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Getting the Job Done

Affordable Mercury Control at Coal-Burning Power Plants

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For more information about NWF or to view this report online visit:
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Cover Photo: Monroe Power Plant - Center for Great Lakes & Aquatic Sciences;
Young girl catching bluegill at Occoquan Bay NWR - FWS - Robert H. Pos

Foreword

Since childhood, I have spent much of my free time fishing the scenic rivers and streams of Western Pennsylvania, where I grew up. However, there is a cloud over these peaceful waters. Forty-four states including my home state now have advisories against eating fish caught in local waters, due to mercury contamination. America's favorite pastime is at risk.

Mercury is a powerful neurotoxin that can cause irreversible harm to the brain and nervous system of children when they are developing in the womb. Mercury is a particular problem for sport fishermen, subsistence anglers, American Indians, and others who have freshwater fish as a mainstay of their diet. The mercury comes mainly from air pollution, particularly from coal-fired utilities and certain other industries. Mercury is emitted into the air, falls into our waters from rain or snow, and then accumulates in fish.

What can be done to solve this problem is one of our nation's most pressing environmental questions. The Environmental Protection Agency wants to control mercury, but its plans are too little too late. Industry says cleanup will be too difficult and too expensive. In this report, part of the National Wildlife Federation's Clean the Rain campaign, we utilize the EPA's own data to show that 90 percent mercury control will cost residential ratepayers as little as a cup of coffee per month, even in major coal-burning states. The technology to make this happen is readily available.

The National Wildlife Federation has been working on the mercury issue for over a decade. We hope that this report will help decision-makers realize that steep reductions in mercury pollution are feasible and affordable today. The health of our fish, our wildlife, and our citizens is at stake. The time to act is now.

Larry Schweiger
President and CEO
National Wildlife Federation

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Executive Summary

Mercury pollution is responsible for widespread toxic contamination of our nation's waters, fish, and wildlife. In 45 states and territories across the country, advisories warn the public to restrict their consumption of many species of fish because of the dangers of mercury exposure. Coal-burning power plants remain the largest unregulated source of mercury pollution in the United States. In this report, NWF assesses the feasibility and cost of controlling harmful mercury emissions from power plants. We find that deep mercury reductions are feasible and affordable today.

The process of setting emission limits for this last major unregulated source of mercury emissions is underway, and has been the focus of a contentious debate for over a decade. While the U.S. Environmental Protection Agency's (EPA) proposed plan sets a national emissions cap that represents a 70 percent reduction from today's levels, its emissions trading program for coal-fired power plants would delay achieving the full reductions until at least 2025. Reductions could remain less stringent at specific plants or in particular regions or states as plants would have the option of controlling emissions or buying pollution credits to demonstrate compliance.

For the price of one cup of coffee per household per month, our nation could dramatically reduce the toxic mercury pollution from coal-burning power plants that contaminates our waters and wildlife.

The EPA justifies this proposal—an unprecedented regulatory approach for toxics—by stating that achieving more rapid and more significant reductions in mercury emissions from each plant is not technically or economically feasible.

This report provides an alternative perspective on the economic feasibility of reducing mercury pollution from power plant smokestacks nationwide. NWF recaps existing studies showing the effectiveness and availability of mercury control technology. Using EPA data, we then estimate the cost of installing and operating this technology across entire state power plant fleets. NWF's analysis found that the installation of currently available technology to achieve 90 percent mercury control on coal-fired power plants is affordable.

To estimate the average cost of installing mercury controls and the corresponding increase in electricity bills, NWF looked at power plant fleets located in five coal-dependent states—Illinois, Michigan, Ohio, Pennsylvania and North Dakota. These states are home to power plants that burn the types of coal and operate the range of power plant boiler configurations found nationwide. While many different technology options and approaches exist to control mercury emissions from power plants, this report focuses on technology that has been fully tested and is commercially available today to achieve very high levels of mercury control: activated carbon injection and fabric filters.

To estimate the cost of using this technology, NWF applied the most recent EPA cost data, boiler by boiler, to the power plants in the five case study states. Given that less expensive technology options are currently available for some plants, and other lower-cost options will likely become commercially available in the near term, the findings likely overestimate the costs of achieving 90 percent mercury control.

Key findings from this report include:

- Mercury emissions can be controlled by 90 percent at power plants burning bituminous, subbituminous, and lignite coals.
- In our five case study states, all of which rely significantly on coal, achieving 90 percent mercury control could cost the average residential customer 69 cents to approximately $2.14 a month, depending on the state.
- Commercial and industrial increases were similarly reasonable—between 1 and 3 percent increases in electric bills.
- For the most common configurations, the cost of achieving 90 percent control is only slightly higher than achieving 70 or 80 percent control.
- The findings reinforce similar cost estimates made by equipment manufacturers, the Department of Energy, and the EPA.

Despite industry claims that the technology is not ready and that costs of 90 percent mercury emissions control are too high, this report demonstrates that it is both achievable and affordable today. For a minimal increase in consumers' energy bills, coal-burning power plants can be retrofitted with cutting-edge mercury control equipment that will provide public health and environmental benefits nationwide. Not only does mercury reduction bolster the large commercial and recreational fishing industries in many states, it also generates jobs in manufacturing, installing, and operating this equipment.

Achieving deep mercury pollution reduction is a critical part of modernizing our nation's energy infrastructure. Making this investment in pollution controls, cleaner coal technologies, renewable energy, energy efficiency and energy conservation promises large and ongoing environmental and economic benefits.

Based on the findings of this report, NWF recommends that:

- The federal government must follow the Clean Air Act and finalize a mercury emissions standard for coal-fired power plants that would reduce mercury emissions by up to 90 percent by the end of the decade.
- State governments should enact regulations and other policies to facilitate innovation and rapid adoption of pollution control and clean energy technologies.
- Both state and federal policy makers should pursue a comprehensive energy strategy that provides incentives for extensive multi-pollutant reductions, increased fuel efficiency, and an enhanced reliance on renewable energy sources.

NWF is confident that policy makers, power plant managers and executives, and equipment manufacturers can meet the challenge of 90 percent mercury control today. There is no need and no excuse for handing this problem down to our children.

I. Introduction

Mercury: A Pervasive Pollutant

Mercury is a highly toxic heavy metal that enters our air and water through many sources, such as coal-burning power generation, cement and chlorine manufacturing, and municipal, medical, and hazardous waste incineration. While mercury has been used in numerous products, such as fluorescent bulbs, thermostats, thermometers and mercury switches, uses in the U.S. and other countries have declined substantially in the past 15 years. Meanwhile, the country's 430 coal-fired power plants remain the nation's largest unregulated industrial source of mercury air pollution, contaminating our waters, wildlife, and people.

Once released to the air, mercury can fall to the Earth with rain, snow or dust particles. After it settles in lake or river sediments, mercury can be converted by bacteria into methylmercury—a more toxic, organic form. Methylmercury readily accumulates in the food chain, so that top predator fish can have methylmercury concentrations over one million times higher than the surrounding water.[1] Mercury in fish then threatens people and wildlife that consume the fish.

Mercury interferes with the development and function of the central nervous system, as well as the cardiovascular and reproductive systems. Even at moderate levels, mercury can cause permanent developmental harm (including attention deficit and fine and gross motor skill delays) in humans, and reproductive harm to wildlife. Mercury poses particular risks to children as their nervous systems are not fully developed until age 14.[2]

> Regulations restricting mercury air pollution have clear positive effects on the environment in a matter of years, not decades.

In January 2004, a U.S. Environmental Protection Agency (EPA) scientist released new research estimating that nearly one in six U.S. women of childbearing age has mercury levels in her blood above what is considered safe for an unborn child, doubling previous estimates.[3] This new estimate equates to approximately 630,000 newborns each year who may have been exposed to unsafe levels of mercury *in utero*.

People are usually exposed to methylmercury through eating common fish species. In April 2004, the EPA and Food and Drug Administration (FDA) issued new, stronger warnings about eating certain fish, including tuna, swordfish, shark, and king mackerel because of mercury contamination.[4] Today, 44 states and one U.S. territory issue advisories warning people to limit consumption of fish caught in their lakes, streams and coastal waters because of high levels of mercury contamination.[5]

In addition to posing serious human health threats, mercury pollution can also affect state and local economies that rely heavily on income from sport fishing. According to the American Sportfishing Association, fishing ranks among the top family leisure-time activities. An estimated 44 million people fish in the U.S. and generate nearly $42 billion in retail sales each year.[6] Studies show that mercury advisories cause anglers to choose other locations to fish and take fewer overall fishing trips.[7]

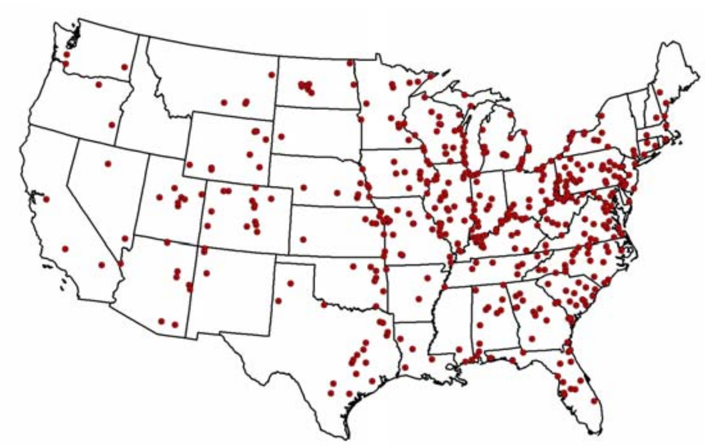
On top of threats to human health and the economy, mercury pollution can harm a variety of wildlife. Fish-eating animals—including numerous birds, mink and otters—are particularly vulnerable. Potential mercury impacts on birds include reduced hatchability, reduced clutch size, increased numbers of eggs laid outside the nest, and aberrant behavior of juveniles.[8] Numerous field studies have documented reproductive and other threats to various bird species, including shorebirds in the New York/New Jersey area,[9] loons in New England,[10] and egrets in Florida.[11] Other wildlife studies have documented adverse effects on Ontario otters and mink in the southeastern U.S.[12] [13]

Mercury From Coal-Fired Power Plants

Coal-fired power plants are the country's largest remaining unregulated source of mercury pollution. In 1999 (the most recent year for which data are available), the EPA estimated that coal-fired power plants accounted for 41 percent of the country's total industrial mercury emissions.[14]

While some airborne mercury can travel long distances, mercury from power plants also deposits locally and regionally. Estimates from computer modeling by EPA indicate that up to 14 percent of the mercury emitted by coal-burning power plants deposits within 30 miles of a plant.[15] Parts of the eastern seaboard receive a greater proportion of U.S. mercury emissions than areas in the arid west—for example, at Pines Lake, New Jersey, 80 percent of mercury deposition comes from North American sources.[16] Recent modeling in the Great Lakes found that approximately 48 percent of the mercury depositing in Lake Michigan came from sources within 60 miles of the lake Though this study only examined North American sources, researchers concluded that coal combustion in the U.S. was "the most significant source category contributing mercury through atmospheric deposition to the Great Lakes."[17]

Figure 1: U.S. Coal-fired Power Plants



Source: Clear the Air, 2001

Recent studies show that regulations restricting mercury air pollution have clear, measurable effects on the environment in a matter of years, not decades. For example, a multi-year study by the state of Florida found a nearly one-to-one relationship between mercury deposition and fish tissue levels. Following significant reductions in incinerator emissions starting in the early 1990s, mercury levels in largemouth bass and egrets declined substantially, up to 80 percent.[18] A similar study in northern Wisconsin found that over a six year period, a 60 percent reduction in mercury deposition correlated with a 30 percent decline in mercury levels in yellow perch.[19]

Regulating Mercury from Coal-Fired Utilities

The U.S. Environmental Protection Agency (EPA) is currently in the process of regulating mercury emissions from power plants for the first time. The process has stretched over a period of fourteen years, starting when Congress amended the Clean Air Act in 1990 and gave EPA new authority to aggressively regulate toxic air pollutants from major industries. Finally, in December 2000, EPA formally initiated the rulemaking process for power plants, and committed to finalizing a regulation by December 2004. (A settlement agreement has extended this deadline for three months to March 2005.)

Table 1: U.S. EPA Utility MACT Timeline

	Rulemaking & Regulatory	Other Events
1990	Congress amends Clean Air Act—temporarily grants utilities exemption for air toxics regulations pending EPA studies: mercury emissions by 1993 and utility toxic emissions by 1994	
1997		EPA releases Mercury Study Report to Congress; utilities found to be largest source of mercury emissions in the U.S.
1998	EPA agrees under consent decree to issue regulatory determination by 2000, rule proposal by 2003 and final rule by 2004	-EPA releases Study of Hazardous Air Pollutant Emissions form Electric Utility Steam Generating Units; mercury is listed as the HAP of greatest concern (out of 67). -Bill requires study of health impacts before rulemaking.
1999		EPA cost estimates for mercury control revised downward from $5 billion to $1.7 billion
2000	EPA announces decision to regulate mercury and other air toxics from utilities	-National Academy of Sciences releases mercury study, finds 60,000 children in U.S. at risk and supports EPA's reference dose -MACT for municipal & medical waste incinerators requires 85% mercury reduction
2001	EPA convenes Utility MACT Working Group	-FDA issues new marine fish consumption advisory for women and children due to mercury -Centers for Disease Control and Prevention completes study on mercury concentrations in women's blood and hair, finding 1 in 10 above safe levels
2002	-Bush Administration announces Clear Skies Initiative -Utility MACT Working Group submits recommendations to EPA's Clean Air Act Advisory Committee	EPA's Office of Research and Development releases mercury technology report, finding high mercury removal possible through existing controls and activated carbon injection.
2003	-EPA ends contact with Utility MACT Working Group -EPA proposes rule, with proposal not to regulate under toxics provisions of CAA	CDC completes second study on mercury concentrations in women's blood and hair, finding 1 in 12 above safe levels
2004	-Rule published -Public hearings	Record number of comments submitted to EPA
2005	March 15—Rule to be promulgated	

The Clean Air Act requires EPA to develop emissions standards for each of the nation's 430 coal-fired power plants in operation today. Congress clearly stated in the Act that EPA must set standards that require the maximum degree of reduction in emissions of hazardous air pollutants (including mercury). However, the proposed rule that EPA issued in January 2004 suggests a different approach. Rather than set strict limits for each plant, EPA seeks to establish a national emissions cap and then allow plants to meet that cap by either reducing their emissions or buying "pollution credits" from cleaner companies. The proposal sets a 70 percent reduction cap in mercury emissions by 2018. In contrast, were EPA to follow its congressional mandate, an emission rule requiring each power plant to meet a technically feasible stringent standard would likely reduce mercury emissions by up to 90 percent by 2008.

The EPA has argued that its alternative mercury reduction proposal is necessary for two reasons: the technology to achieve deep reductions in mercury emissions is not available; and the cost to achieve such deep reductions would be too great.

For the past five years, significant attention has been devoted to better understanding how best to control mercury emissions from coal-fired power plants. The EPA has issued several extensive technical studies. Numerous industry, state, and non-governmental reports have been published on the technical feasibility of controlling mercury. The conclusions reached are essentially the same:

- Currently available technology designed to control other power plant pollutants can be very effective in capturing mercury emissions.
- Several mercury-specific technologies are very effective in capturing mercury from power plants burning different coals.
- One such technology, activated carbon injection, has been extensively tested and is commercially available.
- New technology designed to capture mercury along with other pollutants is proving to be very effective and will be an option of choice for companies looking to address multiple pollutants simultaneously.

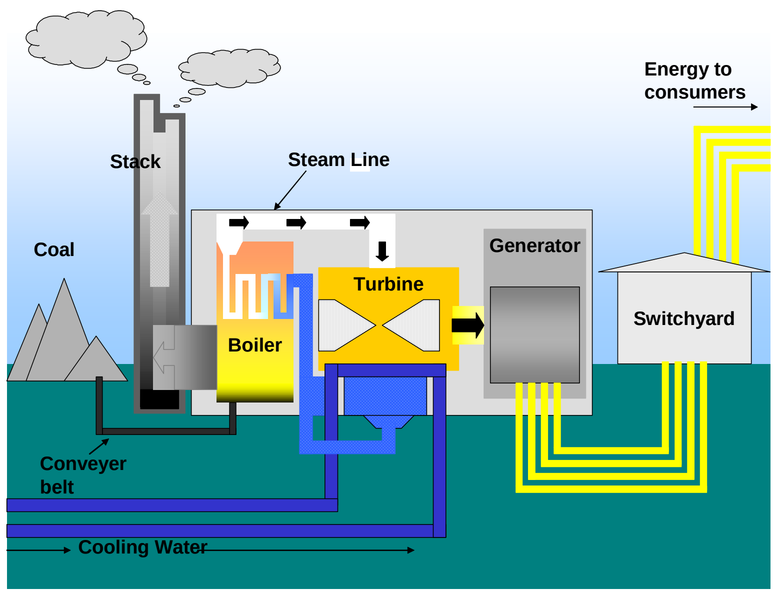
Less information has been provided on what it would cost to install this new technology. Several estimates have been made by equipment manufacturers and EPA, industry and non-profit groups (e.g., the Center of Clean Air Policy and the Clean Air Task Force) on the national cost to comply with a variety of mercury control scenarios. However, to our knowledge, no detailed analysis has been done to assess the cost to consumers of achieving 90 percent mercury control on every plant in selected states.

The purpose of this report is to do just that. Using cost information compiled by EPA from industry sources and other research, National Wildlife Federation reviewed five coal-burning states and estimated what the cost would be if every coal plant installed the technology necessary to achieve 90 percent mercury control. The results indicate that the increased cost to consumers is small. Hence, EPA's argument that tight mercury controls on power plants cannot be set—despite being mandated by the Clean Air Act—is not supported. The technology to meet stringent mercury limits is not only available to power plants, it is also truly affordable.

II. Technology Options for Controlling Mercury at Coal-Fired Power Plants

Coal was first burned as an industrial fuel in Britain in the late 12th Century,[20] and it is still burned in significant quantities to generate power today. In 2002, coal generation accounted for just over one-half the electric power generation in the U.S.[21] In a typical power plant, coal is fed to burners in a large furnace. Water circulating in pipes is heated from the burned coal, and the resulting steam turns the blades of a turbine, which in turn runs an electricity generator. Gases produced by the burned coal pass through a flue gas system, and then exit through the stack.

Figure 2: Schematic Diagram of a Coal-fired Power Plant



Source: adapted from Tennessee Valley Authority www.tva.gov/power/coalart.htm

Mercury is a naturally occurring element found in coal. When coal is burned, the mercury is released into the air. Once released, mercury cycles through the air, water, and environment much more readily than it did when it was sequestered in the raw coal.

U.S. coal-fired power plants burn three types of coal: bituminous, subbituminous, and lignite.[*22] Of the 870 million tons of coal sold to the electric power sector in the U.S. in 2002, 47.4 percent was bituminous, 45 percent was subbituminous, and 7.5 percent was lignite.[23] In general, eastern utilities burn primarily bituminous coal, while western utilities burn mostly subbituminous coal. A relatively small number of states (e.g., North Dakota and Texas) rely heavily on lignite coals.

