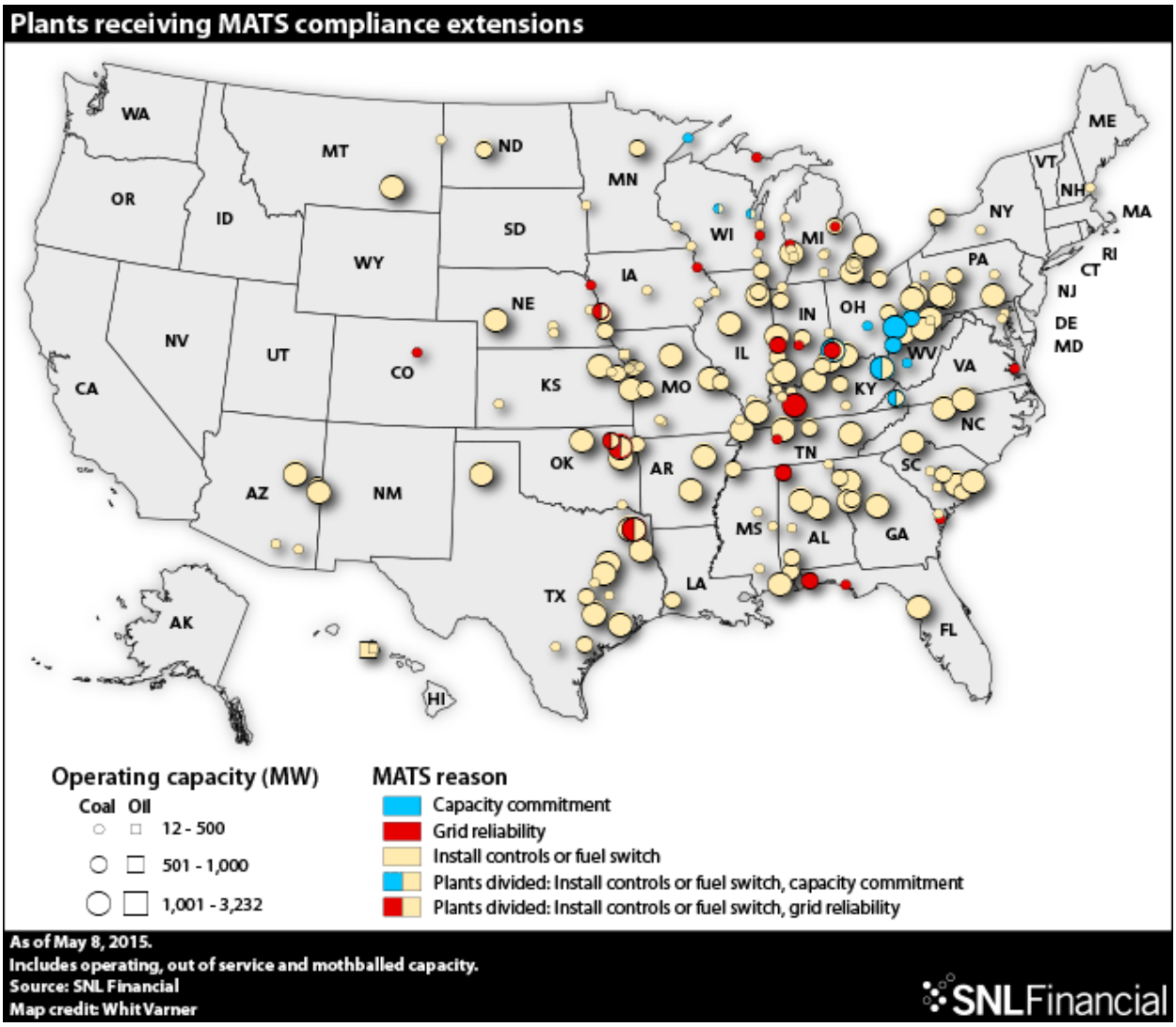
Vacating MATS could also have the side effect of clearing legal obstacles for the EPA's proposed carbon dioxide rule. MATS regulates power plants under Section 112 of the Clean Air Act, and the carbon rule would regulate under Section 111. Opponents of the carbon rule say the EPA may not regulate power plants twice under different sections of the law. Striking down MATS would leave the way clear for the carbon rule.

Nevertheless, the MATS rule appears to have already achieved its goals, which is a primary complaint of many opponents of EPA rules. An ongoing challenge of the proposed carbon rule notwithstanding, courts typically do not rule on federal rules until they are final. But the years-long process of getting a case on the docket at lower courts and possibly all the way to the Supreme Court means a rule could have had its full effect before a final court ruling can be made.

"I think that's one of the real problems with the way this whole system works," Holmstead said. "It is kind of a shame there's a rule that may be illegal but people have to comply with it."

The Sierra Club's Gallagher agrees that the case has been made irrelevant by passing time.

"The case and the ramifications of this case have been overtaken by other regulatory developments," he said.



Charlotte Cox contributed to this article.

This story was amended 2:30 p.m. on May 14 to clarify the context of the NRG spokesman's statement.

ATTACHMENT F

Mercury Installation List

ICAC's Mercury Control Division developed a database of mercury control reagent and sorbent feed systems based on results from a voluntary survey of ICAC members in which the members identified specific installations along with each power plant's likely mercury control strategy. The database has certain limitations in that not every technology supplier is an ICAC member and not all member companies contributed to the database, however a picture emerges of technologies that are being widely applied to coal-based units, 398 (181 GW) of which are captured in the database.

Unit Size (MW)	Coal	Hg Control 1	Hg Control 2	Hg Control 3
376	Other	ACI		
175	Blend	ACI		
185	Blend	ACI		
720	Blend	ACI		
884	Blend	ACI		
723	Lignite	ACI		
110	PRB	ACI		
84	PRB	ACI		
220	PRB	ACI		
131	PRB	ACI		
305	PRB	ACI		
425	PRB	ACI		
890	Blend	ACI		
913	Blend	ACI		
360	PRB	ACI		
365	PRB	ACI		
838	PRB	ACI		
740	Blend	ACI		
755	Blend	ACI		
933	Blend	ACI		
933	Blend	ACI		
115	App	ACI		
115	App	ACI		
115	App	ACI		
520	App	ACI		
110	PRB	ACI		
272	PRB	ACI		
375	PRB	ACI		
463	ILB	ACI		
255	ILB	ACI		
445	ILB	ACI		
580	ILB	ACI		
584	ILB	ACI		
264	PRB	ACI		
50	PRB	ACI		
148	PRB	ACI		
765	PRB	ACI		
850	PRB	ACI		
531	PRB	ACI		
212	PRB	ACI		
58	PRB	ACI		
126	PRB	ACI		
396	PRB	ACI		
82	PRB	ACI		
145	PRB	ACI		
109	Blend	ACI		

275	PRB	ACI
281	PRB	ACI
869	Blend	ACI
269	Blend	ACI
293	Blend	ACI
161	Blend	ACI
163	Blend	ACI
174	Blend	ACI
157	Blend	ACI
331	Blend	ACI
465	Blend	ACI
540	Blend	ACI
371	PRB	ACI
580	PRB	ACI
61	PRB	ACI
84	PRB	ACI
337	App	ACI
660	App	ACI
343	App	ACI
343	App	ACI
250	Lignite	ACI
477	Lignite	ACI
150	PRB	ACI
655	App	ACI
655	App	ACI
690	PRB	ACI
700	PRB	ACI
613	PRB	ACI
650	PRB	ACI
630	Blend	ACI
630	Blend	ACI
20	Other	ACI
30	Other	ACI
428	PRB	ACI
366	PRB	ACI
575	PRB	ACI
374	PRB	ACI
112	PRB	ACI
112	PRB	ACI
235	PRB	ACI
361	PRB	ACI
426	PRB	ACI
629	PRB	ACI
620	PRB	ACI
674	PRB	ACI
677	PRB	ACI
920	Blend	ACI

920	Blend	ACI
616	PRB	ACI
613	PRB	ACI
726	PRB	ACI
870	PRB	ACI
790	PRB	ACI
786	PRB	ACI
783	PRB	ACI
537	Blend	ACI
536	Blend	ACI
935	PRB	ACI
682	PRB	ACI
495	PRB	ACI
404	PRB	ACI
165	Blend	ACI
850	Blend	ACI
850	Blend	ACI
850	Blend	ACI
550	Blend	ACI
352	Blend	ACI
352	Blend	ACI
360	PRB	ACI
360	PRB	ACI
360	PRB	ACI
550	PRB	ACI
550	PRB	ACI
300	PRB	ACI
536	PRB	ACI
805	PRB	ACI
682	PRB	ACI
592	PRB	ACI
566	PRB	ACI
560	PRB	ACI
560	PRB	ACI
560	PRB	ACI
448	Lignite	ACI
427	PRB	ACI
430	PRB	ACI
450	PRB	ACI
83	PRB	ACI
79	PRB	ACI
282	Lignite	ACI
282	Lignite	ACI
250	Lignite	ACI
250	Lignite	ACI
119	PRB	ACI
242	PRB	ACI

800	PRB	ACI		
422	PRB	ACI		
925	PRB	ACI		
334	App	ACI		
334	App	ACI		
275	App	Carbon Based Sorbent		
275	App	Carbon Based Sorbent		
435	Lignite	Carbon Based Sorbent		
435	Lignite	Carbon Based Sorbent		
623	PRB	Carbon Based Sorbent		
634	PRB	Carbon Based Sorbent		
634	PRB	Carbon Based Sorbent		
140	App	Carbon Based Sorbent		
261	Wbit	Carbon Based Sorbent		
560	PRB	Carbon Based Sorbent	Boiler oxidant	
685	App	Carbon Based Sorbent		
685	App	Carbon Based Sorbent		
399	PRB	Carbon Based Sorbent		
446	PRB	Carbon Based Sorbent		
363	App	Non-carbon based sorbent		
405	App	Non-carbon based sorbent		
790	App	Non-carbon based sorbent		
155	PRB	Carbon Based Sorbent		
167	PRB	Carbon Based Sorbent		
570	Wbit	Carbon Based Sorbent		
190	App	Carbon Based Sorbent		
209	App	Carbon Based Sorbent		
201	Wbit	Carbon Based Sorbent		
114	PRB	Carbon Based Sorbent	Boiler oxidant	
114	PRB	Carbon Based Sorbent	Boiler oxidant	
230	PRB	Carbon Based Sorbent	Boiler oxidant	
360	PRB	Carbon Based Sorbent	Boiler oxidant	
100	App	Carbon Based Sorbent		
96	PRB	Carbon Based Sorbent		
96	PRB	Carbon Based Sorbent		
218	PRB	Carbon Based Sorbent		
218	PRB	Carbon Based Sorbent		
557	PRB	Carbon Based Sorbent		
557	PRB	Carbon Based Sorbent		
557	PRB	Carbon Based Sorbent		
557	PRB	Carbon Based Sorbent		
520	PRB	Carbon Based Sorbent		
100	Other	Carbon Based Sorbent		
488	PRB	Carbon Based Sorbent		
50	Other	Carbon Based Sorbent		
50	Other	Carbon Based Sorbent		
50	Other	Carbon Based Sorbent		

100	PRB	Carbon Based Sorbent		
217	PRB	Carbon Based Sorbent		
560	PRB	Carbon Based Sorbent	Boiler oxidant	
578	PRB	Carbon Based Sorbent	Boiler oxidant	
575	PRB	Carbon Based Sorbent	Boiler oxidant	
560	PRB	Carbon Based Sorbent	Boiler oxidant	
893	PRB	Carbon Based Sorbent		
893	PRB	Carbon Based Sorbent		
570	Lignite	Carbon Based Sorbent		
550	Lignite	Carbon Based Sorbent		
550	Lignite	Carbon Based Sorbent		
50	Other	Carbon Based Sorbent		
650	App	Carbon Based Sorbent		
355	PRB	Carbon Based Sorbent		
355	PRB	Carbon Based Sorbent		
463	PRB	Carbon Based Sorbent		
544	PRB	Carbon Based Sorbent		
165	Wbit	Carbon Based Sorbent	Boiler oxidant	
220	Wbit	Carbon Based Sorbent	Boiler oxidant	
800	Wbit	Carbon Based Sorbent		
800	Wbit	Carbon Based Sorbent		
891	PRB	Carbon Based Sorbent		
891	PRB	Carbon Based Sorbent		
891	PRB	Carbon Based Sorbent		
891	PRB	Carbon Based Sorbent		
50	App	Carbon Based Sorbent		
50	App	Carbon Based Sorbent		
566	PRB	Carbon Based Sorbent		
750	App	Carbon Based Sorbent		
136	App	Carbon Based Sorbent		
359	App	Carbon Based Sorbent		
112	PRB	Carbon Based Sorbent		
388	PRB	Carbon Based Sorbent		
362	PRB	Carbon Based Sorbent	Boiler oxidant	
160	PRB	carbon based sorbent		
167	App	carbon based sorbent		
90	App	carbon based sorbent		
90	App	carbon based sorbent		
165	App	carbon based sorbent		
420	App	carbon based sorbent		
348	WBit	carbon based sorbent		
329	WBit	carbon based sorbent		
575	WBit	carbon based sorbent		
575	WBit	carbon based sorbent		
480	PRB	carbon based sorbent		
440	PRB	carbon based sorbent		
199		boiler additive		

668	boiler additive	WFGD additive
668	boiler additive	WFGD additive
668	boiler additive	WFGD additive
668	boiler additive	WFGD additive
668	boiler additive	WFGD additive
512	boiler additive	WFGD additive
512	boiler additive	WFGD additive
1426	boiler additive	WFGD additive
358	boiler additive	WFGD additive
592	boiler additive	WFGD additive
114	boiler additive	WFGD additive
180	boiler additive	WFGD additive
495	boiler additive	WFGD additive
230	boiler additive	WFGD additive
360	boiler additive	WFGD additive
578	boiler additive	WFGD additive
578	boiler additive	WFGD additive
578	boiler additive	WFGD additive
578	boiler additive	WFGD additive
326	boiler additive	WFGD additive
1300	boiler additive	WFGD additive
1300	boiler additive	WFGD additive
175	boiler additive	WFGD additive
175	boiler additive	WFGD additive
175	boiler additive	WFGD additive
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200	boiler additive	WFGD additive
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200	boiler additive	WFGD additive
200	boiler additive	WFGD additive
706	boiler additive	
706	boiler additive	
706	boiler additive	
706	boiler additive	
789	boiler additive	
204	boiler additive	
204	boiler additive	
891	boiler additive	
891	boiler additive	
891	boiler additive	
891	boiler additive	
272	boiler additive	
495	boiler additive	
358	boiler additive	
358	boiler additive	
778	boiler additive	

