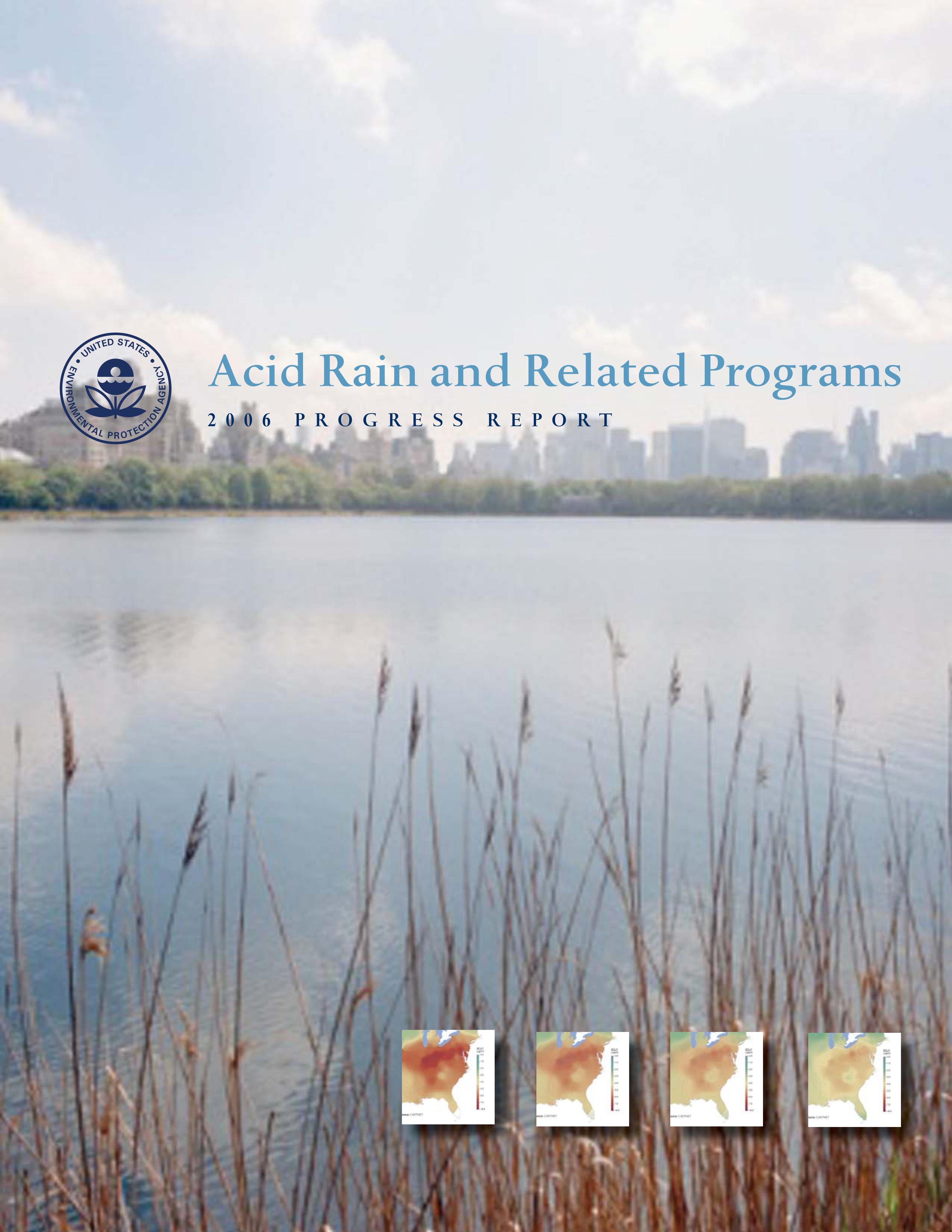
Acid Rain and Related Programs

2006 PROGRESS REPORT



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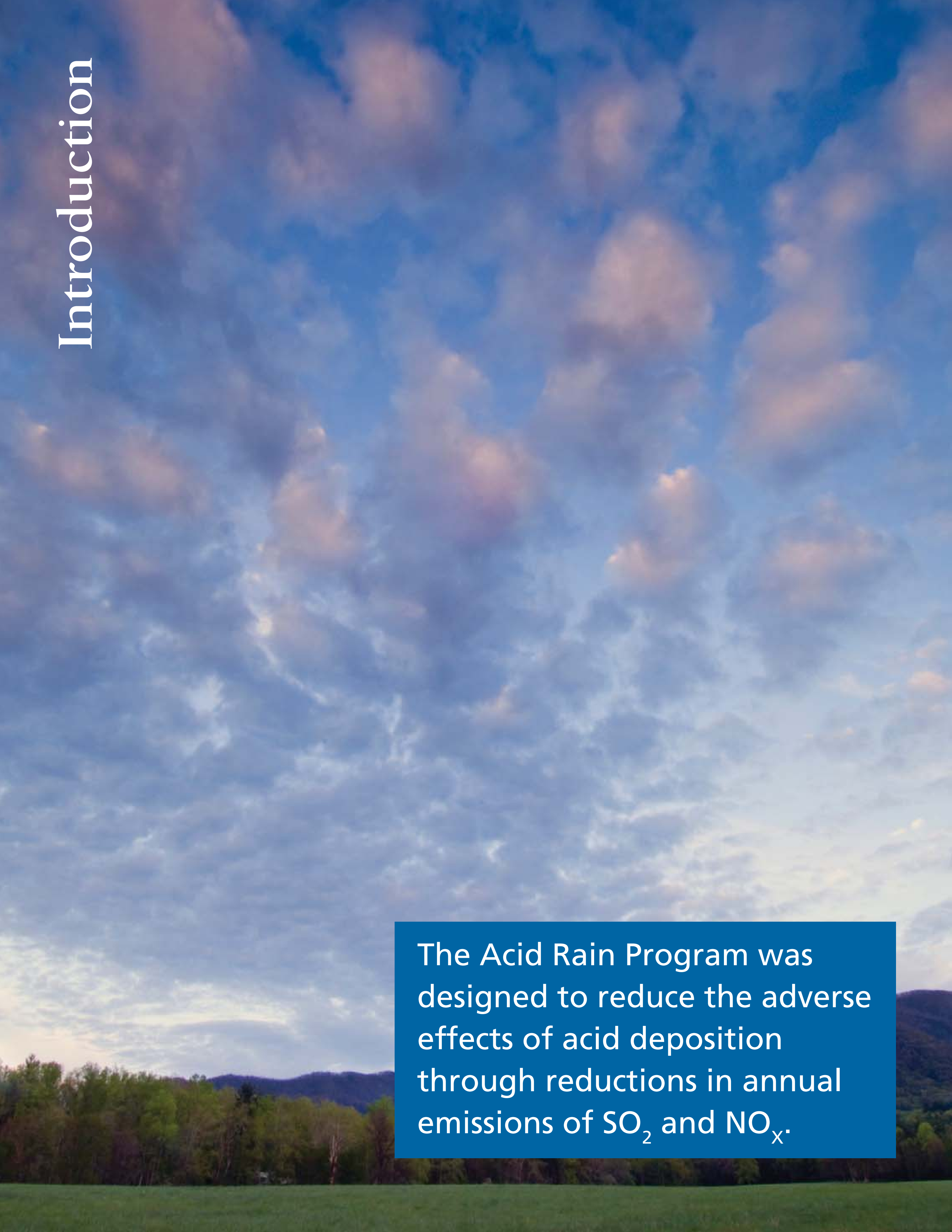
Contents

Introduction



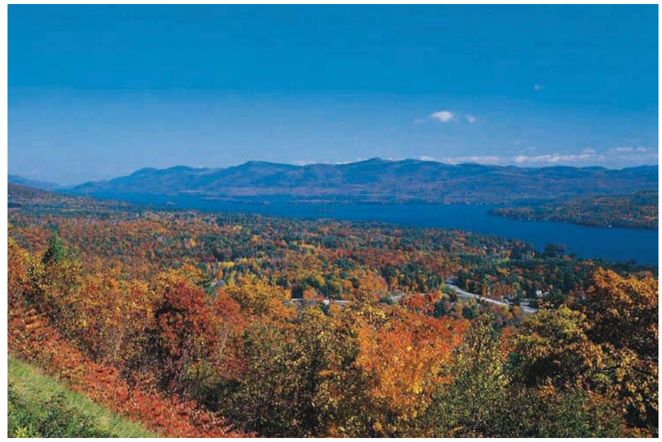
The Acid Rain Program was designed to reduce the adverse effects of acid deposition through reductions in annual emissions of SO_2 and NO_X.

Introduction

The U.S. Environmental Protection Agency (EPA) publishes an annual report to update the public on compliance with the Acid Rain Program (ARP), its status of implementation, and progress toward achieving environmental goals.

The *Acid Rain and Related Programs 2006 Progress Report* updates data reported in previous years, specifically:

- Sulfur dioxide (SO_2) emissions, allowance market information, and program compliance.
- Nitrogen oxides (NO_X) emissions and program compliance.



- Status and trends in acid deposition, air quality, and ecological effects.
- New programs, such as the Clean Air Interstate Rule (CAIR), that are building on the ARP to further improve environmental quality.

Key Findings

- Total SO_2 emissions fell below 10 million tons for the first time under ARP.
- NO_X emissions in 2006 were 3.3 million tons below 1990 levels.
- Acid deposition has declined significantly from levels measured before ARP, with corresponding water quality improvements in lakes and streams.
- Estimated public health benefits from ARP emission reductions exceed program costs by a margin of more than 40 to 1.

In this year's report, EPA incorporates early CAIR compliance planning into the findings associated with the ARP, including contributions to a significant SO_2 emission decrease in 2006, and other relationships between the ARP, CAIR, and other new air quality rules.

For more information on the ARP, CAIR, and related programs, including additional information on SO_2 and NO_X emissions, acid deposition monitoring, environmental effects of acid deposition, and detailed unit-level emission data, please visit EPA's Clean Air Markets Web site at <www.epa.gov/airmarkets>.

Summary

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Sulfur dioxide (SO_2) and nitrogen oxides (NO_X) are the key pollutants involved in the formation of acid rain. These pollutants also contribute to the formation of fine particles (sulfates and nitrates) that are associated with significant human health effects and regional haze. Sulfates and nitrates are transported and deposited at levels harmful to sensitive ecosystems in many areas of the country. Additionally, NO_X combines with volatile organic compounds (VOCs) to form ground-level ozone (smog). The U.S. electric power industry accounts for approximately 70 percent of total U.S. SO_2 emissions and 20 percent of total U.S. NO_X emissions from man-made sources.[1]

The Acid Rain Program (ARP) was created under Title IV of the 1990 Clean Air Act Amendments (CAAA) to reduce the adverse effects of acid deposition through reductions in annual emissions of SO_2 and NO_X. The Act calls for SO_2 reductions of 10 million tons from 1980 emission levels, largely achieved through a market-based cap and trade program, which utilizes emission caps to permanently limit SO_2 emissions from power plants. NO_X reductions under the ARP are achieved through a program closer to a more traditional, rate-based regulatory system. The NO_X program is designed to limit NO_X emission levels to 2 million tons less than those projected for the year 2000 without implementation of Title IV.

Since the start of the ARP in 1995, reductions in SO_2 and NO_X emissions from the power sector have contributed to significant improvements in air quality and environmental and human health. The SO_2 program affected 3,520 electric generating units (EGUs) in 2006 (with most emissions produced by 1,062 coal-fired units). The NO_X program applied to a subset of 982 operating coal-fired units in 2006.

The 2006 compliance year marked the 12th year of the program. During this period, the ARP has:

- Reduced SO_2 emissions by more than 6.3 million tons from 1990 levels, or about 40 percent of total power sector emissions.
    - SO_2 emissions from ARP units fell sharply, declining 830,000 tons from 2005 levels. Reduced energy demand, decreased oil use because of fuel prices, and early Clean Air Interstate Rule (CAIR) compliance all appear to be factors in this decline.
    - Total SO_2 emissions fell below 10 million tons for the first time under the ARP. Sources emitted approximately 9.4 million tons of SO_2 in 2006, below the emission cap of 9.5 million tons.

- With nearly 6.1 million unused (banked) allowances from prior years, SO_2 emissions were 40 percent below the total 2006 allowable SO_2 emissions of 15.7 million tons.

- Cut NO_X emissions by 3.3 million tons from 1990 levels, so that emissions in 2006 were less than half the level anticipated without the program. Other efforts, such as the NO_X Budget Trading Program (NBP) in the eastern United States, also contributed to this reduction.

- Led to significant decreases in acid deposition. For example, between the 1989-1991 and 2004-2006 observation periods, wet sulfate deposition decreased 35 percent in the Northeast and 33 percent in the Midwest. These reductions have resulted in positive changes in environmental indicators, including improved water quality in lakes and streams.

- Provided the most complete and accurate emission data ever developed and made those data available through comprehensive electronic data reporting and Web-based tools for agencies, researchers, affected sources, and the public.

- Delivered pioneering e-government results, automating administrative processes, reducing paper use, and providing online systems for doing business with EPA.

- Achieved extremely high compliance levels, with 100 percent compliance with the allowance holding requirements for SO_2 in 2006, and a single unit out of compliance for NO_X.

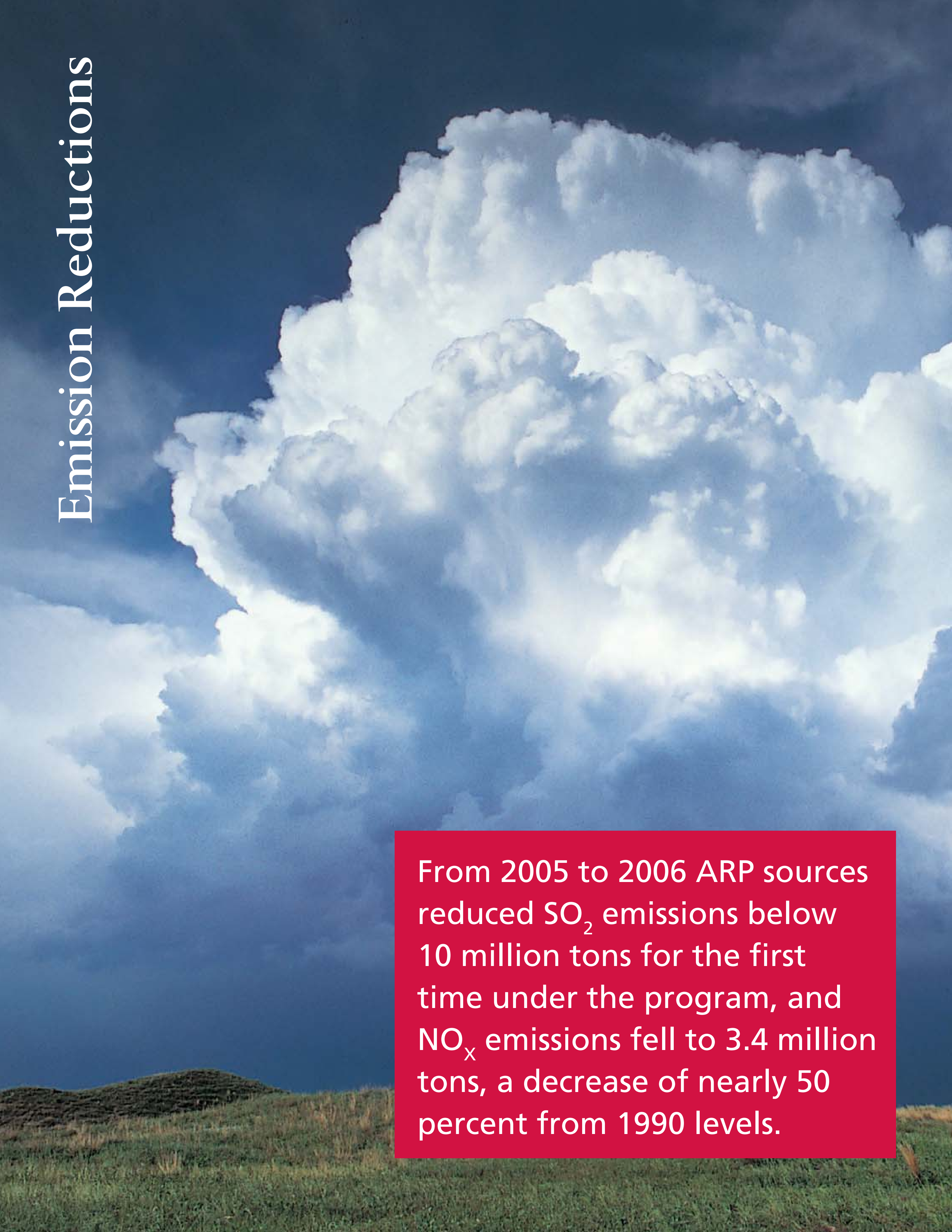
- Reduced implementation costs by allowing sources to choose cost-effective compliance strategies.

After 12 years of implementation, monitoring, and assessment, the ARP has proven to be an effective and efficient means of meeting emission reduction goals under the Clean Air Act (CAA). A 2005 study estimated the program's benefits at $122 billion annually in 2010, while cost estimates are around $3 billion annually (in 2000$).[2] Despite the program's historic and projected benefits, EPA analyses of recent studies of human health, data from long-term monitoring networks, and ecological assessments have revealed the need for additional emission reductions to protect human health and continue ecological recovery and protection. EPA recognized the need for further SO_2 and NO_X controls on the power industry to address pollutant transport problems many states face in efforts to attain National Ambient Air Quality Standards (NAAQS) for ozone and fine particles. The success of the acid rain trading and NO_X emission reduction programs, along with the need for further reductions, provided the impetus for a suite of new rules promulgated in 2005: CAIR, the Clean Air Visibility Rule (CAVR), and the Clean Air Mercury Rule (CAMR).