Coals vary in the amount and type of mercury they release, and in the amount of other impurities they contain, such as chlorine and sulfur. These factors influence which options are best for meeting mercury reduction requirements.

Mercury is released from power plants in three main forms: pure elemental mercury gas; oxidized mercury gas[†]; and particulate-bound mercury (where mercury is attached to soot, ash, or other particles). While virtually all of the mercury in coal is thought to be converted to elemental mercury under high temperature in the furnace, mercury can be

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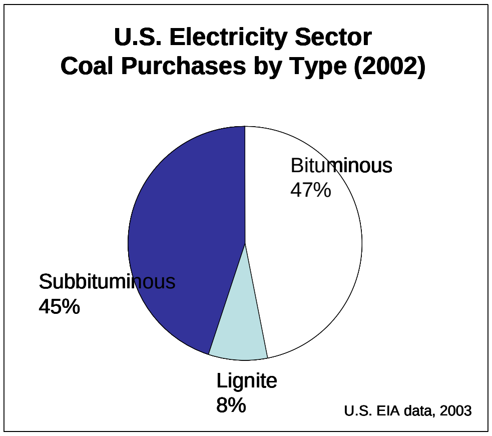
[*] Some plants in the Eastern U.S. recently burned anthracite coals, although consumption appeared to have stopped by 2002 (U.S. Energy Information Administration, 2003, Electric Power Annual 2002, DOE/EIA-0348(2002), December 2003). In addition, a relatively small number of boilers burn waste coals—coals that had been discarded following previous coal mining, mainly in the eastern U.S.

[†] Oxidized mercury gas is often referred to as reactive gaseous mercury or RGM

oxidized—particularly in the presence of chlorine—once the flue gas leaves the furnace, cools, and passes through pollution control equipment.

Figure 3



Because bituminous coals tend to be higher in chlorine, they tend to produce more oxidized mercury, whereas subbituminous and lignite coals tend to produce more elemental mercury in the flue gas.[24] While mercury levels tend to be higher in bituminous coals, oxidized mercury is easier to capture, especially with controls already in place for other pollutants.

In contrast, subbituminous and lignite coals release more elemental mercury which is harder to control. Subbituminous coal also contains much less sulfur than bituminous coals. As a result, over the past decade many plants have switched to burning lower sulfur subbituminous coals to meet sulfur dioxide emissions standards, in lieu of installing stack controls.

Methods of Reducing Mercury From Coal-Fired Power Plants

There are a number of approaches to reducing mercury emissions from coal-fired power plants. These can include one or more of the following techniques: coal cleaning processes which take mercury out of the coal before combustion; post-combustion technologies to capture mercury in the flue gas; improving power plant efficiencies (so that less coal is burned for the same energy output); switching fuels (e.g., to lower mercury coal or to cleaner natural gas); using renewable sources (such as wind energy); and reducing energy demand (e.g., through consumer energy efficiency improvements and energy conservation).[25] While NWF recognizes the need to consider all approaches for generating energy in the cleanest, most efficient manner, we focus here on assessing retrofit control technologies because they are a proven, available, and widely applicable form of mercury control for the existing power plant fleet.

There are three primary post-combustion approaches that can be pursued to control mercury emissions from coal-fired power plants:

- Utilize or enhance existing control technology installed for other pollutants to effectively capture mercury.
- Adopt a mercury-specific control technique, such as activated carbon injection.
- Adopt a multi-pollutant approach, designed to control mercury along with other pollutants.

Utilizing Existing Particulate, Nitrogen Oxides Or Sulfur Dioxide Control Technology To Control Mercury

Under the Clean Air Act, coal-fired power plants have been required for over a decade to limit emissions of particulates, nitrogen oxides, and sulfur dioxide, pollutants which create smog and acid rain. Several of the technologies used to control these pollutants also capture mercury, in some cases up to 90 percent.

The primary technologies used by utilities to control pollutants other than mercury are summarized in Table 1. While electrostatic precipitators (ESPs) for particulate control are most widely installed on U.S. power plants, they are the least efficient in capturing mercury. Technologies that perform better at controlling mercury emissions, such as fabric filters and wet scrubbers, to date are not widely installed (see Table 2).

Table 2: Common Pollution Control Technologies Used by Coal-Fired Power Plants[26]

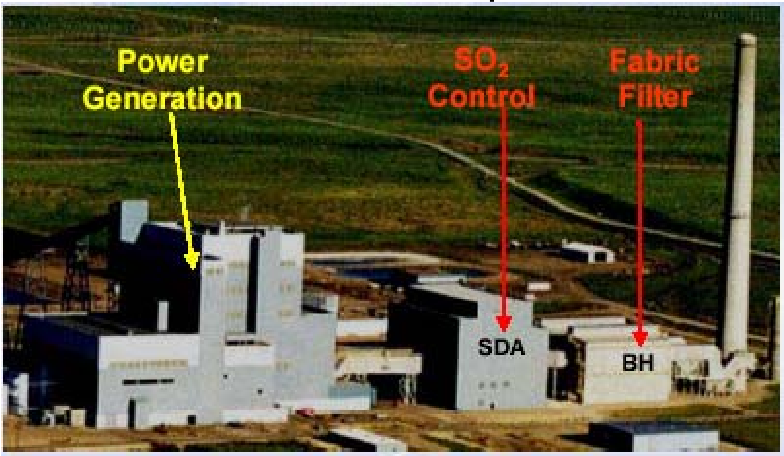
Pollutant	Common Control/Reduction Approach	Description
Sulfur dioxide (SO_2)	Burn low sulfur coal	Switch to lower sulfur bituminous or subbituminous coal
	Wet scrubber (wet FGD)	Flue gas passes through an absorber unit in which a limestone/water slurry is sprayed, absorbing SO_2
	Dry scrubber (dry FGD)	Dry powdered lime or another sorbent is injected into the ductwork upstream of a particulate matter control device. The dry lime sorbs SO_2, and is then retained in the PM device.
	Spray dryer absorber/ Dry Scrubber (SDA)/semi-dry scrubber	Intermediate between wet and dry scrubbers. The flue gas passes through an absorber unit downstream of the air heater in which a limestone/water is sprayed, absorbing SO_2. The heat of the flue gas evaporates the water, and the resulting particles are retained in the PM device. A new dry scrubbing technology called advanced FGD is discussed under 'multi-pollutant controls', below.
Nitrogen oxides (NOx)	Combustion controls (e.g. low NOx burners)	Modify equipment or operating conditions to alter flame temperature and other conditions, reducing nitrogen oxides (NOx) formation
	Selective catalytic reduction (SCR)	Use metal catalyst with ammonia gas to reduce the oxidized nitrogen in flue gas to molecular nitrogen
	Selective non-catalytic reduction (SNCR)	Inject reducing agent into flue gas at specific point to reduce oxidized nitrogen
Particulate matter (PM)	Electrostatic precipitators (ESPs)	Impart electrical charge to particles in flue gas, and attract to oppositely charged metal plates. An ESP can be either hot-side (hs-ESP)or cold-side (cs-ESP) depending on whether it is located on the furnace or turbine side of the air heater.
	Fabric filters (FF)	Flue gases pass through porous fabric material; particles collected by filter itself and by "cake" that builds up. COHPAC is a specially designed fabric filter placed downstream of an ESP to improve particle collection.

Table 3: Profile of Pollution Control Configurations on Power Plants, 1999[27]

Percentage of boilers	Number of boilers	Control technology in place	Purpose of technology
69%	791	Electrostatic precipitators (ESPs) only (hot side or cold side[‡])	Particulate control
12%	133	ESPs and Wet scrubbers (FGD)	Particulate control Sulfur control
3%	38	Fabric filters (FFs) and Spray dryer absorbers (SDA)	Particulate control Sulfur control
2%	24	ESPs or FFs and Selective catalytic reduction (SCR) or Selective non-catalytic reduction (SNCR)	Particulate control Nitrogen oxide control

[‡] See definition above

Figure 4: Power plant with semi-dry scrubber for sulfur dioxide control and fabric filter for particulate control



Source: ADA-ES

Additional controls, particularly SCRs for nitrogen oxides, are currently being installed in response to the NOx SIP Call, and additional SO_2 scrubbers are projected to be installed if the proposed Clean Air Interstate Rule is enacted.[$ 28]

Table 4 summarizes the effectiveness of these existing pollution control technologies in capturing mercury. The data comes from EPA's 1999 Information Collection Request, which assessed incidental mercury control for approximately 80 boilers across the country.

Table 4: Average Mercury Capture by Existing Post-Combustion Control Configurations at Coal-Fired Utility Boilers in U.S.*[29]

Control Strategy	Control Device Configuration	Average Mercury Capture (Percent) by Control Configuration, by Coal Type		
		Bituminous	Subbituminous	Lignite
Particulates only	Cs-ESP	36	3	-4
	Hs-ESP	9	6	Not tested
	FF	90	72	Not tested
Particulates and sulfur using an SDA	ESP+SDA	Not tested	35	Not tested
	FF + SDA	98	24	0
Particulates and sulfur (SDA) and nitrogen oxides	FF+SDA+ SCR	98	Not tested	Not tested
Particulates and sulfur using an FGD	Cs-ESP+FGD	74	29	44
	Hs-ESP+FGD	50	29	Not tested
	FF+FGD	98	Not tested	Not tested

*Pulverized coal-fired boilers. Capture percentage refers to capture across the pollution control device—i.e., 90 percent means a 90 percent reduction in concentration going out of device compared to concentration going in.

As Table 4 shows, mercury capture is much lower for plants burning subbituminous and lignite coal—although very limited testing was performed on lignite plants. None of the existing technology combinations reach 90 percent mercury control routinely for these coals. Mercury-specific controls will likely be necessary for these plants to reach a 90 percent mercury control standard.

However, several options are available for plants burning bituminous coals using these technologies. Specifically, a fabric filter alone or a scrubber with a fabric filter may be

[$] Significant retrofits are already underway and are anticipated to occur to meet current and proposed rules to cut nitrogen oxides and sulfur dioxide emissions. With the Clean Air Interstate Rule, total coal generating capacity retrofitted with FGDs (sulfur controls) is anticipated to increase to 187 gigawatts (out of a total of about 300 nationwide) by 2015, up from 96 gigawatts in 1998; and total capacity retrofitted with SCRs is anticipated to increase to 178 gigawats, up from less than 1 gigawatt in 1998.

sufficient to achieve 90 percent or greater mercury control. While less than 10 percent of all coal-fired boilers currently use these technologies, this may change as plants install new controls to meet upcoming regulatory requirements.

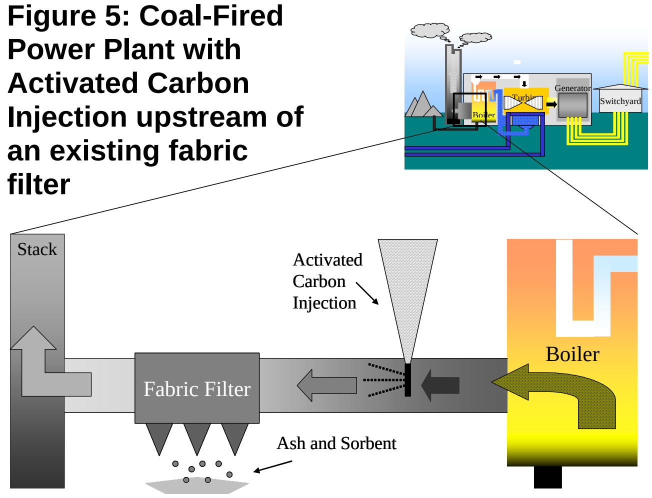
There is relatively limited data on the mercury control benefits of flue gas nitrogen oxides controls (i.e., SCR or SNCR)—in limited cases, i.e. for plants that also used wet scrubbers and burned bituminous coals, overall control approaching 90 percent has been observed. Catalysts are now being adapted to facilitate mercury capture, but more research into the effects of these nitrogen oxides control measures on mercury reduction is needed. As of 1999, only two percent of plants had installed these devices; however, as mentioned above, additional installation is ongoing.

Mercury-Specific Control Techniques

Extensive work is underway to make commercially available a number of different technologies that are capable of capturing high levels of mercury. They range in approach from modifying existing wet scrubbers to better control mercury, adding catalysts to mercury gas to convert elemental mercury to the more easily captured oxidized mercury, to injecting sorbents such as carbon in the flue gas to adsorb mercury. For this report, we focus primarily on carbon injection technology because it is commercially available for power plants and has been extensively tested.

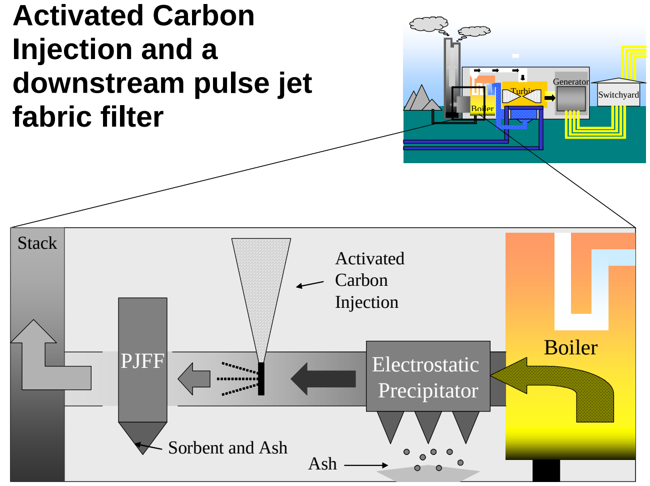
Activated carbon injection (ACI) works by injecting powdered carbon, a highly adsorbent material, into the flue gas to adsorb elemental and oxidized mercury. The carbon particles are then trapped by a particulate control device (an ESP or fabric filter). While the activated carbon can be injected upstream of an electrostatic precipitator or fabric filter, it also can be injected downstream of an electrostatic precipitator, and then collected by a second (usually smaller) 'polishing' fabric filter, called a pulse jet fabric filter (PJFF)**. For many plants currently using an electrostatic precipitator, studies suggest the latter approach may be more cost effective, even though it requires an additional upfront capital investment. The cost of a polishing fabric filter would be offset by the reduced amount of carbon needed to capture high levels of mercury. Additionally, a polishing fabric filter will help plants capture fine particulates, thereby helping them meet more stringent fine particulate standards.

Figure 5: Coal-Fired Power Plant with Activated Carbon Injection upstream of an existing fabric filter



Source: adapted from diagrams by ICAC, ADA-ES, Alstom and others

Figure 6: Coal-Fired Power Plant with Activated Carbon Injection and a downstream pulse jet fabric filter



Source: adapted from diagrams by ICAC, ADA-ES, Alstom and others

** A number of other variations on these approaches are also being tested—such as modifying or adding on to the primary particulate control device such that activated carbon can be injected into the device to capture mercury subsequent to the primary particulate control.

Full-scale test results

Numerous full-scale tests involving ACI have been performed over the past five years. Table 5 summarizes the results of completed full-scale tests at power plants of various configurations burning different coals. An additional 18 full-scale tests are ongoing or scheduled for 2004-2005.[30]

Table 5: Mercury Control Efficiencies With Powdered Activated Carbon Injection in Full-Scale Tests at Coal-Fired Power Plants[a]

Plant (State)	Coal Type	Existing Controls	Add-On Technology	% Mercury Reduction	Reference
Alabama Power – Gaston Unit 3 (AL)	bituminous	hs-ESP	ACI and COHPAC fabric filter	Up to 90	Bustard et al., 2002[31]
Southern Co. – Yates Units 1,2 (GA)	bituminous	cs-ESP	ACI	Up to ~75	Richardson et al., 2004[32]
PG&E –NEG Brayton Point Unit 1 (MA)	bituminous	Two cs-ESPs	ACI	Up to 90	Durham et al., 2003a[33]
WEPCO – Pleasant Prairie Unit 2 (WI)	Sub-bituminous	cs-ESP	ACI	70 (long-term)	Durham et al., 2003b[34]
Sunflower Electric's Holcomb Station	Sub-bituminous	Spray dryer (SDA), FF	ACI – several sorbent types	Up to 90+	Sjostrom et al., 2004[35]
DTE Energy Detroit Edison St. Clair Power Plant (MI)	85/15 subbituminous/ bituminous	cs-ESP	Brominated ACI	Up to 80	McCoy et al., 2004[36]
Leland Olds Station Unit 1 (ND)	lignite	Two parallel cs-ESPs	ACI	63 (average for month-long test)	Thompson et al., 2004[37]
Great River Energy – Stanton Unit 10 (ND)	lignite	Spray dryer(SDA), FF	Untreated ACI Iodine-impregnated ACI	Up to 81 Up to 96	Sjostrom, et al., 2002[38]

a: hs-ESP is hot-side electrostatic precipitator, cs-ESP is cold-side electrostatic precipitator, FF is fabric filter, ACI is activated carbon injection, COHPAC is Combined Hybrid Particulate Collector (patented type of fabric filter). For Leland Olds test, target mercury removal rate was only 55 percent, and carbon injection rate was adopted accordingly.

Tests completed to date show that:

- Greater than 90 percent mercury control is possible at plants equipped with ACI and a fabric filter burning bituminous and subbituminous coals.
- At least 80 percent control is possible for plants burning lignite coal using ACI and a fabric filter, with higher reductions likely with a modified activated carbon or higher activated carbon injection rates.

Pre-Combustion and Multi-Pollutant Approaches to Mercury Control

There are a number of new technologies being developed to capture high levels of mercury along with other pollutants. Some of these technologies look very promising in small scale tests, and may be available for commercial application in the near future. Some of the most promising technologies include:

- K-Fuel™ Coal Benefication Process: Crushed coal is treated with heat and pressure to remove sulfur minerals, mercury, and moisture. Released mercury is captured on a carbon filter. In addition to having lower mercury content, the resulting coal also has a higher heating value (meaning less is needed to provide the same amount of energy).[39] Commercial production of K-fuel will begin in spring 2005, with two thirds of the first plant's projected output already sold.[40]
- Advanced Dry Flue Gas Desulfurization (Advanced FGD, Advanced Dry Scrubbing): This process is similar to that of existing spray dryer absorbers. The process utilizes a fluidized bed or a flash dryer for the reactor (a separate chamber through which flue gas flows). Exhaust gases react with a lime slurry to capture sulfur oxides, hydrochloric acid and mercury. In addition to achieving substantial sulfur dioxide reductions (95 percent and higher), the technology can result in up to 98 percent mercury capture for bituminous coals. At least four commercial versions of the technology are currently available.[41]
- Electro Catalytic Oxidation (ECO): This technology uses an electric discharge to oxidize pollutants; an ammonia scrubber to remove sulfur dioxide and water-soluble pollutants; an electrostatic precipitator to remove acid mists and fine particles; and a carbon filter system to capture mercury.[42] A 50 MW commercial demonstration of the ECO system is being performed in Ohio at FirstEnergy's Burger plant.