778	boiler additive	
323		WFGD additive
165		WFGD additive
165		WFGD additive
275		WFGD additive
275		WFGD additive
275		WFGD additive
750		WFGD additive
750		WFGD additive
531		WFGD additive
531		WFGD additive
745		WFGD additive
411		WFGD additive
657		WFGD additive
745		WFGD additive
745		WFGD additive
834		WFGD additive
87		WFGD additive
200		WFGD additive
575		WFGD additive
550		WFGD additive
265		WFGD additive
265		WFGD additive
104		WFGD additive
265		WFGD additive
617		WFGD additive
617		WFGD additive
557		WFGD additive
557		WFGD additive
557		WFGD additive
557		WFGD additive
356		WFGD additive
356		WFGD additive
463		WFGD additive
544		WFGD additive
566		WFGD additive
261		WFGD additive
365	Subbitumino carbon based sorbent	
239	Subbitumino carbon based sorbent	
358	Subbitumino carbon based sorbent	
374	Subbitumino carbon based sorbent	
574	Subbitumino carbon based sorbent	
574	Subbitumino carbon based sorbent	
621	Subbitumino carbon based sorbent	
621	Subbitumino carbon based sorbent	
183	Subbitumino carbon based sorbent	
183	Subbitumino carbon based sorbent	

183	Subbitumino	carbon based sorbent
183	Subbitumino	carbon based sorbent
183	Subbitumino	carbon based sorbent
183	Subbitumino	carbon based sorbent
383	Subbitumino	carbon based sorbent
383	Subbitumino	carbon based sorbent
579	Subbitumino	carbon based sorbent
579	Subbitumino	carbon based sorbent
566	Subbitumino	carbon based sorbent
750	Subbitumino	carbon based sorbent
88	Subbitumino	carbon based sorbent
100	Subbitumino	carbon based sorbent
615	Subbitumino	carbon based sorbent
615	Subbitumino	carbon based sorbent
460	Subbitumino	carbon based sorbent
289	Subbitumino	carbon based sorbent
359	Subbitumino	carbon based sorbent
326	Bituminous	carbon based sorbent
326	Bituminous	carbon based sorbent
593	Lignite	carbon based sorbent
593	Lignite	carbon based sorbent
793	Lignite	carbon based sorbent
793	Lignite	carbon based sorbent
793	Lignite	carbon based sorbent
593	Subbitumino	carbon based sorbent
593	Subbitumino	carbon based sorbent
793	Subbitumino	carbon based sorbent
591	Lignite	carbon based sorbent
660	Bituminous	carbon based sorbent
660	Bituminous	carbon based sorbent
660	Subbitumino	carbon based sorbent
660	Subbitumino	carbon based sorbent
360	Subbitumino	carbon based sorbent
893	Subbitumino	carbon based sorbent
893	Subbitumino	carbon based sorbent
326	Subbitumino	carbon based sorbent
355	Subbitumino	carbon based sorbent
299	Subbitumino	carbon based sorbent
598	Subbitumino	carbon based sorbent
190	Bituminous	carbon based sorbent
413	Bituminous	carbon based sorbent
540	Subbitumino	carbon based sorbent
424	Bituminous	carbon based sorbent
424	Bituminous	carbon based sorbent
790	Subbitumino	carbon based sorbent
213	Subbitumino	carbon based sorbent
351	Subbitumino	carbon based sorbent

570	Subbitumino	carbon based sorbent
294	Subbitumino	carbon based sorbent
346	Bituminous	carbon based sorbent
42	Subbitumino	carbon based sorbent
281	Lignite	carbon based sorbent
281	Lignite	carbon based sorbent
279	Lignite	carbon based sorbent
665	Subbitumino	carbon based sorbent
682	Subbitumino	carbon based sorbent
383	Subbitumino	carbon based sorbent
383	Subbitumino	carbon based sorbent
450	Subbitumino	carbon based sorbent
280	Subbitumino	carbon based sorbent
280	Subbitumino	carbon based sorbent
352	Subbitumino	carbon based sorbent
352	Subbitumino	carbon based sorbent
352	Subbitumino	carbon based sorbent
400	Subbitumino	carbon based sorbent
730	Subbitumino	carbon based sorbent
730	Subbitumino	carbon based sorbent
380	Subbitumino	carbon based sorbent
300	Subbitumino	carbon based sorbent
300	Subbitumino	carbon based sorbent
328	Subbitumino	carbon based sorbent
328	Subbitumino	carbon based sorbent
90	Subbitumino	carbon based sorbent
155	Subbitumino	carbon based sorbent
383	Subbitumino	carbon based sorbent
396	Subbitumino	carbon based sorbent
820	Subbitumino	carbon based sorbent

ATTACHMENT G

NACAA
national association of clean air agencies

National Association of Clean Air Agencies
Survey on MATS Compliance Extension Requests
August 11, 2015

The Mercury and Air Toxics Standards (MATS), issued on December 21, 2011 (published in the *Federal Register* on February 16, 2012[1]), are intended to limit emissions of mercury, acid gases and other toxic pollution from power plants. MATS calls for a three-year compliance period for existing sources, with a deadline of April 16, 2015, but provides for an extra year, upon request, for sources that need additional time to comply.

The National Association of Clean Air Agencies (NACAA)[2] conducted surveys to determine how many requests for one-year MATS compliance extensions (under 40 CFR 63 Subpart UUUUU) state and local agencies received and how many requests were granted. The following table contains updated information from 68 agencies in 49 states, DC and Puerto Rico. According to the responses:

- 189 extension requests were made;
- 184 requests were granted;
- 1 request was accommodated through a permit waiver; and
- 4 were not granted due to incomplete information.

According to EPA's Regulatory Impact Analysis, there are 460 coal-fired power plants that are affected by the MATS rule. Therefore, only approximately 41 percent of the plants indicated that they need additional time to comply and, of those, 98 percent were granted an extension.

If you have additions or changes to this information, please provide them to Mary Sullivan Douglas of NACAA at mdouglas@4cleanair.org.

The following are the responses NACAA received:[3]

[1] http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf
[2] NACAA is a national, non-partisan, non-profit association of air pollution control agencies in 41 states, the District of Columbia, four territories and over 116 metropolitan areas.
[3] If a state or local agency is not listed, it does not necessarily mean that it has not received any extension requests. It could merely signify that it did not respond to NACAA's requests for information.

Agency	Compliance Extension Requests Received	Requests Granted	Comments
Alabama	7	7	
Alabama-Jefferson Co.	1	1	Facility expected to comply on time.
Alaska	0	0	Alaska has not yet taken delegation of this rule, so any extension requests would be handled by Region 10. We are not aware of any requests submitted to Region 10.
Arizona	5	5	
Arkansas	3	3	
California	0	0	See local agency-specific entries.
California-Mojave Desert	0	0	The three sources do not need extensions. One ceased operation and is decommissioning. The second will comply by not burning oil. The third falls under the exemption and is not subject to MATS.
California-San Joaquin Valley	0	0	
California-South Coast	0	0	The one applicable source falls under the exemption, is not subject to MATS and does not need an extension.
Colorado	4	2	One extension is from all requirements in full; one extension is for HCl only; two requests were not granted due to incomplete information.
Connecticut	0	0	
Delaware	1	1	An April 2015 request for a 1-year extension from compliance with the monitoring and reporting requirements during startup and shutdown was approved.
District of Columbia	0	0	
Florida	0	0	Info from state not available.
Georgia	6	6	
Hawaii	2	2	
Idaho	0	0	There are no affected sources.
Illinois	5	5	All 5 are partial extensions, which cover only small parts of the rule (not the same parts for each source). The majority of the rule will take effect on the compliance date.

Agency	Compliance Extension Requests Received	Requests Granted	Comments
Indiana-Indianapolis	1	1	Approval granted by the state.
Iowa	5	5	Iowa has not taken delegation of this rule, so any extension requests are handled by EPA Region. 7. All information on extensions is based on what Iowa receives from EPA. Note that one extension was for the tune-up requirements only, and the compliance date is 12/31/2015. The other extensions are one-year extensions for fuel switching, installing control, or shutdown.
Kansas	12	12	
Kentucky-Louisville	2	2	One of these is already in compliance.
Louisiana	1	1	
Maine	0	0	
Maryland	2	2	
Massachusetts	0	0	
Michigan	19	19	
Minnesota	2	2	One has passed (shutdown by May 2015) and 1remains for April 2016.
Mississippi	4	4	
Missouri	11	11	
Montana	2	2	
Nebraska	5	5	
Nebraska-Lincoln	0	0	
Nebraska-Omaha	1	1	
Nevada	0	0	
Nevada-Washoe Co.	0	0	
New Hampshire	1	1	
New Jersey	1	1	7 coal units already comply, 1 converted to gas and 2 others shut down. The 1 extension noted here was granted to an oil-fired unit.
New Mexico	0	0	
New York	2	2	
North Carolina	1	1	
North Carolina-Western (Asheville)	0	0	
North Dakota	2	2	One request was for a 6-week extension.

Agency	Compliance Extension Requests Received	Requests Granted	Comments
Ohio	11	11	4 of those extensions are conditional upon the recent startup/shutdown provisions being finalized and an assessment of the need for the extensions to continue after finalization.
Oklahoma	3	3	
Oregon	0	0	
Oregon-Lane Co.	0	0	
Pennsylvania	17	17	
Pennsylvania-Allegheny Co.	0	0	
Pennsylvania-Philadelphia	0	0	
Puerto Rico	3	1	Two requests denied due to incomplete information.
Rhode Island	0	0	
South Carolina	7	7	One of the facilities that received an extension closed in late 2013.
Tennessee	4	4	
Tennessee-Knoxville	0	0	
Tennessee-Shelby County	1	1	
Texas	13	13	
Utah	0	0	
Vermont	0	0	There are no affected sources.
Virginia	3	3	A fourth request was withdrawn.
Washington	0	0	
Washington-Northwest	0	0	
Washington-Southwest	0	0	The sole coal-fired power plant in Washington already complies.
Washington-Spokane	0	0	There are no affected sources.
Washington-Yakima	0	0	There are no affected sources.
West Virginia	8	8	
Wisconsin	10	10	
Wyoming	1	0	Extension not needed after state issued permit waiver that met the source's needs.
TOTAL	189	184	

ATTACHMENT H

Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants

Prepared by:

URS

April 5, 2011

Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants

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Appendix A Technology Descriptions

Index of Acronyms

ACI	Activated Carbon Injection
AH	Air Heater
AQC	Air Quality Control
CAA	Clean Air Act
CFB	Circulating Fluidized Bed
CO	Carbon monoxide
COHPAC	Compact Hybrid Particulate Collector
DSI	Dry Sorbent Injection
EMPC	Estimated Maximum Possible Concentration
ESP	Electrostatic Precipitator
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FGDd	Dry Flue Gas Desulfurization (Spray dryer or circulating fluidized bed scrubber)
FGDw	Wet Flue Gas Desulfurization
HAP	Hazardous Air Pollutant
HCl	Hydrochloric Acid
HCN	Hydrogen cyanide
Hg	Mercury
ICI	Industrial, Commercial, and Institutional
ICR	Information Collection Request
LOI	Loss on Ignition
MACT	Maximum Achievable Control Technology
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSR	Normalized Stoichiometric Ratio
PM	Particulate Matter
PRB	Powder River Basin Coal
RICE	Reciprocating Internal Combustion Engine
SBS	Sodium Bisulfate
SCR	Selective Catalytic Reduction
SOFA	Separated Over-Fire Air
SO_3	Sulfur Trioxide
TEF	Toxic Equivalency Factor
TEQ	Toxicity Equivalent
UPL	Upper Prediction Limit
ZWD	Zero Water Discharge

URS

Executive Summary

This report[1] describes the results of an assessment conducted by URS Corporation (URS) to evaluate the availability of pollution control technologies to meet the requirements of the proposed National Emission Standards for Hazardous Air Pollutants (NESHAP) for Utility Electric Generating Units ("EGUs") (the "Toxics Rule"). This assessment was designed to answer the ultimate question of whether control technologies are available that will equip EGUs to meet the emission limitations the Environmental Protection Agency (EPA) has proposed, regardless of current configuration. URS identified proven, commercially available control technologies that will enable EGUs to achieve compliance with the Toxics Rule, given adequate investment by the owners. In the event that an EGU requires the installation or upgrade of control equipment, the technologies available typically require less than three years to install after detailed design and permitting is complete.

To begin, URS identified a number of typical control equipment configurations present at existing EGUs. An assessment was performed to evaluate additional control technologies appropriate for those configurations that would enable EGUs to comply with the Toxics Rule emission limitations on hazardous air pollutants ("HAP"). URS consulted its own experience and database of pollution control technologies and reviewed published literature, conference proceedings, expert analysis and procurement information regarding the availability, cost and efficacy of numerous available control technologies. URS applied this information and its own experience to evaluate the menu of control options that would be available to EGUs of different configurations, and to rank those options. This analysis took into account the performance, maturity and number of existing commercial installations of the control technologies. While special cases may exist, this analysis demonstrates that the Toxics Rule emission limitations are generally achievable through the application of proven, commercially available technologies, regardless of the starting configuration of the facility.

Assuming EPA signs the final Toxics Rule as scheduled on November 16, 2011, the rule will not be effective until early 2012, or 60 days after it is published in the Federal Register. EGUs will not be required to comply with the Toxics Rule until three years after the effective date, or early 2015 – nearly four years after proposal. To the extent that existing facilities require additional control technology to comply with the Toxics Rule, the technology is known, available and the industry has demonstrated its ability to install and to operate these controls.

[1] This report was prepared by URS Corporation for Exelon Corporation.

The controls that will be most commonly needed, such as activated carbon injection (for mercury control) or dry sorbent injection (for SO_3 control on bituminous fired plants and acid gas control at some western sub-bituminous fired EGUs) typically require less than eighteen months to install once permitting is completed. Barring unreasonable permitting or supply chain delays, EGU owners who act promptly will be able to complete such low capital upgrades by the compliance date. Facilities requiring high capital upgrades such as the addition of wet FGDs will face longer installation times. Owners of EGUs requiring such additions will need to select technologies and contractors and to file permit applications promptly to meet the 2015 compliance deadline. For those facilities facing unique challenges in completing necessary upgrades by 2015, EPA has indicated that it will provide extensions of up to one year.

1.0 Introduction

In performing this assessment, URS considered the emissions limitations proposed by EPA in the Toxics Rule, reviewed relevant commercially available control technologies and evaluated seven hypothetical configurations of existing control equipment to determine whether such facilities could be brought into compliance with the proposed Toxics Rule emission limitations. It was concluded that: 1) in many instances, no additional controls would be required; 2) where additional controls would be necessary, the most common top-ranked control technologies can typically be installed in less than 24 months; and 3) in all other instances considered in this assessment, the top-ranked control technology can typically be installed in less than 36 months after detailed design and permitting is complete.

2.0 Technology Survey

2.1 EPA's Proposed Emission Limitations

In the Toxics Rule, EPA proposes emissions limitations for five different sub-categories of EGUs. Coal-fired EGUs are divided into lignite, non-lignite and integrated gasification/ combined cycle ("IGCC") sub-categories. Oil-fired EGUs are divided into solid fuel (petroleum coke) and liquid fuel sub-categories. EPA has proposed emission limitations for mercury, hydrogen chloride ("HCl") and total particulate matter ("PM") for all coal-fired EGU sub-categories and the solid fuel oil sub-category, with HCl being a surrogate for all acid gases and PM being a surrogate for non-mercury HAP metals. For liquid oil-fired EGUs, EPA has proposed limits on total HAP metals (including mercury), HCl and hydrogen fluoride ("HF"). EPA has proposed to regulate dioxins/furans and other organic HAPs for all sub-categories through work practice standards rather than numerical emission limitations. EPA has also proposed a number of alternative compliance methods. For example, coal-fired EGUs may use sulfur dioxide ("SO_2") as a surrogate for acid gases in certain circumstances, and may test for total non-mercury HAP metals or ten individual HAP metals in lieu of complying with the PM limitation.