Building on the ARP model, EPA promulgated CAIR in the spring of 2005 to address transport of fine particles and ozone in the eastern United States, CAVR to improve visibility in national parks and wilderness areas, and CAMR to reduce nationwide mercury emissions from coal-fired power plants. Starting in 2009 and 2010, CAIR establishes regional caps on SO_2 and NO_X emissions. Annual SO_2 emissions for affected eastern states are capped at 3.7 million tons in 2010 and 2.6 million tons in 2015. Annual NO_X emissions for affected eastern states are capped at 1.5 million tons in 2009 and 1.3 million tons in 2015. CAIR will operate concurrently with the ARP.

CAVR addresses SO_2 and NO_X power sector emissions from non-CAIR states located in the West and parts of New England. Affected sources under CAVR must reduce SO_2 and NO_X emissions that impair visibility in national parks and wilderness areas. Notably, EPA allows states to establish additional regional cap and trade programs to accomplish these reductions from power plants and other stationary sources.

CAMR establishes a national cap on mercury emissions beginning in 2010 and utilizes a market-based cap and trade program. Additionally, new coal-fired power plants will be required to meet standards of performance that limit mercury emissions. These programs will serve as a key component of strategies to protect human health and the environment across the United States into the next decade.



Emission Reductions

From 2005 to 2006 ARP sources reduced SO_2 emissions below 10 million tons for the first time under the program, and NO_x emissions fell to 3.4 million tons, a decrease of nearly 50 percent from 1990 levels.

Origins of the Acid Rain Program

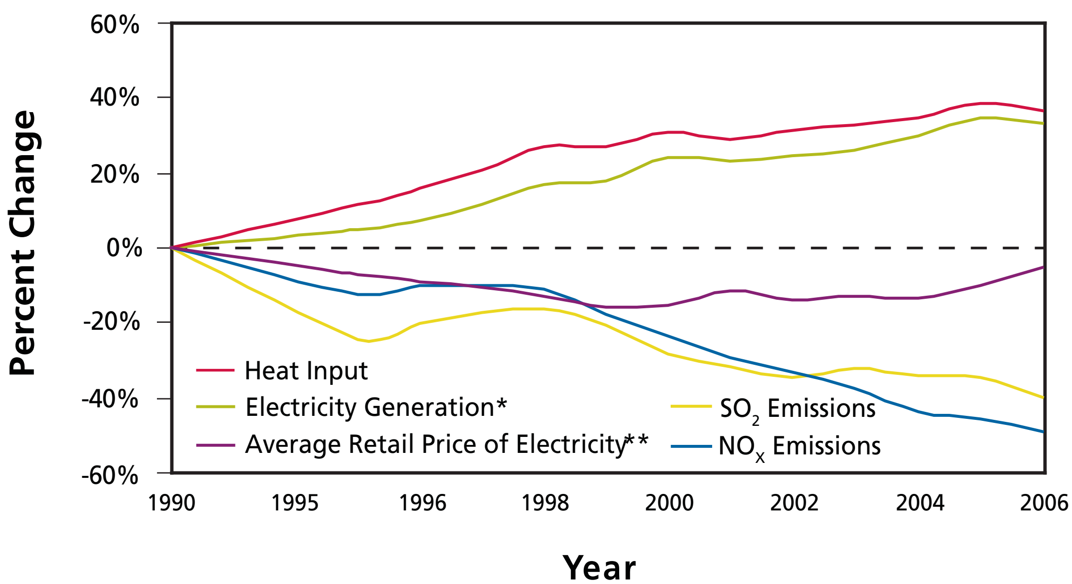
Acid deposition, more commonly known as acid rain, occurs when emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) react with water, oxygen, and oxidants in the atmosphere to form various acidic compounds. Prevailing winds transport these compounds hundreds of miles, often across state borders, where they impair air quality and damage public health, acidify lakes and streams, harm sensitive forests and coastal ecosystems, degrade visibility, and accelerate the decay of building materials.

The Acid Rain Program (ARP), established under Title IV of the 1990 Clean Air Act Amendments (CAAA), requires major reductions of SO_2 and NO_X emissions from the electric power industry. The SO_2 program sets a permanent cap on the total amount of SO_2 that may be emitted by electric generating units (EGUs) in the contiguous United States. The program is phased in, with the final 2010 SO_2 cap set at 8.95 million tons, a level of about one-half of the emissions from the power sector in 1980.

As seen in Figure 1, emissions of both SO_2 and NO_X have decreased markedly under the ARP while combustion of fossil fuels, measured as "heat input," for electricity generation has increased significantly.

Using a market-based cap and trade mechanism to reduce SO_2 emissions allows flexibility for individual combustion units to select their own methods of compliance. Currently, one allowance provides a

Figure 1: Trends in Electricity Generation, Fossil Energy Use, Prices, and Emissions from the Electric Power Industry



* Generation from fossil fuel-fired plants.

** Constant year 2000 dollars adjusted for inflation.

Source: Energy Information Administration (electricity generation, retail price); EPA (heat input and emissions, representing all affected ARP units), 2007 regulated unit limited authorization to emit one ton of SO_2. The Clean Air Act (CAA) allocates allowances to regulated units based on historic fuel consumption and specific emission rates prior to the start of the program.[3] The total allowances allocated for each year equal the SO_2 emission cap. The program encourages early reductions by allowing sources to bank unused allowances in one year and use them in a later year.

The ARP adopts a more traditional approach to achieve NO_X emission reductions. Rate-based limits apply to most of the coal-fired electric utility boilers subject to the ARP. An owner can meet these NO_X limits on an individual unit basis or through averaging plans involving groups of its units.

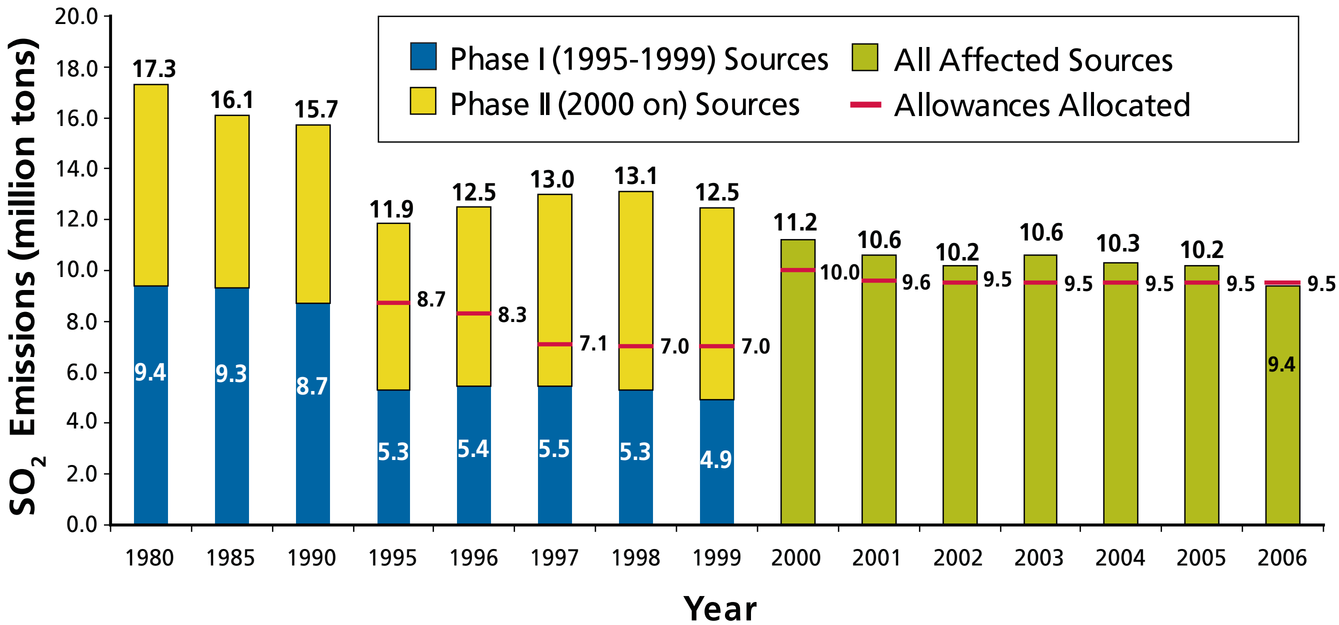
The ARP is composed of two phases for SO_2 and NO_X. Phase I applied primarily to the largest coal-fired electric generation sources from 1995-1999 for SO_2 and from 1996-1999 for NO_X. Phase II for both pollutants began in 2000. In 2006, the SO_2 Phase II requirements applied to 3,520 units, with most of the emissions produced by 1,062 coal-fired units. The Phase II NO_X requirements applied to 982 of those units that have a generation capacity of 25 megawatts (MW) or more and burned coal between 1990 and 1995.

SO_2 Emission Reductions

Electric power generation is by far the largest single source of SO_2 emissions in the United States, accounting for approximately 70 percent of total SO_2 emissions nationwide.[4]

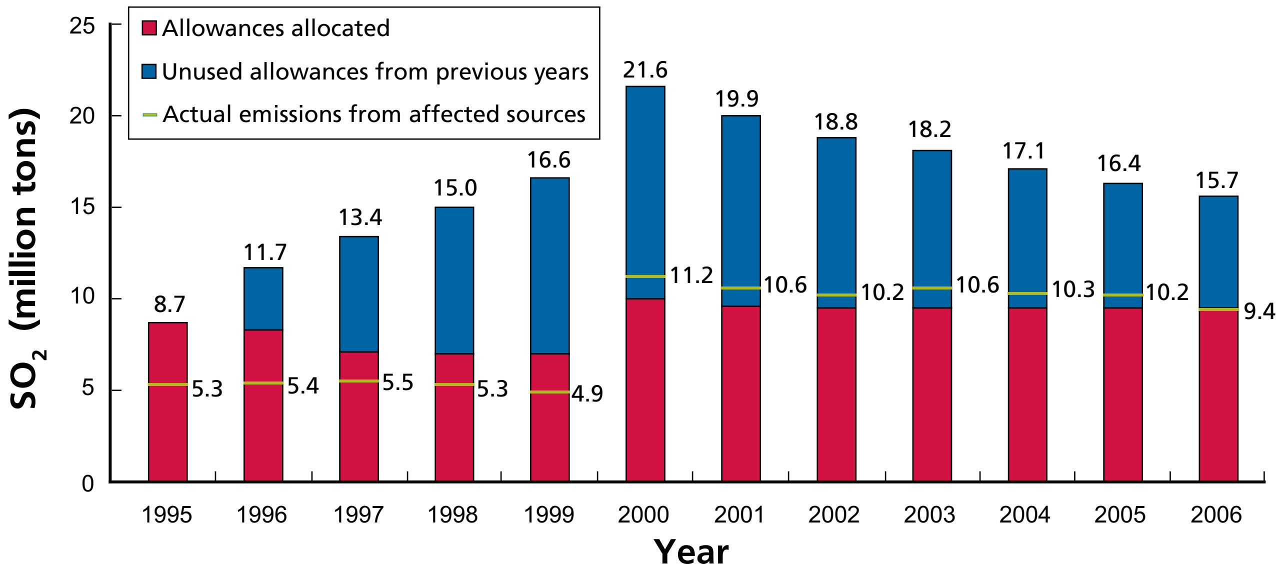
As shown in Figure 2, ARP sources have reduced annual SO_2 emissions by 46 percent compared to 1980 levels and 40 percent compared to 1990 levels. Reductions in SO_2 emissions from other sources not affected by the ARP (including industrial and commercial boilers and the metals and refining industries) and use of cleaner fuels in residential and commercial burners have contributed to a similar overall decline (47 percent) in annual SO_2 emissions from all sources since 1980. National SO_2 emissions from all sources have fallen from nearly 26 million tons in 1980 to less than 14 million tons in 2006 (see <www.epa.gov/ttn/chief/trends>).

Figure 2: SO_2 Emissions from Acid Rain Program Sources



Source: EPA, 2007

Figure 3: SO_2 Emissions and the Allowance Bank, 1995-2006

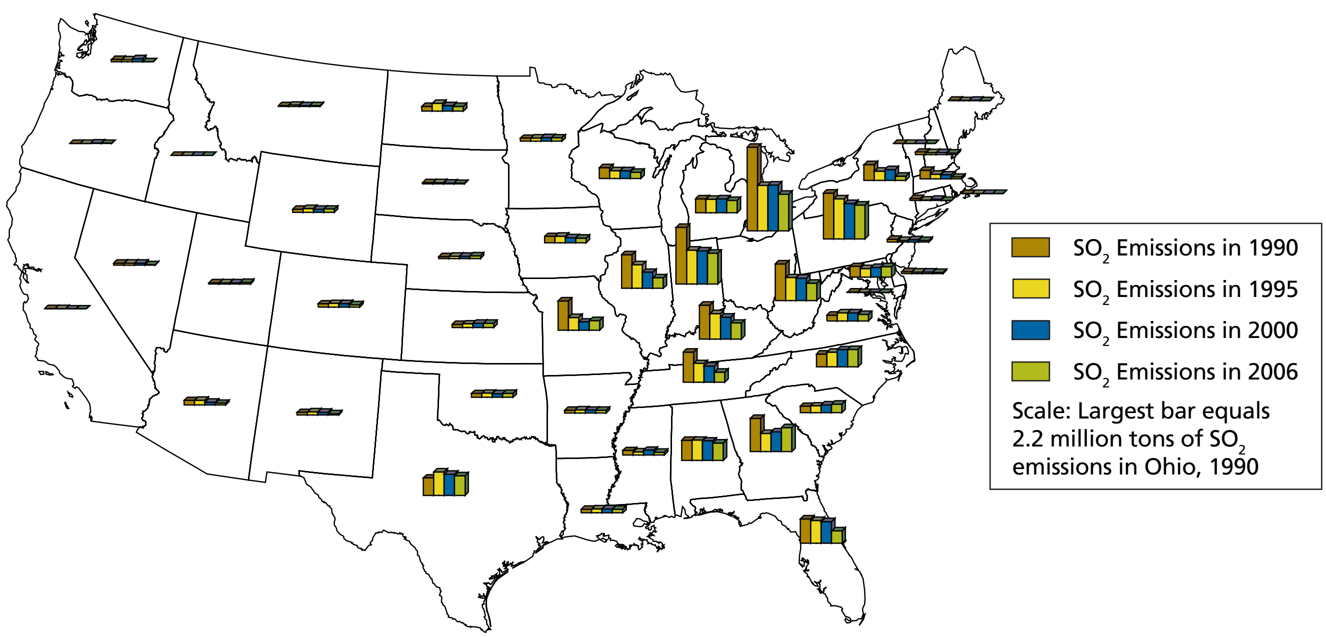


Source: EPA, 2007

For 2006, EPA allocated over 9.5 million SO_2 allowances under the ARP. Together with more than 6.1 million unused allowances carried over (or banked) from prior years, there were 15.7 million allowances available for use in 2006. Sources emitted approximately 9.4 million tons of SO_2 in 2006, less than the allowances allocated for the year, and far less than the total allowances available (see Figure 3).[5]

The number of banked allowances grew, from 6.1 million available for 2006 compliance to 6.3 million available for 2007 and future years. In the next several years, industry anticipation of stringent emission requirements under CAIR is expected to encourage sources to pursue additional reductions. While these reductions will result in an increase in banked allowances, tighter retirement ratios under CAIR (that

Figure 4: State-by-State SO_2 Emission Levels, 1990-2006



Source: EPA, 2007

in effect lower the SO_2 emission cap) will lead to depletion of the bank and further reduce emissions. In 2010, the total number of Title IV allowances allocated annually will drop to 8.95 million and remain statutorily fixed at that annual level. Because of the retirement ratios in the CAIR region, EPA projects that emissions will be significantly lower than this statutory cap. Table 1 explains in more detail the origin of the allowances that were available for use in 2006, and Table 3 shows how those allowances were used.

From 2005 to 2006, reductions in SO_2 emissions from ARP units in 35 states and the District of Columbia totaled 873,000 tons. Modest increases in 13 states totaled 43,000 tons, resulting in a net national decrease of 830,000 tons, or more than 8 percent, for the year. Among the states with large reductions, 12 states (Florida, Illinois, Indiana, Kansas, Kentucky, Massachusetts, North Carolina, Nevada, New York, Ohio, Pennsylvania, and Virginia) decreased emissions by more than 25,000 tons each. The largest reduction was in Ohio, where ARP units reduced emissions by more than 123,000 tons from 2005 levels.

The states with the highest emitting sources in 1990 have seen the greatest SO_2 reductions during the ARP (see Figure 4 on page 9). Most of these states are upwind of the areas the ARP was designed to protect, and reductions have resulted in important environmental and health benefits over a large region.

For the 32 states and the District of Columbia that reduced annual SO_2 emissions from 1990 to 2006, total annual SO_2 emissions were approximately 6.7 million tons lower in 2006 than they were in 1990. For the 16 states where annual emissions increased from 1990 to 2006, total emissions were up by only about 328,000 tons from 1990 levels. In contrast, the 2006 emissions were more than 100,000 tons less than 1990 levels in each of 13 states: Florida, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Missouri, New York, Ohio, Pennsylvania, Tennessee, West Virginia, and Wisconsin. The six states with the greatest annual reductions include Ohio, which decreased emissions by 1.3 million tons, and Illinois, Indiana, Missouri, Tennessee, and West Virginia, each of which reduced emissions by more than 500,000 tons per year.

Table 1: Origin of 2006 Allowable SO_2 Emission Levels

Type of Allowance Allocation	Number of SO_2 Allowances	Explanation of Allowance Allocation Type
Initial Allocation	9,191,897	The initial allocation of allowances is granted to units* based on the product of their historical utilization and emission rates specified in the CAA.
Allowance Auction	250,000	The allowance auction provides allowances to the market that were set aside in a Special Allowance Reserve when the initial allowance allocation was made.
Opt-in Allowances	97,678	Opt-in allowances are provided to units entering the program voluntarily. There were eight opt-in units in 2006.
Total 2006 Allocation	9,539,575	
Total Banked Allowances**	6,116,062	Banked allowances accrue in accounts from previous years. These allowances were available for compliance in 2006 or any future year.
Total 2006 Allowable Emissions	15,655,637	

* In this report, the term "unit" means a fossil fuel-fired combustor that serves a generator that provides electricity for sale. The vast majority of SO_2 emissions under the program result from coal-fired generation units, but oil and natural gas units are also included in the program.