Commercial Availability

Technology to reduce mercury from power plants is not only being tested around the country, it is also commercially available. In fact, according to the Institute of Clean Air Companies, power plants are already bidding on or finalizing contracts for mercury control equipment. This activity is being driven by a combination of state consent decrees, state rules, or new permit requirements. For example, mercury standards being implemented over the next three to five years in Massachussetts, Connecticut and Wisconsin will affect more than 50 coal-fired plants. In Iowa, MidAmerican Energy's 970MW Council Bluffs

Other Effective Mercury Technologies Being Developed

While we focus on activated carbon injection in this report, many other methods of mercury control are also being tested. These tests may well identify cheaper and more effective means for individual plants to achieve stringent mercury reductions. Some of these include:

Michigan: TOXECON ™ We Energies is working with ADA Environmental Solutions and others to demonstrate the patented TOXECON multi-pollutant control process on its Presque Isle plant in Marquette, MI. The project will consist of installing an injection system for powdered activated carbon and other sorbents into a downstream fabric filter for three units. In addition to achieving significant mercury control (up to 90 percent), substantial sulfur dioxide and nitrogen oxide reductions are anticipated as well.
Source: U.S. Doe, 2004, Multi-Pollutant Emission Control, www.netl.doe.gov/publications/factsheets/project/proj205.pdf

Pennsylvania: New multi-pollutant controls US DOE has funded Consol Energy Inc., in South Park, PA, to test a multi-pollutant technology on a pilot scale at the 288 MW Allegheny Energy Supply Mitchell plant. The approach involves cooling the flue gas, condensing mercury on fly ash, and then trapping the fly ash on the existing particle collection device. A magnesium compound is injected to prevent acid corrosion of the plant components. In addition to removing mercury, the technology removes sulfur trioxide, and can also lead to improved heat rate, which would decrease emissions of nitrogen oxides and other pollutants as well.
Source: U.S. DOE, 2004, TOXECON Refit for Mercury and Multi-Pollutant Control, www.netl.doe.gov/publications/factsheets/project/proj224.pdf

Michigan & Ohio: Wet scrubber optimization Michigan South Central's Endicott plant has been the site of research efforts with Babcock & Wilcox Company and McDermott Technology, Inc. to optimize wet scrubbers for mercury control. The plant has a 60 MW boiler with a cold-side ESP in place, and the research involves adding a proprietary reagent to an existing wet scrubber. Preliminary tests indicated significant mercury control, with minimal impact on fly ash for disposal or sale. Wet scrubber optimization is also being tested at Cinergy's Zimmer station in Ohio.
Source: Nolan, P.S. et al, Mercury Emissions Control in Wet FGD Systems, Presented Air Quality III Conference, Arlington, VA, 2002.

plant now under construction is required to install activated carbon injection to meet its mercury emission limit prior to going online in 2007.[43]
Aside from activated carbon injection, there are nearly a dozen other pollution control technologies under development and at various stages of reaching commercial availability (see Table 6, below). According to a December 2003 survey of pollution control equipment vendors, five of seven companies surveyed indicate their technologies are currently available. Two plan to enter the market in 2004 and 2005. Three report achieving mercury reductions of at least 80 to 90 percent from all coal types, and one achieves more than 90 percent reduction from western subbituminous and lignite coals.[44]

Table 6: Commercial Status of Power Plant Mercury Control Technologies[45]

Mercury Control Approach	Commercial Status	Projected Availability Date	Comments
Conventional coal cleaning	Available	Currently available	An option for roughly 23% of eastern coals. See K-Fuel® for western coals.
Optimization of existing controls	Available	Currently available	Additional mercury control achievable on existing boilers.
Installation of conventional controls	Available	Currently available	30% reduction projected to meet other emission limits for $PM_{2.5}$
Activated carbon injection	Available	Currently available	Systems for power plants now being offered by ADA-ES
COHPAC-TOXECON	Available	Currently available	Both components now commercially available. Full-scale tests complete on integrated system. 5-year full-scale test will finish in 2007.
B-PAC®	Near commercial	June 2004	
Enhanced wet scrubbing	Near commercial	2005	
K-Fuel™	Near commercial	Early 2005	
Powerspan—ECO®	Near commercial	3rd quarter 2004	
Advanced Hybrid Filter™	Emerging		Pilot-scale tests
Airborne Process	Emerging		Pilot-scale tests
LoTox™ Process	Under development		Bench-scale tests
MerCAP™	Under development		Bench-scale tests
MB Felt Filter	Under Development		Bench-scale tests

Conclusion

While newer sorbents or other multi-pollutant control approaches described above may ultimately provide a more efficient and cost effective means of controlling mercury emissions, we can point with certainty to activated carbon injection as an effective, commercially available method of mercury control. ACI has been widely tested at power plants burning different coals with a range of configurations, and has proven to be very effective especially when used in conjunction with a fabric filter. Therefore, we have based our cost analysis on the use of this technology for controlling mercury emissions from power plants.

III. Assessing the Costs of Achieving 90% Mercury Control

In this report, NWF estimates the cost of achieving 90 percent mercury control from power plants in five states that rely significantly on coal for electricity generation: Ohio, Pennsylvania, Illinois, Michigan, and North Dakota. These states are also major mercury emitters, ranking 2, 3, 5, 13 and 15 in the nation for mercury emissions from electric utilities.[46] They also represent the plant configurations and range of coal types burned by power plants nationwide. Our results show that 90 percent mercury control is economically feasible for these five states, and suggest equal affordability on a national scale.

Our Approach

In several recent reports, EPA has presented cost estimates for installing technology to control mercury emissions at coal-fired power plants with different coal types, sizes and configurations. We matched these model plant cost estimates with 2002 data on coal consumption, generation, and existing and planned pollution control configurations at each power plant boiler in five states. We calculated annualized costs for mercury control boiler-by-boiler, and then estimated what the statewide costs would mean for the rate-payers in each state. A complete explanation of our methodology is provided in Appendix A.

While plants can use a number of technologies to meet mercury reduction standards, we narrowed our analysis by focusing only on the cost of using activated carbon injection with or without a polishing fabric filter. For a relatively small number of plants burning high sulfur bituminous coal, we applied advanced dry scrubbers to achieve over 90 percent mercury control (and over 95 percent sulfur dioxide control).

By applying what is effectively a single technology solution to all plants as they are configured today, our cost calculations are likely overestimated. Not only are mercury control technologies emerging which may prove less expensive than activated carbon, but plants, especially those burning bituminous coal, may find they can achieve 90 percent or greater mercury control by optimizing existing or planned conventional controls for nitrogen oxides, sulfur dioxides and particulates.

Results: Estimates of Mercury Control Costs in Five States

Our analysis found that retrofitting every coal-fired utility boiler with mercury control equipment sufficient to achieve 90 percent mercury control would cost the average household from about 70 cents to a little over $2.00 a month, depending on the state. Commercial and industrial increases were similarly reasonable—between 1 and 3 percent. The charts below summarize our findings.

Table 7a: Estimated Total and Residential Costs of Controlling Mercury at Coal-Fired Power Plants in Five States

	Mercury Control Costs		***Residential Costs***[a]			
State	Mercury Control Costs per kilowatt hour of power generated from coal (in cents)	Percentage of revenues/ percentage increase in customer rates	Current avg. residential rate in cents per kilowatt hour*	Avg. Residential Monthly Electricity Consumption in kilowatt hours*	Avg. Residential Monthly Bill ($)*	Increase in Avg. Residential Monthly Bill ($)
PA[b]	0.21($0.0021)	1.4%	9.7 ($0.097)	812	$78.91	$1.08
OH[b]	0.22	2.9%	8.3	880	72.91	2.14
IL	0.17	1.0%	8.4	773	64.82	0.69
MI	0.15	1.2%	8.3	683	56.60	0.69
ND	0.17	2.9%	6.4	1,037	66.28	1.94

*Data from reference 47.[47]

Table 7b: Estimated Costs to Commercial and Industrial Customers of Controlling Mercury at Coal-Fired Power Plants in Five States

	Commercial[a]			***Industrial***[a]		
State	Current average price in cents per kilowatt hour*	Average monthly bill ($)*	Estimated average monthly increase ($)	Current average price in cents per kilowatt hour*	Average monthly bill ($)*	Estimated average monthly increase ($)
PA[b]	8.0 ($0.08)	$470.81	$6.42	6.1($0.06)	$7870.29	$107.30
OH[b]	7.7	478.41	14.03	4.7	8438.56	$247.55
IL	7.5	548.74	5.82	5.0	28,825.63	305.47
MI	7.4	478.45	5.87	5.0	9501.69	116.51
ND	5.8	345.08	10.09	4.0	5445.81	159.19

a: In our analysis, we have assumed that different customer classes will continue to pay different utility rates. Accordingly the values above reflect each customer class paying the same percent increase, but they will not experience the same per kilowatt hour increase. Detailed description of our methodology can be found in Appendix A.
b: It is assumed that certain plants in Ohio and Pennsylvania will install advanced dry scrubbers to meet sulfur control requirements and achieve 90+ percent mercury capture as a co-benefit. These relatively large sulfur control costs are included in the numbers above. These plants may have several cheaper options available to them, especially if they install SCRs and/or scrubbers to meet pending air quality requirements. Appendix A shows the relative impact on consumer costs of several different ways of meeting 90 percent mercury control for these plants.
*Data from reference 47.

Additionally, we found that:

- It is more cost-effective to use activated carbon injection combined with a fabric filter to achieve high levels of mercury control than ACI alone, particularly for plants burning subbituminous coal.
- For plants with fabric filters already installed, the costs of achieving 90 percent mercury control are much lower, due to the effectiveness of fabric filters at retaining all forms of mercury.
- Using the combination of activated carbon injection and a fabric filter, the cost of attaining 90 percent mercury control is only slightly higher than 70 to 80 percent control. (See Appendix A)

NWF's findings are consistent with other cost estimates for controlling mercury from power plants. Using some very conservative assumptions, we find mercury control costs between 0.15 and 0.22 cents/kWh averaged across plants statewide—which is equivalent in these states to a 1 to 3 percent increase in customer rates or a comparable percentage of utility revenues.

By comparison, the Institute for Clean Air Companies states that mercury control technology would add between 0.1 to 0.3 cents per kilowatt-hour to the average retail customer rate of 8 cents per kilowatt-hour—a 1.2 to 3.7 percent increase.[48] A 2003 Department of Energy study shows comparable costs, estimating that 60-90 percent control for subbituminous coals would cost 0.191 to 0.236 cents per kWh, while similar 70-90% control on bituminous coal would range in cost from 0.127 to 0.215 cents per kilowatt hour.[49] Finally, EPA itself stated in 2000 "that there are cost-effective ways of controlling mercury emissions from power plants. Technologies available today and technologies expected to be available in the near future can eliminate most of the mercury from utilities at a cost far lower than 1 percent of utility industry revenues."[50]

State Case Studies

For the states analyzed below, we applied the following general scenarios to meet a 90 percent mercury control target:

- If a boiler is equipped with an electrostatic precipitator, we assumed installation of activated carbon injection and a polishing fabric filter, regardless of coal type.

- If a boiler is equipped with a fabric filter and is burning bituminous coal, we assumed installation of activated carbon injection only.

- If a boiler is equipped with a fabric filter and a dry scrubber and is burning subbituminous or lignite coals, we assumed installation of activated carbon injection and a polishing fabric filter. No boilers burning subbituminous coal in our study were installed with a fabric filter only.

- If a boiler is burning higher sulfur bituminous coal and has no flue gas sulfur control (wet or dry scrubbers) installed, we assumed the installation of advanced dry flue gas desulfurization (advanced FGD) to achieve both mercury and sulfur dioxide reductions. We also consider other options for these plants as several less expensive options might be considered.

A detailed explanation of our cost calculations and assumptions applied for the individual plants can be found in Appendix A.

State Profile: Pennsylvania

The State

- 56% electricity generated from coal
- 3rd nationally in utility mercury emissions

The Plants

- 85% of coal burned is bituminous, with remainder waste coal
- 78 coal-fired boilers at 36 plants
- Most boilers used an electrostatic precipitator, 20 boilers used fabric filters, 21 used wet or dry scrubbers

The Technology

- Activated carbon injection and a polishing fabric filter installed on most boilers.

The Cost

- An estimated $1.08 more per month on the average household bill—a 1.4% increase.

Coal-Fired Power Generation in Pennsylvania

Pennsylvania generates over half of its electricity from coal. In 2002, coal-fired power plants provided 56 percent of Pennsylvania's electricity.[51] Most of the coal burned in Pennsylvania is bituminous.

Overall, Pennsylvania ranks third in the nation for the most mercury emitted by electric utilities.[52] Coal-fired power plants are also the largest in-state source of mercury air pollution—emitting 9961 pounds of mercury and accounting for 63 percent of the state's total mercury emissions in 1999.[53] The state's Keystone power plant is one of the largest mercury emitters in the U.S - reporting mercury air emissions of 1,235 lbs. in 2002.[54]

Coal Consumption and Plant Configurations

In 2002, there were 78 coal-fired electric utility boilers operating at 36 plants. Most boilers (57) burned bituminous coals only, while 16 boilers burned exclusively waste coals, and five boilers burned blends of bituminous and waste coals. Overall, approximately 85 percent of the coal burned in Pennsylvania in 2002 was bituminous.[55] For this analysis waste coals were treated as bituminous because they tend to be anthracite or bituminous.

Most plants use an electrostatic precipitator, but 20 boilers have a fabric filter for particulate control. Twenty-one boilers have wet or dry scrubbers for sulfur-dioxide control. Six boilers that burn higher sulfur bituminous coals have no scrubbers in place.

90% Mercury Control Solutions

We assume that activated carbon injection and a polishing fabric filter would be needed to reliably reach 90 percent mercury capture at all boilers in Pennsylvania which use electrostatic precipitators. Since Pennsylvania's plants burn bituminous coal, we assume that activated carbon injection will only be sufficient for the boilers already using a fabric filter for particulate control. Due to low emission rates at 14 of these boilers, it was assumed that they would not need to reduce mercury further. For six boilers we assume installation of advanced dry scrubbers (AFGD) for joint mercury and sulfur dioxide control.

In general, this methodology likely overestimates costs. Tests suggest that activated carbon injection alone may be sufficient to achieve very high mercury control on a wider range of bituminous configurations. (See Section 2). Also, as discussed in Appendix A, advanced dry scrubbers are an effective, but costly option, and several other mercury control options may exist for these plants.

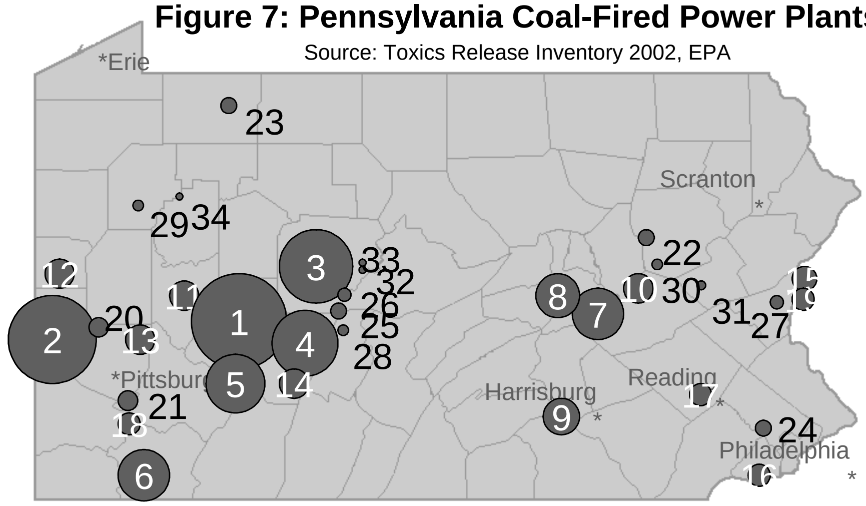
Cost of Achieving 90% Mercury Control at Pennsylvania's Coal Plants

The average Pennsylvania residential electricity customer uses 812 kilowatt hours (kWh) of energy per month and pays a $79 utility bill. Pennsylvania's 36 plants can be retrofitted to achieve 90 percent control, while costing Pennsylvania consumers only $1.08 more per month, on average.

Commercial businesses would pay about $6.42 on an average bill of $470, while the average $7,870 industrial bill would increase $107.30 monthly.

Figure 7: Pennsylvania Coal-Fired Power Plants

Source: Toxics Release Inventory 2002, EPA



Rank	Electric Utility /Plant	Total Mercury Air Emissions (Lbs.)	Location
1.	Reliant Energy Keystone Power Plant	1235	Shelocta
2.	Bruce Mansfield	790	Shippingport
3.	Reliant Energy Shawville Station	632	Shawville
4.	EME Homer City Generation L.P.	545	Homer City
5.	Reliant Energy Conemaugh Power Plant	496	New Florence
6.	Allegheny Energy, Inc. Hatfield Power Station	421	Masontown
7.	Mount Carmel Cogen Facility	327	Marion Heights
8.	Sunbury Generation L.L.C.	309	Shamokin Dam
9.	PPL Brunner Island Steam Electric Station	298	York Haven
10.	Montour Steam Electric Station	277	Danville
11.	Allegheny Energy Inc. Armstrong Power Station	247	Kittanning
12.	New Castle Power Plant	240	West Pittsburg
13.	Cheswick Power Plant	187	Springdale
14.	Reliant Energy Seward Power Plant	156	New Florence
15.	Reliant Energy Portland Power Plant	115	Portland
16.	Exelon Generating Co. Eddystone Generating Station	106	Eddystone
17.	Reliant Energy Titus Power Plant	72	Birdsboro
18.	Reliant Energy Inc., Elrama Power Plant	61	Elrama
19.	PPL Martins Creek Steam Electric Station	50	Bangor
20.	AES Beaver Valley L.L.C.	45	Monaca
21.	Mitchell Power Station	44	Courtney
22.	Hunlock Creek Energy Ventures	39	Hunlock Creek
23.	Reliant Energy Warren Station	35	Warren
24.	Cromby Generating Station	31	Phoenixville
25.	Ebensburg Power Co.	26	Ebensburg
26.	Cambria Cogen Co.	14	Ebensburg
27.	PG&E Natl. Energy Group Northampton Generating Plant	13	Northampton
28.	Colver Power Project	7	Colver
29.	PG&E Scrubgrass Generating Plant	2	Kennerdell
30.	Northeastern Power Co. Kline Township	1	Mc Adoo
31.	Panther Creek Parnters	1	Nesquehoning
32.	Gilberton Power Co. John B. Rich	0	Frackville
33.	Wheelabrator Frackville Energy Co. INC	0	Frackville
34.	Piney Creek LP	0	Clarion

Estimated costs of controlling mercury at Pennsylvania's coal-fired power plants, and the resulting impacts on electricity bills, are given in Table 8 below.

Table 8: Pennsylvania	
Mercury control cost per kilowatt hour of power generated from coal	0.21 cents ($0.0021) per kWh
Total annual cost of 90% mercury control	$223 million
Total annual utility revenues	$11.3 billion
Increase in customer rates	1.4%
Residential Costs	
Current average residential rate	9.7 cents ($0.097) per kWh
Average monthly residential energy consumption	812 kWhs
Average monthly residential electricity bill	$78.91
Estimated increase in average monthly residential electricity bill to achieve 90% mercury control	$1.08
Commercial Costs	
Current average commercial rate	8.0 ($0.008) cents per kWh
Average monthly commercial electricity bill	$470.81
Estimated increase in average monthly commercial electricity bill to achieve 90% mercury control	$6.42
Industrial Costs	
Current average industrial rate	6.1 cents ($0.061) per kWh
Average monthly industrial electricity bill	$7,870.29
Estimated increase in average monthly industrial electricity bill to achieve 90% mercury control	$107.30

Impacts of Achieving 90% Mercury Control at Pennsylvania's Coal Plants

90 percent mercury control at Pennsylvania's coal-fired utilites would mean a dramatic drop in total state mercury emissions and would benefit both the state and downwind areas.