2.2 URS' Technology Survey

URS conducted a review of commercially-available air quality control ("AQC") technologies that may be employed by coal- and oil-fired EGUs in order to meet emission limitations proposed by EPA in the Toxics Rule. This technology survey presents control technologies for Mercury, HCl, and PM, the default emission limitations in the Toxics Rule for

coal-fired EGUs and solid fuel oil-fired EGUs.[2] Although EPA proposed different emission limitations for liquid fuel oil-fired EGUs, the technologies available for controlling PM and HCl at other EGUs would control total HAP metals and HF (as well as HCl) at liquid fuel oil-fired EGUs.

To conduct the control technology assessment, URS utilized internal information on air quality control technologies, as well as information from published literature and conference proceedings, discussions with technology experts, and procurement information associated with some technologies. For each pollutant category, air quality control technologies were evaluated for their ability to achieve sufficient performance levels. Although costs were not a primary factor in the selection of appropriate technologies, they were considered when comparing different technologies with similar expected performance levels. The multi-pollutant nature of various technologies was also considered, as some processes would be expected to effectively remove pollutants from a number of potential HAP categories, allowing a holistic approach to achieving compliance with the Toxics Rule. Through this analysis, a ranking of available control technologies was developed that takes into account cost, maturity and the ability to treat multiple HAPs. This assessment did not consider possible technologies for controlling dioxin/ furan emissions or organic HAPs. Under the proposed Toxics Rule, these HAPs are to be controlled through work practice standards.

The analysis demonstrates that there is a range of control technologies available to EGUs requiring additional levels of control for mercury, HCl or PM. These technologies are proven and mature, and in fact are already installed at many EGUs. Many of the available technologies involve relatively low capital retrofits that typically require less than eighteen months to install. Some technologies, such as wet or dry scrubbers, have longer installation times and EGU owners requiring such additions will need to move more rapidly to meet the 2015 compliance deadline.

2.3 Assumptions Regarding Existing Sources

URS assessed AQC technologies for expected performance, cost, and schedule to construct at power plants of several different configurations. It should be noted that for any particular facility, technology assessments must be conducted on a site-specific basis, taking into account the plant's existing equipment, current operating scenarios, physical layout and balance of plant considerations, as well as economic and long-term planning considerations. For the purposes of this study, several common configurations of AQC technology already in place at

[2] URS did not specifically address the applicability of any particular technology to IGCC units.

existing fossil-fuel fired facilities were identified to address expected need for additional controls to reduce the emissions of toxic air pollutants. These hypothetical configurations consist of one or a combination of control technologies for PM, SO_2 or oxides of nitrogen ("NO_x").

The most common PM control technologies are fabric filters ("FFs") and electrostatic precipitators ("ESPs"). The most common SO_2 controls are flue gas desulfurization ("FGD") systems (commonly called "scrubbers"), which can be either wet ("FGDw") or dry ("FGDd"). The most common NO_x controls are selective catalytic reduction ("SCR") systems.

The potential need for additional controls to comply with the Toxics Rule was evaluated for seven different hypothetical configurations of AQC technology at existing EGUs, as presented in Table 2-1. The objective of the assessment was to present the most plausible technologies for each plant configuration to achieve the HAP emission limitations. This analysis does not indicate that all plant configurations will need additional controls; nor does it imply that any particular controls installed at a specific plant will unequivocally meet the emission limitations proposed in the Toxics Rule. The analysis is intended as an overview of commercially available, proven technologies that may potentially be employed in order to lower emissions of the targeted HAP species for a given plant configuration. The analysis took into account cost as well as the performance, maturity level, and number of existing commercial installations of each technology. Selected technologies included different control processes that could be implemented for different fuel types, including opportunities for fuel switching. Additionally, the ability of certain technologies to control multiple HAPs was considered when making final selections.

2.4 Summary of Survey Results

URS identified several alternative control strategies that could be deployed where these hypothetical configurations will likely require additional control for PM, HCl and mercury. Up to four different technologies were identified for each scenario, each of which would provide the additional level of control required. Those technologies were then ranked according to the criteria described above. Table 2-1 lists several alternatives for each configuration requiring additional control. Each facility would choose one of these alternatives to achieve compliance with the Toxics Rule, based on the site-specific conditions at that facility. As the table reflects, many facilities with existing PM and SO_2 controls may need no additional controls to meet the PM and HCl limits in the Toxics Rule, respectively.[3] However, if the controls at such facilities

[3] These configurations are noted in the table as "no additional control needed."

are already at their maximum capacity or face other operational challenges, these facilities may indeed need additional controls for PM or HCl as well. Suggestions are provided for upgrades and add-on controls for these outlier plants in the discussion in Section 3.0.

In Table 2-1, configurations that are unlikely to need additional controls to comply with the Toxics Rule are shaded in green. Those likely to require additional controls that can be installed in no more than 24 months are shaded in blue. Those likely to require additional controls that can be typically installed in 36 months (but require more than 24 months) are shaded in yellow. Installation times for new controls are not cumulative. Rather, EGU owners installing multiple control technologies would schedule installation of those controls, and any ancillary modifications to the plant, during the same planned outage, or a coordinated series of outages, provided all controls could be installed prior to the deadline for compliance with the Toxics Rule. Nonetheless, if a particular control cannot be installed prior to this deadline, it is probable that controls necessary for other HAPs would be installed separately, because these control technologies are not, by and large, interdependent.

Section 3.0 of this report provides brief discussions of the rationale behind the various technology selections for each of the hypothetical configurations considered. For each configuration, the report provides strategies for controlling PM, HCl and mercury. Appendix A presents further information on the technologies discussed in this report, including each technology's maturity; the number of commercial installations, if known, the technology's expected performance; capital and operating costs; and the typical schedule for design, installation, and startup.

URS

Table 2-1. Pollution Control Options for Coal- and Oil-Fired Power Plants[4]

Existing Configuration	Control Options to Achieve Toxics Rule Emission Limitations		
	PM	HCl	Hg
Fabric Filter only (§ 3.2)	*No additional control needed*	1) FGDd; or 2) FGDw; or 3) Dry Sorbent Injection;[5] or 4) Coal switch	1) ACI with SO_3 control; or 2) FGDw with re-emission additives; or 3) Combustion Modification; or 4) Coal switch
Fabric Filter with Wet Flue Gas Desulfurization (§ 3.3)	*No additional control needed*	*No additional control needed*	1) ACI with SO_3 control; or 2) FGD additives; or 3) Bromide addition
Fabric Filter with Dry Flue Gas Desulfurization (§ 3.4)	*No additional control needed*	*No additional control needed*	1) ACI with SO_3 control; or 2) Bromide addition
Fabric Filter with Dry Flue Gas Desulfurization and Selective Catalytic Reduction (§ 3.5)	*No additional control needed*	*No additional control needed*	1) ACI with SO_3 control; or 2) Bromide addition; or 3) Coal switch
Electrostatic Precipitator with Wet Flue Gas Desulfurization and Selective Catalytic Reduction (§ 3.6)	1) ESP upgrade; or 2) Scrubber upgrade; or 3) Toxecon; or 4) Wet ESP	*No additional control needed*	1) ACI with SO_3 control; or 2) Bromide addition; or 3) FGDw re-emission additives; or 4) Toxecon
Electrostatic Precipitator only (§ 3.7)	1) ESP upgrade; or 2) Toxecon; or 3) Wet ESP; or 4) FGDw	1) FGDd/FF; or 2) Toxecon w/ Dry Sorbent Injection; or 3) Coal switch; or 4) FGDw	1) Toxecon; or 2) ACI with SO_3 control; or 3) FGDw + Bromide; or 4) Coal switch
Electrostatic Precipitator with Wet Flue Gas Desulfurization (§ 3.8)	1) ESP upgrade; or 2) FGDw upgrade; or 3) Toxecon	*No additional control needed*	1) ACI with SO_3 control; or 2) Bromide addition; or 3) FGDw re-emission additives; or 4) Toxecon

[4] Green highlighting indicates that additional controls are unlikely to be necessary to achieve Toxics Rule emission limitations. Blue highlighting indicates that the top-ranked control technology has installation times of 24 months or less, after permitting. Yellow highlighting indicates that the top-ranked control technology has typical installation times of more than 24 months but less than 36 months, after permitting.

[5] Dry sorbent injection includes Trona, hydrated lime, SBS and other reagents.

3.0 Analysis of Control Alternatives

3.1 Overview

With adequate investment, it should be possible for virtually any EGU to comply with all emission limits under the Toxics Rule, but the required strategy for meeting these limits will depend on each plant's existing control configuration. The following sections present seven typical air pollution control configurations at fossil-fuel fired power plants, as listed in Table 2-1. Each regulated HAP (or surrogate) is discussed in terms of the plant configuration and likely controls that may be necessary or useful in achieving EPA's proposed mercury and air toxics limits. Through the reasoning that is presented in the sections below, technologies have been selected as the most likely to assist in meeting EPA's proposed mercury and air toxic standards, as presented in Table 2-1. Technologies discussed in this section are all commercially available technologies with a history of demonstrated performance, and each is capable of achieving compliance with the Toxics Rule. It is acknowledged that site specific factors will impact the ultimate performance of any AQC technology at a given plant. Additional technologies in the developmental stages may be available and have not been included in the scope of this survey. For further detail on these technologies see Appendix A.

3.2 Fabric Filter Configuration

3.2.1 Particulate Matter (PM)

A properly sized and functional FF should provide adequate PM control to comply with the Toxics Rule. If a facility is in need of additional removal, one option would be to add a wet scrubber after the baghouse to remove additional PM as well as HCl. Toxecon could also be added (downstream carbon injection and baghouse) if multi-pollutant control is desired, as this system provides not only additional PM control, but mercury control as well.

3.2.2 Hydrochloric Acid (HCl)

Plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions and with a sufficient additional margin could adequately control emissions of HCl with the installation of a dry FGD system. FGDd would be effective for relatively high HCl content and, for this configuration, would be less costly than FGDw. However, additional PM emissions can be expected with the operation of an FGDd system; therefore, for units with a FF that is not capable of controlling additional PM loadings, a wet FGD would be an effective way to control both HCl and PM.

For plants burning bituminous coal, switching to a western sub-bituminous coal would appreciably reduce HCl emissions. If coal substitution alone does not achieve compliance for these plants, dry sorbent injection will be sufficient to treat the reduced load of HCl. For plants already burning PRB coal and configured with an efficient FF, dry sorbent injection can be expected to reduce HCl emissions sufficiently to meet the Toxics Rule emission standard, and will be significantly less costly than a wet or dry scrubber.

3.2.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions and with a sufficient additional margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, fly ash sales may be impacted by ACI installation upstream of the FF due to increased carbon levels in the collected fly ash. Additionally, under this configuration, control of SO_3, which tends to hinder the effectiveness of ACI Hg removal, may be necessary for effective operation of ACI when burning high sulfur coal.

If mercury re-emissions from the wet FGD system cause the EGU to exceed the Toxics Rule emission limitation, the use of scrubber additives to reduce the re-emissions may be more cost-effective than ACI.

If further Hg control is needed, using Low NO_x Burners or increasing their NO_x removal performance can lead to higher Loss on Ignition (LOI) to the fly ash, and better Hg removal.

Some plants firing bituminous coal might be challenged to achieve Hg emission limitations due to SO_3 interference with sorbent-based mercury control processes. Plants firing lignite (particularly Texas lignite) will require high levels of removal in order to comply with the Toxics Rule. However, in both cases, a switch to western sub-bituminous coal could appreciably lower mercury emissions. In the case of bituminous coals this would be through decreasing flue gas SO_3 concentrations, and thus increasing the performance of ACI for Hg control. For Texas lignite coals, Hg emissions would likely be lowered due to significantly lower fuel Hg concentrations, as well as moderate improvement in ACI performance.

3.3 Fabric Filter and Wet FGD Configuration

3.3.1 Particulate Matter (PM)

Plants equipped with FF and FGDw are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its fabric filter or scrubber, or both, to achieve the PM emission limitation.

3.3.2 Hydrochloric Acid (HCl)

Plants equipped with FF and FGDw are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule.

3.3.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient additional margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO_3 control may be necessary for effective operation of ACI when burning high sulfur coal.

If mercury re-emissions from the wet FGD system cause the EGU to exceed the Toxics Rule emission limitation, the use of scrubber additives may be able to reduce re-emission of mercury more cost-effectively than ACI.

Finally, although less effective without a selective catalytic reduction (SCR) system, bromine addition could be sufficient for trimming emissions at EGUs firing low sulfur coal if the Hg emission rate needs only small incremental improvement.

3.4 Fabric Filter-Dry FGD Configuration

3.4.1 Particulate Matter (PM)

Plants equipped with FF and FGDd are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its fabric filter or scrubber, or both, to achieve the PM emission limitation.

3.4.2 Hydrochloric Acid (HCl)

Plants equipped with FF and FGDd are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. However, if needed, a dry sorbent injection system would provide a low capital option to trim emissions.

3.4.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient additional margin, an Activated Carbon Injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO_3 control may be necessary for effective operation of ACI when burning high sulfur coal.

Finally, although less effective without a selective catalytic reduction (SCR) system, bromide addition could be sufficient for trimming emissions at EGUs firing low sulfur coal if the Hg emission rate needs only small incremental improvement.

3.5 SCR-FGDd-FF Configuration

3.5.1 Particulate Matter (PM)

Plants equipped with SCR, FF and FGDd are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its FF or scrubber, or both, to achieve the PM emission limitation.

3.5.2 Hydrochloric Acid (HCl)

Plants equipped with SCR, FF and FGDd are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If necessary, removal rates would be improved by either upgrading the scrubber or installing a dry sorbent injection system.

3.5.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO_3 control may be necessary for effective operation of ACI when burning high sulfur coal.

Removal rates of Hg from bromide addition are high in combination with the SCR, especially for PRB coal, and could also provide polishing capability for bituminous coals that require only incremental improvements in removal. However, the SCR, FGDd, FF configuration is not typical for plants firing bituminous coal. If installed on a bituminous coal plant, it is possible that mercury control performance could be constrained by elevated SO_3 levels. A switch to Western sub-bituminous coal would improve the performance of the plant's various mercury controls as well as yield acid gas emission reductions.

3.6 SCR-ESP-Wet FGD Configuration

3.6.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option to provide additional control would be an upgrade of the ESP, the scrubber mist eliminator, or both. Alternatively, a wet ESP may be installed. Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired.

3.6.2 Hydrochloric Acid (HCl)

Plants equipped with a high-efficiency wet FGD system are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If additional removal is needed, removal efficiencies could be improved by one or more of the FGD upgrades described in Appendix A.