** Total banked allowances are adjusted from the *2005 Progress Report* to account for additional deductions made for electronic data reporting (EDR) resubmissions after 2005 reconciliation was completed.

Source: EPA, 2007

Why SO_2 Emissions Decreased Sharply in 2006

For the first time under the ARP, SO_2 emissions in 2006 fell below 10 million tons. Overall reductions from 2005 were over 830,000 tons (see Table 2). This decrease stemmed from a number of factors:

- Heat input (measured in million British thermal units (mmBtu)) dropped for oil-fired units, with a comparable increase in heat input from gas-fired units as well as much less oil use at dual fuel units classified as gas-fired units. Switching from oil to gas reduces SO_2 because oil is higher in sulfur content than natural gas. Fuel switching resulted in about a 243,000-ton SO_2 reduction from oil and gas units combined.
- Emissions from coal-fired units decreased by about 593,000 tons. Reductions came from both uncontrolled units and those with installed flue gas desulfurization equipment (scrubbers).
  - Reductions in heat input and the SO_2 emission rate of units without scrubbers resulted in a decrease of about 412,000 tons of SO_2 emissions. Overall heat input for these units was down 2.1 percent, but the overall emission rate was down even more, about 3.5 percent. The emission rate decline may be partially attributable to early CAIR compliance planning.
  - Units equipped with scrubbers (either in both 2005 and 2006, or just 2006) caused a decrease in SO_2 emissions of about 182,000 tons. Heat input to these units declined by less than 1 percent, but their emission rate dropped nearly 11 percent, reflecting the addition of several scrubbers on previously uncontrolled units. Some of the scrubber installations were expected as a result of existing state or federal actions. Others appear to be part of an early compliance response to CAIR.
- Overall, about 650 coal units had at least some decrease in mass emissions due to reduced heat input, reduced emission rate, or both.

Table 2: SO_2, NO_x, and Heat Input Trends in Acid Rain Program Units, by Fuel Type

Fuel Type	2004			2005			2006		
	SO_2	NO_x	HI	SO_2	NO_x	HI	SO_2	NO_x	HI
Coal	9,839	3,484	20.48	9,836	3,356	20.77	9,243	3,208	20.44
Oil	378	139	1.00	350	130	1.00	135	64	0.58
Gas	37	133	4.84	34	142	5.34	7	130	5.70
Other	3	6	0.03	3	6	0.03	7	7	0.05
Total	10,256	3,762	26.35	10,223	3,633	27.14	9,392	3,409	26.78

Notes: All emission data are in thousand tons and all heat input data are in billion mmBtu. Totals may not reflect individual rows due to rounding. Fuel type represents primary fuel type, and many units may combust more than one fuel.

Source: EPA, 2007

SO_2 Program Compliance

Approximately 9.4 million allowances were deducted from sources' accounts in 2006 to cover emissions. Table 3 displays these allowance deductions, as well as the remaining banked allowances from 1995 through 2006. In 2006, all ARP facilities were in compliance with the SO_2 allowance holding requirements. Title IV set a penalty of $2,000 per ton in 1990, which is adjusted annually for inflation. The 2006 penalty level was set at $3,152 per excess ton. The ARP's cap and trade approach offers emission sources the flexibility to comply with regulations using their choice of the most cost-effective strategies available. Since the program's inception, the compliance rate has consistently been extraordinarily high.

Table 3: SO_2 Allowance Reconciliation Summary, 2006

Total Allowances Held (1995-2006 Vintages)*	15,655,637
Facility Accounts**	12,483,262
General Accounts***	3,172,375
Allowances Deducted for Emissions****	9,392,922
Penalty Allowance Deductions (2007 Vintage)	0
Banked Allowances	6,262,715
Facility Accounts	3,090,340
General Accounts	3,172,375

* The allowance transfer deadline is March 1 of the year following the compliance year. At this point, facility accounts are frozen, and no further transfers of allowances are recorded. The freeze on accounts is removed when the annual reconciliation is complete.

** From 1995 through 2005, EPA reconciled emissions and allowances for compliance under the ARP separately for each unit. In 2006, EPA began reconciling emissions and allowances at the facility level for compliance purposes.

*** General accounts that are not subject to reconciliation can be established in the Allowance Tracking System (ATS) by any utility, individual, or other organization.

**** Includes 489 allowances deducted from opt-in sources for reduced utilization.

Source: EPA, 2007

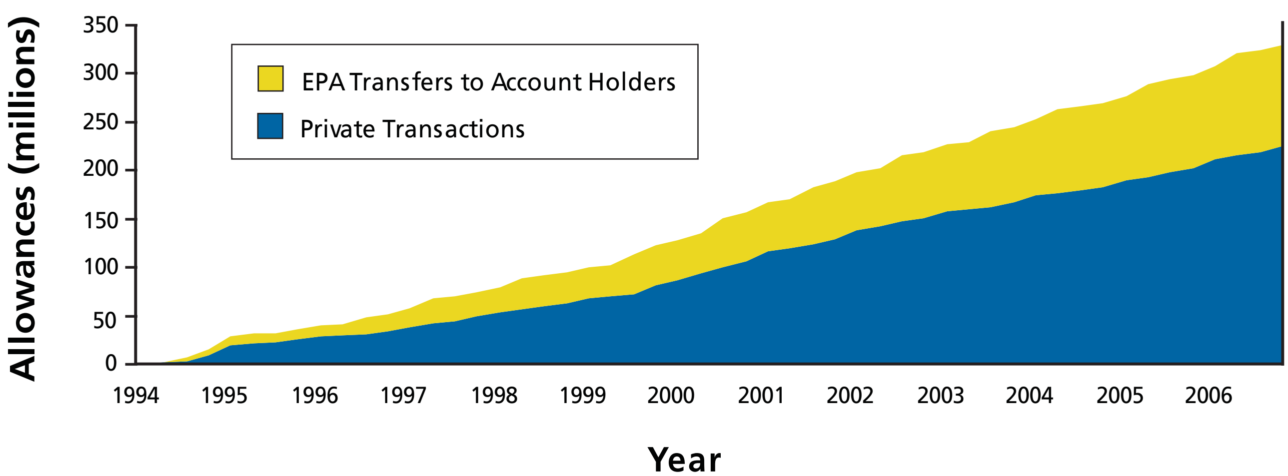
SO_2 Allowance Market

Figure 5 shows the cumulative volume of SO_2 allowances transferred under the ARP. The figure differentiates between allowances transferred in private transactions and those annually allocated and transferred to sources' accounts by EPA. Private transactions are indicative of both market interest and use of allowances as a compliance strategy. Of the nearly 330 million allowances transferred since 1994, about 68 percent were traded in private transactions. In December 2001, parties began to use a system developed by EPA to allow online allowance transfers. In 2006, account holders registered about 94 percent of all private allowance transfers through EPA's online transfer system.[6]

In 2006, nearly 6,400 private allowance transfers (moving roughly 22.4 million allowances of past, current, and future vintages) were recorded in the EPA Allowance Tracking System (ATS). About 9.5 million (42 percent) were transferred in economically significant transactions (i.e., between economically unrelated parties). Transfers between economically unrelated parties are "arm's length" transactions and are considered a better indicator of an active, functioning market than are transactions among the various units of a given company.

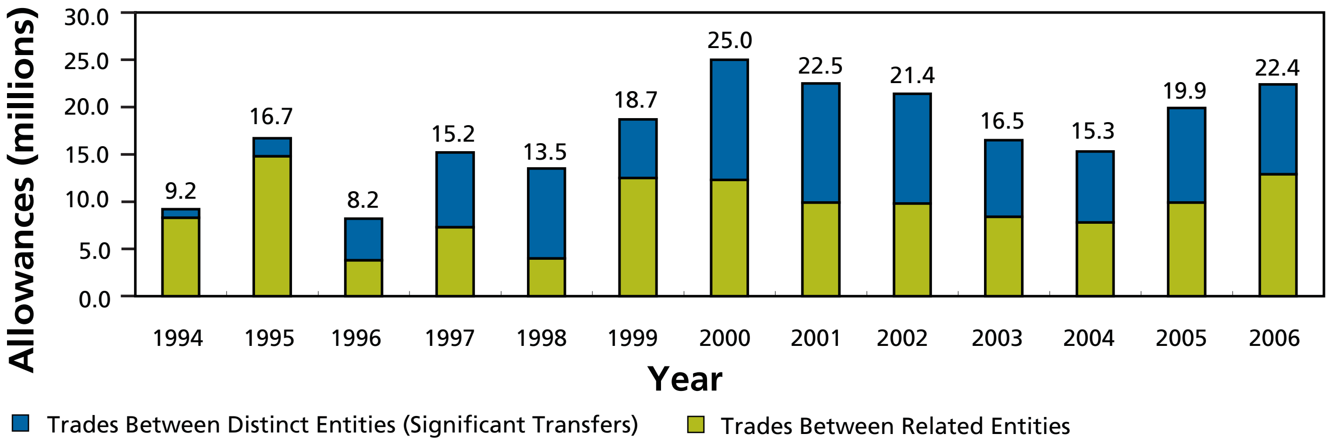
In the majority of all private transfers, allowances were acquired by power companies. Figure 6 shows the annual volume of SO_2 allowances transferred under the ARP (excluding allocations, retirements, and other transfers by EPA) since official recording of transfers began in 1994. Note that the volume of private transfers recorded in 2006 rose for the second straight year and returned to levels not seen since 2000-2001. Market liquidity had declined due to an overall contraction in the related electricity markets following disruptions precipitated by events such as the collapse of Enron in late 2001.

Figure 5: Cumulative SO_2 Allowances Transferred through 2006



Source: EPA, 2007

Figure 6: SO_2 Allowances Transferred under the Acid Rain Program



Source: EPA, 2007

NO_X Emission Reductions and Compliance

Title IV requires NO_X emission reductions for certain coal-fired EGUs. Unlike the SO_2 program, Congress applied rate-based emission limits based on a unit's boiler type to achieve NO_X reductions (see Table 4). The NO_X emission limit is expressed as pounds of NO_X per unit of heat input (lbs/mmBtu) for each boiler subject to a NO_X limit. Owners can meet the NO_X limits for each individual unit or meet group NO_X limits through averaging plans for groups of units that share a common owner and designated representative. In 2006, all but one unit met its NO_X emission requirements under the ARP.

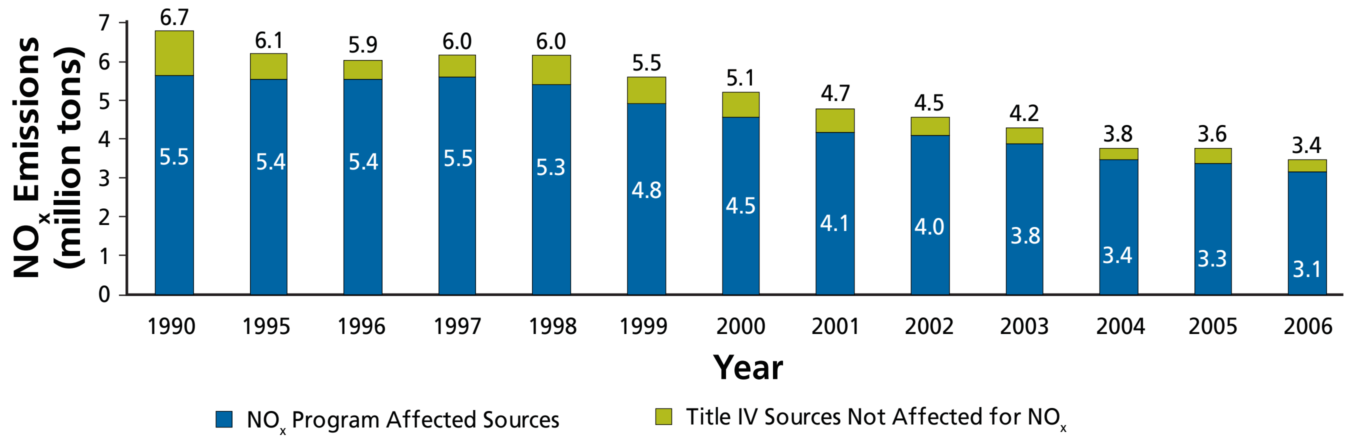
The ARP seeks to attain a 2 million ton annual reduction in NO_X emissions from all ARP sources relative to the NO_X emission levels that were projected to occur in 2000 absent the ARP (8.1 million tons). This goal was first achieved in 2000 and has been met every year thereafter, including 2006. Figure 7 on page 14 shows that NO_X emissions from all ARP sources were 3.4 million tons in 2006. This level is 4.7 million tons less than the projected level in 2000 without the ARP, or more than double the Title IV NO_X emission reduction objective. These reductions have been achieved even though the amount of fuel burned to produce electricity (as measured by heat input) at all ARP units in 2006 has increased 37 percent since 1990. While the ARP

Table 4: NO_X-Affected Title IV Units by Boiler Type and NO_X Emission Limit

Coal-Fired Boiler Type	Title IV Standard NO_X Emission Limits (lb/mmBtu)	# of Units
Phase 1 Group 1 Tangentially Fired	0.45	132
Phase 1 Group 1 Dry Bottom, Wall-Fired	0.50	113
Phase II Group 1 Tangentially Fired	0.40	301
Phase II Group 1 Dry Bottom, Wall-Fired	0.46	295
Cell Burners	0.68	37
Cyclones > 155 MW	0.86	54
Wet Bottom > 65 MW	0.84	24
Vertically Fired	0.80	26
Total All Units	n/a	982

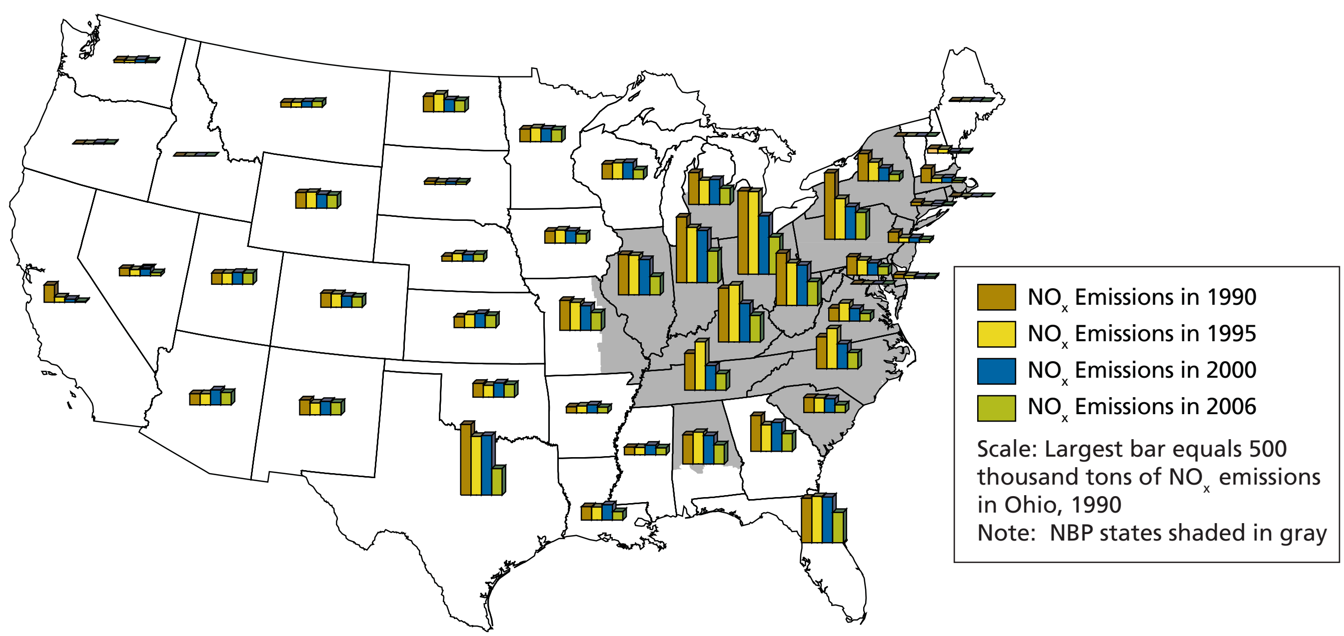
Source: EPA, 2007

Figure 7: NO_x Emission Trends for Acid Rain Program Units, 1990-2006



Source: EPA, 2007

Figure 8: State-by-State NO_x Emission Levels for Acid Rain Program Sources, 1990-2006



Source: EPA, 2007

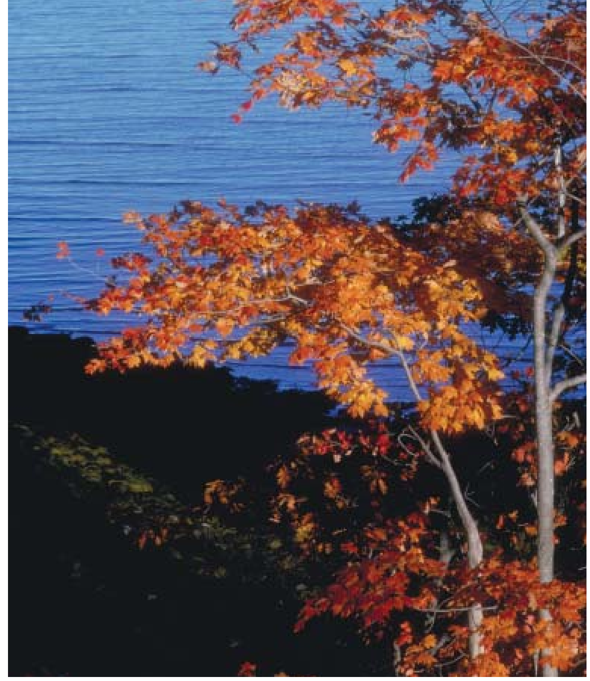
was responsible for a large portion of these annual NO_x reductions, other programs—such as the Ozone Transport Commission (OTC), NO_x Budget Trading Program (NBP) under EPA's NO_x State Implementation Plan (SIP) Call, and other regional NO_x emission control programs—also contributed significantly to the NO_x reductions achieved by sources in 2006.