Pennsylvania issues a fish advisory warning people to limit their consumption of all species of fresh water fish caught in any of the state's waters. Cleaning up mercury pollution is essential to protect and bolster the state's $1.6 billion recreational fishing industry, enjoyed by the more than two million residents and non-residents who fish in Pennsylvania each year.[56]

Investing in a cleaner energy infrastructure and reducing mercury pollution in Pennsylvania can directly benefit the state's public health, waters, wildlife and economy.

State Profile: Ohio

Coal-Fired Power Generation in Ohio

In 2002, Ohio generated 90 percent of its electricity from coal and burned almost exclusively bituminous coal.[57]

Nationwide, Ohio ranks second in the amount of mercury emitted by power plants. Coal-fired power plants are also the largest in-state source of mercury air pollution—emitting 7,117 pounds of mercury and accounting for over two-thirds of the total state emissions reported in 1999.[58] The state's Conesville power plant is one of the largest mercury emitters in the U.S.—reporting mercury air emissions of 1,300 lbs. in 2002.[59]

Coal Consumption and Plant Configurations

As of 2002, Ohio had 80 boilers at 22 plants burning 89 percent bituminous coal. Sixty-five boilers burned bituminous coal, nine burned subbituminous coal, and six boilers burned blends of bituminous and subbituminous coal.

Most boilers (61) have cold-side ESPs for particulate control, while fourteen boilers have hot-side ESPs and six have fabric filters in place. Only six boilers use wet scrubbers for sulfur control. Twenty boilers burn higher sulfur bituminous coal but had no scrubbers in place as of 2002.[60]

90% Mercury Control Solutions

We assume that activated carbon injection and a polishing fabric filter would be needed to reliably reach 90 percent mercury capture at most boilers in Ohio. For the few plants burning bituminous coal with a fabric filter in place, we assume that activated carbon injection alone will be sufficient. For 20 boilers we assume installation of advanced dry scrubbers (AFGD) for joint mercury and sulfur dioxide control.

The State
- 90% electricity generated from coal
- Second nationally in utility mercury emissions

The Plants
- 89% of coal burned was bituminous
- 80 coal-fired boilers at 22 plants
- 75 boilers with ESPs, seven with wet scrubbers; 20 burn high sulfur coal and used no scrubbers

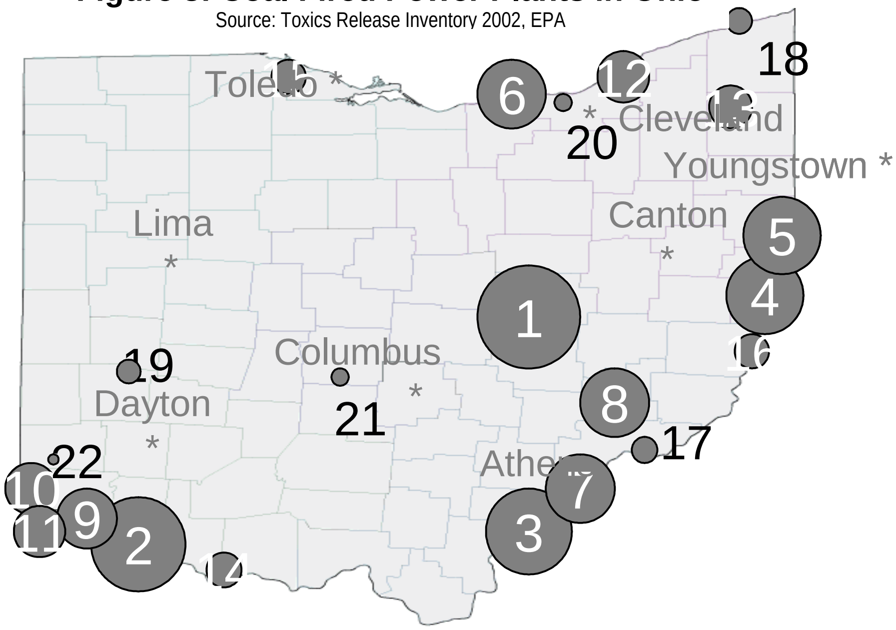
The Technology
- Activated carbon injection and a polishing fabric filter installed on most boilers.

The Cost
- An estimated $2.14 more per month on the average household bill—a 2.9% increase.

In general, this methodology likely results in an overestimation of costs. As shown in Section 2, tests suggest that activated carbon injection alone may be

Figure 8: Coal Fired Power Plants in Ohio

Source: Toxics Release Inventory 2002, EPA



Rank	Electric Utility /Plant	Total Mercury Air Emissions (Lbs.)	Location
1.	American Electric Power Conesville Plant	1300	Conesville
2.	J.M. Stuart Station	845	Manchester
3.	American Electric Power Gavin Plant	660	Cheshire
4.	American Electric Power Cardinal Plant	560	Brilliant
5.	W.H. Sammis Plant	540	Stratton
6.	Avon Lake Power Plant	398	Avon Lake
7.	Ohio Valley Electric Corp. (Kyger Creek Station)	390	Cheshire
8.	American Electric Power Muskingum	360	Beverly
9.	W.H. Zimmer Generating Station	359	Moscow
10.	CG&E Miami Fort Generating Station	356	North Bend
11.	CG&E Beckjord Generating Station	347	New Richmond
12.	Eastlake Plant	320	Eastlake
13.	Niles Power Plant	204	Niles
14.	Killen Station	175	Manchester
15.	Bayshore Plant	120	Oregon
16.	R. E. Burger Plant	110	Shadyside
17.	Richard H. Gorsuch Generating Station	95	Marietta
18.	Ashtabula	63	Ashtabula
19.	O. H. Hutchings Station	47	Miamisburg
20.	Lakeshore Plant	43	Cleveland
21.	American Electric Power Picway Plant	25	Lockbourne
22.	City of Hamilton Power Plant	3	Hamilton

sufficient to achieve very high mercury control on a wider range of bituminous configurations.

As discussed in Appendix A, advanced dry scrubbers are an effective, but costly option —and several other mercury control options may exist for these plants. Ohio is the site of ongoing tests of several new mercury control technologies, and is home to companies developing these technologies for use nationwide

Cost of Achieving 90% Mercury Control at Ohio's Coal Plants

The average Ohioan residential electricity customer uses 880 kilowatt hours (kWh) of power per month and pays a $73 electricity bill. Ohio's 22 power plants can be retrofitted to achieve 90 percent mercury control for the cost of only about $2.14 more per month per household.

Commercial businesses would pay about $14.03 on an average bill of $478, while the average $8,439 industrial bill would increase $247.55 monthly.

Estimated costs of controlling mercury at Ohio's coal-fired power plants, and the resulting impacts on electricity bills, are given in the table below.

Table 9: Ohio	
Mercury control cost per kilowatt hour of power generated from coal	0.22 cents ($0.0022) per kWh
Total annual cost of 90% mercury control	$287 million
Total annual utility revenues	$10.4 billion
Increase in customer rates	2.9%
Residential Costs	
Current average residential rate	8.3 cents ($0.083) per kilowatt hour (kWh)
Average monthly residential energy consumption	880 kWhs
Average monthly residential electricity bill	$72.91
Estimated increase in average monthly residential electricity bill to achieve 90% mercury control	$2.14
Commercial Costs	
Current average commercial rate	7.7 cents ($0.077) per kWh
Average monthly commercial electricity bill	$478.41
Estimated increase in average monthly commercial electricity bill to achieve 90% mercury control	$14.03
Industrial Costs	
Current average industrial rate	5.0 cents ($0.05) per kWh
Average monthly industrial electricity bill	$8438.56
Estimated increase in average monthly industrial electricity bill to achieve 90% mercury control	$247.55

Impacts of Achieving 90% Mercury Control at Ohio's Coal Plants

90 percent mercury control at Ohio's coal-fired utilites would mean a dramatic drop in total state mercury emissions and would benefit both the state and downwind areas.

Ohio recently updated its fish advisory based on tests of its waterways and fish conducted in 2001-2002. The 2004 advisory recommends that Ohioans restrict their consumption of all locally caught fish to no more than one meal a week. The advisory also provides information on fish from particular bodies of water, such as Lake La Su An, Lake Lavere, and Lake Sue in Williams County, where largemouth bass are recommended for no more than one meal per month due to mercury contamination.[61] Cleaning up mercury pollution is essential to protect and bolster Ohio's 1,370,765 anglers and the state's $761 million recreational fishing industry, as well as its commercial fishing industry.[62] Investing in a cleaner energy infrastructure and reducing mercury pollution in Ohio can directly benefit the state's public health, waters, wildlife and economy.

State Profile: Illinois

The State:
- 46.1% electricity generated from coal
- 5th nationally in utility mercury emissions

The Plants:
- 80.5% burn subbituminous coal
- 56 coal-fired boilers at 21 plants
- Most boilers used an electrostatic precipitator, no boilers used a fabric filter.

The Technology:
- Activated carbon injection and a polishing fabric filter installed on most boilers.

The Cost:
- An estimated $0.69 more per month on the average household bill—a 1.1% increase.

Coal-Fired Power Generation in Illinois

In 2002, coal-fired power plants provided 46.1 percent of Illinois' electricity.[63] The state burns predominately subbituminous coal.

Illinois ranks fifth in the nation for mercury emitted by power plants. Coal-fired power plants are also a major in-state source of mercury air pollution in Illinois—emitting 6,016 pounds of mercury and accounting for 47.3 percent of the state's total mercury emissions in 1999.[64]

Coal Consumption and Plant Configurations

As of 2002, there were 56 boilers operating at 21 plants in the state, burning 80.5 percent subbituminous coal. A total of 30 boilers burned subbituminus coal, while six burned a blend of subbituminous and bituminous. For this analysis, boilers which burn blended coal were treated as burning only subbituminous coal.

Most boilers (51) used electrostatic precipitators to control particulate pollutants, and none of the boilers analyzed in Illinois used a fabric filter.[65]

90% Mercury Control Solutions

We assume that activated carbon injection and a polishing fabric filter would be needed to reliably reach 90 percent mercury capture at coal-fired boilers in Illinois. For 10 boilers at four plants, we assume that advanced dry scrubbers are needed.

In general, this methodology likely results in an overestimation of costs because new technology will soon be available. For example, Illinois' Powerton plant was the site of a test activated carbon injection with a COHPAC fabric filter which achieved over 90 percent mercury control.[66]

Cost of Achieving 90% Mercury Control at Illinois' Coal Plants

The average Illinois residential electricity customer uses 773 kilowatt hours (kWh) of energy per month and pays a $65 utility bill. Illinois' 21 plants can be retrofitted to achieve 90 percent control, while costing Illinois consumers only $0.69 more per month, on average.

Commercial businesses would pay about $5.82 more on an average bill of $549, while the average $28,826 industrial bill would increase $305.47 monthly.

Estimated costs of controlling mercury at Illinois' coal-fired power plants, and the resulting impacts on electricity bills, are given in the table below.

Table 10: Illinois	
Mercury control cost per kilowatt hour of power generated from coal	0.17 cents ($0.0017) per kWh
Total annual cost of 90% mercury control	$138.9 million
Total annual utility revenues	$9.6 billion
Increase in customer rates	1.1%
Residential Costs	
Current average residential rate	8.4 cents ($0.084) per kWh
Average monthly residential energy consumption	773 kWhs
Average monthly residential electricity bill	$64.82
Estimated increase in average monthly residential electricity bill to achieve 90% mercury control	$0.69
Commercial Costs	
Current average commercial rate	7.5 cents ($0.075) per kWh
Average monthly commercial electricity bill	$548.74
Estimated increase in average monthly commercial electricity bill to achieve 90% mercury control	$5.82
Industrial Costs	
Current average industrial rate	5 cents ($0.05) per kWh
Average monthly industrial electricity bill	$28,825.63
Estimated increase in average monthly industrial electricity bill to achieve 90% mercury control	$305.47

Impacts of Achieving 90% Mercury Control at Illinois's Coal Plants

90 percent mercury control at Illinois's coal-fired utilities would mean a dramatic drop in total state mercury emissions and would benefit both local and downwind areas. Computer modeling done by the U.S. EPA found that for a site in the Chicago area, 63 percent of the mercury deposition was attributable to Illinois sources, and 41 percent of Illinois emissions were predicted to fall in-state.[67]

Anglers in the Great Lakes states have faced fish consumption advisories for nearly three decades. Illinois' current mercury advisory applies to fish caught in all inland waters, as well as in the Great Lakes. People are warned to limit consumption of popular species such as bass and walleye.[68] Cleaning up mercury pollution is essential to protect Illinois' 1,237,000 anglers, and the more than $598 million dollars they spend on fishing each year.[69]

Investing in a cleaner energy infrastructure and reducing mercury pollution in Illinois can directly benefit the state's public health, waters, wildlife and economy.

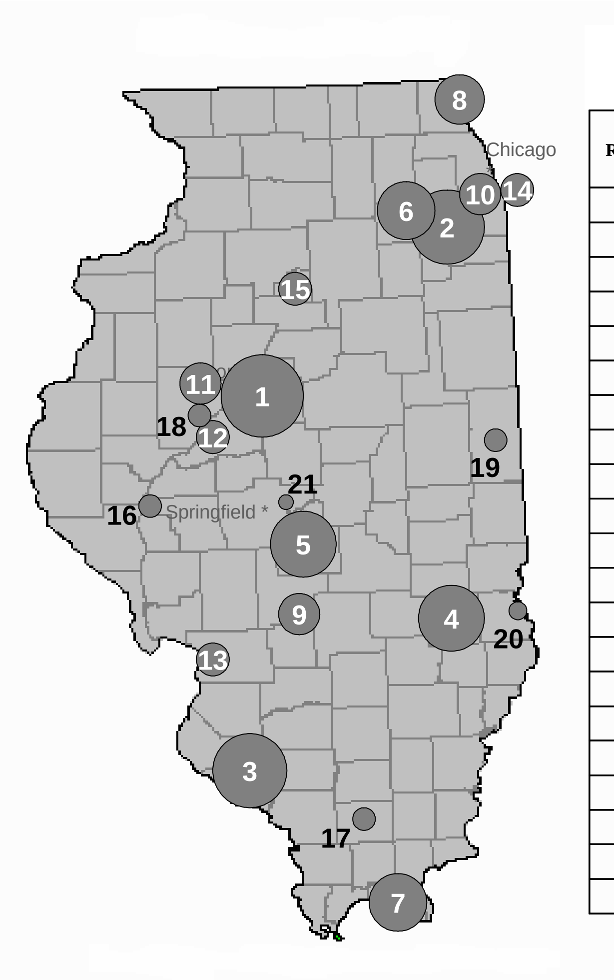


Figure 9: Coal Fired Power Plants in Illinois

Source: Toxics Release Inventory 2002, EPA

Rank	Electric Utility /Plant	Total Mercury Air Emissions (Lbs.)	Location
1.	Edison Powerton Generating Station	527	Pekin
2.	Midwest Generation Joliet Generating Station	431	Joliet
3.	Dynegy Midwest Generation, Inc.	427	Baldwin
4.	Ameren Energy Generating Newton Power Station	377	Newton
5.	Kincaid Generation L.L.C.	369	Kincaid
6.	Edison Will County Generating Station	353	Romeoville
7.	Electric Energy, Inc.	351	Joppa
8.	Waukegan Generating Station	257	Waukegan
9.	Ameren Energy Generating Coffeen Power Station	174	Coffeen
10.	Crawford Generating Station	153	Chicago
11.	American Energy Res. Gen. Edwards	139	Bartonville
12.	Dynegy Havana Power Station	85	Havana
13.	Dynegy Wood River Power Station	81	Alton
14.	Edison Int'l Fisk Generating Station	80	Chicago
15.	Dynegy Hennepin Power Station	72	Hennipen
16.	Ameren Energy Gen. Meredosia Power Station	62	Meredosia
17.	Southern Illinois Power Cooperative	56	Marion
18.	American Energy Res. Gen. Duck Creek	55	Canton
19.	Dynegy Vermillion Power Station	51	Oakwood
20.	Ameren Energy Gen. Hutsonville Power Station	39	Hutsonville
21.	City Water Light & Power City of Springfield	26	Springfield

State Profile: Michigan

Coal-Fired Power Generation in Michigan

Michigan generated 57 percent of its electricity from coal in 2002.[70] Its plants burn half subbituminous, half bituminous coal.

Nationwide, Michigan ranks 13th in the amount of mercury emitted by power plants. Coal-fired power plants are also a major in-state source of mercury air pollution in Michigan—emitting 3,094 pounds of mercury and accounting for 60 percent of the state's total mercury emissions in 1999.[71]

Coal Consumption and Plant Configurations

As of 2002, there were 57 coal-fired boilers at 20 plants in the state, burning 50 percent subbituminous coal. 26 Michigan boilers burn bituminous coal; 19 burn subbituminous coal only and 11 burn blends of subbituminous and bituminous coal. For this analysis, boilers which burn blended coal were treated as burning only subbituminous coal.

Most boilers have electrostatic precipitators to control particulate pollutants, but eight boilers use a fabric filter. As of 2002, six boilers had scrubbers installed to control sulfur dioxide emissions.[72]

90% Mercury Control Solutions

We assume that activated carbon injection and a polishing fabric filter would be needed to reliably reach 90 percent mercury capture at most boilers in Michigan. We assume activated carbon injection alone will be sufficient for the seven boilers using a fabric filter and burning bituminous coal.

In general, this somewhat rigid methodology likely overestimates costs. Also, as described in Section 2, Michigan is currently the site of full-scale mercury control tests which may provide additional and potentially cheaper mercury control options for plants burning subbituminous coal.

The State
- 57% electricity generated from coal
- 13th nationally in utility mercury emissions

The Plants
- 50% of coal burned subbituminous
- 57 coal-fired boilers at 20 plants
- Most boilers used an electrostatic precipitator, 8 used a fabric filter, 6 used scrubbers

The Technology
- Activated carbon injection and a polishing fabric filter installed on most boilers.

The Cost
- An estimated $0.69 more per month on the average household bill—a 1.2% increase.

Cost of Achieving 90% Mercury Control at Michigan's Coal Plants

The average Michigan residential electricity customer uses 683 kilowatt hours (kWh) of power per month and pays a $57 electricity bill. Michigan's 20 power plants can be retrofitted to achieve 90 percent mercury control for the average cost of only about $0.69 more per month per household.

Commercial businesses would pay about $5.87 on an average bill of $478, while the average $9,501.69 industrial bill would increase approximately $116.51 monthly.

Estimated costs of controlling mercury at Michigan's coal-fired power plants, and the resulting impacts on electricity bills, are given in Table 11 below.