3.6.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. The primary choice for plants firing bituminous coal would likely be ACI with additional SO_3 control technology; some plants with this configuration might not require any additional mercury control. For plants firing low-sulfur fuels, the primary choice would likely be bromine addition. For plants requiring additional PM control, or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Under this configuration, scrubber re-emissions additives may be required to control Hg emissions in conjunction with other control technology, depending on mercury removal performance of the wet FGD.

3.7 ESP Only Configuration

3.7.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option for additional control would be an upgrade of the ESP. Alternatively, a wet ESP may be installed. Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired. In some cases, particularly plants burning bituminous fuels, a wet FGD may be installed if additional SO_2 control is also desired.

3.7.2 Hydrochloric Acid (HCl)

A dry FGD system will provide effective control for relatively high HCl content, but may require installation of a fabric filter to control the additional particulate loadings dry FGD would add. A dry FGD system is likely to be more cost effective than a wet FGD, if switching to a FF to handle the additional particulate loading is not necessary. Toxecon used in conjunction with sorbent injection would be a viable control option if multi-pollutant control is desired. For plants firing bituminous coal, a switch to a western coal would reduce the HCl loading on the ESP, likely enabling dry sorbent injection alone to achieve the Toxics Rule emission limitation.

3.7.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. For plants burning western coals, or those requiring additional PM control or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Alternatively, an ACI system using brominated sorbent may be used for plants burning western coals; however, mercury removal under this option depends on ESP performance. Installation of a wet FGD may be a viable option for plants that desire additional SO_2 control; using this strategy, bromide addition may also be an option for mercury control for EGUs firing western fuels.

The primary choice for a plant firing bituminous coal would likely be an ACI with additional SO_3 control technology. However, plants firing bituminous coal will be challenged to achieve desired mercury reductions due to SO_3 interference. Plants firing lignite containing high mercury levels (e.g., Texas lignite) will require high levels of removal which are difficult to obtain across an ESP. In both cases, a switch to a low-sulfur sub-bituminous coal would lower mercury emissions via better mercury control performance and, for Texas lignite fired EGUs, lower coal mercury levels.

3.8 ESP-FGDw Configuration

3.8.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option to provide additional control would be an upgrade of the ESP, the scrubber mist eliminator, or both. Alternatively, Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired.

3.8.2 Hydrochloric Acid (HCl)

Plants equipped with a high-efficiency wet FGD system are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If additional removal is needed, removal efficiencies could be improved by one or more of the FGD upgrades described in Appendix A or by or a dry sorbent injection system.

3.8.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. For plants requiring additional PM control or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Bromine addition would likely be the primary control strategy for plants burning low-sulfur fuels. Alternatively, for plants burning low-sulfur fuel, ACI is another control option. ACI would also be an option for plants firing bituminous coal, but SO_3 control technology may be necessary Under this configuration, scrubber re-emission additives may be required to control Hg emissions in conjunction with other control technology, depending on mercury removal performance of the wet FGD.

3.9 Installation Schedule

None of the typical configurations considered in this assessment included existing mercury controls, though many EGUs are presently equipped with ACI. Accordingly, this analysis concludes that every EGU configuration would require mercury control, and identifies ACI as the technology of choice for six of the seven configurations considered. ACI has a typical installation time of 12 to 18 months after permitting. As URS assumes fabric filters to provide adequate PM control to comply with the Toxics Rule PM emission limitation, ESP upgrades are the top-ranked alternative for improving PM control from EGUs. Depending on the scope of the upgrade, installation times for ESP upgrades typically run from six months for the simpler upgrades to twenty-four months for the most comprehensive upgrades. Dry FGD technology, with a typical installation time of 24 to 36 months, was identified as the top-ranked

technology for only two of the seven configurations evaluated. Dry FGD has the longest installation time of the top-ranked technologies.

These installation times are not cumulative; rather, plants installing multiple technologies would typically coordinate installation so that all controls for mercury, HCl and PM would be installed during the same outage, although some additional outage time may be necessary to co-ordinate simultaneous installation. With nearly four years between the proposal of the Toxics Rule and the date EGUs must come into compliance, these improvements can be accomplished on-time, provided EGU owners move quickly to initiate these upgrades in response to the proposed rule, and no unreasonable delays occur in the permitting process or supply chain.[6]

4.0 Conclusion

Using the emission limitations proposed by EPA in the Toxics Rule as its guide, URS examined the existing field of demonstrated, available AQC technologies to determine whether these technologies would be sufficient to allow typical coal-fired and oil-fired EGUs to achieve these emission limitations. URS concluded that the emission limitations proposed in the Toxics Rule can be achieved by typical EGUs through the application of successfully demonstrated, available AQC technologies. The controls considered in this analysis can typically be installed in 18 months (for ACI), 24 months (for ESP upgrades), or 36 months (for FGDs) after detailed design and permitting is complete. If EGU owners make their technology choices and initiate the permitting process promptly, they should be able to comply with the Toxics Rule emission limits by the deadline of early 2015 (almost 48 months after proposal of the rule). Plants facing extreme delays in permitting or the supply chain, or with atypically complex upgrade requirements, have an opportunity to request an additional year to come into compliance with the Toxics Rule.

[6] Potential delays associated with heavy equipment lead times have not been included in this analysis because it is not possible to predict at this time whether any particular delay will occur.

APPENDIX A

A.0 Technology Descriptions

This section provides a high-level overview of each add-on control technology that has been presented in the main body of this report. Because some of these technologies treat multiple HAPs, they cannot easily be categorized by the pollutant they treat. However, several of the technologies described are upgrades or modifications to AQC systems present at existing EGUs. These modifications are grouped separately from technologies not considered in the hypothetical configurations discussed in Section 3.0 of the report.

Equipment costs provided in the following technology descriptions are typical; site specific circumstances may lead to higher or lower costs due to site specific requirements. Additionally, cost estimates include equipment and operating costs, where specified; planning and financing costs are not included. The estimated schedules for implementation of the technologies represent time from the placement of the equipment order to installation. This assessment is based on cost and schedule information available today, and the estimates provided here may be affected by future changes in pricing and scheduling demand.

A.1 Modifications to Existing AQC Systems at EGUs

A.1.1 Cold-side ESP Upgrades

The use of electrostatic precipitator (ESP) technology for the removal of PM is well established and has been implemented for over 100 years. Decades old, or poorly performing ESPs that were designed for lower emission performance can be upgraded to improve collection efficiency and reduce operating costs. Often the performance can be increased through a thorough examination to insure that worn or broken components are replaced, and insuring that the gas flow distribution through the system is uniform. Other ESP modifications and upgrades may include:

- Upgrade of control systems such as power controlled rapping (PCR). $0.27/kW
- Upgrade of ESP power supplies. $1/kW
- Add SO_3 and/or ammonia injection (to the flue gas upstream of the ESP) to improve ash agglomeration. $2-10/kW
- Replace wire and weight systems, widening the gas passages and adding rigid discharge electrodes. This will improve the mechanical integrity of the electrodes and can improve performance with existing TR sets.
- Increase the number of electrical bus sections.
- Add rappers to decrease the amount of collecting surface area served by each rapper

- Increase the collecting surface area - several vendors report that many of the older ESPs in the US can be modified to increase the collecting surface area by 10-20% within their existing footprint. Another option is to add an additional field. $30-0/kW
- Reduce gas flow through the ESP by repairing upstream leaks or upgrading air heaters to limit air in-leakage
- Add a Bipolar Agglomerator to the inlet of the ESP. $25-40/kW.

The capital costs associated with these upgrades will depend on the extent to which the ESP is modified. If the unit is particularly old or poorly performing, more repairs or modifications may be necessary. Some vendors claim that modifications such as upgrading the power supplies and controls will pay for themselves within one to two years due to savings in power consumption. Operating costs for many of these modifications will not increase over the cost of previous operation, and in many cases the operating costs will decrease due to gains in collection and power consumption efficiency. The operating costs for injecting SO_3 and/or ammonia for ash conditioning will be approximately 2-4 $/kW-yr.

Another method to improve the performance of an ESP would be to add a Bipolar Agglomerator to the ESP inlet duct. An agglomerator manufactured by Indigo Technologies uses a bipolar charging zone to charge part of the dust positively and part of the dust negatively. This is accomplished by passing the flue gas through a series of alternating positive and negative parallel passages. The dust then enters a mixing zone where the oppositely charged particles are attracted to each other and form a larger agglomerated particle that can be more easily removed in the ESP. The agglomerator is similar to an ESP without collection plates. This technology is relatively new with only 45 commercial installations at power plants, mostly outside the U.S. Reductions in opacity are reported to be 40% to 70%, with some units burning sub-bituminous and bituminous fuels reporting reductions in opacity of approximately 50%. The cost to add an agglomerator to an existing system is approximately $25-40/kW. The operating costs are approximately $0.02/kW-yr and consist primarily of the power required to operate the unit.

- ESP UpgradeTechnology Maturity: mature
- Number of Units Upgraded: hundreds
- Expected Performance:
  - PM: +99%
- Capital Costs: 0.27 - 20 $/kW
- Operating Costs: .02- 4 $/kW-yr.
- Installation Schedule: 6-12 months from award of design to operation for low capital options; 12-24 months for implementation of higher capital cost modifications / additions
  - **Outage Required:** 0-7 days if no plate/electrode modification. 2-4 weeks with plate/electrode modification.

A.1.2 Fabric Filter Upgrades

A typical fabric filter should be able to meet MACT PM emission standards. If a plant is unable to meet emission standards with a fabric filter, the cause is most likely due to bag failures. To minimize bag failures it may be possible to optimize the cleaning process to minimize these problems. On a pulse jet baghouse this may include adjusting the pulse pressure and duration to more thoroughly clean the bags. By cleaning more thoroughly, the interval between cleaning may be reduced and the life of the bags could be extended. Optimization of fabric filter performance may also be achieved by an evaluation of the maintenance schedule. An analysis of process and maintenance data could lead to an understanding of how to anticipate bag failure and replace them before the failure actually occurs.

Another alternative to increase PM collection would be to replace the existing bags with different material such as a membrane bag. Different bag materials will have different pressure drop characteristics and it will be necessary to determine whether the plant has existing fan capacity to handle the upgrade.

An additional solution would be to add additional compartments to the existing baghouse to increase the collection surface, or add a COHPAC system. The Toxecon could be necessary if a multi-pollutant strategy is desired and it is advantageous to maintain fly ash sales from the existing baghouse. Adding additional compartments or a Toxecon system are both capital intensive solutions and may not be practical for plants that have restricted space available for retrofit.

- **Technology Maturity:** mature (fabric filter)
- **Number of Commercial Installations:** many
- **Expected Performance:**
  - PM: +99%
- **Costs for Optimizing Fabric Filter Performance:** $200K - $500K, excluding projects where complete bag replacement is required
- **Schedule:** 3-6 months for performance optimization
- **Costs for Adding Compartments or Toxecon:** 75-130 $/kW
- **Schedule:** 12-24 months from detailed design to startup
  - **Outage Required:** 7-10 days. (3-4 weeks if a new fan is required)

A.1.3 FGDw Additives

As discussed in Section 1.2.8, wet scrubbers can remove acid gases, PM and mercury. However, removal of Hg^{+2} by wet FGD systems can be limited by a phenomenon called "re-emission" that results in a portion of the scrubbed Hg^{+2} being chemically reduced to Hg^{0} in the FGD liquor. Once reduced, the insoluble Hg^{0} is released back into the flue gas. The re-emission process is not currently well understood, but is believed to occur by reaction with bisulfite ions (dissolved SO_2 at lower Ph) in the FGD liquor, according to the following overall reaction:

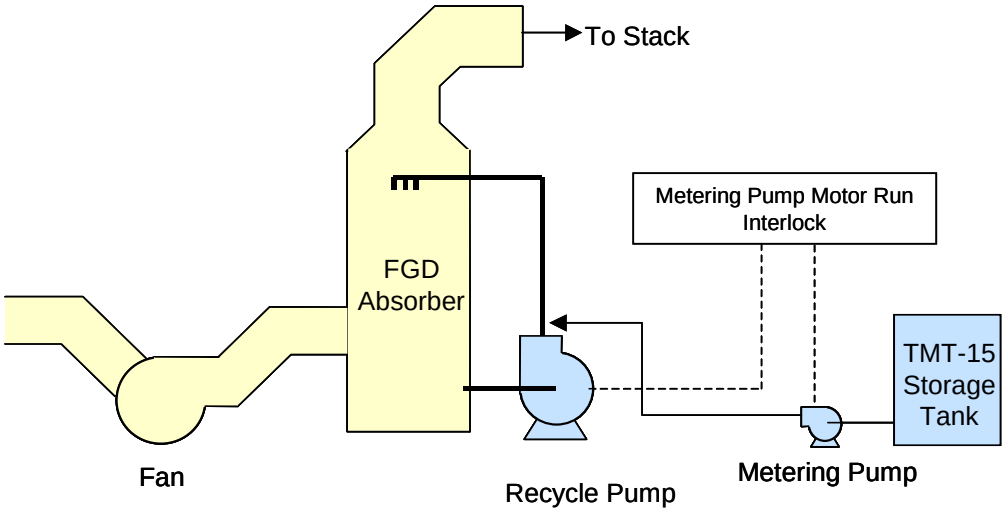
$$Hg^{+2} + HSO_3^- + H_2O \leftrightarrow Hg^0 + SO_4^{=} + 3\ H^+$$

The main pathway for this reaction is believed to be through the formation of complexes between Hg^{+2}, sulfite, chloride, and possibly thiosulfate ions (present in inhibited oxidation FGD systems). Even in forced oxidation FGD systems, there can be sufficient sulfite present for re-emission reactions to occur. As more is understood, it may be possible to control FGD chemistry to minimize re-emission (e.g., by controlling forced oxidation air rates and/or liquor chloride concentrations). However, a near-term solution may be the use of FGD additives to precipitate Hg^{+2} out of the liquid phase before it undergoes reduction reactions.

Additives generally work by rapidly precipitating oxidized mercury from the FGD liquor, so it will not react with other liquid-phase species such as sulfite ions and be reduced to the elemental form. Most additives contain sulfides, which produce a very insoluble salt with oxidized mercury.

The most straightforward method of adding sulfides to FGD systems might be to introduce H_2S into the scrubbed gas upstream of the FGD absorber. However, H_2S is extremely toxic and most utilities would not want to handle this gas at their plants. Another approach is to add sulfide-containing salts to the FGD liquor. However, some of these salts can release H_2S if they are exposed to low Ph, aqueous conditions. Four commercially available additives are discussed below: Degussa's TMT-15, Nalco's additive 8034, Babcock & Wilcox's sodium hydrosulfide (NaHS) additive, and Solucorp's IFS-2C additive. Figure A-1 shows a schematic for a sample TMT-15 addition system.

Figure A-1. TMT-15 Additive System for FGD Absorber with One Recycle Pump



One operational issue that has not fully been addressed is the impact of re-emission additives on gypsum Hg content. Some owners of FGDw systems sell the gypsum that is produced as a byproduct of the scrubber. An increase in the mercury content of the gypsum byproduct could affect sales of the product. Currently there are few if any specifications on gypsum Hg content, but re-emission additives that precipitate mercury could increase gypsum Hg content to the point where the gypsum would potentially no longer be salable. If this is the case, the effective cost of re-emission additives would increase for those FGDw operators who are no longer able to sell the gypsum byproduct for $5-10/ton, but rather a liability costing $5-20/ton to dispose of in a landfill.