From 2005 to 2006, NO_x emissions from ARP units dropped by 224,000 tons, a net decrease of more than 6 percent. Thirty-six states and the District of Columbia reduced 2006 NO_x emissions by 247,000 tons below 2005 levels. Of these states, Alabama, Florida, Iowa, Louisiana, Nevada, New York, and Ohio reduced their NO_x emissions by more than 10,000 tons each from 2005 levels. Twelve states had modest increases in NO_x emissions in 2006, totaling 23,000 tons above 2005 levels.

As with SO_2, the states with the highest NO_x-emitting sources in 1990 tended to see the greatest power plant NO_x emission reductions (see Figure 8). The sum of reductions in the 41 states and the District of Columbia that had lower annual NO_x emissions in 2006 than in 1990 was approximately 3 million tons, while the sum of increases in the seven states that had higher annual NO_x emissions in 2006 than in 1990 was much smaller, about 37,000 tons. Nine of the 13 states with NO_x emission decreases of more than 100,000 tons were in the Ohio River Basin.

Role of Seasonal NO_x Control Programs in Reducing Annual Emissions

States subject to EPA's 1998 NO_x SIP Call have achieved significant reductions in ozone season NO_x emissions since the baseline years 1990 and 2000. All of these states have achieved reductions since 1990 as a result of programs implemented under the CAAA, with many of them reducing their emissions by more than half since 1990. A significant portion of these decreases in NO_x emissions has been achieved since 2000, largely as a result of reductions under the OTC program and NBP. With the CAIR ozone season NO_x program taking effect in 2009, further emission declines will occur across the region through the year 2020. For NBP compliance reports, see: <www.epa.gov/airmarkets/progress/progress-reports.html>.



Emission Monitoring and Reporting

The ARP requires program participants to measure, record, and report emissions using continuous emission monitoring systems (CEMS) or an approved alternative measurement method. The vast majority of emissions are monitored with CEMS while the alternatives provide an efficient means of monitoring emissions from the large universe of units with lower overall mass emissions. Figures 9 and 10 on page 17 show the number of units with and without SO_2 CEMS for various fuel types, as well as the amount of SO_2 emissions monitored using CEMS.

CEMS and approved alternatives are a cornerstone of the ARP's accountability and transparency. Since the program's inception in 1995, affected sources have met stringent monitor quality assurance and control requirements, and reported hourly emission data in quarterly electronic reports to EPA. Using automated software audits, EPA rigorously

checks the completeness, quality, and integrity of these data. All emission data are available to the public on the Data and Maps Web site maintained by EPA's Clean Air Markets Division (CAMD) at <http://camddataandmaps.epa.gov/gdm/>. The site also provides access to other data associated with emission trading programs, including reports, queries, maps, charts, and file downloads covering source information, emissions, allowances, program compliance, and air quality.

The emission monitoring requirements for the ARP are found in 40 CFR Part 75. These provisions are also required for participation in the NBP. The Part 75 requirements will also be used in the future to implement CAIR and CAMR.

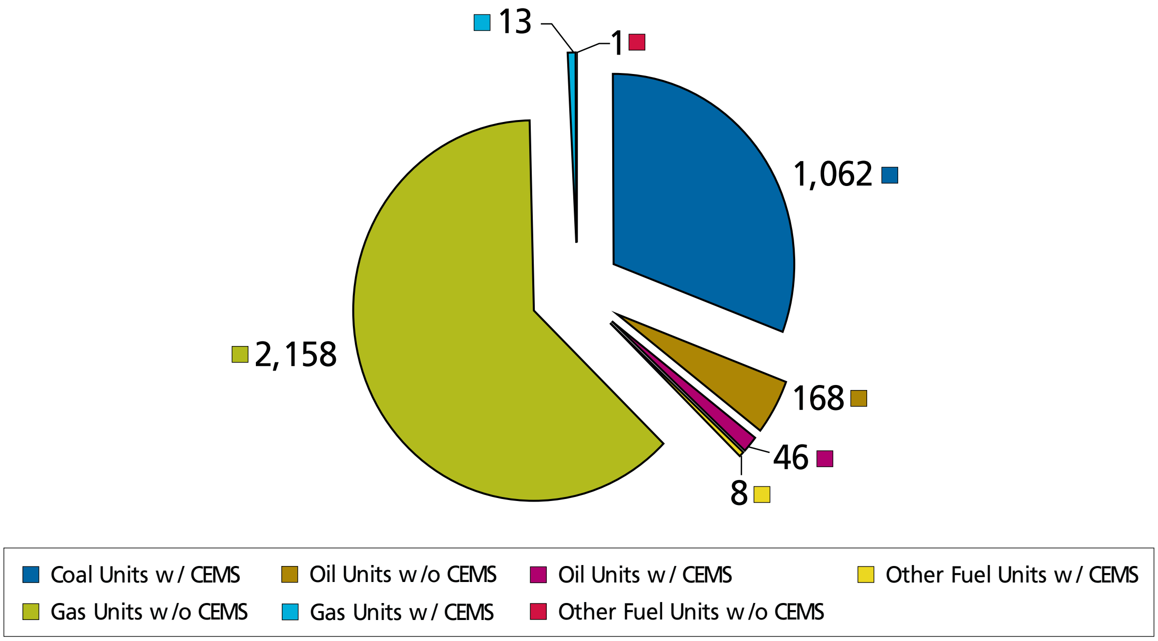
Emissions Collection and Monitoring Plan System (ECMPS)

CAMD is reengineering the way the regulated community maintains, evaluates, and submits monitoring plans, quality assurance (QA) certifications, and quarterly emission data. An important tool in this effort is the Emissions Collection and Monitoring Plan System (ECMPS). ECMPS will replace the current processes and multiple software tools used for evaluating, submitting, and receiving the data. ECMPS will be available for use in 2008, but will be required for all sources beginning in 2009.

CAMD's goals for the ECMPS project include:

- Creating a single desktop tool for authorized users to import and evaluate their data and to submit it to CAMD.
- Creating a new data reporting format based on the flexible XML (Extensible Markup Language) standard.
- Creating a centralized database at CAMD for receiving and maintaining submitted data. The desktop tool has direct access to this database.
- Providing users with the ability to assure the quality of data prior to submission and receive one set of evaluation results (feedback).
- Maintaining select data outside of the electronic data report.
- Developing and implementing new security requirements.

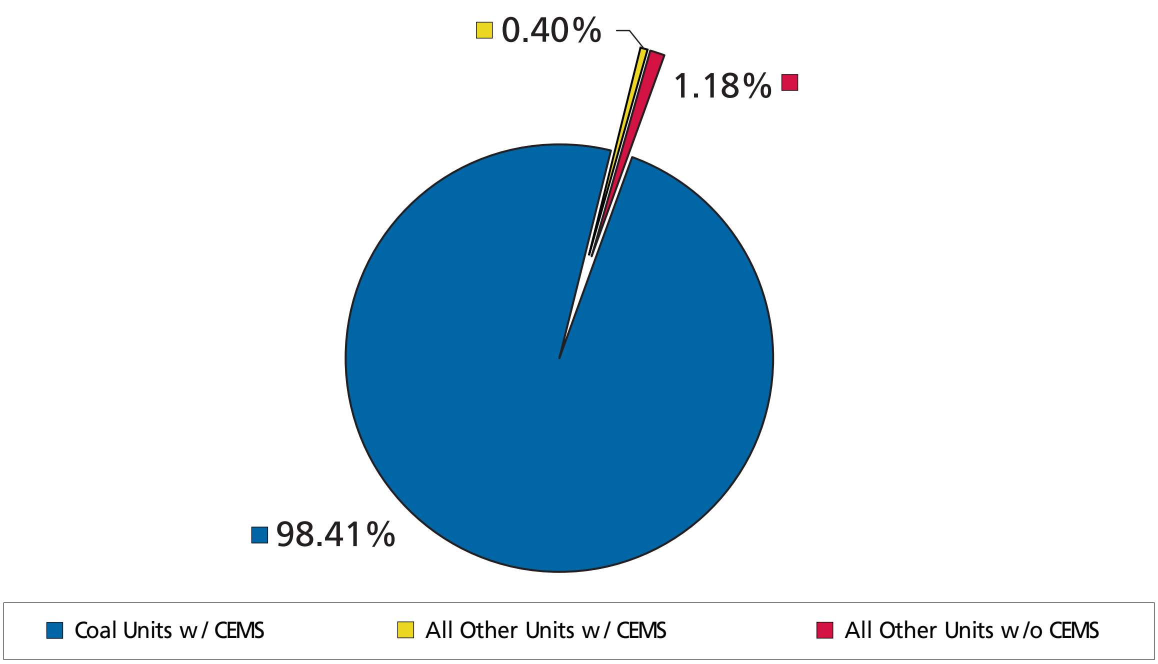
Figure 9: SO_2 Monitoring Methodology for the Acid Rain Program, Number of Units



Note: "Other fuel units" include units that in 2006 combusted primarily wood, waste, or other non-fossil fuel. The total number of units in Figure 9 excludes 64 affected units that did not operate in 2006.

Source: EPA, 2007

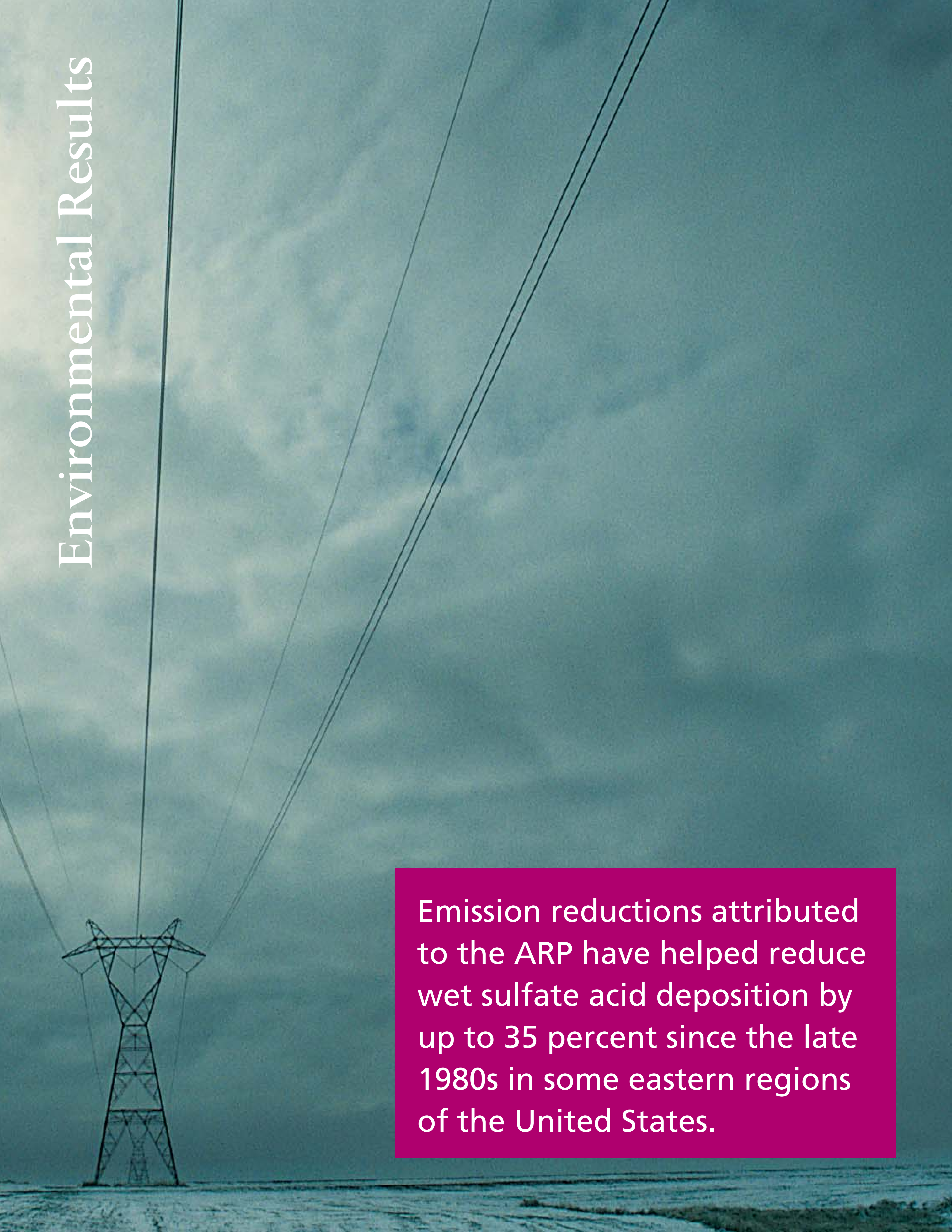
Figure 10: Monitoring Methodology for the Acid Rain Program, Total SO_2 Mass



Note: Percentages do not add to 100 percent due to rounding.

Source: EPA, 2007

Environmental Results



Emission reductions attributed to the ARP have helped reduce wet sulfate acid deposition by up to 35 percent since the late 1980s in some eastern regions of the United States.

Status and Trends in Air Quality, Acid Deposition, and Ecological Effects

The emission reductions achieved under the ARP have led to important environmental and public health benefits. These include improvements in air quality with significant benefits to human health; reductions in acid deposition; the beginnings of recovery from acidification in fresh water lakes and streams; improvements in visibility; and reduced risk to forests, materials, and structures. Table 5 on page 20 shows the regional changes in key air quality and atmospheric deposition measurements linked to the ARP's SO_2 and NO_X emission reductions.

Understanding the Monitoring Networks

To evaluate the impact of emission reductions on the environment, scientists and policymakers use data collected from long-term national monitoring networks such as the Clean Air Status and Trends Network (CASTNET) and the National Atmospheric Deposition Program/National Trends Network (NADP/NTN). These complementary, long-term monitoring networks provide information on a variety of indicators necessary for tracking temporal and spatial trends in regional air quality and acid deposition (see Table 6 on page 21).

CASTNET provides atmospheric data on the dry deposition component of total acid deposition, ground-level ozone, and other forms of atmospheric pollution. Established in 1987, CASTNET now consists of 87 sites across the United States. EPA's Office of Air and Radiation operates most of the monitoring stations; the National Park Service (NPS) funds and operates approximately 30 stations in cooperation with EPA. Many CASTNET sites have a continuous 20-year data record, reflecting EPA's commitment to long-term environmental monitoring. Information and data from CASTNET are available at <www.epa.gov/castnet>.

NADP/NTN is a nationwide, long-term network tracking the chemistry of precipitation. NADP/NTN offers data on hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations. The network is a cooperative effort involving many groups, including the State Agricultural Experiment Stations, U.S. Geological Survey, U.S. Department of Agriculture, EPA, NPS, the National Oceanic and Atmospheric Administration (NOAA), and other governmental and private entities. NADP/NTN has grown from 22 stations at the end of 1978 to more than 250 sites spanning the continental United States, Alaska, Puerto Rico, and the Virgin Islands. Information and data from NADP/NTN are available at <http://nadp.sws.uiuc.edu>.

While CASTNET provides ambient air quality data, EPA also uses data from other ambient monitoring networks, including the State and Local Ambient Monitoring and National Ambient Monitoring Systems (SLAMS/NAMS). These networks are used to document National Ambient Air Quality Standards (NAAQS) attainment and show trends in ambient air quality over time.

Table 5: Regional Changes in Air Quality and Deposition of Sulfur and Nitrogen, 1989-1991 versus 2004-2006 (From Rural Monitoring Networks)

Measurement	Region	Average 1989-1991	Average 2004-2006	Percent Change
Ambient SO_2 Concentration (µg/m^3)	Mid-Atlantic	12.2	7.5	-39
	Midwest	10.0	5.1	-49
	Northeast	6.7	2.8	-58
	Southeast	5.2	3.3	-37
Wet Sulfate Concentration (mg/L)	Mid-Atlantic	2.3	1.6	-31
	Midwest	2.2	1.5	-33
	Northeast	1.9	1.1	-40
	Southeast	1.3	1.1	-18
Ambient Sulfate Concentration (µg/m^3)	Mid-Atlantic	6.2	4.4	-29
	Midwest	5.4	3.6	-34
	Northeast	3.8	2.4	-37
	Southeast	5.4	4.1	-24
Wet Sulfate Deposition (kg/ha)	Mid-Atlantic	26.8	19.2	-28
	Midwest	22.3	14.9	-33
	Northeast	22.2	14.5	-35
	Southeast	18.1	14.3	-21*
Wet Inorganic Nitrogen Deposition (kg/ha)	Mid-Atlantic	5.9	5.0	-16*
	Midwest	5.9	5.4	-9*
	Northeast	5.5	4.1	-25*
	Southeast	4.3	4.1	-5*
Wet Nitrate Concentration (mg/L)	Mid-Atlantic	1.5	1.0	-30
	Midwest	1.5	1.2	-17
	Northeast	1.4	0.8	-38
	Southeast	0.8	0.7	-10
Ambient Nitrate Concentration (µg/m^3)	Mid-Atlantic	0.8	0.7	-1*
	Midwest	2.1	1.7	-18
	Northeast	0.4	0.4	3*
	Southeast	0.6	0.7	17
Total Ambient Nitrate Concentration (Nitrate + Nitric Acid) (µg/m^3)	Mid-Atlantic	3.2	2.5	-20*
	Midwest	4.0	3.2	-20*
	Northeast	1.9	1.4	-26*
	Southeast	2.2	2.0	-7*

*Percent change is estimated from raw measurement data, not rounded; refined techniques for measuring and calculating percentages yield values that are at or below the sensitivity of the method may not be significant due to the combination of margin of error and spatial averaging.