Table 11: Michigan	
Mercury control cost per kilowatt hour of power generated from coal	0.15 cents ($0.0015) per kWh
Total annual cost of 90% mercury control	$100 million
Total annual utility revenues	$7.4 billion
Increase in customer rates	1.2%
Residential costs	
Current average residential rate	8.3 cents ($0.083) per kilowatt hour (kWh)
Average monthly residential energy consumption	683 kWhs
Average monthly residential electricity bill	$56.60
Estimated increase in average monthly residential electricity bill to achieve 90% mercury control	$0.69
Commercial Costs	
Current average commercial rate	7.4 cents ($0.074) per kWh
Average monthly commercial electricity bill	$478.45
Estimated increase in average monthly commercial electricity bill to achieve 90% mercury control	$5.87
Industrial Costs	
Current average industrial rate	4.9 cents ($0.049) per kWh
Average monthly industrial electricity bill	$9501.69
Estimated increase in average monthly industrial electricity bill to achieve 90% mercury control	$116.51

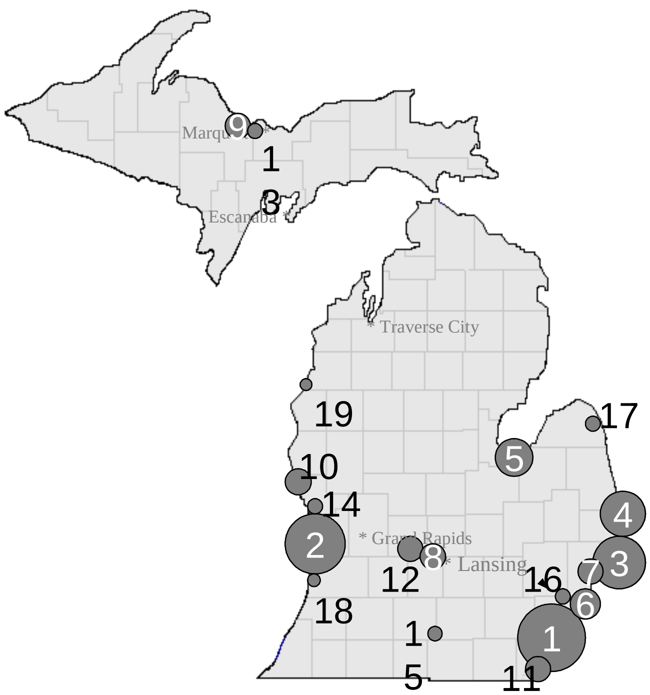
Impacts of Achieving 90% Mercury Control at Michigan's Coal Plants

Ninety percent mercury control at Michigan's coal-fired utilities would mean a dramatic drop in total state mercury emissions and would benefit both local and downwind areas. Computer modeling done by EPA found that for southeastern Michigan, 79 percent of the mercury deposited was predicted to originate in-state, and 45 percent of Michigan emissions were predicted to fall within the state.[73]

Mercury pollution impacts Michigan's public, wildlife, and economic health. Anglers in the Great Lakes states have faced fish consumption advisories for nearly three decades. Michigan's current mercury advisory applies to fish caught in all inland waters, as well as in the Great Lakes. People are warned to limit consumption of popular species such as perch, bass, walleye, and northern pike.[74] Cleaning up mercury pollution is essential to protect the more than 1.3 million anglers who fish in Michigan, and the nearly $840 million dollars they spend on fishing each year.[75]

Figure 10: Coal Fired Power Plants in Michigan

Source: Toxics Release Inventory 2002, EPA



Rank	Electric Utility /Plant	Total Mercury Air Emissions (Lbs.)	Location
1.	Detroit Edison Monroe Power Plant	618	Monroe
2.	J.H. Campbell Generating Plant	370	West Olive
3.	Detroit Edison-Belle River Power Plant	311	China Twnshp
4.	Detroit Edison-St. Clair Power Plant	252	E. China Twnshp
5.	Consumer Energy DE Karn JC Weadock Generating Plant	240	Essexville
6.	Detroit Edison-Trenton Channel Power Plant	202	Trenton
7.	Detroit Edison River Rouge Power Plant	123	River Rouge
8.	Lansing Board of Water and Light Eckert Station	102	Lansing
9.	Presque Isle Power Plant	90	Marquette
10.	B.C. Cobb Generating Plant	85	Muskegon
11.	JR Whiting Generating Plant	80	Erie
12.	Lansing Board of Water and Light Erickson Station	28	Lansing
13.	Marquette BD of Light and Power	18	Marquette
14.	Grand Haven Board of Light and Power	16	Grand Haven
15.	Michigan South Central Power Agency Endicoft Station	13	Litchfield
16.	Wyandotte Department of Municipal Services	11	Wyandotte
17.	Detroit Edison Co. Harbor Beach Power Plant	9	Harbor Beach
18.	Holland BPW James De Young Gen. Station	7	Holland
19.	T.E.S. Filer City Station	5	Filer City

State Profile: North Dakota

The State

- 95% electricity generated from coal
- 15th nationally in utility mercury emissions

The Plants

- 97% lignite coal
- 13 coal-fired boilers at 7 plants
- Three SO2 scrubbers and four fabric filters in place

One Solution

- Activated carbon injection and a polishing fabric filter installed on all boilers

The Cost

- An estimated $1.94 more per month on the average household bill—a 2.9% increase

Coal-Fired Power Generation in North Dakota

North Dakota generates its electricity almost exclusively from coal. In 2002, coal-fired power plants provided 95 percent of North Dakota's electricity.[76] It is also one of several states where power plants burn predominantly lignite coal.

Nationwide, North Dakota ranks 15th for the amount of mercury emitted by power plants. Coal-fired power plants are also the predominant source of mercury air emissions in-state—accounting for almost 80 percent of mercury emissions reported from all North Dakota sources in 1999[77].

Coal Consumption and Plant Configurations

As of 2002, there were 13 coal-fired boilers at seven plants in the state, burning 97 percent lignite coal. Only one plant (Leland Olds) reported using blends of lignite and subbituminous coal.

Four boilers used spray dryer absorbers, while three boilers had wet scrubbers installed. Four boilers used fabric filters for particulate control, while the remaining boilers had electrostatic precipitators in place as of 2002.[78]

90% Mercury Control Solutions

We assume that activated carbon injection and a polishing fabric filter would be needed to reliably reach 90 percent mercury capture on all boilers in the state, including those with existing fabric filters.

This may overestimate cost. Tests done on plants burning lignite coal with a dry scrubber and a fabric filter (including tests at Stanton) suggest that injecting activated carbon alone may be sufficient to achieve 80-90 percent mercury control—but this configuration was not analyzed in the EPA data on which we draw.

Because mercury releases from burning lignite coals behave similarly to subbituminous coals,[79] and EPA did not assess costs for lignite coals, we applied EPA cost estimates for comparable subbituminous configurations to North Dakota's plants.

Costs of Achieving 90% Mercury Control at North Dakota's Coal Plants

The average North Dakota residential electricity customer uses 1,037 kilowatt hours (kWh) of power per month and pays a $66 electricity bill. We estimate that retrofitting North Dakota plants to achieve 90 percent mercury control would cost the average household about $1.94 more per month.

Commercial businesses would pay about $10.09 on an average bill of $345, while the average $5,445 industrial bill would increase $159.19 monthly.

Estimated costs of controlling mercury at North Dakota's coal-fired power plants, and the resulting impacts on electricity bills, are given in the table below.

Table 12: North Dakota	
Mercury control cost per kilowatt hour of power generated from coal	0.17 cents ($0.0017) per kWh
Total annual cost of 90% mercury control	$49.9 million
Total annual utility revenues	$557 million (in-state)
Increase in customer rates	2.9%
Residential Costs	
Current average residential rate	6.4 cents per kWh
Average monthly residential energy consumption	1037 kWhs
Average monthly residential electricity bill	$66.28
Estimated increase in average monthly residential electricity bill to achieve 90% mercury control	$1.94
Commercial Costs	
Current average commercial rate	5.8 cents per kWh
Average monthly commercial electricity bill	$345.08
Estimated increase in average monthly commercial electricity bill to achieve 90% mercury control	$10.09
Industrial Costs	
Current average industrial rate	4.0 cents per kWh
Average monthly industrial electricity bill	$5445.81
Estimated increase in average monthly industrial electricity bill to achieve 90% mercury control	$159.19

Impacts of Achieving 90% Mercury Control at North Dakota's Coal Plants

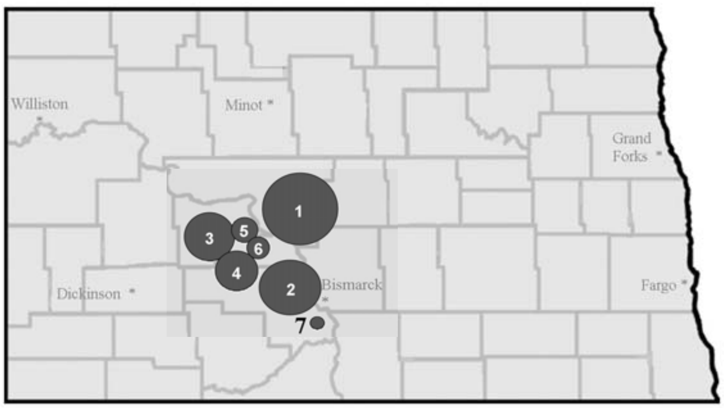
Controlling mercury emissions in North Dakota will benefit both the state and other downwind areas. If North Dakota's coal-fired plants were to achieve 90 percent mercury control, annual emissions from these plants would be reduced by nearly a ton.

North Dakota has a statewide mercury fish consumption advisory affecting all rivers and all lakes.[80] Current advisories warn people to limit consumption of many common species of fish, including northern pike, yellow perch, white bass, walleye and channel catfish.[81] Cleaning up mercury pollution is essential to protect the approximately one in five North Dakotans who fish and to the $177.5 million they spend every year on fishing-related recreation.[82]

Investing in a cleaner energy infrastructure and reducing mercury pollution in North Dakota can directly benefit the state's public health, waters, wildlife, and economy.

Figure 11: Coal Fired Power Plants in North Dakota

Source: Toxics Release Inventory 2002, EPA



Rank	Electric Utility /Plant	Total Mercury Air Emissions (lbs.)	Location
1.	Great River Energy Coal Creek Station	832	Underwood
2.	Minnkota Power Cooperative, Inc. Milton N. Young Station	502	Center
3.	Basin Electric Power Coop Antelope Valley Station	420	Beulah
4.	Otter Tail Power Co. Coyote Station	310	Beulah
5.	Basin Electric Power Coop Leland Olds Station	170	Stanton
6.	Great River Energy Stanton Station	100	Stanton
7.	R.M. Heskett Station	30	Mandan

Note: maps above are not necessarily to scale, and plant locations are approximate. In addition, plant mercury emissions data from the TRI database are given only for plants considered in this assessment.

IV. Other Policy Considerations

Benefits of Reducing Mercury Emissions

The primary focus of this report is to quantify the cost of mercury reductions. However, the benefits for public health, the economy, and the environment that can be associated with reduced mercury emissions are many and should be taken into consideration when setting policy goals.

To date, no formal assessment has been done on the economic benefits of controlling mercury emissions by 90 percent nationwide. In EPA's proposal to regulate mercury from power plants, the agency estimates that the benefits of reducing mercury emissions "are large enough to justify substantial investment."[83] In May 2004, the Congressional Research Service issued a report to Congress that found the "quantifiable benefits [of EPA's current proposal] are estimated at more than $15 billion annually (about 16 times the compliance cost, or more than nine times the social costs)"[84] While these estimates are for achieving a less stringent mercury reduction target (and the benefits estimate derives from reductions in other pollutant emissions rather than mercury), they suggest that the overall benefits of reducing mercury emissions will exceed the costs significantly, even if the reduction levels are tighter than what was proposed by EPA.

Improving Public and Environmental Health

In 2003 EPA identified 11 health and welfare benefits that would result from reducing mercury emissions from power plants. These included health benefits such as reduced neurological disorders, learning disabilities and developmental delays, as well as reducing cardiovascular impacts and reproductive effects in adults. Other benefits included reducing negative impacts on birds and mammals, protecting of currently healthy ecosystems and protecting commercial, subsistence and recreational fishing.[85]

While not quantified, these general impacts provide a starting point for quantitatively assessing the wide range of benefits associated with reducing mercury contamination. For example, according to the National Academy of Sciences, 60,000 children are born each year who, as a result of mercury exposure, are likely to need remedial education once they enter school. The range of services needed by these children is likely to vary; however, special education costs already stress public education budgets. The EPA assessed the economic impacts of subtle neurological impairments in its 1997 review of the benefits and costs of the Clean Air Act, concluding that the cost to an individual of each lost IQ point was about $3,000.[86]

Bolstering the Fishing and Tourism Industries

Recreational fishing is a major component of our local and national economies. More people in the U.S. fish than play golf and tennis, combined,[87] and research shows that nearly 70 percent of anglers consume their catch.[88] Recent reports from the U.S. Fish and Wildlife Service and the American Sportfishing Association indicate that recreational fishing annually generates:[89]

- $116 billion in overall economic activity
- 1 million jobs, resulting in more than $30 billion in salaries and wages

- $36 billion in expenditures
- $7 billion in state and federal taxes

Forty-five US states and territories currently issue fish consumption advisories due to mercury contamination. Studies show that these advisories lead anglers to take fewer trips, spend less money on trips, and choose non-contaminated fishing destinations—whether in-state or elsewhere. [90] For local economies that are heavily dependent on sport fishing, the impact of this lost revenue could be significant.

Creating jobs and spurring economic growth

A central economic benefit of requiring stringent mercury reductions nationwide has little to do with improving environmental or public health. Significant investments in cleaner energy technology—and specifically, mercury retrofits—will create and maintain jobs. Like improving roads, modernizing the nation's utility industry—the average coal-burning power plant is nearly 40 years old [91]—is an important infrastructure investment with major employment and economic benefits. Investing in new energy technology not only bolsters innovative new industries, but spurs demand for labor as well as the materials necessary to install the technology—structural steel and electrical equipment, etc—that can be supplied by U.S. companies.

The Institute of Clean Air Companies (ICAC) estimates that the manufacture, installation and operation of pollution control equipment would create 300,000 jobs nationwide over the next decade.[92] Already, pollution control equipment manufacturers employ more than 130,000 people.

What the future holds

As the utility industry faces the prospect of having to meet a multitude of environmental standards—whether for mercury, fine particles, sulfur dioxide, nitrogen oxides, or even carbon dioxide—long-term planning for how best to modernize its fleet will be inevitable. Adoption of mercury control technologies will be only one component of a company's investment in a range of cleaner coal or cleaner energy technologies. Investment in energy conservation and renewable energy sources will also likely increase with the need to meet more stringent environmental standards. For example, energy consumption in the Midwest could be reduced by nearly 30 percent if customers used more efficient lighting, ballasts, appliances, and motors.[93]

These modernization projects hold out great promise for public and environmental health and for the economy. One example is coal gasification. Integrated Gasification Combined Cycle (or IGCC) plants convert coal, under high temperature and pressure, into a gas which is then combusted. While this method still generates power from a non-renewable energy source, it generates less air pollution than conventional coal burning. Not only is very high mercury capture possible, but IGCC will release far less sulfur dioxide, volatile organic compounds (which create smog) and other pollutants. It also emits carbon dioxide in an isolated stream, making it more feasible to re-use or sequester.[94] IGCC has been used by the chemical industry for nearly a decade, and several small-scale energy generating facilities are operational. At least two proposals have recently been made in the Midwest for full-scale electricity-generating IGCC plants. While none are under construction, the increased interest suggests that IGCC may be rapidly approaching commercial viability.

Modernizing our nation's energy fleet can provide a multitude of economic benefits to local communities. For example, the Iowa Council Bluffs plant expansion mentioned earlier will require an estimated 1,000 workers to build, amounting to nearly $300 million in payroll, according to the utility. Upon completion, the facility will add up to 70 new jobs with a combined annual compensation of $4.8 million.[95] A complementary strategy of increasing investments in renewable energy sources and energy efficiency is also projected to yield significant gains. A recent study found that adoption of cleaner, more efficient energy technologies promised more than 200,000 *net* new jobs and $19 billion in increased annual economic output in the Midwest by 2020.[96] Interestingly, the Iowa utility has also announced a 310 MW wind energy project for completion by 2005—adding an additional 250 construction and 20 operations jobs.[97]

V. Conclusions and Recommendations

There are various technologies available for reducing mercury emissions from coal-fired power plants. This report demonstrates that it is economically feasible to install currently available mercury controls to meet a stringent mercury reduction target. In fact, cost estimates completed by NWF are encouraging: **Increases in electric bills ranging from about 70 cents to a little more than $2.00 would finance steep cuts in mercury pollution.**

NWF is confident that policy makers, power plant managers and executives, and equipment manufacturers can meet the challenge of 90 percent mercury control before the end of the decade. The troubling effects of mercury contamination, coupled with the proven feasibility of reducing mercury emissions from the nation's largest unregulated source, create a convincing case for requiring significant mercury reductions today.

Specifically, NWF recommends that:

- The federal government finalize a mercury emissions standard for coal-fired power plants that would reduce mercury emissions by up to 90% by the end of the decade, as stipulated by the current Clean Air Act.
- State governments enact regulations and other policies to facilitate innovation and rapid adoption of pollution control and clean energy technologies.
- State and federal policy makers pursue a comprehensive energy strategy that provides incentives for multi-pollutant reductions, increased fuel efficiency, and enhanced reliance on renewable energy sources.

We have the means and the responsibility to deeply reduce mercury pollution over the next decade. There is no need and no excuse for handing this problem down to our children.

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Appendix A: Methodology

In order to calculate the cost of achieving 90 percent mercury control at coal-fired power plants in Pennsylvania, Ohio, Illinois, Michigan and North Dakota, NWF applied currently available data on control technology effectiveness and costs. Specifically, we used a recent EPA report (Staudt and Jozewicz, 2003) which provides a set of annualized cost data for different boiler configurations fitted with various mercury control technologies. We also relied on a 2002 EPA report (Kilgroe et al.,2002) which provides a more comprehensive analysis of control options for coal-fired power plants.

We assessed coal type and sulfur content, configuration, and size at every boiler in each state reviewed. We then reviewed the model plant control options identified by EPA for each configuration and selected a technology scenario sufficient to achieve 90 percent mercury control. We then applied the appropriate costs for each solution. As discussed in more detail below, our consolidated statewide figures include initial capital investment, operating costs, costs of debt, and a range of other expenses associated with installing and operating the pollution control equipment. Using both total cost figures and the same cost expressed in cents per kilowatt hour of electricity generated, NWF was able to estimate the costs at individual power plants, and the subsequent impact on each state and on consumer energy bills.

The methodology we used for our costs analysis has applicability not just to the states we reviewed, but nationwide. A similar method could be used to estimate 90 percent mercury control costs for the plants in any state. Nationwide these costs are likely to be equally affordable, as many states do not rely as heavily on coal for power generation as the states reviewed here.

What do the EPA cost estimates include?

Staudt, Jozewicz and Srivastava (2003) consider three general approaches for controlling mercury emissions at coal-fired power plants, including powdered activated carbon injection (with or without addition of a downstream fabric filter), advanced flue gas desulfurization (for both mercury and sulfur control), and other multipollutant options (such as the ECO method) designed to reduce mercury along with sulfur dioxide, nitrogen oxides, and/or particulate matter.