- **Technology Maturity:** Testing 3 years of experience
- **Number of Commercial Installations:** Several, in Europe
- **Expected Performance:**
  - Hg – An additional 10-50% above native capture
- **Capital Costs:** 0.75-1.5 $/Kw
- **Operating Costs:** 0.2-0.5 $/Kw-yr.
- **Installation Schedule:** 6-9 months for design, installation, and parametric testing.
  - **Outage Required:** None.

A.1.4 Flue Gas Desulfurization (FGD) Upgrades

Existing FGD scrubber units can be modified to enhance SO_2 removal performance and improve unit operations and reliability. Such modifications are applicable to older FGD units, units currently not being operated (i.e., moth-balled units) or units originally designed for lower removals than now required or desired. The extent of a given upgrade process is typically a function of the required performance levels, configuration and condition of the existing absorber, and other site-specific balance-of-plant requirements.

Upgrades to a scrubber can offer an appreciable cost advantage over replacing an existing FGD unit with either a new unit or an alternative air quality control technology. This is achieved by salvaging as many structural components and equipment associated with the existing unit as possible. This includes reuse of existing structural steel and absorber shells as well as high-capital process equipment such as pumps and compressors (where applicable).

Upgrades have been performed on a large number of FGD units over the past 15 years and have resulted in increased SO_2 removal performance to levels ranging from 92 – 99%. These have ranged from minor modifications to the internal components of a given unit, to enhance gas-liquid contact, to conversion of some units from one FGD technology to another coupled with the addition or modification of various balance-of-plant equipment or processes. An example of a technology conversion could include modifications to change a dual-alkali scrubber to a limestone forced-oxidation unit.

Because of the large variation of activities and associated costs that are possible within the range of scrubber modifications that can be implemented, it is convenient to classify upgrades into three different categories, as described below.

- Minor Upgrades: These consist of moderate changes to some of the internals of a scrubber module, reusing most of existing process and structural components. The primary focus is enhancement of gas/liquid contacting within the absorber. Examples of applicable modifications include installation of absorber trays or wall rings as well as modifications to the configuration or type of reagent spray headers used (to improve overall reagent coverage and overlap within the absorber). Typical minor upgrades have been used to boost FGD performance to 92 – 97% SO_2 removal.
- Moderate Upgrades: These upgrades typically consist of major overhauls to the internals of a scrubber module to replace poor performing or failing components. In many cases, the existing internal process and structural components are removed; the absorber shell and large equipment components are maintained. Modifications include installation of new and improved reagent spray header arrays and absorber trays.
- Major Upgrades: For some old FGD units, systems operating with lower-efficiency technologies and units that have been out of commission for extended periods of time, major upgrades are required obtain desired levels of performance. Such upgrades typically involve the same activities described for moderate upgrades, but can also include additional replacement of some large equipment along with modifications or additions associated with balance-of-plant equipment. The latter can include additions of or modifications to reagent preparation systems (e.g., ball mills), byproduct dewatering systems, and process slurry recirculation systems. In some cases, enhancements are made to existing mist eliminators to reduce carry-over of particulate material from the scrubber. Conversions from one FGD technology to another may include demolition of old or unneeded process components and/or addition of new ones.

The costs associated with FGD system upgrades are commensurate with the level of capital improvements or replacements required for a specific unit. The costs for minor upgrades typically range from $5 - $10/kW, whereas moderate upgrades typically range from $15 - $25/kW. The costs for major upgrades can be quite variable, depending on the nature of upgrade and extent of balance-of-plant modifications made; these upgrades typically range from $50 to no more than $100/kW. The pending EPA MACT rule coupled with the multi-pollutant control nature of wet FGD scrubbers should ensure that scrubber upgrades continue to be a feasible option for many plants to enhance emission reductions.

The impact of a scrubber upgrade on unit operating costs is determined by the nature of the modification(s). Changes in reagent preparation and process transport costs are impacted by the nature of the modifications made to preparation equipment, recirculation lines, and spray headers. For example, increased pressure-drop across the reagent slurry recirculation system (i.e., due to increased number of spray headers) would result in increased energy costs to operate the process. The addition of improved contactors within the absorber vessel may enable slurry

liquid-to-gas ratios to be reduced, thus having an opposite effect on costs. The addition of new processes associated with byproduct dewatering or water treatment would increase operating costs to varying degrees. A transition to a zero water discharge (ZWD) system could result in elimination of the need for a water treatment system, thus having the opposite effect; however, this benefit would be off-set by higher capital cost and energy usage required for the ZWD scheme. Furthermore, the conversion to an FGD process that produces a marketable gypsum byproduct could result in an appreciable revenue stream for the plant if local market conditions are favorable. Thus, operating cost impacts of scrubber upgrades can vary substantially from plant to plant, ranging from actually reducing operating costs to significantly increasing operating costs, depending on the nature of the existing and modified units.

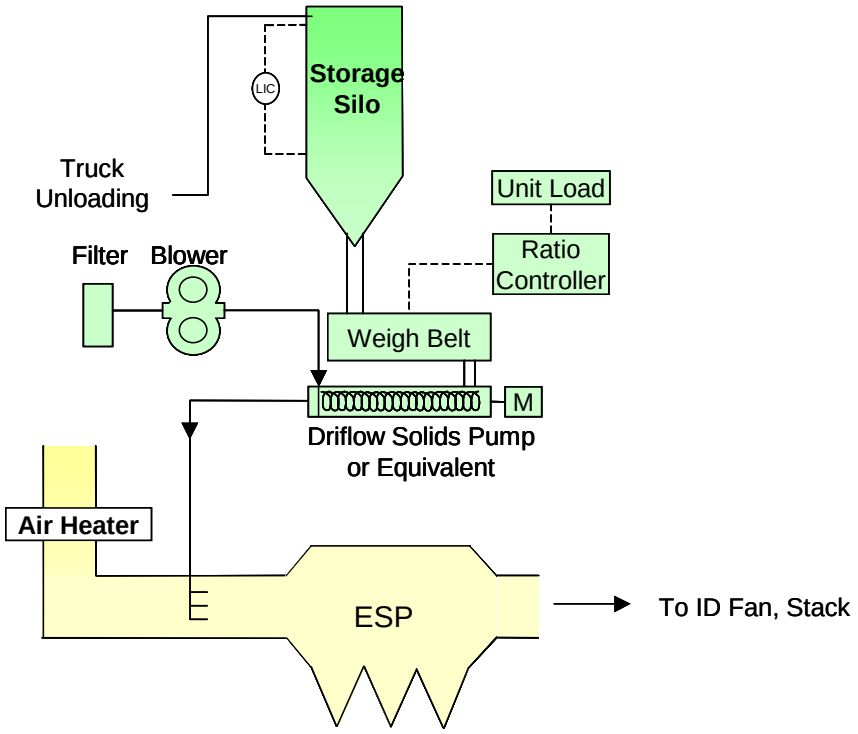
- **Technology Maturity**: FGD scrubber upgrades have been conducted over 15 years.
- **Number of Commercial Installations:** Approximately 50 FGD units have been upgraded to enhance performance or lower overall operating costs.
- **Expected Performance:**
  - SO_2: Upgraded FGD scrubbers have SO_2 removal rates of 92 – 99%.
  - PM: High-efficiency FGD units can typically remove up to 70% of the particulate material entering the absorber in the flue gas.
  - HCl: Most well-performing wet FGD units are able to achieve greater than 90% removal of hydrogen halides. HCl would be expected to be removed across a wet FGD unit at a similar or higher efficiency than SO_2.
- **Capital Costs:**
  - Minor Upgrades: $5 - $10/kW
  - Moderate Upgrades: $15 - $25/kW
  - Major Upgrades: $50 - $100/kW
- **Operating Costs:**
  - Variable (see discussion above)
- **Installation Schedule:** Typical schedules for the design, installation, and startup of FGD upgrades range from 12 – 36 months.
  - **Outage Required:** 4-8 weeks, in two parts.

A.2 Additional AQC Technologies and Process Changes

A.2.1 Activated Carbon Injection (ACI)

Activated carbon injection (ACI) is the most demonstrated of the add-on mercury control technologies considered. Figure A-2 illustrates how ACI would be implemented upstream of a cold-side ESP (injection upstream of a FF baghouse would look similar, except for exchanging a baghouse for the ESP). Sorbent is metered from a storage silo with a weigh belt or volumetric feeder. A blower provides the motive force to convey the sorbent from the feeder to the flue gas duct. The sorbent is injected into the flue gas duct via a series of injection lances. The lances are placed upstream of the PM control device (PCD) or in rare cases upstream of the air heater.

Figure A-2. Simplified Schematic of ACI Installation.



The performance of ACI for mercury control can be very site specific. Factors such as duct residence time, mixing effectiveness, PCD size and type, flue gas temperature, flue gas HCl concentration, concentrations of competing species in the flue gas (e.g., SO_3) and other factors make it difficult to use full-scale performance data from one site to predict performance at another. Each of these parameters is explored below in somewhat more detail.

- The more important design factor for the lances is the promotion of mixing between the activated carbon and the flue gas. Better mixing can be achieved through nozzle design on the lances and careful lance placement. These parameters can be optimized with the help of computational fluid dynamics (CFD) modeling, in which the trajectory of the injected sorbent particles is computed throughout the flue gas path.
- PCD size can be important because carbon/ash carryover from small PCDs can limit the injection rate. Carbon carryover has been visually observed on PM filters placed at the outlet of small and large ESPs, but quantification of the carryover is difficult. URS experience with ACI in front of one small ESP (SCA = 173 ft^2/kacfm) (DOE project DE-FC26-03NT41987) showed that the injected carbon adversely affected ESP sparking, due to carbon tracking on insulators. Increased sparking could limit the amount of carbon that can be injected and hence the mercury capture that can be achieved.
- ACI performance is best at lower flue gas temperatures (<300°F). Carbons are being developed for high temperature applications, such as Sorbent Technologies' H-PAC. At temperatures below 650°F, H-PAC is reputed to have the same mercury removal performance as Sorbent Technologies' standard brominated carbon B-PAC.

- Activated carbon injection performs poorly in flue gas with high SO_3 concentrations, such as flue gas derived from eastern bituminous coals. The SO_3 competes with mercury for adsorption sites on the activated carbon. SO_3 tolerant sorbents (discussed below) and SO_3 mitigation technologies (discussed in a previous section) are possible means to make ACI more effective for bituminous flue gas.
- For low-halogen flue gas, brominated sorbents can offer significantly higher mercury removal than standard activated carbons. Brominated carbons have shown only a small advantage for high chloride flue gas, likely because SO_3 concentrations are high in these types of gases.

There are no data to predict the long-term effects of a permanent activated carbon injection process that is in operation for several years. As noted above, increased sparking has been observed on small ESPs. Carbon breakthrough has been observed on both small and large ESPs. Carbon breakthrough may compromise gypsum quality for units that are equipped with wet FGDs downstream of the ESP. Carbon breakthrough may also trigger New Source Review for units that do not have additional PM controls downstream of the ESP.

A disadvantage of using ACI for mercury control is that the carbon in the fly ash can adversely affect the air entrainment capabilities of concretes made using fly ash to replace some of the cement. The carbon sorbent in the fly ash competitively adsorbs the air-entraining admixtures (AEAs) that are added to concrete for air entrainment and stabilization. This competition results in a larger volume of AEA being needed, and more significantly to ready-mix concrete manufacturers, it results in variability in the amount of AEA needed.

- **Technology Maturity:** Testing & Full Scale Operation; ~10 & 2 years of experience
- **Number of Commercial Installations:** 50+
- **Expected Performance:**
  - Hg – An additional 10-90% above native capture
- **Capital Costs:** 2-10 $/kW (depending upon unit size)
- **Operating Costs:** 2-20 $/kW-yr.
- **Installation Schedule:** 12-18 months for design, installation, and parametric testing.
  - **Outage Required:** None.

A.2.2 Dry Sorbent Injection ("DSI")

Sorbent materials can be injected at various points along the flue gas path to control acid gases. The main target of this technology is SO_3; however additional acids may also be removed such as HCl, HF, and SO_2. The removal of these additional gases depends on the amount and type of material added to the system. Sorbent reagents can be injected either as slurry or as a dry material. Slurry is typically injected using dual fluid nozzles where the water evaporates upon injection leaving dry sorbent material to react with the acid gases in the flue gas. Dry material is injected using pneumatic conveyors to carry the material to the injection point. Sorbent injection

is a mature technology with approximately 90 units currently being treated with one of five main reagents:

- Trona – (22 units) dry injection of a mined mineral consisting of sodium bicarbonate and sodium carbonate
- SBS – (20 units) liquid injection of soda ash or sodium bisulfite
- Hydrated Lime – (28-34 units) dry injection
- Magnesium Hydroxide – (1 unit) slurry
- Ammonia – (8 units) anhydrous or aqueous

Sorbents can be injected at several locations along the flue gas path including into the boiler, before an SCR, before the air heater, before the ESP or fabric filter, or before an FGD system. Table A-1 illustrates injection locations for each Sorbent material and includes the typical SO_3 removal rate at normalized stoichiometric ratios (NSR) of reagent to SO_3. Ammonia is currently used to condition fly ash for removal in an ESP, and could be used for SO_3 control; however the stoichiometric ratio must be carefully regulated to prevent excess ammonia emissions. This may be an attractive option for plants with an existing SCR and infrastructure for ammonia storage on site.

Table A-1. Injection Locations, SO_3 Removal, and Required Stoichiometric Ratio

Typical Injection Location	Trona	SBS Injection	Hydrated Lime	Magnesium Hydroxide	Ammonia
Boiler				●	
Before SCR		●			
Before AH	●	●		●	
Before ESP/FF	●		●		●
Before FGD			●		
Typical SO_3 Removal	70-90%	95-99%	50-80%	50-90%	80-95%
Typical NSR	2-3	1-1.5	3-5	2-4	1.5-2

The typical capital cost for this technology is about $10/kW with the exception of ammonia injection that is approximately $5/kW. This includes pumps, spray nozzles, and control equipment. The operating costs consist of the reagent, maintenance, water, and parasitic power costs. A majority of the operating cost (~80%) consists of the reagent feed stock, thus making the overall operating cost dependent upon the normalized stoichiometric ratio necessary to get the desired removal rate. The NSR listed in the table above is for SO_3, additional reagent will be necessary to capture HCl and HF in some plant configurations. SO_2 capture is also possible by injecting excess reagent; however the PM collection device must be capable of handling the increased PM load, which may be 50-80% greater than the fly ash alone. Table A-2 contains a summary of conceptual capital and approximate costs.