Source: CASTNET and NADP/NTN, 2007

Table 6: Air Quality and Acid Deposition Measures

Chemical Name	Chemical Symbol	Measured In: Ambient Air	Measured In: Wet Deposition	Why are these measured by the networks?
Sulfur Dioxide	SO_2	X		Primary precursor of wet and dry acid deposition; primary precursor to fine particles in many regions.
Sulfate Ion	SO_4^{2-}	X	X	Major contributor to wet acid deposition; major component of fine particles in the Midwest and East; can be transported over large distances; formed from reaction of SO_2 in the atmosphere.
Nitrate Ion	NO_3^-	X	X	Contributor to acid and nitrogen wet deposition; major component of fine particles in urban areas; formed from reaction of NO_X in the atmosphere.
Nitric Acid	HNO_3	X		Strong acid and major component of dry nitrogen deposition; formed as a secondary product from NO_X in the atmosphere.
Ammonium Ion	NH_4^+	X	X	Contributor to wet and dry nitrogen deposition; major component of fine particles; provides neutralizing role for acidic compounds; formed from ammonia gas in the atmosphere.
Ionic Hydrogen	H^+		X	Indicator of acidity in precipitation; formed from the reaction of sulfate and nitrate in water.
Calcium Magnesium Potassium Sodium	Ca_2^+ Mg_2^+ K^+ Na^+	X X X X	X X X X	These base cations neutralize acidic compounds in precipitation and the environment; also play a major role in plant nutrition and soil productivity.

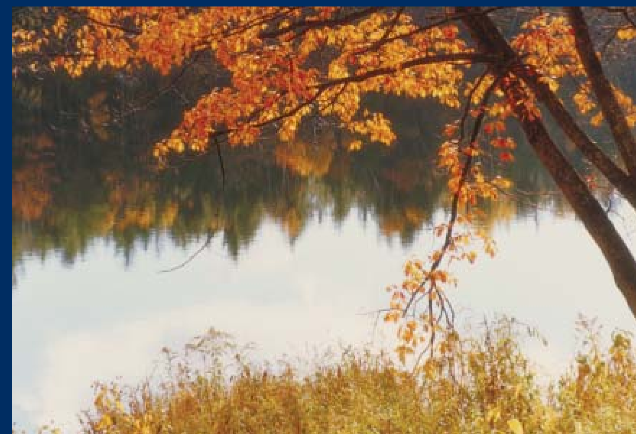
Source: EPA, 2007

Accountability and the ARP: Assessing Ecological Response

To determine the effectiveness of the ARP, EPA must be able to track, assess, and report on the trends and conditions in the environment as they respond to program implementation and emission reductions.

The data collected through air monitoring networks, such as CASTNET and NADP, provide a picture of changes in air quality and pollutant deposition as a result of emission reductions achieved by the ARP (see Figure 11). However, to assess the ecological impact of the ARP, EPA must go a step further and look at how changes in pollutant deposition correspond to changes in ecosystem conditions. This step requires examining the trends and conditions of ecosystems that are susceptible to changes in pollutant deposition and, specifically, studying a few key ecological indicators that can be used to represent ecosystem response and recovery.

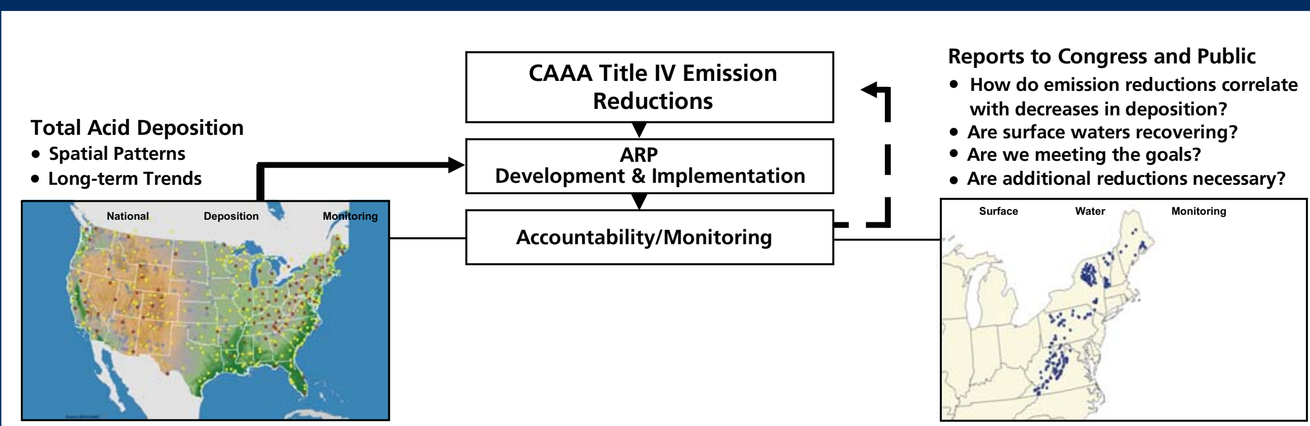
EPA's Temporally Integrated Monitoring of Ecosystems (TIME) and Long-Term Monitoring (LTM) programs are designed to detect trends in the chemistry of lakes or streams in regions sensitive to acid deposition. TIME/LTM monitors a total of 145 lakes and 147 streams, representing all of the major acid sensitive regions of the northern and eastern United States (New England; Adirondack Mountains; northern Appalachian Plateau, including the Catskill Mountains; and the Ridge/Blue Ridge Provinces of Virginia) (see Figure 11). TIME/LTM measures a variety of important chemical characteristics, including acid neutralizing capacity (ANC), pH, sulfate, nitrate, major cations (e.g., calcium and magnesium), and aluminum. The TIME program is the most coherent individual regional dataset for this kind of analysis. In addition, the U.S. Geological Survey has been measuring surface water quality at several research watersheds throughout the United States, where sample collection during hydrologic events and ancillary data on other watershed characteristics have been used to assess the watershed processes controlling acidification of surface waters.



To determine whether decreased emissions have had the intended effect of reducing impacts of acid deposition on ecosystems, EPA links emission trends with data from the CASTNET and NADP networks and the TIME/LTM programs. Combining these links in the "chain of accountability" allows EPA to determine whether emission reductions, and consequent reductions in pollutant deposition, translate into ecological response (i.e., changes in surface water quality necessary to protect fish and other aquatic organisms). This integration of data enables EPA to assess the effectiveness of the ARP in meeting its goal of protecting ecosystems by reducing the adverse effects of acid deposition.

Without long-term monitoring of atmospheric deposition and lake and stream chemistry, EPA would not be able to assess the ecological response to the emission reductions achieved by the ARP. Such monitoring networks are critical for tracking the progress made in restoring and/or protecting sensitive ecosystems under regulatory programs and informing future policy decisions.

Figure 11: National Deposition and Surface Water Monitoring Sites



Source: EPA, 2007

Enhancing Mercury Monitoring Capabilities

In March 2005, EPA promulgated CAMR to reduce mercury emissions from power plants by 2010. In conjunction with CAIR, mercury emission reductions under CAMR are expected to reduce atmospheric concentrations and deposition of mercury. Cutting mercury emissions would also translate to reductions in methylmercury contamination in fish, particularly in mercury-sensitive watersheds throughout many parts of the United States. This reduction would improve the health of people and wildlife that consume fish from these waters. These reductions will be achieved through implementation of a combination of independently operated state programs plus an interstate emission cap and trade program modeled after the ARP.

In order to assess the efficacy of these emerging regulatory programs, scientific information is needed, including a more complete understanding of the fate of mercury emissions with respect to total (i.e., wet and dry) deposition, a quantifiable assessment of the sources contributing to mercury deposition (especially coal-fired power plant emissions), and an assessment as to whether or not mercury "hotspots" exist or may develop over the course of implementing the mercury rules. At present, EPA lacks the ambient mercury concentration and deposition data, particularly on dry deposition in source-impacted areas, to adequately assess the atmospheric mercury changes anticipated from the regulatory programs. In addition, mercury atmospheric data are needed to evaluate and improve mercury model estimates and to facilitate source apportionment analyses.

To meet some of these data needs, EPA is collaborating with NADP, as well as other federal agencies, states, tribes, academic institutions, industry, and other organizations to establish a new, coordinated network for monitoring atmospheric mercury species. The network will measure air concentrations of mercury in its gaseous and particulate forms, event-based mercury wet deposition, and meteorological and land-cover variables needed for estimating dry deposition fluxes. When fully implemented, the network will serve many functions, including:

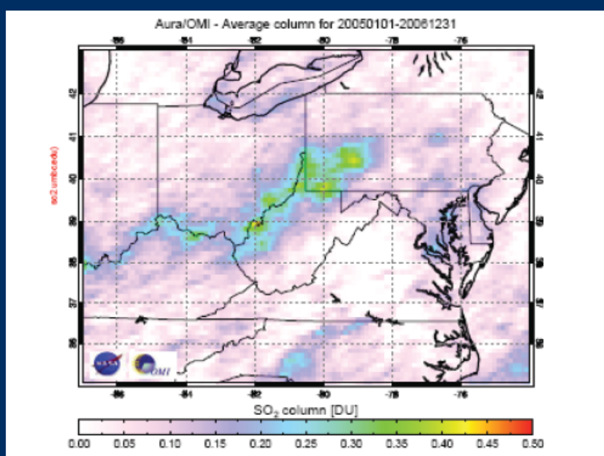
- Facilitate the calculation of wet, dry, and total mercury deposition.
- Provide data for evaluating predictive and diagnostic models and for assessing source-receptor relationships.
- Build a data set for analyzing spatial and temporal trends of ambient mercury concentrations and wet deposition in selected locations.

The network will consist of monitoring stations with a broad range of classifications, including rural, suburban, and urban; near-source/high-emissions; sensitive ecosystems; and regionally representative. Stations will adopt standard operational procedures based on methods developed from EPA and other research efforts. Data will be quality-assured and accessible online. For more information about this effort, please visit the NADP mercury initiative Web site at <http://nadp.sws.uiuc.edu/mtn/>.

Emerging Issues: Remote Assessment Methods

Satellite observations and other remote sensing technologies are emerging as potentially useful new techniques for understanding atmospheric chemistry and analyzing changes in atmospheric pollutant concentrations. For example, the NASA EOS Aura orbiting satellite platform launched in 2004 includes the Ozone Monitoring Instrument (OMI).[7] Researchers have developed an algorithm using the output of this instrument to observe from space the signal of SO_2 gases in the atmosphere near the ground. Using weekly, monthly, or annual average SO_2 concentrations observed by this instrument, maps of degassing and air pollution stationary sources can be generated. SO_2 emissions have been measured by OMI over known sources of air pollution, such as the Ohio River Valley (see Figure 12).

Figure 12: Two-Year Average SO_2 Burdens over the Ohio River Valley



A wealth of data, such as information used in a recent NOAA report on NO_2 observations,[8] as well as the emerging data in the scientific literature on a number of air pollutants, is currently available from satellite observation,[9] and the potential of these sources for analyzing atmospheric chemistry and changes in pollutant emissions provides exciting new opportunities for program assessments.

Air Quality

SO_2

Data collected from monitoring networks show that the decline in SO_2 emissions from the power industry has improved air quality.[10] Based on EPA's latest air emission trends data located at <www.epa.gov/airtrends/index.html>, the national composite average of SO_2 annual mean ambient concentrations decreased 53 percent between 1990 and 2006 as shown in Figure 13. The largest single-year reduction (21 percent) occurred in the first year of the ARP, between 1994 and 1995.

These trends are consistent with the ambient trends observed in the CASTNET network. During the late 1990s, following implementation of Phase I of the ARP, dramatic regional improvements in SO_2 and ambient sulfate concentrations were observed at CASTNET sites throughout the eastern United States, due to the large reductions in SO_2 emissions from ARP sources. Analyses of regional monitoring data from CASTNET show the geographic pattern of SO_2 and airborne sulfate in the eastern United States. Three-year mean annual concentrations of SO_2 and sulfate from CASTNET long-term monitoring sites are compared from 1989-1991 and 2004-2006 in both tabular form and graphically in maps (see Table 5 on page 20 and Figures 17a through 18b on page 28).

The map in Figure 17a shows that from 1989-1991, prior to implementation of Phase I of the ARP, the highest ambient concentrations of SO_2 in the East were observed in western Pennsylvania and along the Ohio River Valley. Figure 17b indicates a significant decline in those concentrations in nearly all affected areas after implementation of the ARP and other programs.

Before the ARP, in 1989-1991, the highest ambient sulfate concentrations, greater than 7 micrograms per cubic meter ($\mu g/m^3$), were also observed in western Pennsylvania, along the Ohio River Valley, and in northern Alabama. Most of the eastern United States experienced annual ambient sulfate concentrations greater than 5 µg/m^3. Like SO_2 concentrations, ambient sulfate concentrations have decreased since the program was implemented, with average concentrations decreasing 35 percent in all regions of the East (see Table 7 on page 27). Both the size of the affected region and magnitude of the highest concentrations have dramatically declined, with the largest decreases observed along the Ohio River Valley (see Figures 18a and 18b on page 28).

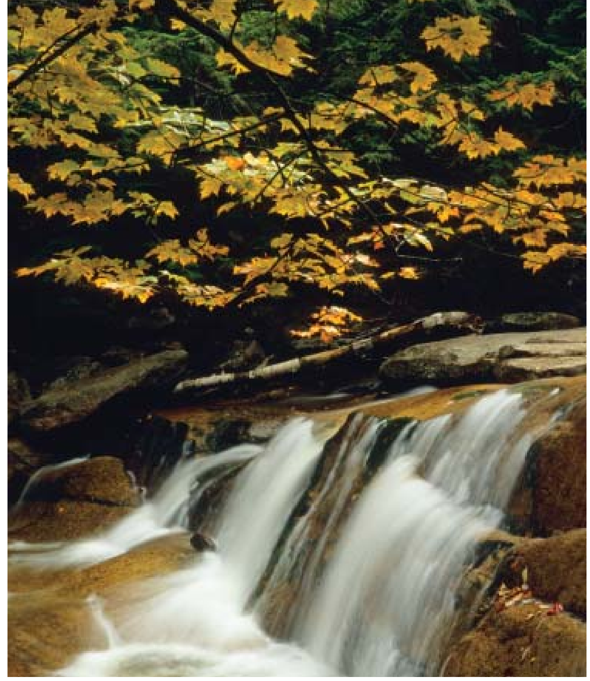
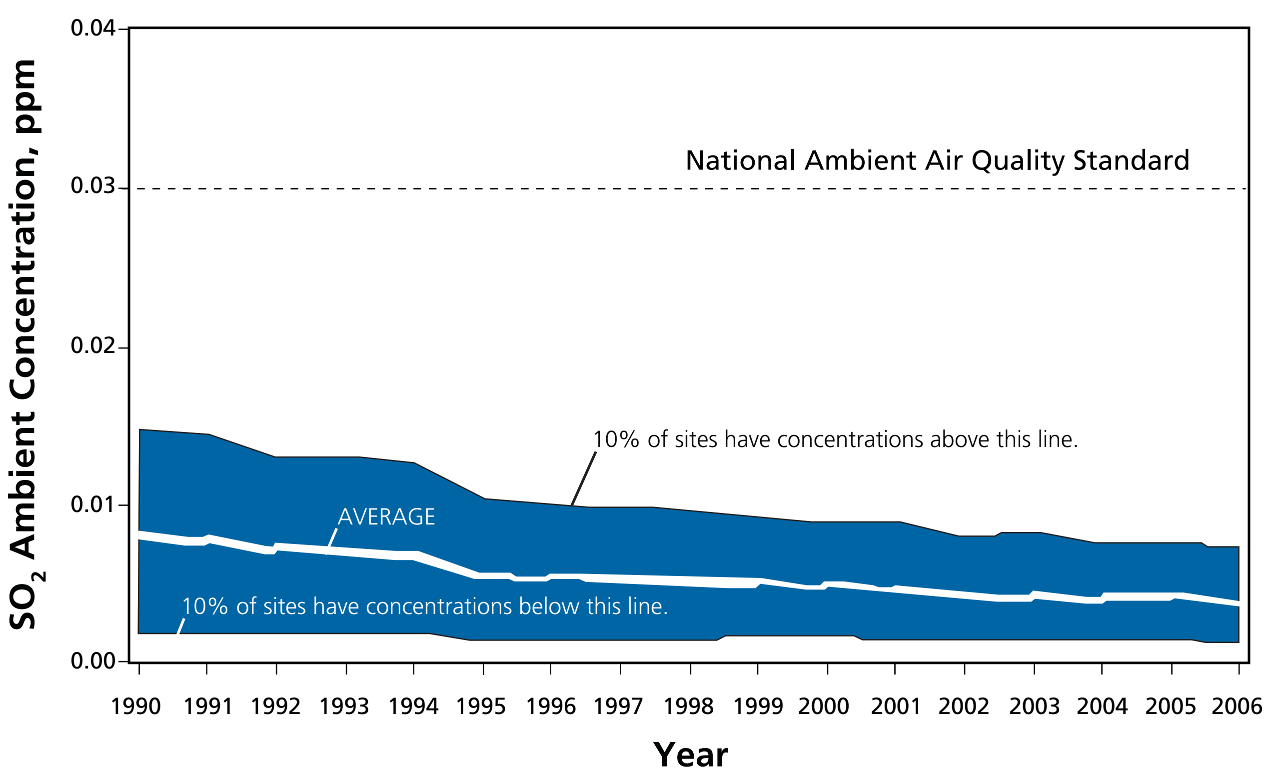


Figure 13: National SO_2 Air Quality, 1990-2006 (Based on Annual Arithmetic Average)



Source: EPA, 2007

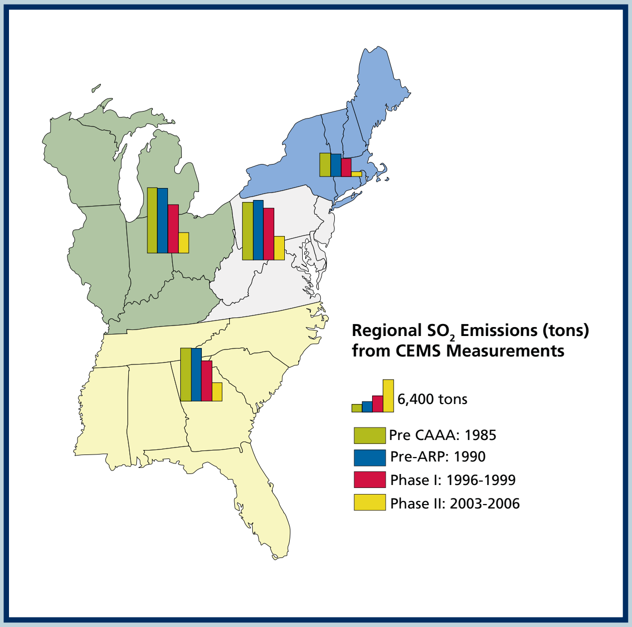
Emerging Issues: Trends in Sulfate Concentrations

Since SO_2 is a precursor to the formation of sulfate, reductions in SO_2 emissions under the ARP were expected to translate into similar reductions in sulfate. Although there is an observed downward trend in the ambient concentration of sulfate since the implementation of the ARP, these reductions have not been as dramatic as those observed for SO_2 emissions and ambient SO_2 concentrations.