With respect to activated carbon injection, Staudt and Jozewicz (2003) looked at two general scenarios: where significant co-benefits were to be accrued with existing or new control equipment for other pollutants (e.g., a plant burning bituminous coals with a wet scrubber for sulfur control and selective catalytic reduction (SCR) for nitrogen oxides control); and also where substantial mercury co-benefits were not expected and ACI was considered as the primary mercury reduction option.

Following the approach of Kilgroe et al. (2002), Staudt and Jozewicz (2003) identified model plants based on type of coal burned (either bituminous or subbituminous), plant size, sulfur levels in the coal burned, and existing pollution control configurations (e.g. electrostatic precipitators or fabric filters for particulate control) – and then assessed costs for these model plants.

Staudt and Jozewicz (2003) calculated both capital costs and operating and maintenance costs for retrofitting plants with new mercury control technologies (or simply for monitoring, if no mercury-specific controls were deemed necessary for a given configuration). The major capital cost was considered to be the process equipment itself, such as the fabric filter unit and ACI system. Staudt and Jozewicz (2003) also included costs of general facilities, engineering and construction management, owners' overhead, inventory and royalty, and contingencies. The authors assumed either a one or two-year construction period, depending on the type of technology installed. Total capital costs were annualized using a capital recovery factor (in this case a value of 13.3 percent).

In calculating operating and maintenance (O&M) costs, Staudt and Jozewicz (2003) assumed a 30-year operating period. Fixed O&M costs included labor for operators, maintenance, training and spare parts. Variable O&M costs included consumable materials such as the sorbent material (powdered activated carbon), water, lime, limestone and ammonia. [*] Additional power costs and waste disposal costs were also part of the O&M calculations. In addition, the authors estimated values for return on debt and equity, income and property taxes, and insurance payments over the 30-year operating period. They also factored in escalation of prices for labor, materials and consumable materials over 30 years.

NWF's Approach and Key Assumptions

With the exception of boilers under 25 megawatts which were not included in our review, NWF assesses what technology would be required for every boiler in our case study states to achieve 90 percent mercury control. For most boiler configurations, however, EPA's assessment provides cost figures for a several technology options and mercury control levels.

For this analysis, we narrowed the options by making several assumptions:

Focus on Activated Carbon Injection. Because activated carbon injection has been tested extensively, and detailed cost data are available, it is the primary technology we considered for this analysis. Only in the case of boilers burning high sulfur bituminous coal with no sulfur controls in place, do we choose another technology – advanced flue gas desulfurization – to control mercury.

Emphasize Solutions for Subbituminous Coal. Because the majority of coal-fired power plants in the U.S. burn bituminous coals, subbituminous coals, or blends of the two (Kilgroe et al., 2002), Staudt and Jozewicz (2003) focused their assessment only on these two coal ranks. To ensure we do not underestimate costs, and because subbituminous coals are more costly to control, we treat boilers which blend coals as if they burn subbituminous exclusively. As discussed further in the North Dakota section below, we also assume that control approaches and costs for boilers burning lignite coal would be similar to those for subbituminous-fired boilers.

Assess Cost of 90 Percent Mercury Control. As mentioned above, we look only at achieving full 90 percent mercury control. In cases where there is more than one option

[*] EPA determines activated carbon injection rates based on mercury control effectiveness of existing pollution control equipment (from the EPA Information Collection Request (ICR) database (EPA, 2004a), and full-scale demonstrations using activated carbon injection.

for achieving 90 percent control, we chose the least expensive option. For example, the two tables below show annualized mercury control cost estimates for two boiler configurations most common in the states we reviewed, namely plants burning bituminous or subbituminous coals with only a cold-side ESP. The technology options and costs we have included in our analysis are highlighted.

Assess Current Configuration. We assess the technology needed to achieve 90 percent mercury control on boilers *as they are currently configured* (based on 2002 data). We do not project addition of controls for NOx, SO2 or PM even though adoption of this technology is likely to reduce the cost of mercury control. It is important to note, however, that additional NOx control devices are being installed under the NOx SIP Call, and further NOx devices and SO2 scrubbers are also projected under pending legislation such as CAIR.

Several other (conservative) technology assumptions are also of note:

- For boilers burning high sulfur bituminous coals with no flue gas sulfur controls in place, it was assumed advanced dry flue gas desulfurization (AFGD) would be installed to meet pending sulfur requirements. These controls are also assumed to control mercury to at least 90 percent. These units are approximately 3-4 times as expensive as typical mercury control retrofits. While utilities would likely install AFGC primarily to meet sulfur dioxide reduction requirements (as well as getting the mercury co-benefit), we are including all of the costs for these boilers in the estimated mercury control costs for all boilers in each state.

A comparison of technology options and costs for two common boiler configurations…

Table A1. Estimated Annualized Costs for Controlling Mercury at Three Levels, For Large and Small Boilers Burning Bituminous Coals, with Cold-Side Electrostatic Precipitators and No SO2 Flue Gas Controls*

Retrofit Option	*Hg Control Efficiency*	*Annual Costs (cents/kWh)*	
		975 Mwe	*100 Mwe*
Activated carbon injection	90%	0.2451 ($0.0025)	0.2.639 ($0.0026)
	80%	0.1381	0.1497
	70%	0.0974	0.1057
Activated carbon injection and polishing fabric filter	**90%**	**0.1233**	**0.1751**
	80%	0.1171	0.1682
	70%	0.1144	0.1650

*From Table 17, Staudt, and Jozewicz, 2003.

Table A2. Estimated Costs for Controlling Mercury at Three Levels, for Large and Small Boilers Burning Subbituminous Coals, with Cold-Side Electrostatic Precipitators and No SO2 Controls*

Retrofit Option	*Hg Control Efficiency*	*Annual Costs (cents/kWh)*	
		975 Mwe	*100 Mwe*
Activated carbon injection	90%	2.0924	2.1756
	80%	2.0924	2.1756
	70%	0.1907	0.2015
Activated carbon injection and polishing fabric filter	**90%**	**0.1369**	**0.1903**
	80%	0.1236	0.1753
	70%	0.1176	0.1685

*From Table 22, Staudt and Jozewicz, 2003.

The tables also demonstrate that:

- Activated carbon injection with a fabric filter provides a less expensive way to achieve 90 percent mercury control than activated carbon alone, particularly for subbituminous coals (where 90 percent control with ACI alone has not been shown in practice).
- Using activated carbon injection with a fabric filter, there is only an incremental cost difference between achieving 90 percent reduction versus 70 percent reduction.

- Some bituminous coal-burning plants have scrubbers for sulfur control and either have or may be planning to add selective catalytic reduction units for nitrogen control. Some tests have shown that this combination can result in significant mercury control, and in some cases may approach 90 percent overall. However, in this assessment, we have assumed activated carbon injection and a fabric filter would be installed at these boilers to meet the mercury reduction target.
- We have assumed that all boilers have individual pollution control devices (ESPs, etc.) associated with each boiler. There may be some cases where flue gases from multiple boilers exit through a common pollution control system (e.g., three boilers feeding one cold-side ESP). In these cases, the retrofit option would likely entail activated carbon injection downstream of the ESP, with addition of a single fabric filter, rather than addition of three separate systems. Because of the lower capital costs in particular (one fabric filter instead of three), the mercury control costs would be lower as well.

How did NWF apply these cost estimates?

- Coal-fired boiler data (including control technology configurations) were obtained from EPA's ICR database (data for 1999) (EPA, 2004a).†
- Because these data were from 1999, updated data on coal burned, generation, and pollution control equipment for other pollutants (for 2002) were obtained from the Energy Information Administration (EIA) compilation of Form 767 data (EIA, 2002a).‡
- Boiler units were matched with EPA model plants (from Staudt and Jozewicz, 2003) and mercury control retrofit options assigned.
- EPA model plants were either large (975 MW for both bituminous and subbituminous coals), or small (either 300 MW for high sulfur bituminous coals or 100 MW for low sulfur bituminous coals and subbituminous coals). In this assessment, units (i.e., boiler/generator combinations) larger than 500 MW were considered large, and smaller than 500 MW were considered small. All calculations were done at the boiler/generator level, rather than at the plant level.
- Based on those assignments, total annual costs for mercury control were calculated for each boiler by multiplying unit control costs (cents/kWh) times generation, and totals were determined for all plants in a state.

Applying EPA cost data to specific state plant configurations in each state yielded both a lump sum annualized cost and a cost per kilowatt hour for the state.[§] From there, we

† This data includes plant names and unit numbers, generation capacity, type of coal burned, and existing pollution control equipment for other pollutants on a boiler-by-boiler basis. These spreadsheets also had generation data for individual boilers for 2002.

‡ Generation data were also obtained for all boilers for 2001, from Form 767 data for that year. For boilers with missing 2001 and 2002 generation data, data from the eGRID2002 database for 1998-2000 were used (EPA, 2004b). This analysis excluded power plants with individual boiler capacities of less than 25 MW.

§ An average overall cost to the utilities in each state was obtained by dividing the total cost for control in each state by the 2002 generation for all involved plants in each state (this is equivalent to weighting control costs (on a mill/kWh basis) by the generation of each boiler). Electric utility sales and revenue data were obtained from the Energy Information Administration (EIA, 2002b).

calculated the cost to consumers (residential, commercial, industrial) assuming all costs are passed on.

If we know an average household's energy consumption is 750 kilowatt hours per month for a given state – and the unit cost of mercury control is 0.15 cents (1.5 mills) per kilowatt hour, we can get a rough estimate of cost per household—i.e. $1.13/month. However, does not take into account that states (and utilities) generate some portion of their electricity from fuels other than coal, sell some of their power out of state, and that costs are not necessarily allocated equally across different classes of customers.

NWF addresses these issues in the case study states by adjusting the mercury control cost in the following way:

- first, by multiplying the control cost by the fraction of the state's power generated from coal—thus spreading the cost across the full electricity portfolio;*
- second, by multiplying the cost by a ratio showing the relative price paid by residential customers for electricity in that state. †
- NWF then multiplied the adjusted per kilowatt hour cost by the average monthly household electricity consumption in each state to determine the increased cost (in dollars) on an average residential monthly bill.

Because of allocation of costs by proportion of revenues from a given customer class, this approach assumes an equal percentage increase on utility bills across customer classes. A slightly different approach that does not adjust for customer class was used in providing rough estimates of cost impacts of mercury control for other states not considered in these case studies (see Appendix C).

Again, these calculations remain estimates. In most states, electricity prices are at least partially regulated, and each state is likely to come up with a mechanism for recovering costs that balances the needs of households, businesses and industry in a manner that is most appropriate for that state.

State Case Studies

Pennsylvania

As of 2002, there were 78 coal-fired electric utility generators operating in Pennsylvania at 36 plants (EIA, 2002a) (Generation data were only available for 55 boilers for 2002). Most boilers (57) burned bituminous coals only, while 16 boilers burned exclusively waste coals, and five boilers burned blends of bituminous and waste coals. Overall, approximately 85 percent of the coal burned in Pennsylvania in 2002 was bituminous

[*] Coal generation data was the sum of data for all plants considered in the analysis; total state generation was obtained from U.S. EIA, 2002b, Electric Sales and Revenue, 2002 Spreadsheets; Available at: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

[†] Data on percentage of sales (in MWh) and revenues ($) by customer class (i.e., residential, commercial, industrial) for 2002 were obtained from U.S. EIA, 2002b (from sales_state and revenue_state spreadsheets, respectively). For the case of North Dakota, for example, 32 percent of total utility generation in-state went to the residential sector, but residential revenues amounted to 38.3 percent of total utility revenues. Thus, the adjusted cost rate was multiplied by 38.3/32 to account for the higher charge to residential customers.

(based on data in EIA, 2002a). Though not specified in the EIA database, it was assumed that waste coals were either bituminous or anthracite waste (the EPA ICR database indicated that many of these boilers were burning blends of bituminous and anthracite coals in 1999). Waste bituminous and anthracite coals typically have higher mercury content than bituminous and anthracite coals (Kilgroe et al., 2002). Assuming similar behavior of mercury released from these waste coals to the parent anthracite and bituminous coals, all such coals were classified as bituminous for the purposes of this report. A full listing of plants and configurations is included in appendix B.

Wet scrubbers were installed on 15 Pennsylvania boilers in 2002, and six boilers had dry scrubbers installed. A number of boilers reported multiple control devices for particulates. Cold-side ESPs were installed on 52 boilers, and fabric filters were installed on 20 boilers.

A summary of Pennsylvania boiler configurations, the corresponding model plant from Staudt and Jozewicz (2003), the mercury control technology applied, and unit control costs are indicated below for Pennsylvania plants.

Table A3: Typical Plant Configurations and Estimated Unit Control Costs Based on Model Plants for Pennsylvania

Coal Rank	Boiler Size	Sulfur Control	PM Control[a]	Model Plant[b]	Retrofit Option[c]	Control Costs (cents/kWh)[d]
Bituminous	Small/Large	None	cs-ESP	9/4	AFGD	0.8932/0.8592
Bituminous	Small/Large	Wet scrubber	cs-ESP	6/1	ACI-PJFF	0.143/0.1195
Bituminous	Large	Low sulfur coal	cs-ESP	11	ACI-PJFF	0.1233
Bituminous	Large	Low sulfur coal	cs-ESP	13	ACI-PJFF	0.1280
Bituminous	Small	Low sulfur coal	cs-ESP	29	ACI-PJFF	0.1751
Bituminous	Small	Low sulfur coal	FF	30	ACI	0.0510

a: cs-ESP is cold-side electrostatic precipitator, hs-ESP is hot-side electrostatic precipitator, FF is fabric filter; b: Model plants from Staudt and Jozewicz (2003) c: AFGD is advanced dry flue gas desulfurization, ACI is activated carbon injection, PJFF is pulse jet fabric filter; d: Control costs (from Staudt and Jozewicz (2003)) are for control at 90 percent level. In case of AFGD, control costs are mid-range of projected costs given in Staudt and Jozewicz (2003

As of 2002, a few units in Pennsylvania (6) burned higher sulfur coals with no sulfur controls in place. For plants burning higher sulfur coals, all of EPA's cost estimates included or assumed sulfur dioxide controls of some kind. Given these options, we assumed that advanced dry flue gas desulfurization (AFGD) would be adopted at these plants to meet current and pending sulfur dioxide reduction requirements, and that mercury would be reduced by over 90 percent as a co-benefit. In this assessment, all of the costs associated with reducing sulfur dioxide and mercury in this manner are included as mercury control costs. A more realistic assumption might be that these plants will address sulfur dioxide reduction either via switching to lower sulfur coal, or by installing traditional scrubbers, in these instances the appropriate mercury control option would be to install ACI and a PJFF – at far less cost. The table below shows the relative impact of including AFGD costs on the overall cost of 90% mercury reduction in Pennsylvania. It also considers the alternative of installing ACI and PJFF on these plants – but this assumes some alternative method of controlling of sulfur dioxide.

Table A4: Estimated Cost of Controlling Mercury at Pennsylvania Coal-Fired Power Plants, Three Scenarios

Scenarios	Avg. Hg Control Cost (cents/kWh)	Total Annual Control Cost ($)	Avg. Residential Monthly Electricity Consumption (kWh)	Avg. Residential Monthly Bill ($)	Increase in Avg. Res. Monthly Bill ($)
Sulfur dioxide control (AFGD) installed for 6 boilers, and sulfur control costs included in statewide costs	0.210 ($0.0021)	$223,119,444	812	$78.91	$1.08
Sulfur dioxide control (AFGD) installed for 6 boilers and excluded in statewide costs	0.131	123,597,255	812	78.91	0.60
Statewide costs when high sulfur coal boilers are controlled with ACI and PJFF instead of AFGD	0.130	138,441,886	812	78.91	0.67

It was assumed that no additional mercury controls would be required for 14 smaller boilers (all but one fluidized bed combustors with fabric filters), as 1999 ICR data show very low mercury emissions rates (< 0.0044 lbs./GWh).

Ohio

As of 2002, there were 80 coal-fired electricity generators operating in Ohio at 22 plants (EIA, 2002a). Most boilers (65) burned bituminous coals only, while nine boilers burned exclusively subbituminous coals, and six boilers burned blends. Overall, 89 percent of the coal burned in Ohio in 2002 was bituminous (based on data in EIA, 2002a). As in other states burning blends, because of the greater difficulty in controlling mercury from subbituminous coals, boilers burning blends were treated as if they burned subbituminous coals only. A full listing of plants and configurations is included in appendix B.

Wet scrubbers were installed on six Ohio boilers, as of 2002. Cold-side ESPs were the most common particulate control device (61 boilers), followed by hot-side ESPs (14) and fabric filters (6). Summary boiler configurations, the corresponding model plants from Staudt and Jozewicz (2003), the mercury control technology applied, and unit control costs are indicated below for Ohio plants.

Table A5: Typical Plant Configurations in Ohio and Estimated Unit Control Costs Based on Model Plants

Coal Rank	Boiler Size	Sulfur Control	PM Control[a]	Model Plant[b]	Retrofit Option[c]	Control Costs (cents/kWh)[d]
Bituminous	Large	Wet scrubber	cs-ESP	1	ACI-PJFF	0.1195
Bituminous	Large	None	cs-ESP	4	Adv. Dry FGD	0.8592
Bituminous	Small	Wet scrubber	cs-ESP	6	ACI-PJFF	0.143
Bituminous	Small	None	cs-ESP	9	Adv. Dry FGD	0.8932
Bituminous	Large	Low sulfur coal	cs-ESP	11	ACI-PJFF	0.1233
Bituminous	Large	Low sulfur coal	hs-ESP	13	ACI-PJFF	0.1280
Subbit or bit/subbit blends	Large	Low sulfur coal	cs-ESP	20	ACI-PJFF	0.1369
Bituminous	Small	Low sulfur coal	cs-ESP	29	ACI-PJFF	0.1751
Bituminous	Small	Low sulfur coal	FF	30	ACI	0.0510
Bituminous	Small	Low sulfur coal	hs-ESP	31	ACI-PJFF	0.1804
Subbit or bit/subbit blends	Small	Low sulfur coal	cs-ESP	38	ACI-PJFF	0.1903

a: cs-ESP is cold-side electrostatic precipitator, hs-ESP is hot-side electrostatic precipitator, FF is fabric filter; b: Model plants from Staudt and Jozewicz (2003) c: Adv. Dry FGD is advanced dry flue gas desulfurization, ACI is activated carbon injection, PJFF is pulse jet fabric filter; d: Control costs (from Staudt and Jozewicz (2003)) are for control at 90 percent level. In case of advanced dry FGD, control costs are mid-range of projected costs given in Staudt and Jozewicz (2003).

As noted above, for most Ohio plants (i.e., those burning lower sulfur bituminous coals and having an electrostatic precipitator for particulate control), the retrofit option of choice for mercury control would be powdered activated carbon injection followed by a polishing fabric filter.