Table A-2. Capital and Operating Costs for Dry Sorbent Injection

	Trona	SBS Injection	Hydrated Lime	Magnesium Hydroxide	Ammonia
Capital Cost ($/kW)	10	10	10	10	5
Reagent Cost ($/ton)	180	275	125	500	600
Approx. Operating Costs for SO_3 and HCl capture ($/kW-yr.)	3.4 - 5	2 - 2.75	2 – 3	5.1 - 8.6	2.2 - 3.5

- **Technology Maturity:** mature; 7+ years of operating experience
- **Number of Commercial Installations:** 90
- **Expected Performance:**
  - SO_3 – 50 - 99% depending on reagent, injection rate and configuration
  - HCl, HF – up to +90%
  - SO_2 – 40 - 90% possible
  - Hg – enhances ACI performance by removing SO_3 especially in bituminous flue gas
- **Capital Costs:** 5 - 10 $/kW
- **Operating Costs:** 2 - 8.6 $/kW-yr. ($SO_3$ only)
- **Installation Schedule:** 9-12 months from award to commercial operation
  - **Outage Required:** None.

A.2.3 Coal Switching

With upcoming MACT limits on HCl and mercury emissions at coal fired power plants, there are several scenarios where coal switching may be a cost-effective option for meeting emission limits, rather than the installation of pollution control devices. There are likely to be two dominant cases where coal switching is a viable option for meeting the upcoming MACT standards:

- Switching from an Eastern bituminous or Lignite coal to a Powder River Basin (PRB) coal to meet HCl emissions limits.
- Switching from Lignite (Texas-derived in particular) to a PRB coal to meet mercury emissions limits.

For units switching from bituminous coal, it is recognized that the feasibility would depend on the ability of a given plant to operate either with higher coal flow (and associated flue gas volume) or at a de-rated capacity.

Without some form of scrubber (wet or dry) it is unlikely that a plant burning eastern bituminous coal could meet the potential HCl emission limits. Installation of a new FGD system or a significant overhaul of an existing FGD system would be capital intensive project, and cost approximately $100/Kw or more. PRB coals have approximately 20-100 times less chloride and

4-10 times less sulfur than eastern bituminous coals. By switching to a PRB coal, it could be possible to meet

HCl emission limits by using a less expensive HCl control technology like alkaline injection. For this switch to be economically favorable, the following would have to be true:

- The site burns eastern bituminous or a lignite coal with significant chloride and sulfur content.
  - The site does not have any HCl control technologies in place, or has a significantly under-performing HCl control technology that would need a significant overhaul to meet HCl emissions limits.
  - The site has a FF or ESP that can handle additional PM loading from alkaline injection for HCl removal. A FF would be more effective in removing HCl with alkaline injection than an ESP, and would also likely be more able to meet PM emissions limits even with the additional PM load.

Due to the high content of mercury in lignite, it is unlikely that a plant using lignite as its only fuel source would economically be able to meet a non-coal specific mercury emission limit. Therefore, complete fuel switching, or if significant pollution control equipment was already in place with high native capture (SCR, FF, FGD), fuel blending would be necessary to meet the emissions limits. Due to similar energy content, availability, and relatively low cost, the most likely candidate for an alternate fuel is PRB coal.

A.2.4 Combustion Modifications

Boiler combustion modifications may be used to optimize mercury capture by unburned carbon, which is subsequently collected along with fly ash in the ESP. It has been observed in limited field testing reports that for bituminous coal fired plants significant mercury control percentages (up to 75%) can be achieved with fly ash having elevated LOI values.[7]

One research organization, G.E. Environmental Services, has conducted full-scale tests on using combustion modifications to optimize this effect. The full-scale tests were co-funded by the U.S. Department of Energy. One project (DE-FC26-03NT41725) has employed coal "re-burning" to optimize mercury capture, while the other (DE-FC26-05NT42310) is investigating air staging using (separated over-fire air [SOFA]).

In the first demonstration project, GE reported up to 60% mercury removal with optimized re-burning and 10-15% LOI in the fly ash at a 300°F ESP inlet flue gas temperature. They reported up to 75% mercury removal at similar conditions, but with a lower, 270°F ESP inlet temperature. In the second project on a 200-MW tangentially-fired unit, GE reports that

[7] Lissianski, Vitali. "Mercury Control Using Combustion Staging". Presented at DOE-NETL Mercury Control Technology R&D Program Review. Pittsburgh, PA. July 13, 2005.

optimized SOFA achieved up to 65% mercury removal with about 5% LOI in the fly ash at a 300°F ESP inlet temperature. They reported a strong effect of flue gas temperature on mercury capture by LOI, and tested duct humidification as a means of lowering the ESP inlet flue gas temperature.

The Lehigh University Energy Research Center also has been investigating the effects of boiler combustion modifications on mercury emissions. They have developed a predictive model, and have conducted full-scale tests at three eastern-bituminous-coal-fired units, ranging from 108- to 650-MW in size. Two sites also fire some imported coals. In testing on a 250-MW tangentially fired boiler, they were able to enhance capture of mercury with the fly ash from a baseline level of about 6% to about 60% with "optimum" low mercury settings and a mid-level excess oxygen value. Variables optimized included excess oxygen, coal mills in service, mill classifier setting, separated over-fire air (SOFA) percentages, burner and SOFA tilt, air heater exit temperatures, and flue gas residence time prior to PM removal. The latter was accomplished by de-energizing an old ESP upstream of a new, larger ESP. However, the 60% mercury reduction level was achieved in some tests without de-energizing the old ESP.

Combustion modification, to increase mercury capture, will increase carbon content in the fly ash. If the ash is being sold, increased carbon content could either reduce the value or render the ash unsalable. Such costs can be significant when ash goes from being a commodity worth $5-20/ton to a liability costing $5-20/ton to dispose of in a landfill.

There are not many studies available on combustion modification and its impact on mercury removal on PRB coal fired power plants. Part of this is due to the general efficiency in combustion of PRB coals, and that achieving an LOI of greater than 1 wt% is difficult. Due to low SO_3 concentrations in the flue gas and the highly alkaline ash, even small increases in LOI have been shown to increase Hg capture.

Based on the evidence at hand, combustion modification may possibly be used for mercury control either in conjunction with another mercury control technology when native capture is low, or as a way of increasing a high native removal such that no other mercury control technologies are necessary. Combustion modification will be most effective if a baghouse is used for PM capture, as increased LOI will be more effective with fabric filters than with ESPs.

- **Technology Maturity:** Testing; ~10 years of operating experience
- **Number of Commercial Installations:** few operating
- **Expected Performance:**
  - NO_x – 0-20% additional removal
  - Hg – An additional 10-50% above native capture
- **Capital Costs:** 0.5-1 $/kW (Study necessary to "tune")
- **Operating Costs:** 0.2-1 $/kW-yr. (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter5.pdf)

- **Installation Schedule:** 3-6 months for experimental design and "tuning" of the combustion tests.
  - **Outage Required:** None.

A.2.5 Dry Flue Gas Desulfurization

Dry FGD (also referred to as a "spray dryer") is typically employed for the removal of SO_2 emissions, but may also be used to accomplish removal of acid gases and selenium. Removal of these additional species may be necessary to achieve anticipated emissions standards under the Toxics Rule. In a spray dryer absorber vessel, flue gas comes in contact with an atomized slurry of alkaline reagent and recycled solids for removal of SO_2 and acid gases. The alkaline reagent, typically lime, reacts with incoming pollutants to form calcium salts, such as calcium sulfate, calcium chloride, and calcium fluoride. Solids from the scrubber are captured in a downstream fabric filter. A portion of the reaction products and fly ash are recycled to the reagent slurry feed and the remaining are transported to landfill for disposal. The spray dryer technology, a type of dry flue gas desulfurization (dry FGD), operates at 20-30° F above saturation temperature, and as such, does not generate a wastewater purge stream as in a wet FGD, or limestone forced oxidation (LSFO) system. Spray dryers are limited in removal capabilities for higher sulfur coals compared to their wet FGD counterpart, and scrubber vessels are limited in size, generally treating up to 350 MW for a single vessel.

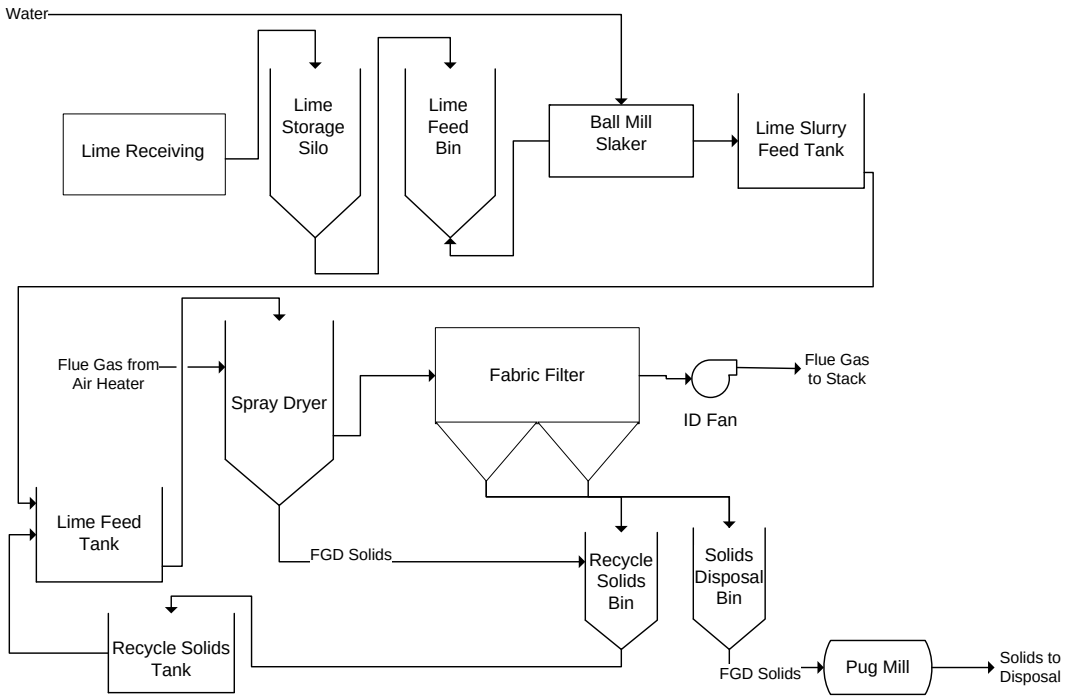
The spray dryer technology represents a mature technology that has over 30 years of operating experience, including operation at several of Exelon's facilities. Although spray dryers have traditionally been employed for SO_2 emissions reduction from coal-fired power plants, they have also been shown to effectively remove acid gases (HCl, HF), and particulate with the downstream fabric filter, to meet anticipated MACT limits.

The lime spray dyer may be appropriate for removal of particulate, acid gases, and selenium and SO_2 at facilities that do not currently employ a scrubber system. Facilities with an existing electrostatic precipitator (ESP) or fabric filter (FF) may choose to continue operation of the existing particulate control device in order to maintain flyash sales or they may opt to abandon existing particulate control devices, relying on the spray dryer's downstream fabric filter for particulate control, and disposing of all fly ash and FGD solid byproduct.

A general process flow diagram of the lime spray dryer is shown in Figure A-3. Major capital cost components of a lime spray dryer system include the following systems:

- Lime reagent supply and handling equipment,
- Absorber vessel and associated pumps and tanks,
- Flue gas handling systems (duct work and ID fans), and
- Waste/byproduct handling systems.

Figure A-3. Lime Spray Dryer FGD System



The spray dryer system requires a significant engineering effort and footprint at the plant site. Capital costs will be affected by the type of fuel, the desired removal efficiency, specific site arrangement and existing equipment considerations. Typical capital costs for a lime spray dryer system would likely be in the range of $220-260/kW. Additional project costs will be incurred including engineering, construction, and general facilities that are not accounted for in the above range. Operating costs for the lime spray dyer include lime reagent, water use, maintenance, parasitic power, and solids disposal costs. Lime reagent is a major operating cost, generally on the order of $100+/ton. Operating costs are typically around $50-80/kW-yr, again highly dependent upon site-specific factors such as fuel type, system removal efficiency, reagent and disposal costs.

- **Technology Maturity:** mature; 30+ years operating experience
- **Number of Commercial Installations:** many
- **Expected Performance:**
  - SO_2 – 95%, dependent on fuel sulfur content
  - Acid Gases – up to 95% HCl, 45-95% HF, depending on coal properties
  - Hg – up to 90% when combined with carbon injection
- **Capital Costs:** Dependent upon unit size, site-specific factors
- **Operating Costs:** 30-50 $/kW-yr
- **Installation Schedule:** 24-36 months from detailed design to start-up

A.2.6 Halogen Injection

In this technology, halogen-containing chemicals are injected into the furnace to supplement the coal chlorine in its effect on mercury oxidation. Halogen salts added are typically calcium bromide ($CaBr_2$). These salts, added with the coal or injected into the furnace, decompose at furnace temperature to form HBr/Br_2 in the flue gas. These vapor-phase halogen acids react with elemental mercury in the back pass of the furnace as the flue gas cools, to produce oxidized mercury that can be removed by a downstream wet FGD system.

Full-scale tests of furnace halogen injection have been conducted on a number of coal-fired units that fire Powder River Basin coal, Texas lignite, and North Dakota lignite. Results from these parametric tests have shown that low concentrations of bromine (20-200 ppm in the coal) can produce 50-90% oxidized mercury in the flue gas.

For example, calcium bromide injection tests were conducted at TXU's Monticello Steam Electric Station Unit 3, which is equipped with a cold-side ESP and a limestone forced oxidation scrubber. Monticello fires a 50/50 blend of PRB and Texas Lignite. Baseline mercury removal at the unit ranges from 10 to 40%. Two two-week continuous injection tests were conducted at rates equivalent to 55 ppm and 113 ppm Br in the coal. At an injection rate equivalent to 55 ppm Br in the coal, the oxidation of mercury at the FGD inlet was 67%, and the removal of mercury was 65% (computed from coal and FGD outlet gas Hg concentrations). At an injection rate equivalent to 113 ppm Br in the coal, the oxidation of mercury at the FGD inlet was 85%, and the overall removal of mercury was 86%.

Parametric and long term testing at other sites have shown that bromide addition is most effective with coals that are low in chloride (PRB) and at plants that have an SCR. The SCR, in conjunction with the bromine, act to oxidize the elemental mercury better than either individually.

The long-term effects of bromine injection on FGD chemistry and FGD or boiler materials of construction are not known. To date, the longest test durations have been sixty days, which is not long enough to evaluate corrosion effects. It is also not known if the increased concentration of bromine in the fly ash and scrubber liquor/solids will impact the reuse of these byproducts.

Capital equipment to be installed for the furnace halogen injection process is relatively simple, much like the equipment for activated carbon injection. The equipment consists of storage tanks for the halogen solution, pumps and a metering system to convey the solution to the coal, and a process control system. The capital cost of installation is estimated as $3/kW.

The largest component of the operating cost for the process is the calcium bromide solution. This solution is currently available at ~ $1/lb of 52 wt% solution. It should be noted that there have been several increases in the price of calcium bromide over the last two years. Today's price is more than double the 2004 price. It is unclear if such price increases should be expected in the future. The primary consumer of calcium bromide is the oil industry, which uses it as an operational fluid for offshore oil wells.