The ARP was established to reduce emissions of the two key contributors to the formation of acid deposition, SO_2 and NO_X. As discussed earlier, SO_2 and NO_X emissions can react in the atmosphere to form fine particulates which are harmful to the human respiratory system and damaging to sensitive ecosystems. Sulfate particles are formed after gaseous SO_2 is emitted and oxidized by hydroxyl radical ions. Sulfate particles can then be deposited on the surface (dry deposition) or the particles can react with H_20_2 or O_3 in clouds or fog to form sulfuric acid (H_2SO_4). Sulfuric acid in wet deposition is known as acid rain.

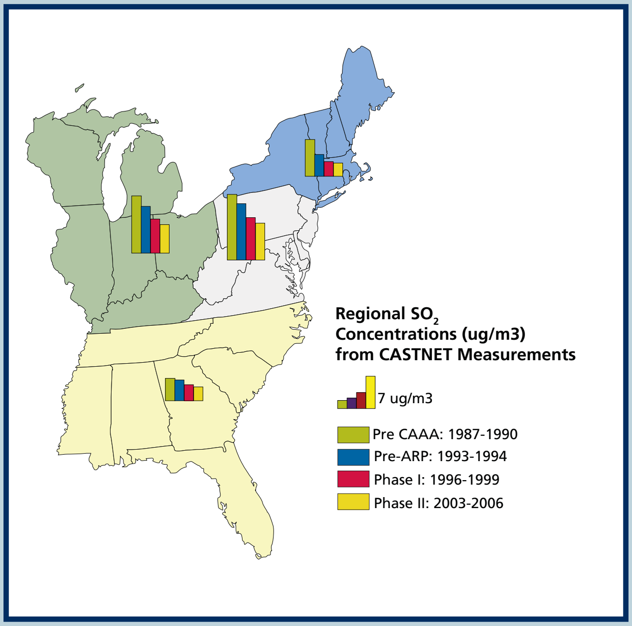
In order to assess environmental results of the ARP, air quality monitoring networks, such as CASTNET, were established to measure ambient concentrations of SO_2 and sulfate. These data, combined with SO_2 emission data from CEMS at ARP-affected sources, provide an idea of how emission reductions under the ARP are translating into reductions in acid deposition over time (see Figures 14 through 16 and Table 7).

Figure 14: Trends in Regional Annual SO_2 Emissions (Coal-fired, Acid Rain Program Units)



Source: EPA, 2007

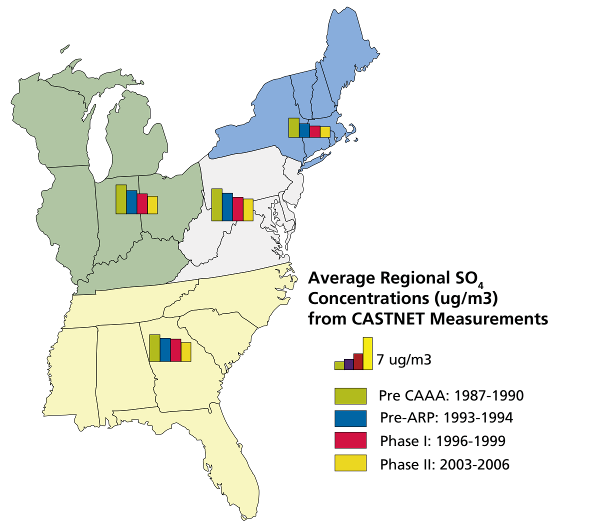
Figure 15: Trends in Regional SO_2 Ambient Concentrations (CASTNET Sites)



Source: EPA, 2007

Further study is necessary to understand the cause of annual changes in ambient sulfate concentrations. A study of meteorological data and multiple species data, such as ozone and ammonia ion concentrations, might provide insight into the factors influencing the rate of sulfate formation and what, if any, additional sources or pollutants might be responsible for the trends in sulfate concentrations in air quality.

Figure 16: Trends in Regional Ambient Sulfate Concentrations (CASTNET Sites)



Source: EPA, 2007

Table 7: Summary of Regional Trends Data (SO_2 Emissions and Ambient SO_2 and Sulfate Concentrations)

Region	Change in SO_2 Emissions	Change in SO_2 Concentration	Change in Sulfate Concentration
	1985* versus 2003-2006	1987-1990 versus 2003-2006	1987-1990 versus 2003-2006
Northeast	-79%	-64%	-43%
Midwest	-68%	-50%	-38%
Mid-Atlantic	-58%	-44%	-33%
Southeast	-66%	-40%	-29%
Total Change in East	-67%	-50%	-35%

* Data are not available for 1987-1989; therefore, 1985 is used for this comparison.

Source: EPA, 2007; CASTNET, 2007

Figure 17a: Annual Mean Ambient SO_2 Concentration, 1989-1991

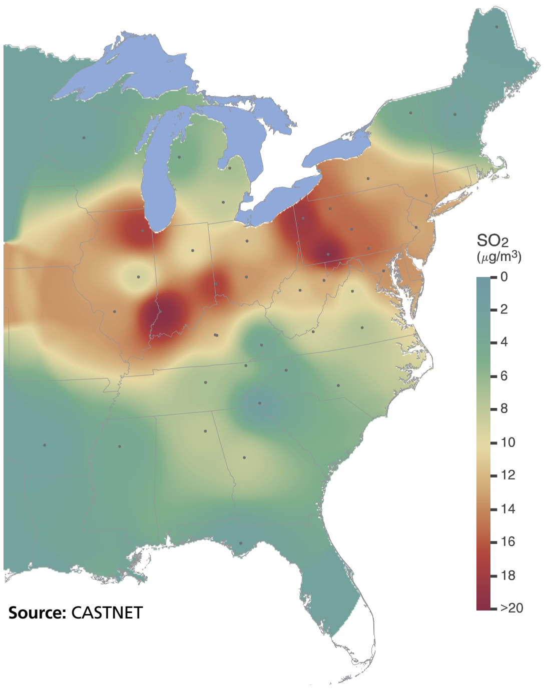


Figure 17b: Annual Mean Ambient SO_2 Concentration, 2004-2006

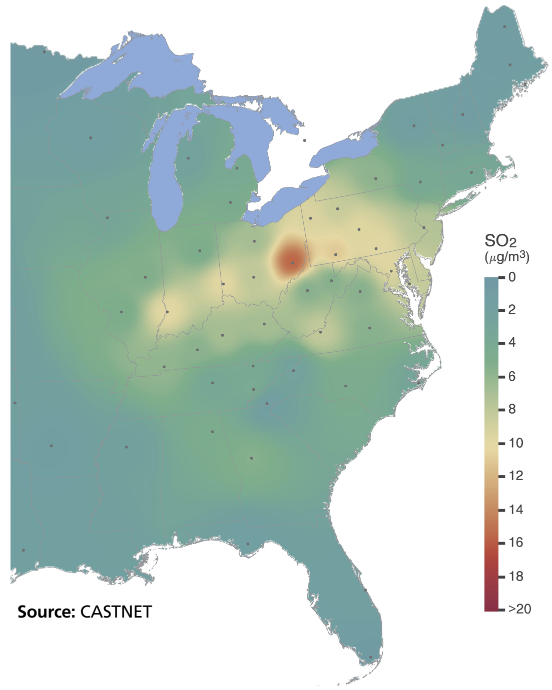


Figure 18a: Annual Mean Ambient Sulfate Concentration, 1989-1991

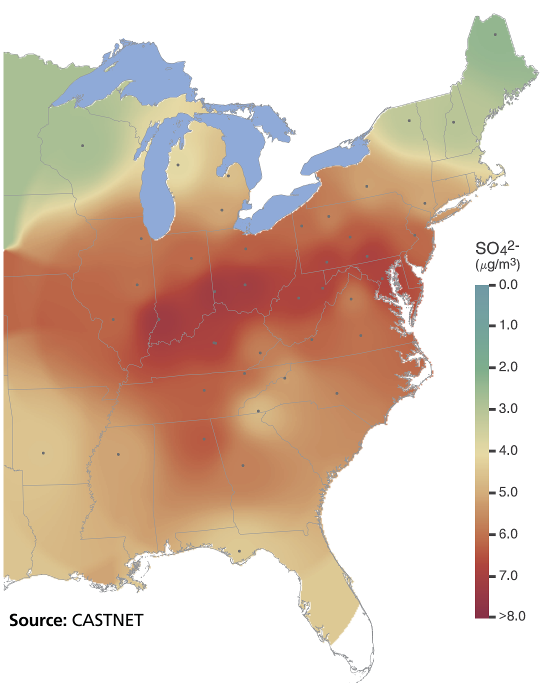
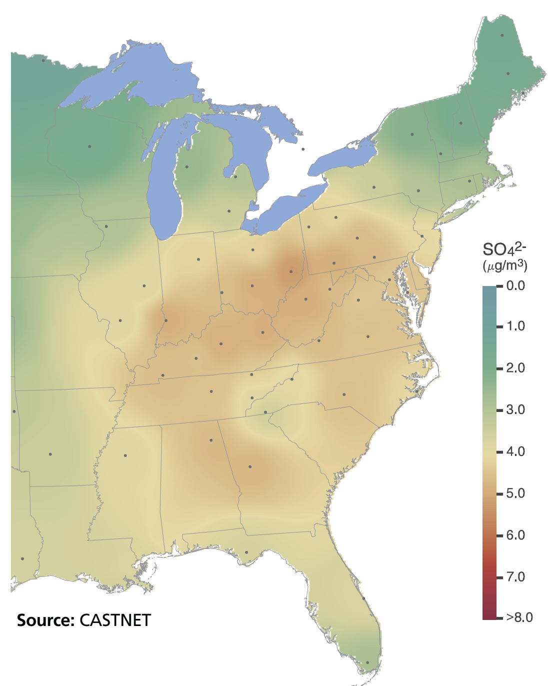


Figure 18b: Annual Mean Ambient Sulfate Concentration, 2004-2006

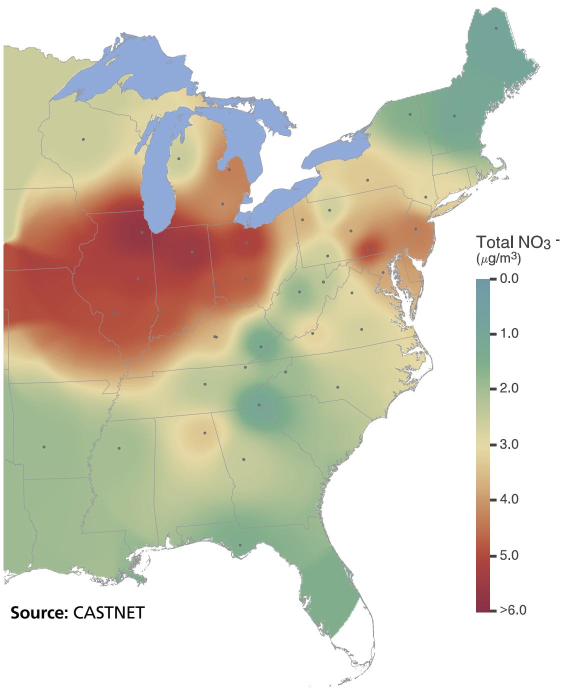


Note: For maps depicting these trends for the entire continental United States, see maps available at <www.epa.gov/castnet/mapindex.html>.

NO_X

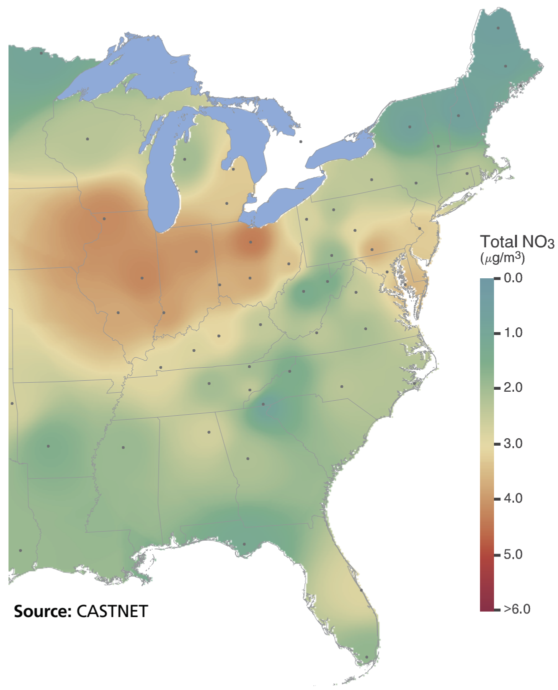
Although the ARP has met its NO_X emission reduction targets, emissions from other sources (such as motor vehicles and agriculture) have led to increased ambient nitrate concentrations in some areas. NO_X levels can also be affected by emissions transported via air currents over wide regions.[11] From 2004 through 2006, reduced ozone season NO_X emissions from power plants under the NO_X SIP Call led to more significant region-specific improvements in some indicators than have been seen in previous years. For instance, annual mean ambient nitrate concentrations for 2004-2006 decreased in the Midwest by nearly 20 percent from the annual mean concentration in 1989-1991 (see Figures 19a and 19b). While these improvements may be partly attributed to added NO_X controls installed for compliance with the NO_X SIP Call, the findings at this time are not conclusive.

Figure 19a: Annual Mean Total Nitrate Ambient Concentration, 1989-1991



Source: CASTNET

Figure 19b: Annual Mean Total Nitrate Ambient Concentration, 2004-2006



Source: CASTNET

Note: For maps depicting these trends for the entire continental United States, see maps available at <www.epa.gov/castnet/mapindex.html>.

Acid Deposition

NADP/NTN monitoring data show significant improvements in some deposition indicators. For example, wet sulfate deposition (sulfate that falls to the earth through rain, snow, and fog) has decreased since the implementation of the ARP in much of the Ohio River Valley and northeastern United States. Some of the greatest reductions have occurred in the mid-Appalachian region, including Maryland, New York, West Virginia, Virginia, and most of Pennsylvania. Other less dramatic reductions have been observed across much of New England, portions of the southern Appalachian Mountains, and some areas of the Midwest. Between the 1989-1991 and 2004-2006 observation periods, average decreases in wet deposition of sulfate averaged around 30 percent for the eastern United States (see Table 5 on page 20 and Figures 20a and 20b). Along with wet sulfate deposition, wet sulfate concentrations have also decreased significantly. Since the 1989-1991 period, average levels decreased 40 percent in the Northeast, 31 percent in the Mid-Atlantic, and 33 percent in the Midwest. A strong correlation between large-scale SO_2 emission reductions and large reductions in sulfate concentrations in precipitation has been noted in the Northeast, one of the areas most affected by acid deposition.