20 units in Ohio burned higher sulfur coals with no sulfur controls in place(model plants 4 and 9). For plants burning higher sulfur coals, all of EPA's cost estimates included or assumed sulfur dioxide controls of some kind. Given these options, we assumed that advanced dry flue gas desulfurization (AFGD) would be adopted at these plants to meet current and pending sulfur dioxide reduction requirements, and that mercury would be reduced by over 90 percent as a co-benefit. In this assessment, all of the costs associated with reducing sulfur dioxide and mercury in this manner are included as mercury control costs. A more realistic assumption might be that these plants will address sulfur dioxide reduction either via switching to lower sulfur coal, or by installing traditional scrubbers, in these instances the appropriate mercury control option would be to install ACI and a PJFF – at far less cost. The table below shows the relative impact of including AFGD costs on the overall cost of 90% mercury reduction in Ohio. It also considers the alternative of installing ACI and PJFF on these plants – but this assumes some alternative method of controlling of sulfur dioxide. Note that a more standard approach that considers only mercury control costs, cuts Ohio estimates nearly in half.

Table A6: Estimated Cost of Controlling Mercury at Ohio Coal-Fired Power Plants, Three Scenarios

Scenarios	Avg. Hg Control Cost (cents/kWh)[a]	Total Annual Control Cost ($)	Avg. Residential Monthly Electricity Consumption (kWh)	Avg. Residential Monthly Bill ($)	Increase in Avg. Res. Monthly Bill ($)[b]
Sulfur control (AFGD) installed for 20 boilers, and sulfur control costs included in statewide costs	0.224 ($0.00224)	$287,145,482	880	$72.91	$2.14
Sulfur control (AFGD) installed for 20 boilers and excluded in statewide costs	0.120	153,307,587	880	72.91	1.14
Statewide costs when high sulfur coal boilers are controlled with ACI and PJFF instead of AFGD	0.139	177,367,527	880	72.91	1.32

a: Average mercury control cost for affected plants (i.e., total cost for controlling mercury via given approach at all plants divided by total generation at those plants). b. Increase in monthly residential electricity bill is estimated using approach described earlier in this appendix.

Illinois

As of 2002, there were 56 coal-fired boilers in Illinois operating at 21 plants (EIA, 2002a). Most boilers (30) burned subbituminous coals only, and an additional six boilers burned blends of bituminous and subbituminous. Overall, subbitminous coals accounted for 80.5 percent of coal burned at Illinois power plants in 2002. A full listing of plants and configurations is included in appendix B.

Because of the greater difficulty in controlling mercury from subbituminous coals, boilers burning blends were assumed to require retrofits necessary to control mercury from boilers burning subbituminous coals only. As of 2002, wet scrubbers were installed on five Illinois boilers, while cold-side ESPs were the most common particulate control devices (51 boilers); none had fabric filters in place. The chart below summarizes the boiler configurations existing in Illinois and the corresponding model plant, the mercury control technology applied, and control costs from Staudt and Jozewicz (2003).

Table A7: Typical Plant Configurations in Illinois and Estimated Unit Control Costs Based on Model Plants

Coal Rank	Boiler Size	Sulfur Control	PM Control[a]	Model Plant[b]	Retrofit Option[c]	Control Costs (cents/kWh) [d]
Bituminous	Small	Wet scrubber	cs-ESP	6	ACI-PJFF	0.143
Bituminous	Small	None	cs-ESP	9	Adv. Dry FGD	0.8932
Subbit or bit/subbit blends	Large	Low sulfur coal	cs-ESP	20	ACI-PJFF	0.1369
Bituminous	Small	Low sulfur coal	cs-ESP	29	ACI-PJFF	0.1751

Subbit or bit/subbit blends	Small	Low sulfur coal	cs-ESP	38	ACI-PJFF	0.1903
Subbit or bit/subbit blends	Small	Low sulfur coal	hs-ESP	40	ACI-PJFF	0.196

a: cs-ESP is cold-side electrostatic precipitator; hs-ESP is hot-side electrostatic precipitator; FF is fabric filter; b: Model plants from Staudt and Jozewicz (2003) c: ACI is activated carbon injection; PJFF is pulse jet fabric filter; d: Control costs (from Staudt and Jozewicz (2003)) are for control at 90 percent level. . In case of advanced dry FGD, control costs are mid-range of projected costs given in Staudt and Jozewicz (2003)

In this analysis, it was assumed that to reach 90 percent or greater reduction in mercury emissions from these plants, activated carbon injection with an add-on fabric filter would be needed in most cases. For 10 boilers burning high sulfur coals but not having scrubbers, it was assumed advanced dry FGD units would be installed, with mercury reduction as a co-benefit An analysis identical to that done for Pennsylvania and Ohio (above) indicates that overall costs for mercury reduction assuming either of the alternative scenarios (i.e. not counting AFGD costs as mercury costs, or retrofitting with ACI and PJFF instead) leads to 8 – 10 % lower overall Illinois costs; all but one of the boilers concerned are less than 100MW capacity.

Michigan

As of 2002, there were 57 coal-fired utility boilers in Michigan at 20 plants (EIA, 2002a). About one-half of the boilers (26) burned bituminous coals only, 19 burned subbituminous coals only, and 11 burned blends of the two. Overall, 50.6 percent of the coal burned in 2002 was subbituminous. A full listing of plants and configurations is included in Appendix B.

Because of the greater difficulty in controlling mercury from subbituminous coals, boilers burning blends were assumed to require retrofits necessary to control mercury from boilers burning subbituminous coals only. As of 2002, two boilers had wet scrubbers installed, one boiler had a dry scrubber, and three boilers had spray dryer adsorbers. Most (50) boilers had cold-side ESPs for particulate control, and eight boilers had fabric filters installed. The chart below summarizes the boiler configurations existing in Michigan and the corresponding model plant, the mercury control technology applied and control costs from Staudt and Jozewicz (2003).

Table A8: Typical Plant Configurations and Estimated Unit Control Costs Based on Model Plants for Michigan

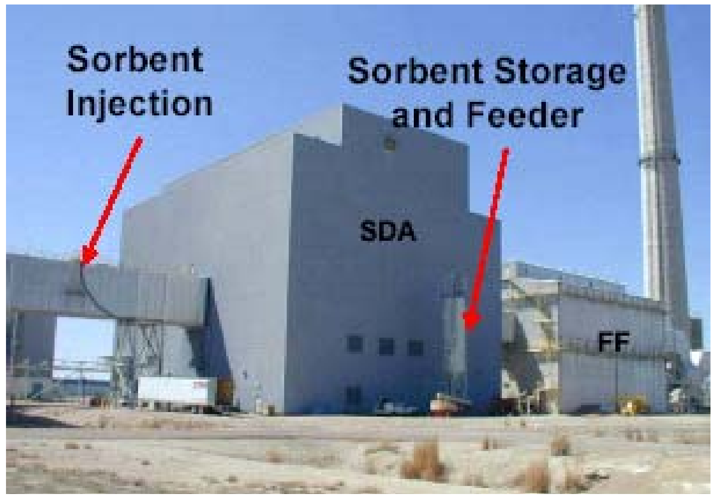
Coal Rank	Boiler Size	Sulfur Control	PM Controla	Model Plantb	Retrofit Optionc	Control Costs (cents/kWh) d
Bituminous	Small	Wet scrubber	cs-ESP	6	ACI-PJFF	0.1430
Bituminous	Large	Low sulfur coal	cs-ESP	11	ACI-PJFF	0.1233
Subbit or bit/subbit blends	Large	Low sulfur coal	cs-ESP	20	ACI-PJFF	0.1369
Bituminous	Small	SDA or dry scrubber	FF	27	ACI	0.037
Bituminous	Small	Low sulfur coal	cs-ESP	29	ACI-PJFF	0.1751
Bituminous	Small	Low sulfur coal	FF	30	ACI	0.051

Subbit or bit/subbit blends	Small	Low sulfur coal	cs-ESP	38	ACI-PJFF	0.1903
Subbit or bit/subbit blends	Small	Low sulfur coal	hs-ESP	40	ACI-PJFF	0.196

a: cs-ESP is cold-side electrostatic precipitator; hs-ESP is hot-side electrostatic precipitator; FF is fabric filter; b: Model plants from Staudt and Jozewicz (2003) c: ACI is activated carbon injection; PJFF is pulse jet fabric filter; d: Control costs (from Staudt and Jozewicz (2003)) are for control at 90 percent level.

In this analysis, it was assumed that to reach 90 percent or greater reduction in mercury emissions from these plants, activated carbon injection with an add-on polishing fabric filter would be needed in plants having ESPs for particulate control, and ACI alone would suffice to achieve substantial control for boilers equipped with fabric filters, as shown above.

Figure A1. Power Plant with SDA and Activated Carbon Injection upstream of an existing fabric filter



North Dakota

As of 2002, there were 13 coal-fired electricity generators in North Dakota at seven plants (EIA, 2002a). The great majority of the coal burned was lignite (i.e., 24,484,000 tons out of 25,223,000 tons, or 97 percent), with the remainder subbituminous. Three boilers in 2002 had wet scrubbers installed, while four boilers had spray dryer adsorbers installed. Cold-side ESPs were installed on nine boilers, and fabric filters were installed on four boilers (coupled in this case with SDAs). A full listing of plants and configurations is included in Appendix B.

Staudt and Jozewicz (2003) only considered bituminous and subbituminous coals in their analysis. There were very limited data that derived from the EPA ICR on the control effectiveness of other pollution control devices for plants burning lignite coal (Kilgroe et al., 2002). However, because mercury releases from lignite coals are assumed to behave somewhat similarly to subbituminous coals (Kilgroe et al., 2002), it was assumed here that cost estimates for the most similar configurations of model boilers burning subbituminous coals would be appropriate. Tests separate from the EPA study, notably at Great River Energy's Stanton Station in North Dakota, suggest that similar approaches are applicable. The model plants identified for the most common configurations in North Dakota were as follows:

Table A9: Typical Plant Configurations and Estimated Unit Control Costs Based on Model Plants for North Dakota

Boiler Size	Sulfur Control[a]	PM Control[b]	Model Plant[c]	Retrofit Option[d]	Control Costs (cents/kWh)[e]
Small	Wet scrubber	cs-ESP	38	ACI-PJFF	0.1903
Large	Wet scrubber	cs-ESP	20	ACI-PJFF	0.1369
Small	SDA	FF	39	ACI-PJFF	0.1774
Small	Low sulfur coal	cs-ESP	38	ACI-PJFF	0.1903

a: SDA is spray dryer absorber. b: cs-ESP is cold-side electrostatic precipitator, hs-ESP is hot-side electrostatic precipitator, FF is fabric filter; c: Model plants from Staudt and Jozewicz (2003) d: ACI is activated carbon injection; PJFF is pulse jet fabric filter; e: Control costs (from Staudt and Jozewicz (2003)) are for control at 90 percent level. As stated above, most coal burned in North Dakota is lignite, but control costs for subbituminous coals are assumed to apply.

It is assumed that to reach 90 percent or greater reduction in mercury emissions from these plants, activated carbon injection with an add-on fabric filter would be needed in all cases. As shown above, it is assumed that use of the spray dryer absorber does not result in any significant mercury control for lignite coals – i.e., ACI with FF is needed whether or not a SDA is in place. In addition, it is assumed that an existing fabric filter is not sufficient, without downstream activated carbon injection and an additional FF, to control mercury at greater than 90 percent from lignite coals.

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Appendix B: Plant-by-plant Configuration Data

The charts below give plant by plant information for the five case study states, including generator capacity, type of coal burned, control configurations and net generation.

Table B1: Configuration of Pennsylvania Coal-Fired Power Plants (2002)

Plant Name	Owner	Boiler Nos.	Coal Rank[a]	Total Generator Capacity (MW)[b]	Sulfur Controls[c]	Particulate Controls[d]	2002 Net Generation (MWh)[e]
AES BV Partners Beaver Valley	AES Beaver Valley	032-035	Bit	149	Wet scrubber	cs-ESP, wet scrubber	1,021,812
Armstrong	Allegheny Energy Supply Co LLC	1, 2	Bit	326	-	cs-ESP	2,140,768
Bruce Mansfield	Pennsylvania Power Company	1-3	Bit	2742	Wet scrubber	Wet scrubber; cs-ESP (3)	15,974,911
Brunner Island	PP&L, Inc.	1-3	Bit	1558	-	cs-ESP (2, 3)	9,948,949
Cambria CoGen	Cambria CoGen Company	2 units	WC	98	-	FF	753,534*
Cheswick Power Station	Orion Power Midwest LP	1	Bit	565	-	hs-ESP	3,033,280
Colver Power Project	TIFD VIII-W Inc.	COLV	WC	131	-	FF	842,351
Conemaugh	Reliant Energy NE Mgt Co	1, 2	Bit	1872	Wet scrubber	cs-ESP, wet scrubber	12,655,849
Cromby Generating Station	Exelon Generation Co LLC	#1	Bit	188	Wet scrubber	MC, cs-ESP, wet scrubber	462,947
Ebensburg Power Company	Ebensburg Power Company	GEN 1	WC	60	Dry scrubber	FF	427,033*
Eddystone Generating Station	Exelon Generation Co LLC	1, 2	Bit	642	Wet scrubber	MC, cs-ESP, wet scrubber	1,408,613
Elrama	Orion Power Midwest LP	1-4	Bit	510	Wet scrubber (4)	MC, cs-ESP	2,315,270
Foster Wheeler Mt. Carmel, Incorporated	El Paso Merchant Energy Co	TG1	WC	46	Dry scrubber	FF	356,382*
Hatfield's Ferry	Allegheny Energy Supply Co LLC	1-3	Bit	1728	-	cs-ESP	9,753,564
Homer City	Midwest Generation	1-3	Bit	2012	Wet scrubber (3)	cs-ESP	12,111,351
Hunlock Power Station	UGI Development Co	6	Bit/WC	50	-	cs-ESP	NA
John B. Rich Memorial Power Station	Gilberton Power Company	CFB2, GEN 1	WC	88 (GEN 1)	-	FF	692,948*
Johnsonville Mill	Weyerhaueser Co	54638	Bit	60	-	cs-ESP	221,646*
Keystone	Reliant Energy NE Mgt Co	1, 2	Bit	1872	-	cs-ESP	12,216,444
Kline Township Cogen Facility	Northeastern Power Co.	GEN 1	WC	58	Dry scrubber	SC, FF	444,885*
Martins Creek	PP&L, Inc.	1, 2	Bit	312	-	cs-ESP	1,137,663
Mitchell	Allegheny Energy Supply Co LLC	33	Bit	299	Wet scrubber	cs-ESP	1,706,654*
Montour	PP&L, Inc.	1, 2	Bit	1624	-	cs-ESP	8,736,727

Plant Name	Owner	Boiler Nos.	Coal Rank[a]	Total Generator Capacity (MW)[b]	Sulfur Controls[c]	Particulate Controls[d]	2002 Net Generation (MWh)[e]
New Castle	Orion Power Midwest LP	1- 5	Bit (3-5)	425	-	cs-ESP (3, 4)	1,577,446
Northampton Generating Company, L.P.	PG&E National Energy Group	GEN 1	WC	114	-	FF	865,703
Panther Creek Energy Facility	Panther Creek Partners	2 units	WC	83 (GEN1)	Dry scrubber	FF	741,051*
Piney Creek	Piney Creek LP	GEN 1	WC	36	Dry scrubber	FF	282,135*
Portland	Reliant Energy Mid-Atlantic PH	1, 2	Bit	427	-	cs-ESP	1,816,520
Scrubgrass Generating Company, L. P.	PG&E Operating Service Co	1,2	WC	190	-	FF	704,112*
Seward	Reliant Energy Mid-Atlantic PH	12, 14, 15	Bit	218	-	MC (12, 14), cs-ESP (12, 14, 15)	833,704
Shawville	Reliant Energy Mid-Atlantic PH	1-4	Bit	597	-	cs-ESP	3,021,554
St. Nicholas Cogen	Schuylkill Energy Resource Inc	NA (1 unit)	WC	NA	-	FF	667,675*
Sunbury	Sunbury Generation LLC	1A, 1B, 2A, 2B, 3, 4	WC/Bit (1A, 1B, 2A, 2B); Bit. (3,4)	409	-	MC & FF (1/2 A/B), cs-ESP (3, 4)	1,658,650
Titus	Reliant Energy Mid-Atlantic PH	1-3	Bit	225	-	cs-ESP	1,081,143
Warren	Reliant Energy Mid-Atlantic PH	NA (4 units)	Bit	NA	-	NA	NA
Wheelabrator Frackville Energy Company, Inc.	Wheelabrator Environmental Sys	GEN 1	WC	48	-	FF	359,510*

Source: Unless otherwise stated, data from U.S. Energy Information Administration (EIA), 2002a. Compilation of Form 767 data for 2002, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia767.html/ a. Coals are either bituminous (Bit) or waste coal (WC). For blends, first coal is predominant coal; b. Data from U.S. EPA Information Collection Request (1999); c. Indicates whether flue gas sulfur controls are in place. (Does not indicate if plant is burning low sulfur coal to meet sulfur requirements.) d. cs-ESP: cold-side electrostatic precipitator; hs-ESP: hot-side electrostatic precipitator. FF: fabric filter; SC: single cyclone; MC: multiple cyclone. As shown, in a few cases, units had multiple particulate control devices (e.g., cs-ESP and multiple cyclones). e. Asterisks indicate generation data for 2000, from Emissions Generation and Integrated Resource Database, available at: http://www.epa.gov/airmarkets/egrid/index.html). Additional note: Warren plant identified as "retired" in EIA 2002 database, but also had data for coal consumption (but not generation), so is included above.