An existing patent[8] on the use of bromine to oxidize mercury may require royalty payments to the patent holder. The amount of the royalty payment is not known at this time.

- **Technology Maturity:** Testing 5 years of experience
- **Number of Commercial Installations:** None
- **Expected Performance:**
  - Hg – An additional 10-78% above native capture, with downstream FGD system
- **Capital Costs:** 2.5-3.5 $/kW
- **Operating Costs:** 0.25-2.5 $/kW-yr. (Chemical cost only, no royalties)
- **Installation Schedule:** 6-12 months for design, installation, and parametric testing.
  - **Outage Required:** None.

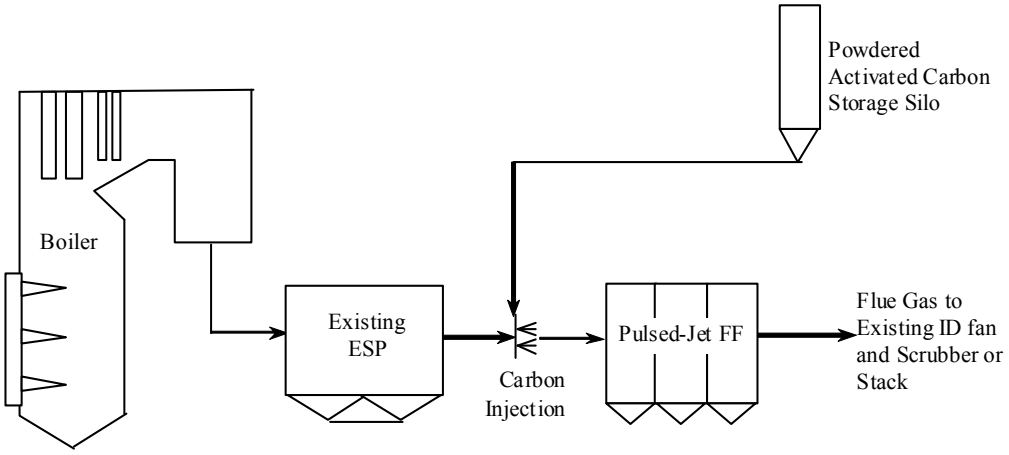
A.2.7 Toxecon

Toxecon is an EPRI developed technology that involves the injection of dry sorbent, such as powdered activated carbon into a compact pulsed-jet fabric filter installed downstream of an existing primary PM control device. The Toxecon system has been demonstrated to achieve 90%+ removal of mercury from the flue gas and offers additional reduction of PM with the installation of the baghouse. In facilities that do not currently operate an FGD scrubber, Toxecon may be coupled with alkali injection upstream of the fabric filter to achieve acid gas control, for reduction of HCl, HF, and SO_2. In general, this technology may be an attractive control option for facilities operating a hot-side ESP with no FGD system.

A generic process flow diagram of the system is shown in Figure A-4. A new pulsed-jet fabric filter is installed downstream of an existing PM control device, and a pneumatic conveying system and storage silo are included for sorbent injection. If additional alkali injection is included, a second storage silo and transport system will be required. Note that the capital cost of the DOE demonstration project at Wisconsin Energy's Presque Isle Power Plant in Michigan was $52.9MM treating approximately 270 MWe, indicating a capital cost of over $190/kW. However, costs for this demonstration project were likely inflated due to the nature of the demonstration/first-of-its-kind installation. Additionally, a capital cost saving configuration of Toxecon may be employed whereby the last fields of the ESP are converted to a fabric filter PM collector (Toxecon 1.5). In this case, the sorbent injection point would be just downstream of the ESP fields, and upstream of the converted fields. Elimination of the new fabric filter housing from the system configuration would be expected to reduce the capital costs by 50-60% in comparison with the full Toxecon system.

[8] Vosteen, B. US Patent 6878358.

Figure A-4. Toxecon System



Operating costs of the Toxecon system include costs for powdered activated carbon, power associated with additional pressure drop across the fabric filter, solids disposal, and fabric filter maintenance, including bag filter replacement. Operating costs are estimated to be $4-6/kW-yr.

- **Technology Maturity:** Commercial demonstration completed; sorbent injection and fabric filter are proven technologies.
- **Number of Installations**: ~5
- **Expected Performance:**
  - Hg – 90%+
  - Acid Gases – up to 90% HCl, HF with alkali injection
  - SO_2 – 40-70% with alkali injection
  - Se – up to 90% with alkali injection
- **Total Project Costs:** Demonstration project cost $190/kW)
- **Operating Costs:** 4-6 $/kW-yr.
- **Installation Schedule:** 12-24 months from detailed design to start-up
  - **Outage Rrequired:** 5-10 days.

A.2.8 Wet Flue Gas Desulfurization (FGDw)

Wet flue gas desulfurization processes remove SO_2 from coal- and oil-combustion flue gas by reacting the gas with a re-circulating alkaline reagent solution or slurry. The alkaline reagent, typically a limestone or lime slurry, reacts with the incoming SO_2 in a spray tower to form calcium salts such as calcium sulfate dihydrate (gypsum) or calcium sulfite. Solid precipitation occurs in an integrated reaction tank. The produced byproduct solids are removed from the process by way of a slurry purge routed either to a solid filtration system or to a gravity settling pond. Removal of SO_2 across a wet FGD system is determined by the size and design of the scrubber unit, the gas-liquid contact properties, and the scrubber operating parameters (i.e.,

nature of the FGD process chemistry). High efficiency FGD scrubbers are capable of removing 95 – 99% of the SO_2 present in the gas, depending on many factors associated with unit design, operating conditions, and flue gas composition. Wet FGD systems have historically been able to achieve higher SO_2 removal levels than dry FGD systems and are generally more cost effective (than dry scrubbers) for the treatment of flue gas derived from coal containing moderate to high sulfur levels (i.e., >2%).

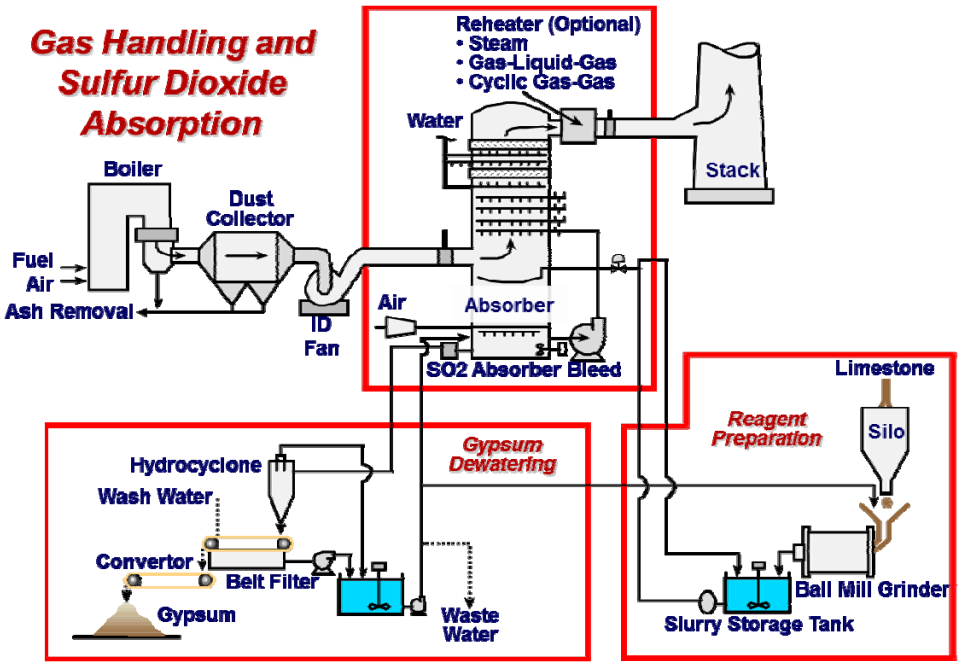
Wet FGD is a mature technology that has over 40 years of commercial operating experience in the U.S and represents greater than 80% of FGD technology installed on fossil fuel-fired power plants. The addition of wet FGD represents an appreciable cost to a utility due to high associated capital costs but the technology is technically sound and operational risks associated with the technology have decreased with continued operating experience and technology development. Although wet FGD is typically employed for SO_2 removal, it is also effective at removing acid gases, such as HCl and HF, from flue gas; wet FGD absorbers can also remove up to 50 – 70% of the particulate matter present in the gas, depending on the gas-liquid contact properties of the unit. Furthermore, evaluation of coal and process data from the EPA ICR database indicates that plants configured with wet FGD achieve high levels of selenium removal from the flue gas.

A wet FGD system may be appropriate for the removal of SO_2 and acid gases at plants that do not currently employ a scrubber system. Furthermore, the wet FGD absorber would be expected to provide additional removal (50-70%) of particulate matter penetrating the upstream electrostatic precipitator (ESP) or fabric filter (FF). Wet FGD processes are also effective at removing oxidized forms of mercury from flue gas. Thus, for bituminous coal fired plants with high flue gas mercury oxidation, particularly those employing SCR for NO_x control, high levels (70 – 90%) of mercury removal might be expected across a wet FGD system. For units firing Western sub-bituminous coal that typically produce flue gas mercury mainly in the elemental form, wet FGD provides the option for a plant to employ a mercury oxidation technology, such as boiler halogen (salt) addition, to decrease mercury emissions. For units configured with FF or Toxecon, wet FGD provides for the ability to take advantage of the natural tendency of fabric filters to oxidize mercury thus enhancing overall system removal; this effect is even greater when employing activated carbon injection upstream of the fabric filter resulting in most of the mercury that is not removed across the fabric filter getting removed across the FGD absorber.

Despite being effective at removing oxidized forms of mercury from flue gas, some wet FGD absorbers have experienced mercury re-emissions from the process. Here, mercury captured by the FGD unit is chemically reduced back to volatile elemental mercury that subsequently exits the absorber with the flue gas. Mercury re-emissions are not well understood at this time but are believed to be impacted by a number of FGD operating parameters (associated with the process chemistry). The re-emissions can be controlled using chemical additives added to the process to complex or precipitate the captured mercury.

Figure A-5 illustrates the primary components of a wet FGD process. The process can be operated under forced-, inhibited-, and natural oxidation modes. A number of reagents can be used to provide alkalinity to the process; limestone and lime represent to most common used.

Figure A-5. Illustration of Wet FGD Process; Example shows LSFO Process



For a typical limestone forced oxidation FGD process, the major cost components are associated with the following process systems:

- Flue gas handling (ductwork; bypass dampers, motive force, etc.)
- Absorber unit
- Reaction tank
- Reagent preparation
- Solids dewatering and handling
- Oxidation air
- Mist elimination
- Gas reheat (for units operating dry stacks)
- Control systems
- Wastewater treatment
- Chimney (e.g., modification from dry to wet stack)

Operating and maintenance cost categories include:

- Feed materials and chemicals
- Labor and supervision
- Waste disposal
- Maintenance, materials, and other costs
- Auxiliary power costs
- Water/water treatment costs

A wet FGD system requires a significant engineering effort and appreciable footprint at the plant site. Capital costs will be affected by the size of the boiler, type of fuel fired, required removal efficiency, solids dewatering approach, specific site arrangement, and existing equipment considerations. Capital costs for a wet FGD system can range from roughly $300 - $600/kW, depending on a large number of factors; additional project costs will be incurred including engineering, construction, and general facilities that are not accounted for in the above range. Fixed O&M costs can range from approximately $9 - $19/kW-yr, depending on the size of the unit, and variable O&M costs can range from $15 - $38/kW-yr. The latter is impacted by plant size and site specific factors such as delivered reagent costs, byproduct transport and disposal costs, water and wastewater costs, and auxiliary power consumption costs; these costs can be offset by revenues associated with byproduct sales.

- **Technology Maturity**: Over 40 years of commercial operation.
- **Number of Commercial Installations:** Wet FGD is installed on many plants representing roughly one-third of the coal-derived electric generation (i.e., >100 GW) in the U.S.
- **Expected Performance:**
  - SO_2: High-performance FGD scrubbers can achieve 95 – 99% SO_2 removal.
  - HCl: Most well-performing wet FGD units are able to achieve hydrogen halide removal rates equal to or greater than the respective SO_2 removal rate.
  - PM: High-efficiency FGD units can typically remove up to 50-70% of the particulate material entering the absorber in the flue gas.
  - Mercury: Wet FGD units can typically remove 85-90% of the oxidized mercury present in the incoming flue gas; elemental mercury removal is typically less than 10%. Overall mercury removal is impacted by the extent of mercury re-emissions experienced by a given absorber unit.
- **Capital Costs:**
  - $300 - $600/kW
- **Operating Costs:**
  - Fixed O&M costs can range from $9 - $19/kW-yr while variable O&M costs can range from $15 - $38/kW-yr.

- **Installation Schedule:**
  - Typical schedules for the design, installation, and startup of new FGDs range from 24 – 44 months.
- **Outage Required:**
  - 4 – 8 weeks.

A.2.9 Wet Electrostatic Precipitator (WESP)

Wet electrostatic precipitators (WESPs) have been used in many industries for the effective control of sulfuric acid and PM for over 100 years. However, only in the past several years has the WESP been considered practical and necessary for utility applications. WESPs have been considered and employed on the utility scale in order to reduce ultra-fine and condensable PM, including acid mist removal downstream of a wet scrubber. Although utility applications of WESP are fairly new, they have been shown to achieve high levels of SO_3 removal (> 80%) when used in combination with a wet FGD system. The collection of submicron PM is improved in the WESP over the dry ESP due to the ability of a WESP to achieve higher corona power levels, and the operation at saturation temperature, which promotes condensation of soluble acid aerosols.

A WESP is configured much like a dry ESP, using multiple collecting and electrode fields. It is designed for large gas volumes, high PM inlet loading rates, and low outlet emissions. The parallel collecting fields are arranged in series and housed in a single enclosure. Collecting plates in a WESP are specifically designed to ensure uniform water film over the entire collecting area and an integral part of the WESP design is location of water spray nozzles to allow sufficient coverage over the collector plates. WESPs generally employ special alloys in order to avoid corrosion. One vendor has touted their membrane WESP as offering 20-30% cost savings over the conventional WESP by replacing solid sheet/tube collecting electrodes with fabric membranes that disperse water through capillary action. The membrane WESP has seen installation on non-utility applications up to approximately 185 MWe.

A WESP incurs higher capital costs than its dry counterpart, mainly due to the materials of construction required in order to avoid corrosion problems. Because the cost of the system is highly dependent on incoming flue gas and wash water content, which will vary from site-to-site, capital costs may fall in range of $75- 200/kW, depending upon unit size. As stated above, the commercial membrane WESP may potentially offer 20-30% cost savings over its traditional counterpart.

Operational costs of the WESP include pressure drop typically associated with a PM collector, energizing of the collector plates, as well as water consumption and water discharge. There are also potential water treatment costs; however they are not included in the costs presented here. In many cases the wastewater is sent to the FGD reaction tank.