Figure 20a: Annual Mean Wet Sulfate Deposition, 1989-1991

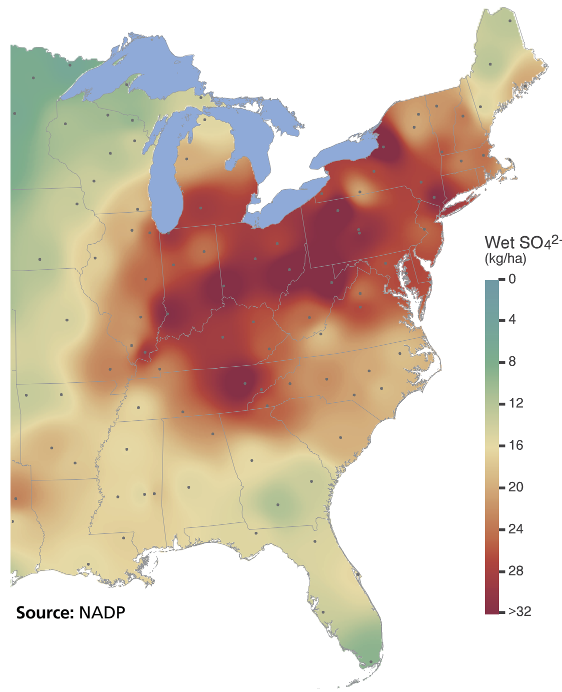
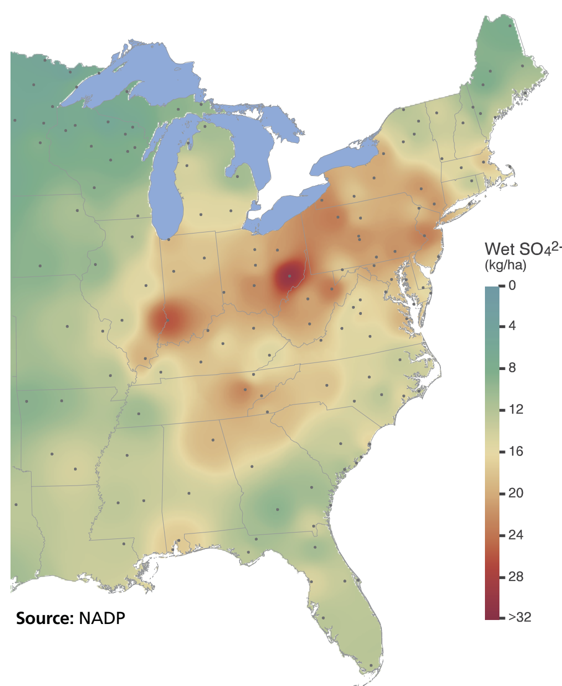
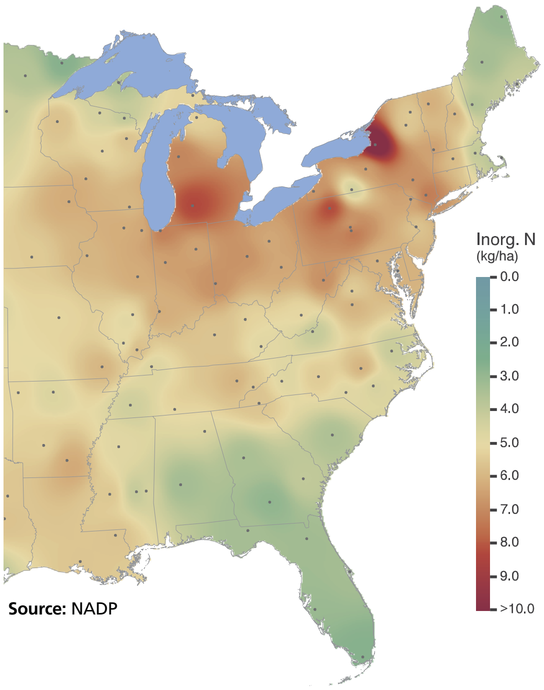


Figure 20b: Annual Mean Wet Sulfate Deposition, 2004-2006



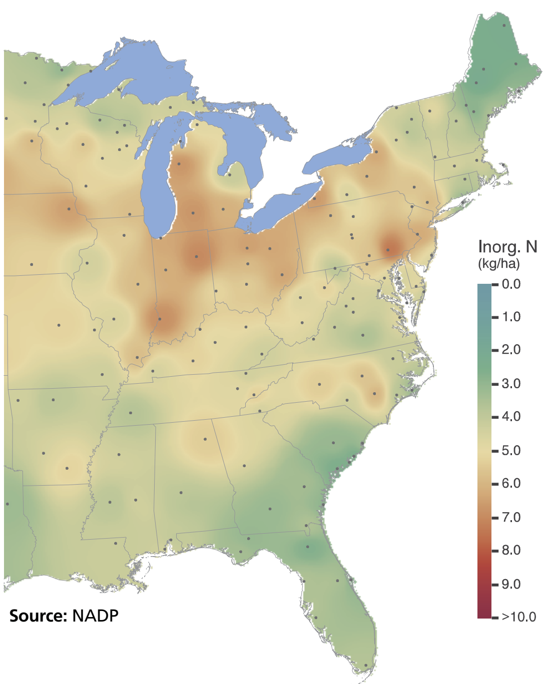
Note: For maps depicting these data for the entire continental United States, see maps available at <www.epa.gov/castnet/mapindex.html>.

Figure 21a: Annual Mean Wet Inorganic Nitrogen Deposition, 1989-1991



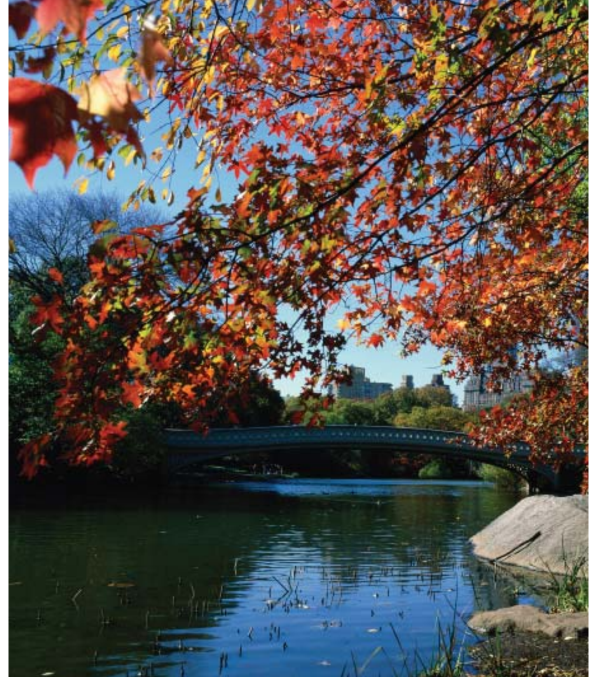
Source: NADP

Figure 21b: Annual Mean Wet Inorganic Nitrogen Deposition, 2004-2006



Source: NADP

Note: For maps depicting these data for the entire continental United States, see maps available at <www.epa.gov/castnet/mapindex.html>.



A principal reason for reduced concentrations of sulfate in precipitation in the Northeast is a reduction in the long-range transport of sulfate from emission sources located in the Ohio River Valley. The reductions in sulfate documented in the Northeast, particularly across New England and portions of New York, were also affected by SO_2 emission reductions in eastern Canada. NADP data indicate that similar reductions in precipitation acidity, expressed as hydrogen ion (H^+) concentrations, occurred concurrently with sulfate reductions, but have not decreased as dramatically due to a simultaneous decline in acid-neutralizing base cations, which act to buffer acidity.

Reductions in nitrogen deposition recorded since the early 1990s have been less pronounced than those for sulfur. As noted earlier, emission trends from source categories other than ARP sources significantly affect air concentrations and deposition of nitrogen. Inorganic nitrogen deposition decreased modestly in the Mid-Atlantic and Northeast but remained virtually unchanged in other regions (see Figures 21a and 21b).

Emerging Issues: Using Critical Loads to Assess Ecosystem Health

A critical load is a quantitative estimate of the exposure to one or more pollutants below which significant harmful effects on specific sensitive elements of the environment do not occur according to present knowledge.

> -From the 1988 United Nations Economic Commission for Europe (UNECE) Protocol Concerning the Control of Nitrogen Oxides or Their Transboundary Fluxes. Accepted by the United States in July 1989.

Recommendations in separate reports of the National Research Council (NRC) and the federal Clean Air Act Advisory Committee (CAAAC) urge EPA to expand its ecosystem protection capacities by exploring issues such as the use of critical loads in the development of secondary NAAQS.

The NRC formed a Committee on Air Quality Management to examine the role of science and technology in the implementation of the CAA and to recommend ways in which the scientific and technical foundations for air quality management in the United States can be enhanced. In its findings and recommendations to EPA, the NRC Committee pointed out the need for alternative air quality standards to protect ecosystems and recommended investigating the use of critical loads as a potential mechanism to address this need.[12] CAAAC echoed the recommendation to examine critical loads as a useful tool for ecosystem protection in its 2005 report to EPA.[13]

Critical loads provide a science-based tool for managers and policymakers to assess the progress made by federal air emission reduction programs, evaluate the impact of potential new emission sources in federally protected areas, and manage sensitive natural resources where air pollution and other disturbances occur. Critical loads were first developed and applied in Europe to address the impacts of acid deposition associated with SO_2 and NO_X emissions. The UNECE Convention on Long-Range Transboundary Air Pollution was signed in 1979. Critical loads were adopted in 1988 as part of the protocol process to address the effects of air pollution on ecosystems, human health, and cultural resources.

In North America, the concept of critical loads was applied in the 1960s with the first Great Lakes Water Quality Agreement, which set lake phosphorus loading limits to reduce eutrophication. Canada established the first critical load for air pollution in the 1980s (for wet sulfate deposition) as part of a U.S.-Canada memorandum on transboundary air pollution. Although the United States was a signatory to the memorandum, critical loads were not used in the United States until 1989, when the U.S. Forest Service applied the critical loads concept as a screening tool to protect air quality in Class I areas.

Over the past five years, there has been renewed interest in critical loads in the United States. Recent critical loads initiatives include the Conference of New England Governors and Eastern Canadian Premiers project to map forest sensitivity to sulfur and nitrogen deposition; the *Federal Land Managers Air Quality Report*, which articulated a commitment to fostering the development of critical loads; a series of meetings known as the "Riverside Meetings" convened by the U.S. Forest Service; and a 2006 multi-agency Critical Loads Workshop.

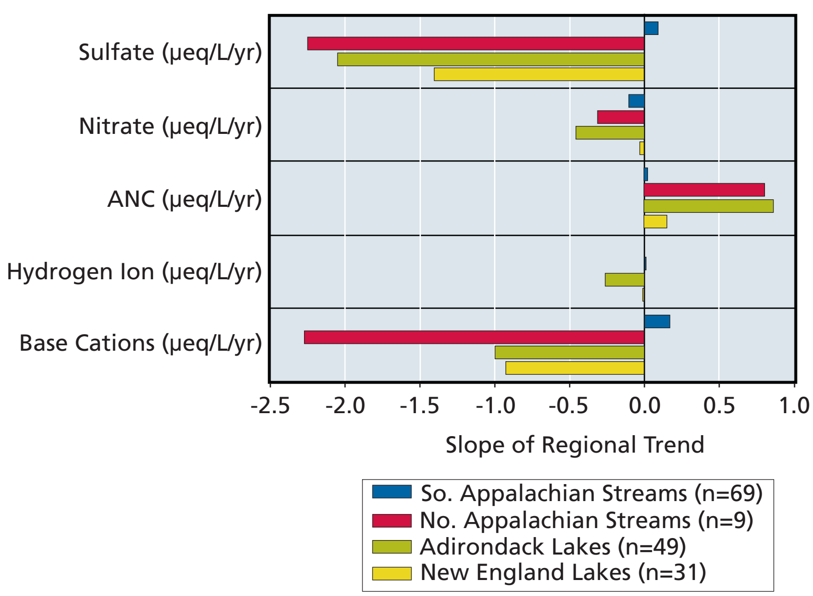
For more information on EPA's assessment-related activities, go to <www.epa.gov/airmarkets>. See also <http://nadp.sws.uiuc.edu/clad/>.

Improvements in Surface Water

Acid rain, resulting from SO_2 and NO_X emissions, is one of many large-scale anthropogenic effects that negatively affect the health of lakes and streams in the United States. Since the implementation of the ARP, scientists have observed measurable improvements in some lakes and streams in four regions of the eastern United States—New England, the Adirondack Mountains, the northern Appalachians (including the Catskill Mountains), and the southern Appalachians (including the Blue Ridge)—and found signs of recovery in many, but not all, of those areas (see Figure 22).[14]

The long-term monitoring networks that exist in these regions provide information on the chemistry of lakes and streams, and a look at how water bodies are responding to changes in emissions. The data presented here show regional trends in acidification from 1990 to 2005 (see Figure 22). For each lake or stream in the network, measurements of various indicators of recovery from acidification were taken. These measurements were plotted against time, and trends for the given lake or stream during the 15-year period were then calculated as the change in each of the measurements per year (e.g., change in concentration of sulfate per year). Using the trends calculated for each water body, median regional changes were determined for each of the measures of recovery. A negative value of the "slope of the regional trend" means that the measure has been declining in the region, while a positive value means it has been increasing. The greater the value of the trend, the greater the yearly change. Movement

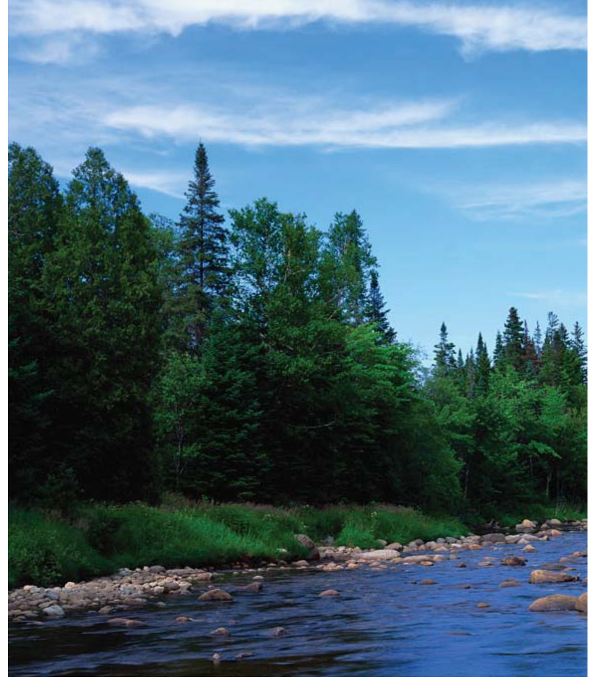
Figure 22: Regional Trends in Eastern Lakes and Streams, 1990-2005



Note: Bars show the magnitude of the regional trend for each variable in each region.

Source: EPA, 2007

toward recovery is indicated by positive trends in acid neutralizing capacity (ANC) and negative trends in sulfate, nitrate, hydrogen ion (measured in micro-equivalents per liter per year [µeq/L/yr]), and aluminum (measured in micrograms per liter per year [µg/L/yr]). Negative trends in base cations (which are weak acid cations in soils, such as calcium, magnesium, and potassium) and positive trends in organic acids can balance out the decreasing trends in sulfate and nitrate and prevent ANC from increasing. The results of these regional trend analyses are shown in Figure 22 on page 33 and Table 8.



Trends in surface water from 1990 to 2005 include:

- Sulfate concentrations are declining substantially in all but one of the regions. In the southern Appalachians, however, sulfate concentrations are increasing. This region is unusual because its soils can store large amounts of sulfate deposited from the atmosphere. Only after large amounts of sulfate have accumulated in the soils do stream water sulfate concentrations begin to increase, remaining elevated until the stored sulfur is depleted. This phenomenon is now being observed in the southern Appalachians, despite decreasing sulfate in atmospheric deposition. Still, due to inclusion of the latest data, the magnitude and direction of the trends in this region are substantially changed from the *2005 Acid Rain Program Progress Report*.

Table 8: Results of Regional Trend Analyses on Lakes and Streams, 1990-2005*

Chemical Variable	New England Lakes (n = 31)	Adirondack Lakes (n = 49)	No. Appalachian Streams (n = 9)	So. Appalachian Streams (n = 69)
Sulfate (µeq/L/yr)	**-1.42**	**-2.07**	**-2.30**	+0.09
Nitrate (µeq/L/yr)	**-0.03**	**-0.37**	**-0.31**	**-0.10**
Acid Neutralizing Capacity (µeq/L/yr)	+0.15	**+0.93**	**+0.80**	+0.08
Base Cations (µeq/L/yr)	**-0.93**	**-1.19**	**-2.25**	+0.17
Hydrogen Ion (µeq/L/yr)	**-0.01**	**-0.24**	+0.01	-0.01
Organic Acids (µeq/L/yr)	**+0.04**	**+0.15**	-0.06	insufficient data
Aluminum (µg/L/yr)	insufficient data	**-4.72**	insufficient data	insufficient data

* Values show the slope of the regional trend (the median value for the trends in all of the sites in the region). Regional trends that are statistically significant are shown in bold.

Source: EPA, 2007

Trend estimates using previous data (through the early 2000s) were heavily influenced by gypsy moth defoliation of trees in most of the region's watersheds, particularly affecting trends in ANC, sulfate, and nitrate. As ecosystems have recovered from the impacts of this defoliation event, the extent of deposition impacts on this region appear less severe than in past years.

- Nitrate concentrations are decreasing significantly in all of the regions. This trend does not appear to reflect changes in emissions or deposition in these areas and is likely a result of ecosystem factors.