Table B2: Configuration of Ohio Coal-Fired Power Plants (2002)

Plant Name	Owner	Boiler Nos.	Coal Rank[a]	Total Generator Capacity (MW)[b]	Sulfur Controls[c]	Particulate Controls[d]	2002 Net Generation (MWh)[e]
Ashtabula	The Cleveland Electric Illuminating Company	7,8,10, 11	Subbit (7); Bit (8,10,11)	394	-	cs-ESP	1,236,300
Avon Lake	Orion Power Midwest LP	10, 12	Bit	766	-	cs-ESP	4,147,937
Bay Shore	Toledo Edison Company	1-4	Bit (1); Subbit/bit (2); Subbit (3,4)	641	-	FF (1) cs-ESP (2-4)	3,544,053
Cardinal	Cardinal Operating Co.	1-3	Bit	1830	-	cs-ESP (1,2); hs-ESP (3)	8,555,492
Conesville	Columbus Southern Power Company	1-6	Bit	1945	Wet scrubber (5, 6)	cs-ESP	12,041,120
Eastlake	The Cleveland	1-5	Subbit	1375	-	cs-ESP	6,723,402

Plant Name	Owner	Boiler Nos.	Coal Rank[a]	Total Generator Capacity (MW)[b]	Sulfur Controls[c]	Particulate Controls[d]	2002 Net Generation (MWh)[e]
	Electric Illuminating Company						
Gen J.M. Gavin	Ohio Power Company	1, 2	Bit	2600	Wet scrubbers	cs-ESP	15,717,077
Hamilton	City of Hamilton, OH	8,9	Bit	76	Other (9)	hs-ESP (8), hs-ESP, FF (9)	291,971
J.M. Stuart	Dayton Power and Light	1-4	Bit	2340	-	hs-ESP	15,350,802
Killen	Dayton Power and Light	2	Bit	612	-	hs-ESP	3,612,922
Kyger Creek	Ohio Valley Electric Corporation	1-5	Bit/subbit	1085	-	cs-ESP	6,852,119
Lake Shore	The Cleveland Electric Illuminating Company	18, 91, 92, 94	Subbit (18)	454	-	cs-ESP (18)	859,170 (18)
Miami Fort Station	Cincinnati Gas & Electric Company	6, 7, 8, 5-1, 5-2	Bit	1390	-	cs-ESP	7,928,110
Muskingum River	Ohio Power Company	1-5	Bit	1425		cs-ESP	8,357,764
Niles	Orion Power Midwest LP	1, 2	Bit	266	Wet scrubber (1)	cs-ESP	1,126,157
O.H. Hutchings	Dayton Power and Light Company	H1-6	Bit	414	-	hs-ESP	772,666
Picway	Columbus Southern Power Company	9	Bit	100	-	cs-ESP	380,217
R.E. Burger	Ohio Edison Company	5-8	Bit	273	-	cs-ESP	2,000,541
Richard H. Gorsuch	American Municipal Power - Ohio, Inc.	1-4	Bit	200	-	cs-ESP	1,293,393
W.H. Sammis	Ohio Edison Company	1-7	Bit	2454	-	FF (1-4) cs-ESP (5-7)	15,520,511
W.H. Zimmer Station	Cincinnati Gas & Electric Company	1	Bit	1426	Wet scrubber	cs-ESP	9,734,563
Walter C. Beckjord	Cincinnati Gas & Electric Company	1-6	Bit	1244	-	cs-ESP	6,852,610

Source: Unless otherwise stated, data from U.S. Energy Information Administration (EIA), 2002a. Compilation of Form 767 data for 2002, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia767.html/ a. Coals are either bituminous (Bit) or subbituminous (Sub). For blends, first coal is predominant coal; b. Data from U.S. EPA Information Collection Request (1999); c. Indicates whether flue gas sulfur controls are in place. (Does not indicate if plant is burning low sulfur coal to meet sulfur requirements.) d. cs-ESP: cold-side electrostatic precipitator; hs-ESP: hot-side electrostatic precipitator. FF: fabric filter. In a few cases, units had multiple particulate control devices (e.g., cs-ESP and multiple cyclones). Does not include plants (e.g., Gorge, Mad River, Toronto) on cold standby (and not generating power) in 2002.

Table B3: Configurations of Illinois Coal-Fired Power Plants (2002)

Plant Name	Owner	Boiler Nos.	Coal Rank[a]	Total Generator Capacity (MW)[b]	Sulfur Controls[c]	Particulate Controls[d]	2002 Net Generation (MWh)
Baldwin	Dynegy Midwest Generation Inc	1-3	Sub	1892	-	cs-ESP	12,443705
Coffeen	Ameren Energy Generating Co	01, 02	Bit/sub	1006	-	cs-ESP	5,156,311
Crawford	Midwest Generations EME LLC	7, 8	Sub	581	-	cs-ESP	2,432,338
Dallman	City of Springfield, IL	31-33	Bit	352	Wet scrubber	cs-ESP	1,796,152
Duck Creek	Central Ilinois Light Company	1	Bit	370	Wet scrubber	cs-ESP	2,067,348
E.D. Edwards	Central Ilinois Light Company	1-3	Bit	708	-	cs-ESP	3,544,787
Fisk	Midwest Generations EME LLC	19	Sub	348	-	cs-ESP	1,298,400
Hennepin	Dynegy Midwest Generation Inc	1, 2	Sub	306	-	cs-ESP	2,045,488
Hutsonville	Ameren Energy Generating Co	05, 06	Bit	150	-	cs-ESP	591,335
Joliet 9	Midwest Generations EME LLC	5	Sub	341	-	cs-ESP	1,219,308
Joliet 29	Midwest Generations EME LLC	71, 72, 81, 82	Sub	1081	-	cs-ESP	5,577,674
Joppa Steam	Electric Energy, Inc.	1-6	Sub	1100	-	cs-ESP	8,075,555
Kincaid Generation, L.L.C.	Dominion Energy Services Co	1, 2	Sub	1182	-	cs-ESP	5,847,334
Meredosia	Ameren Energy Generating Co	01-05	Bit	354	-	cs-ESP	1,224,229
Newton	Ameren Energy Generating Co	1, 2	Sub	1235	-	cs-ESP	7,241,019
Powerton	Midwest Generations EME LLC	51, 52, 61, 62	Sub/bit	1640	-	cs-ESP	7,569,928
Southern Illinois Power Co-operative	Southern Illinois Power Cooperative	1-4	Bit	272	Wet scrubber (4)	cs-ESP	1,127,048
Vermilion	Dynegy Midwest Generation Inc	1, 2	Bit	182	-	cs-ESP	1,102,900
Waukegan	Midwest Generations EME LLC	7, 8, 17	Sub	848	-	hs-ESP (7), cs-ESP (8, 17)	4,106,940

Plant Name	Owner	Boiler Nos.	Coal Rank[a]	Total Generator Capacity (MW)[b]	Sulfur Controls[c]	Particulate Controls[d]	2002 Net Generation (MWh)
Will County	Midwest Generations EME LLC	1-4	Sub	1154	-	hs-ESP (3), cs-ESP (1,2, 4)	5,546,303
Wood River	Dynegy Midwest Generation Inc	4, 5	Sub/bit	500	-	cs-ESP	2,195,324

Source: Unless otherwise stated, data from U.S. Energy Information Administration (EIA), 2002a. Compilation of Form 767 data for 2002, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia767.html/ a. Coals are either bituminous (Bit) or subbituminous (Sub). For blends, first coal is predominant coal; b. Data from U.S. EPA Information Collection Request (1999); c. Indicates whether flue gas controls are in place. (Does not indicate if plant is burning low sulfur coal to meet sulfur requirements.) d. cs-ESP: cold-side electrostatic precipitator; hs-ESP: not-side electrostatic precipitator. FF: fabric filter. In a few cases, boilers had multiple particulate control devices (e.g., cs-ESP and multiple cyclones).

Table B4: Configurations of Michigan Coal-Fired Power Plants (2002)

Plant Name	Owner	Boiler Nos.	Coal Rank[a]	Total Generator Capacity (MW)[b]	Sulfur Controls[c]	Particulate Controls[d]	2002 Net Generation (MWh)
B.C. Cobb	Consumers Energy Co.	4, 5	Sub/bit	312	-	cs-ESP	2,150,510
Belle River	Detroit Edison	1, 2	Sub	1396	-	cs-ESP	7,592,171
Dan E. Karn	Consumers Energy Co.	1,2	Sub/bit	530	-	cs-ESP	3,824,249
Eckert Station	Lansing BWL	1-6	Sub	375	-	cs-ESP	1,576,792
Endicott	MI South Central Power Agency	1	Bit	55	Wet scrubber	cs-ESP	NA
Erickson	Lansing BWL	1	Bit	154	-	cs-ESP	808,371
Harbor Beach	Detroit Edison	1	Bit	121	-	cs-ESP	240,329
J.B. Sims	City of Grand Haven, MI	3	Bit	65	Wet scrubber	cs-ESP	NA
J.C. Weadock	Consumers Energy Co.	7,8	Sub/bit	312	-	cs-ESP	2,205,575
J.H. Campbell	Consumers Energy Co.	1-3	Sub (1) Sub/bit (2,3)	1,521	-	cs-ESP	9,268,497
J.R. Whiting	Consumers Energy Co.	1-3	Sub/bit	300	-	cs-ESP	2,262,502
James De Young	Holland BPW	5	Bit	29	-	cs-ESP	NA
Monroe	Detroit Edison	1-4	Bit	3,280	-	cs-ESP	16,721,025
Presque Isle	Wisconsin Electric Power Company	1-9	Bit (1-6) Sub (7-9)	600	-	FF (1-4); cs-ESP (5,6); hs-ESP (7-9)	3,140,386
River Rouge	Detroit Edison	2,3	Bit	651	-	cs-ESP	3,398,301
Shiras	Marquette Board of Light and Power	3	Sub	44	Spray dryer	FF	NA
St. Clair	Detroit Edison	1-4, 6,7	Sub	1,548	-	cs-ESP	6,963,989
TES Filer City Station	TES Filer City Station Ltd. Partnership	1,2	Bit	60	Spray dryer	FF	NA
Trenton Channel	Detroit Edison	9A, 16-19	Bit	776	-	cs-ESP	4,339,843
Wyandotte	City of Wyandotte	5,7,8	Bit (7,8)	73	Dry scrubber (8)	hs-ESP (7); FF (8)	NA

Source: Unless otherwise stated, data from U.S. Energy Information Administration (EIA), 2002a. Compilation of Form 767 data for 2002, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia767.html/ a. Coals are either bituminous (Bit) or subbituminous (Sub). For blends, first coal is predominant coal; b. Data from U.S. EPA Information Collection Request (1999); c. Indicates whether flue gas controls are in place. (Does not indicate if plant is burning low sulfur coal to meet sulfur requirements.) d. cs-ESP: cold-side electrostatic precipitator; hs-ESP: not-side electrostatic precipitator. FF: fabric filter. In a few cases, boilers had multiple particulate control devices (e.g., cs-ESP and multiple cyclones). For Wyandotte plant, included two boilers < 25 MW, because steam is used to power multiple generators. For six plants, generation data was not available either form the EIA 2002 database, or the eGRID2002 database.

Tabel B5: Configurations of North Dakota Coal-Fired Power Plants (2002)

Plant Name	Owner	Boiler Nos.	Coal Rank	Total Generator Capacity (MW)[a]	Sulfur Controls[b]	Particulate Controls[c]	2002 Net Generation (MWh)[d]
Antelope Valley Station	Basin Electric Power Cooperative	B1, B2	Lignite	870	Spray dryer	FF	6,317,250
Coal Creek	Great River Energy	1, 2	Lignite	1052	Wet scrubber	cs-ESP	8,559,098
Coyote	Otter Tail Power Company	1	Lignite	450	Spray dryer	FF	3,059,868
Leland Olds Station	Basin Electric Power Cooperative	1,2	Lignite/ Subbituminous	656	-	cs-ESP	4,576,986
Milton R. Young	Minnkota Power Cooperative, Inc.	B1, B2	Lignite	674	Wet scrubber (B1)	cs-ESP	5,117,272
R.M. Heskett Station	MDU Resources Group	B1,B2	Lignite	100	-	cs-ESP, MC & cs-ESP (B2)	525,763
Stanton Station	Great River Energy	1, 10	Lignite	200	Spray dryer (10)	cs-ESP (1), FF (10)	1,399,737

Source: Unless otherwise stated, data from U.S. Energy Information Administration (EIA), 2002a. Compilation of Form 767 data for 2002, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia767.html/ a. Data from U.S. EPA Information Collection Request (1999); b. Indicates whether flue gas sulfur controls are in place. (Does not indicate if plant is burning low sulfur coal to meet sulfur requirements.) c: cs-ESP: cold-side electrostatic precipitator; hs-ESP: hot-side electrostatic precipitator. FF: fabric filter; MC: multiple cyclone.

Appendix C: Approximate cost impacts for other states

In the five states we assessed, costs of 90 percent mercury control ranged from 0.1 cents to 0.2 cents/kwh per kilowatt hour of power generated from coal. Estimates done by DOE and the Institute for Clean Air Companies range from 0.1 to 0.3 cents/kwh . The table below provides a rough estimate of what mercury pollution control would cost in each of the 50 states, if we assume mercury control costs between 0.1 and 0.3 cents per kilowatt hour.

Note that this is a rough calculation which takes into account only per kilowatt hour cost of mercury controls, the average electricity consumption in the state and the percentage of power the state generates from coal.[**] Obviously, an analysis of plant and fuel specifics would be necessary to generate a more exact estimate.

State	Average Monthly Consumption (kWh)	Average Cost Paid for Electricity per kWh (cents/kWh)	Average Monthly Bill	% of state electricity generation from coal	Average monthly household cost increase—low estimate	Average monthly household cost increase—high estimate
Alabama	1,270	7.12	$90.43	54.2	$0.69	$2.06
Alaska	671	12.05	$80.88	8.5	$0.06	$0.17
Arizona	1,050	8.27	$86.87	40.6	$0.43	$1.28
Arkansas	1,077	7.25	$78.09	48.5	$0.52	$1.57
California	549	12.90	$70.88	1.3	$0.01	$0.02
Colorado	686	7.37	$50.59	77.6	$0.53	$1.60
Connecticut	740	10.96	$81.15	10.3	$0.08	$0.23
Delaware	960	8.70	$83.50	57.7	$0.55	$1.66
D.C.	771	7.82	$60.33	0.0	-	-
Florida	1,201	8.16	$97.95	32.4	$0.39	$1.17
Georgia	1,128	7.63	$86.05	62.3	$0.70	$2.11
Hawaii	643	15.63	$100.52	13.3	$0.09	$0.26
Idaho	1,047	6.59	$68.99	0.9	$0.01	$0.03
Illinois	773	8.39	$64.82	46.1	$0.36	$1.07
Indiana	1,010	6.91	$69.80	93.7	$0.95	$2.84
Iowa	855	8.35	$71.38	83.2	$0.71	$2.13
Kansas	917	7.67	$70.32	75.0	$0.69	$2.06
Kentucky	1,164	5.65	$65.71	90.4	$1.05	$3.16
Louisiana	1,269	7.10	$90.17	23.2	$0.29	$0.88
Maine	522	11.98	$62.52	2.7	$0.01	$0.04
Maryland	1,054	7.71	$81.23	59.5	$0.63	$1.88
Massachusetts	612	10.97	$67.14	27.4	$0.17	$0.50
Michigan	683	8.28	$56.60	56.6	$0.39	$1.16
Minnesota	805	7.49	$60.26	64.3	$0.52	$1.55
Mississippi	1,241	7.28	$90.34	34.6	$0.43	$1.29
Missouri	1,045	7.06	$73.78	83.1	$0.87	$2.60
Montana	813	7.23	$58.77	60.2	$0.49	$1.47
Nebraska	1,007	6.73	$67.76	63.1	$0.63	$1.90

[**] Cost increases are calculated here by multiplying the estimated per kilowatt hour cost of mercury control by the average monthly kilowatt hour consumption in each state. That yields a cost if all power were generated from coal. That number is then multiplied by the percentage of state electricity generated from coal– yielding a cost averaged across the full rate base in the state.

Nevada	943	9.43	$88.87	51.1	$0.48	$1.45
New Hampshire	602	11.77	$70.85	23.3	$0.14	$0.42
New Jersey	697	10.38	$72.31	15.6	$0.11	$0.33
New Mexico	582	8.50	$49.51	87.7	$0.51	$1.53
New York	535	13.58	$72.63	16.6	$0.09	$0.27
North Carolina	1,110	8.19	$90.98	60.4	$0.67	$2.01
North Dakota	1,037	6.39	$66.28	94.6	$0.98	$2.94
Ohio	880	8.29	$72.91	90.4	$0.80	$2.39
Oklahoma	1,077	6.73	$72.44	60.8	$0.65	$1.96
Oregon	992	7.12	$70.60	8.0	$0.08	$0.24
Pennsylvania	812	9.71	$78.91	55.7	$0.45	$1.36
Rhode Island	563	10.21	$57.49	0.0	-	-
South Carolina	1,215	7.72	$93.88	38.3	$0.47	$1.40
South Dakota	939	7.40	$69.52	42.4	$0.40	$1.19
Tennessee	1,303	6.41	$83.50	62.1	$0.81	$2.43
Texas	1,168	8.05	$94.06	36.8	$0.43	$1.29
Utah	723	6.79	$49.14	94.2	$0.68	$2.04
Vermont	590	12.78	$75.35	0.0	-	-
Virginia	1,166	7.79	$90.78	50.8	$0.59	$1.78
Washington	1,067	6.29	$67.16	8.4	$0.09	$0.27
West Virginia	1,047	6.23	$65.25	98.1	$1.03	$3.08
Wisconsin	748	8.18	$61.18	68.1	$0.51	$1.53
Wyoming	816	6.97	$56.85	95.8	$0.78	$2.34

Source for data in first four data columns: U.S. Energy Information Administration (EIA), 2002b. Electric Sales and Revenue, 2002 Spreadsheets. Available at: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

Appendix D: Terms and Acronyms

ACI – Activated Carbon Injection

AFGD – Advanced Flue Gas Desulfurization

CAA – Clean Air Act

CAIR – Clean Air Interstate Rule (proposed in Spring 2004)

CDC – Centers for Disease Control and Prevention

COHPAC – Compact Hybrid Particulate Collector (a patented type of fabric filter)

DOE – U.S. Department of Energy

ECO – Electro Catalytic Oxidation (multipollutant control technology)

EIA – U.S. Energy Information Adminstration (within U.S. DOE)

EPA – Environmental Protection Agency

ESP – Electrostatic Precipitator (a particulate control device)

hs-ESP – Hot Side (upstream of air heater)

cs-ESP – Cold Side (downstream of air heater)

FDA – Food and Drug Administration

FF – Fabric Filter (a particulate control device)

FGD – Flue Gas Desulfurization

HAP – Hazardous Air Pollutant

Hg – Mercury

ICAC – Institute of Clean Air Companies

ICR – Information Collection Request

IGCC – Integrated Gastification Combined Cycle

kWh – Kilowatt Hour

lb – Pound

MACT – Maximum Achievable Control Technology

MC – Multiple Cyclone (particulate control device)

Mill – One thousandth of a dollar (one tenth of a cent or $0.001)

MW – Megawatt

MWe—Megawatt Electric

MWh – Megawatt hour (1000 kWh)

NWF – National Wildlife Federation

NOx – Nitrogen Oxides

O&M – Operations and Maintenance

PAC – Powdered Activated Carbon

PFF – Polishing Fabric Filter (a secondary fabric filter installed downstream of a primary particulate control device)

PJFF – Pulse Jet Fabric Filter (a type of polishing fabric filter)

PM – Particulate Matter

PRB – Powder River Basin (a major subbituminous coal-producing region in Wyoming and Montana)

RGM – Reactive Gaseous Mercury

SC – Single Cyclone (particulate control device)

SCR – Selective Catalytic Reduction(a NOx control device)

SDA – Spray Dryer Absorber, an SO2 control device (also called a wet-dry scrubber)

SIP—State Implementation Plan

SNCR—Selective Non- Catalytic Reduction (a NOx control device)

SO2 – Sulfur Dioxide

TRI – Toxic Release Inventory

VOC—Volatile Organic Compound

For more information see:

DOE, Energy Glossary
http://www.eia.doe.gov/glossary/glossary_main_page.htm

DOE, abbreviations
http://www.eia.doe.gov/neic/a-z/a-z_abbrev/a-z_abbrev.html

National Energy Technology Laboratory, Coal Primer (including glossary)
http://www.netl.doe.gov/coal/Coal%20Primer/index.html

California Air Resources Board, Glossary of Air Pollution Terms
http://www.arb.ca.gov/html/gloss.htm

The Plain English Guide To The Clean Air Act—Glossary
http://www.epa.gov/oar/oaqps/peg_caa/pegcaa10.html

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