- **Technology Maturity:** mature; 100+ years of operating experience on industrial applications;
- **Number of Commercial Installations:** several at the utility-scale;

- **Expected Performance**:
  - PM – 99%+
  - HCl – not quantified; 90% expected
  - Hg – potentially 95% with wet scrubber
- **Capital Costs:** $75-200/kW, dependent upon unit size and configuration
- **Operating Costs:** $3-4/kW-yr.
- **Installation Schedule:** 12-24 months from detailed design to start-up
  - **Outage Required:** 5-10 days.

ATTACHMENT I

Redesignation Demonstration

and

Maintenance Plan

for

The Charlotte-Gastonia-Salisbury, North Carolina 2008 8-Hour Ozone Marginal Nonattainment Area

Prepared by

North Carolina Department of Environment and Natural Resources

Division of Air Quality

April 16, 2015

Point sources are those stationary sources that require an air permit to operate. In general, these sources have a potential-to-emit more than five tons per year of a criteria air pollutant or its precursors from a single facility. The source emissions are tabulated from data collected by direct on-site measurements of emissions or mass balance calculations utilizing emission factors from the EPA's AP-42 or stack test results. There are usually several emission sources for each facility. Emission data are collected for each point source at a facility and reported to the DAQ through its on-line system.

Airports and rail yards are not required to have air quality permits for construction and operation (although they could have equipment such as a boiler or generator that requires a permit). They do have fixed and known locations and their emissions quantities can be comparable to industrial sources so, for purposes of the EPA's National Emission Inventory (NEI), they are included in the point source inventory even though they are traditionally considered nonroad sources.

For EGUs, base year 2014 average July day emissions were obtained from the EPA's CAMD for the three Duke Energy Carolinas EGU facilities located in the Charlotte area (i.e., Allen in Gaston County, Lincoln in Lincoln County, and Buck in Rowan County). For the remaining Title V sources, the latest data available were the 2013 emissions data that the sources submitted to the DAQ, and, for these sources, 2013 emissions were used to represent 2014 base year emission. For sources that emit less than 25 tons per year of NOx or VOC and are subject to emissions statements requirements, the latest data available were the 2013 emissions data that the sources submitted to the DAQ, and, for these sources, 2013 emissions were used to represent 2014 base year emission. The Charlotte nonattainment area includes some small sources that report emissions to the DAQ once every five years and, for these sources, the most recently reported data was used and assumed to be equivalent to 2014 since the emissions from these small sources do not vary much from year to year.[40] The DAQ reviewed recent historical emissions data (i.e., 2010 - 2013) for non-EGU Title V and emissions sources subject to the emissions statements requirements. Based on this review, the DAQ decided that 2013 emissions should be used to represent 2014 emissions due to the uncertainty associated with applying regional growth factors to forecast emissions for one year.

For each of the three EGU facilities located in the Charlotte area, Duke Energy Carolinas provided the DAQ with the projected emissions for July for each facility for each future year. Projected emissions for July were divided by the number of operating days during July to estimate the average summer July day emissions. The forecast reflects compliance with the North Carolina Clean Smokestacks Act and the MATS rule; however, it does not reflect any

[40] North Carolina permit renewal intervals for small sources changed from every five years to every eight years, effective 2014.

additional controls to comply with CSAPR. Therefore, if additional controls are installed to comply with CSAPR the emissions forecast may be lower than reflected in the forecast for the three EGU facilities.

Non-EGU point sources future year emission were adjusted by growth factors based on North American Industry Classification System (NAICS) codes generated using growth patterns obtained from the Annual Energy Outlook 2014 reference case and state employment forecasts.[41] However, for EGUs, the estimated projected future year emissions were based on forecast data provided by the utility company.

The inventory includes 20 natural gas fired boilers that, beginning in 2014, are subject to equivalent emission limitations by permit that North Carolina established per Section 112(j) of the CAA. Because the base year inventory for these boilers did not include the effects of controls installed to comply with the NESHAP, a VOC control factor was applied to future year emissions to account for the effects of the controls. A NOx control factor was not applied to the future year emissions for the boilers because the NESHAP is not expected to significantly affect NOx emissions. No other control factors were applied to point source emissions for the future year inventories.

Aircraft future year emissions were generated by using growth factors produced by running the Federal Aviation Administration's (FAA) Terminal Area Forecast (TAF) model. For each aircraft category, the 2011 operations estimate was divided into the operations estimate of later years to calculate the growth factor.

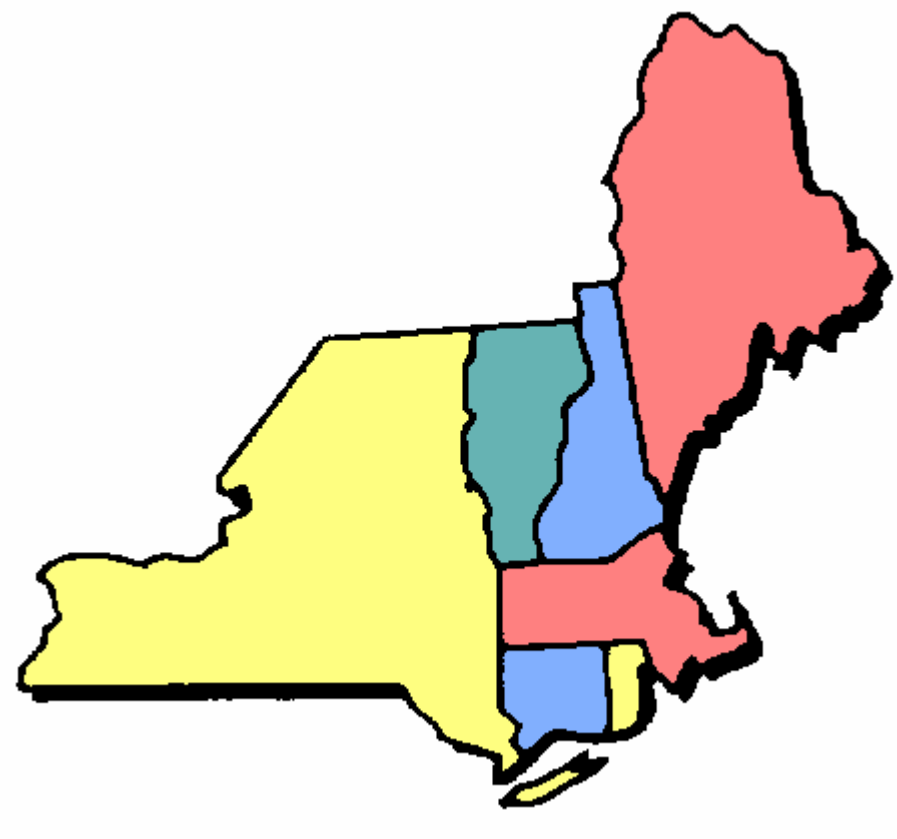
Rail yard future year emissions were estimated by using growth factors calculated using national fuel use estimates for freight and for intercity passenger service found on Table 46 of the Energy Information Administration's (EIA) *Annual Energy Outlook,2014*. Rail yard future year emission were also adjusted by control factors calculated using recommended emission factors for NOx and hydrocarbons (virtually the same as VOC) from Emission Factors for Locomotives, EPA-420-F-09-025.

For detailed discussion on how the point sources emission inventory was developed, see Appendix B.1. A summary of the point source emissions is presented in Table 3.2 and Table 3.3. The emissions are presented in a ton per summer day basis.

[41] Annual Energy Outlook 2014, released May 7, 2014, http://www.eia.gov/forecasts/aeo/.

ATTACHMENT J

Northeast Regional Mercury Total Maximum Daily Load



Connecticut Department of Environmental Protection
Maine Department of Environmental Protection
Massachusetts Department of Environmental Protection
New Hampshire Department of Environmental Services
New York State Department of Environmental Conservation
Rhode Island Department of Environmental Management
Vermont Department of Environmental Conservation
New England Interstate Water Pollution Control Commission

October 24, 2007

Regional TMDL Atmospheric Deposition Goal

To meet the initial TMDL target of 0.3 ppm, the mercury TMDL for the region is 1,750 kg/yr, or 4.8 kg/d. This is divided into a wasteload allocation of 38 kg/yr and a load allocation of 1,712 kg/yr. The load allocation for natural sources is 1,626 kg/yr, leaving an anthropogenic load allocation of 86 kg/yr. Implementation of this goal is divided into three phases. Phase I, from 1998 to 2003, sets a goal of 50 percent reduction, from in-region and out-of-region sources, from the 1998 baseline. With in-region reductions of 1,549 kg/yr achieved as of 2002, the in-region reduction goal has been exceeded. Phase II, from 2003 to 2010, sets a goal of 75 percent reduction. This leaves 20 kg/yr for in-region reductions necessary to meet this target. In 2010, mercury emissions, deposition, and fish tissue concentration data will be re-evaluated in order to assess progress and set a timeline and goal for Phase III to make remaining necessary reductions to meet water quality standards. Not enough data are currently available to accurately assess reductions achieved by out-of-region sources.

Adaptive Implementation

The TMDL is structured to separately show loading goals for in- and out-of-region sources and is expected to be implemented adaptively in order to evaluate the calculated necessary percent reduction from anthropogenic sources. The Northeast states have already reduced deposition by approximately 74 percent between 1998 and 2002 and have reasonable assurances (including product legislation and emissions controls) in place to assure attainment of Phase II goals on an adaptive basis. To meet out-of-region goals, Northeast states recommend EPA implement plant-specific MACT limits for mercury under Section 112(d) of the Clean Air Act to control power plant emissions by 90 percent by cost-effective and available technologies. The Northeast region's ability to achieve the calculated TMDL allocations is dependent on the adoption and effective implementation of national and international programs to achieve necessary reductions in mercury emissions. Given the magnitude of the reductions required to implement the TMDL, the Northeast cannot reduce in-region sources further to compensate for insufficient reductions from out-of-region sources.

The Northeast states are recommending adaptive implementation of this TMDL and that a strict 90 percent MACT standard enacted under section 112(d) be promulgated to meet the national implementation requirements of the TMDL for Phase II (2003-2010, 75 percent reduction). As discussed previously, this TMDL calls for a 98 percent reduction in order to meet the initial target fish tissue concentration. However, the TMDL will be implemented adaptively, so that as regional and national controls are implemented, the response in fish tissue as a result of emissions and deposition reductions will be monitored. If necessary, reduction goals will be modified based on the response seen in fish tissue monitoring.

A significant portion of mercury deposited in the Northeast originates from global sources. While the federal government cannot place controls on these sources, the government can reduce the mercury entering other countries by prohibiting sale of the country's stockpiles of mercury. The Northeast states recommend that sale of United States stockpiles of mercury are prohibited in order to reduce mercury emissions and deposition from international sources.

10 Reasonable Assurances

This regional TMDL for mercury allocates the reduction of pollutant sources to waterbodies throughout the Northeast between point sources, which have been classified as de minimis, and nonpoint sources. States are required to provide reasonable assurance that those nonpoint sources will meet their allocated amount of reductions, which can be much more challenging than documenting reasonable assurances for point source reductions. The actions that provide these assurances take place at the state, national, and international level and are described below.

10.1 State Level Assurances

There are a variety of ways in which a state or states can provide reasonable assurances. These include the implementation of pollution control measures, developing and implementing nonpoint source control plans and, if available, other state regulations and policies governing such facilities. As described in Section 2.3 and Appendix D, the Northeast has a strong commitment to reducing mercury in the environment. The New England states participate in the NEG-ECP MTF and are committed to the regional MAP. As part of the MAP, the New England states have adopted emission limits for large MWCs that are three times more stringent than what EPA requires. This has already resulted in a 90 percent reduction in emissions from this sector. Mercury products legislation adopted in all Northeast states will further reduce these emissions. The MAP also requires a limit for MWIs that is ten times more stringent than EPA requirements. All of the states, including New York State (which is not part of the MTF), have aggressive programs for mercury reduction. The MAP is an adaptive management plan with a goal of virtual elimination. The states' success in meeting MAP goals demonstrates the ability of the Northeast states to make meaningful mercury reductions.

In 2005, NESCAUM prepared *Inventory of Anthropogenic Mercury Emissions in the Northeast* to update their mercury emission inventory with 2002 emissions data. The project was partially undertaken to assist the NEG-ECP in their effort to assess progress in meeting the goals of the MAP. Table 10-1 shows that substantial reductions in mercury emissions have been made for the majority of sources. Overall, regional mercury emissions decreased by 70 percent between 1998 and 2002. The greatest decreases came from MWCs (87.0 percent) and MWIs (96.6 percent). These emissions reductions have resulted in a 74 percent reduction in atmospheric deposition of mercury, as described in Section 7.6.2.

waste management practices as established by the State of Vermont and Vermont State Dental Society and to install dental amalgam separators by January 2007. Hospitals are required to submit a mercury reduction plan to the agency every three years.

10.2 National and International Assurances

The Northeast region's ability to achieve the calculated TMDL allocations is dependent on the adoption and effective implementation of national and international programs to achieve necessary reductions in mercury emissions. Given the magnitude of the reductions required to implement the TMDL, the Northeast cannot reduce in-region sources further to compensate for insufficient reductions from out-of-region sources. While EPA and the federal government are involved in the programs described below, further efforts are necessary to assure that the goals of this TMDL are met. Specifically, it is Northeast States' position that the data and analyses in this TMDL demonstrate that:

(A.) CAMR will be insufficient to achieve the reduction needed to achieve the water quality goals set forth in this TMDL,
(B.) EPA must implement significant reductions from upwind out-of-region sources, primarily coal-fired power plants; and
(C.) MACT provisions of section 112(d) of the CAA should be adopted as the mechanism for implementing this TMDL.

Further, the States note that EPA has the authority to revise CAMR or otherwise require the necessary reduction on a national scale to meet the goals set by this TMDL.

National assurances are also found within EPA's obligation under both section 112 of the CAA and the loading reduction requirements of the TMDL provisions in section 303(d) of the Clean Water Act to act to immediately reduce the emission of mercury from these sources. The timeline for the reduction goals of this TMDL are set forth in Section 9.

CAMR, which regulates mercury emissions from Electrical Generating Units (EGUs) under section 111(d) of the CAA, requires an eventual reduction in mercury emissions of 70 percent at full implementation of the rule, sometime after 2018. CAMR is a two-phase rule, with the first phase requiring reductions in mercury of approximately 20 percent coming as a co-benefit of reductions in sulfur dioxide and nitrous oxides to be made by 2010. Between 2010 and 2018, the CAMR provides for a cap and trade program that is proposed to make further reductions with eventual reductions of 70 percent sometime after 2018.[1]

For further national assurances, the Northeast states are recommending adaptive implementation of this TMDL and that a strict 90 percent MACT standard be enacted under section 112(d) be promulgated to meet the national implementation requirements of the TMDL for Phase II (2003-2010). As discussed previously, this TMDL calls for an 87 percent reduction in order to meet the initial target fish tissue concentration. However, the TMDL will be implemented adaptively, so that as regional and national controls are implemented, the response in fish tissue as a result of emissions and deposition reductions will be monitored. If necessary, reduction goals will be modified based on the response seen in fish tissue monitoring.

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[1] The Northeast states have filed a suit (*State of New Jersey, et al. vs. United States Environmental Protection Agency*) against U.S. EPA challenging CAMR's legality – how its limits were calculated and the establishment of the trading program.