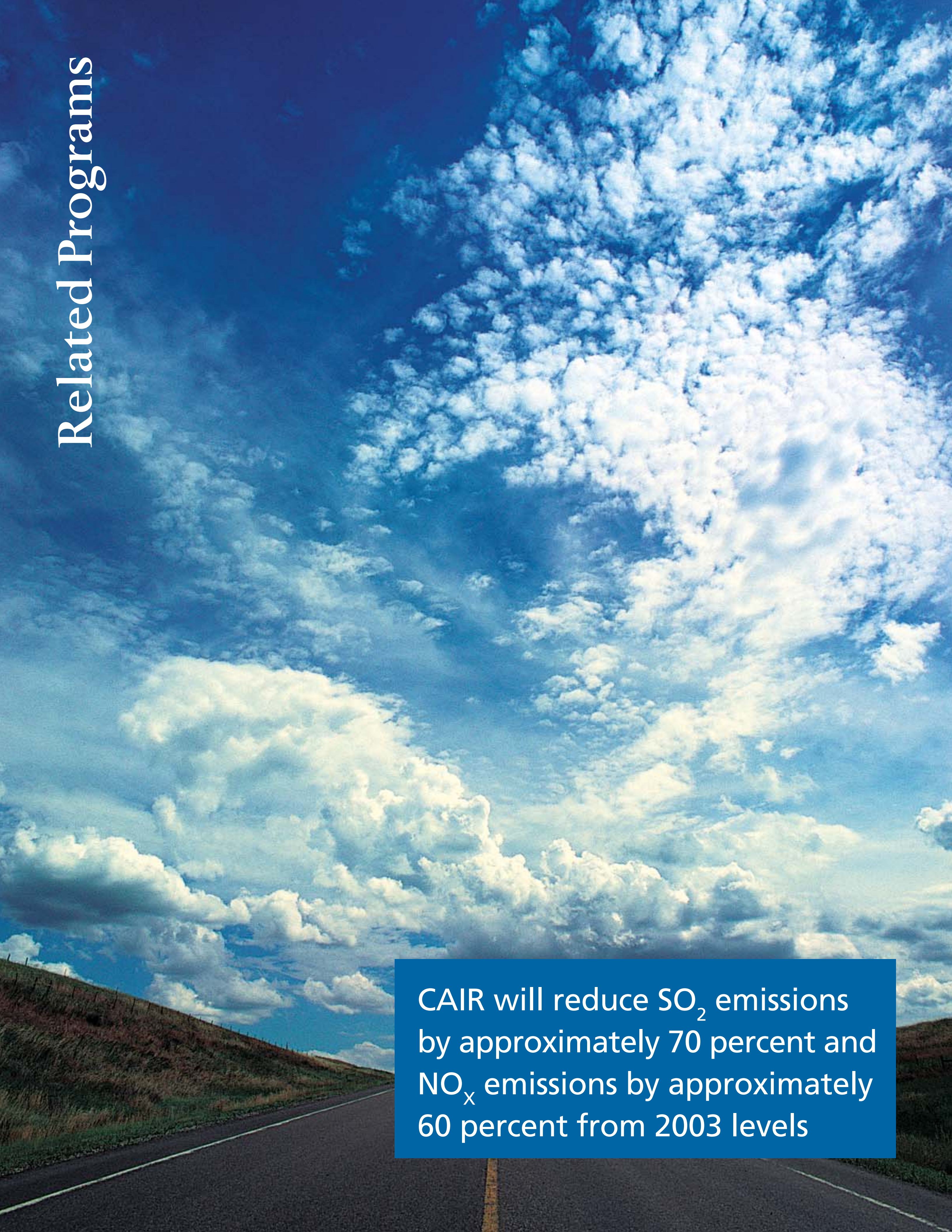
- The acidity of lake and stream water, as indicated by ANC trends, is decreasing in three of the four regions as a result of declining sulfate (and to some extent nitrate).

- Base cations are decreasing in the northern Appalachians, Adirondack Lakes, and New England Lakes. This may be a concern because, although base cation concentrations in lakes and streams are expected to decrease when rates of atmospheric deposition decline, if they decrease too much, they limit recovery in pH and ANC.

- Concentrations of organic acids, natural forms of acidity, are currently increasing in many parts of the world, but the cause is still being debated. Increases in organic acids over time can limit the amount of recovery observed. Only the New England and Adirondack regions are showing significant increases in organic acids, which may be responsible for 10-15 percent less recovery (in ANC) than expected.

- Aluminum is a critical element because it increases when lakes and streams acidify, and is very toxic to fish and other wildlife. The one region where good aluminum data exist (the Adirondacks) is showing strong declines in the most toxic form of aluminum (inorganic monomeric aluminum).

Related Programs



CAIR will reduce SO_2 emissions by approximately 70 percent and NO_x emissions by approximately 60 percent from 2003 levels

Understanding Clean Air Rules

Rule Background

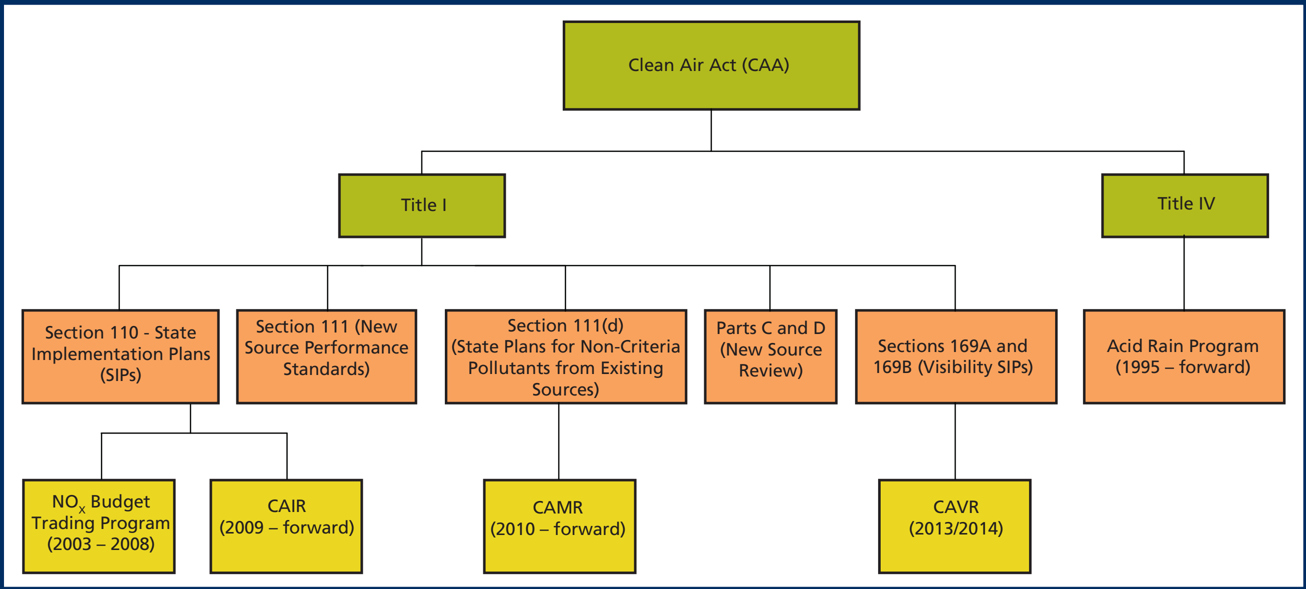
Building on the ARP and NBP, EPA finalized CAIR in 2005, requiring further SO_2 and NO_X emission reductions in 28 eastern states and the District of Columbia. CAIR will reduce region-wide SO_2 emissions by approximately 70 percent and NO_X emissions by approximately 60 percent from 2003 levels to prevent significant contribution to nonattainment in downwind ozone and $PM_{2.5}$ nonattainment areas. CAIR includes emission budgets for each jurisdiction based on application of highly cost-effective controls to fossil fuel-fired EGUs in model cap and trade programs with two phases of reductions. However, states have discretion in deciding which sources to control to meet the budget, and whether to participate in the federally run cap and trade programs delineated in the model rules.

Rules and Programs to Ensure Further Improvements

A combination of well-established, existing programs, and new regulations that will soon begin implementation, are in a position to address the interstate transport of ozone, fine particles, and mercury deposition. Together, these rules and programs will help ensure further improvements in human health and environmental protection. Along with the ARP, the NO_X SIP Call in the eastern United States and the Tier 2 mobile source and diesel rules establish programs that will help states achieve the ozone and fine particle NAAQS.

In the spring of 2005, EPA promulgated a suite of air quality rules designed to achieve additional reductions of SO_2, NO_X, and mercury from power plants. These rules include CAIR, CAMR, and CAVR.[15] See Figure 23 for a flow-chart showing how the power sector rules are connected.

Figure 23: Key Clean Air Rules Related to Electric Power Industry



Source: EPA, 2007

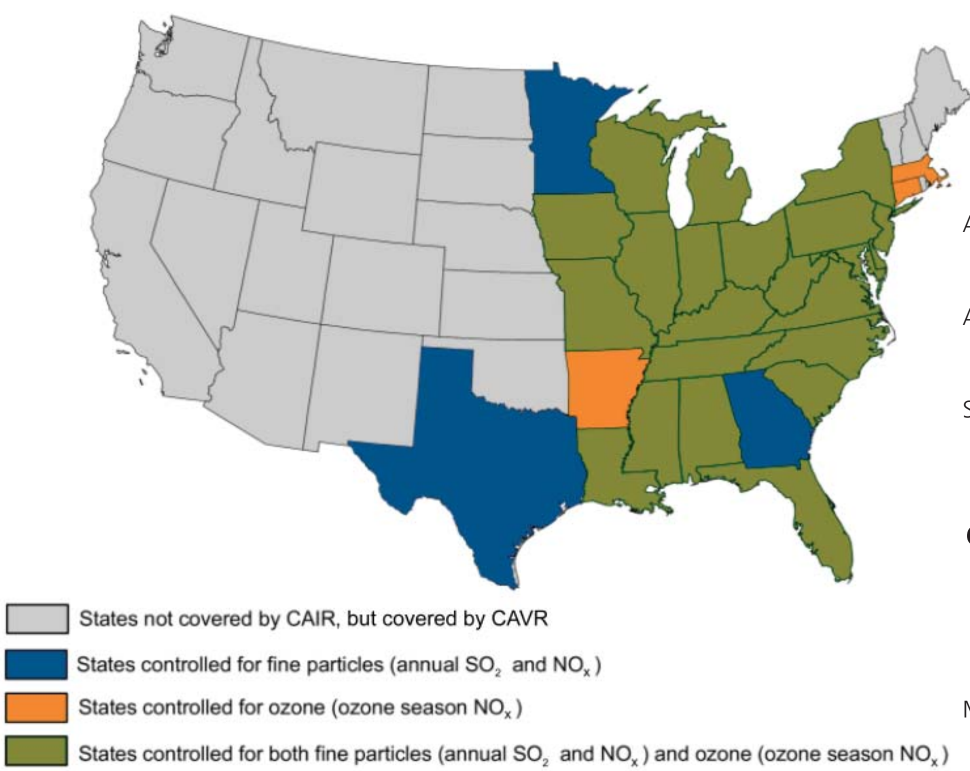
To address their contribution to unhealthy levels of fine particles in downwind states, CAIR requires 25 eastern states and the District of Columbia to reduce and cap annual SO_2 and NO_X emissions.

In addition, CAIR requires 25 eastern states and the District of Columbia to reduce and cap ozone season (May through September) NO_X emissions to address their contribution to unhealthy levels of 8-hour ozone. As shown in Figure 24, most states covered under CAIR are required to address contributions to both $PM_{2.5}$ and ozone nonattainment, and therefore reduce annual SO_2 and NO_X emissions as well as seasonal NO_X emissions. These reductions will help states attain the NAAQS for ozone and fine particles in most areas that were designated as being in nonattainment as of April 2006 (see Figure 25).

All the states covered under CAIR have chosen to participate in the trading programs for SO_2 and NO_X. Some states also have direct control programs that complement the trading programs.

Generally, the CAIR model rules include fossil fuel-fired boilers and combustion turbines serving an electric generator with a nameplate capacity greater than 25 MW and producing electricity for sale. These are generally the same types of sources as covered under the ARP and NO_X SIP Call. However, the universe of CAIR sources is somewhat more inclusive in two ways. First, CAIR affects some sources that either permanently (e.g., simple-cycle turbines and certain cogeneration units) or temporarily (e.g., independent power producers, or IPPs, with power-purchase agreements in effect) were exempt from the ARP. EPA included these units because they were designed and

Figure 24: States Covered under CAIR/CAVR/CAMR for SO_2, NO_X, and Mercury



All states, plus 2 tribes and the District of Columbia, are covered by CAMR.

CAIR Emission Caps*
(million tons)

	2009/2010	2015
Annual SO_2 *(2010)*	3.7	2.6
Annual NO_X ***(2009)***	1.5	1.3
Seasonal NO_X *(2009)*	0.6	0.5

**for the affected regions*

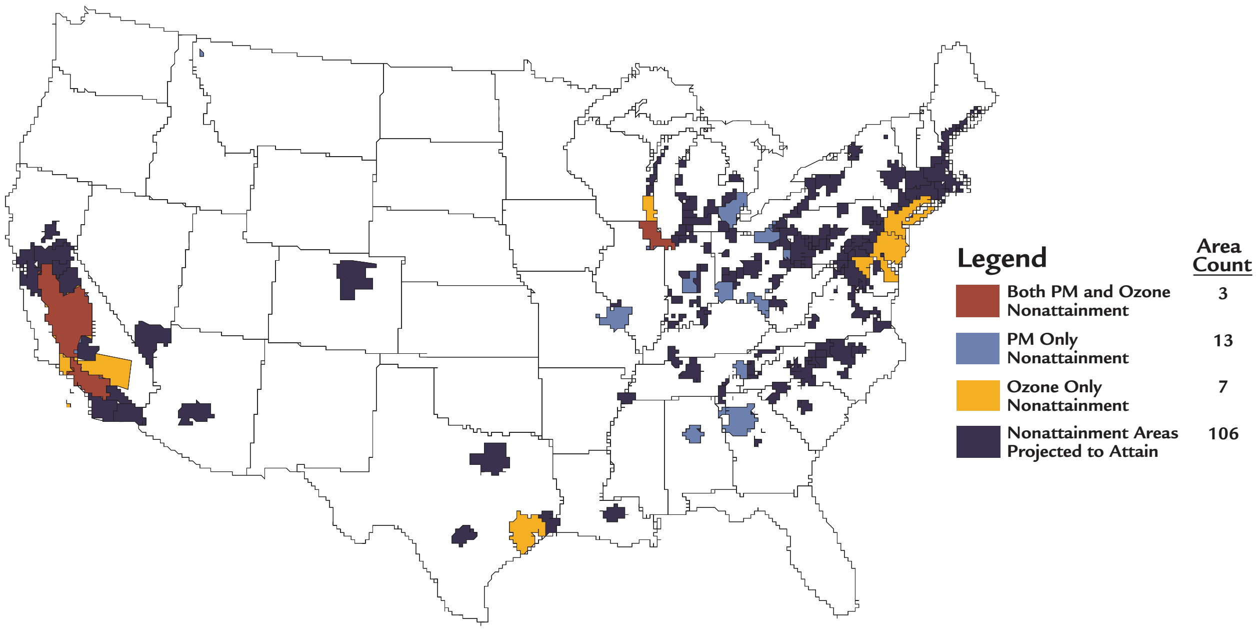
CAMR Annual Emission Caps*
(tons)

	2010	2018
Mercury	38	15

CAVR
Outside of CAIR Region — BART

Source: EPA, 2007

Figure 25: Projected Nonattainment Areas in 2020 After Reductions From CAIR, CAVR, and Clean Air Act Programs



Note: Figure 25 depicts 129 areas that, as of April 2006, were in nonattainment of the $PM_{2.5}$ or ozone NAAQS (or both). As indicated in the legend, 106 of those areas are projected to attain the applicable NAAQS by 2020 as a result of existing programs, such as Title IV of the Clean Air Act, the NO_X SIP Call, some existing state rules, and the addition of CAIR and CAVR. Note that the 23 areas that are forecast to remain in nonattainment may need to adopt additional local or regional controls to attain the NAAQS by the dates set pursuant to the CAA. These additional local or regional measures are not forecast in Figure 25, and therefore the figure overstates the extent of expected nonattainment in 2020.

Source: EPA, 2006

operated to be in the business of producing electricity for sale and were part of the universe of sources that EPA demonstrated could reduce emissions in a highly cost-effective manner for purposes of CAIR.

Second, CAIR affects some power-generating sources that were not regulated under the NO_X SIP Call because the CAIR definition of "fossil-fuel-fired" is consistent with the definition used in the ARP (i.e., combusting any fossil fuel is considered "fossil fuel-fired"). The NO_X SIP Call definition only considers a source to be "fossil fuel-fired" if more than 50 percent of annual heat input results from combusting fossil fuels.

The majority of the approximately 320 new sources expected to be affected under CAIR are simple-cycle combustion turbines outside the NO_X SIP Call region that came online prior to 1991. Most of the others are IPP units or cogeneration units that were exempt from the ARP. Table 9 on page 40 delineates the expanding coverage of electricity generators from the ARP to CAIR and CAMR.

How the New Trading Programs Work

States had the choice of participating in the federal cap and trade programs to reduce SO_2 and NO_X emissions and all have elected to do so. The result is a larger seasonal NO_X program beginning in 2009, a new annual NO_X program beginning in 2009, and a new SO_2 program in the CAIR region with a tighter, regional cap in 2010. All three new CAIR programs require additional reductions in 2015 (See timeline in Figure 26 on page 41). States can either submit state plans for EPA approval or come under a federal plan that also serves as a backstop to enter the program. The state plans can use EPA's model trading rules, with

Table 9: Overview of Fossil Fuel-Fired Electricity Generators Covered under EPA's Cap and Trade Programs

	ARP		NBP	CAIR		CAMR
				$PM_{2.5}$	Ozone	
	Annual SO_2	Annual NO_X	Summer NO_X	Annual NO_X and SO_2	Summer NO_X	Annual Mercury
Basic Applicability	>25 MW	>25 MW coal-fired utility boilers that burned coal between 1990 – 95	>25 MW (but OTC states may be >15 MW) and certain non-EGUs greater than 250 mmBtu/hr	>25 MW	>25 MW and certain non-EGUs greater than 250 mmBtu/hr*	>25 MW, coal-fired
Exceptions	Certain IPPs, cogens, qualifying facilities, and simple cycle turbines	Same as SO_2 plus some boiler types	Certain cogens, plus units that burn less than 50% fossil fuel	Certain cogens (different than NBP)	Certain cogens (different than NBP)	Certain cogens (same as CAIR)
Geographic coverage	48 contiguous states + DC	48 contiguous states + DC	20 states + DC	25 states + DC	25 states + DC	50 states + DC + 2 tribes

* States in the NBP can expand their CAIR NO_X ozone season program applicability to include non-EGUs in the NBP.

Source: EPA, 2007

state-specific approaches to allocating NO_X allowances, allowing sources to opt-in, and including industrial sources that are subject to the NO_X SIP Call trading program. The federal backstop program was published in May 2006 and went into effect in June 2006. Therefore, the regulated community has faced CAIR requirements that have been in effect since June 2006.

Under Title IV of the CAA, the ARP will continue to operate even after the new regional CAIR SO_2 trading program begins in 2010. (Title IV NO_X requirements also remain unchanged under CAIR.) Sources will use Title IV SO_2 allowances to demonstrate compliance with annual CAIR requirements as well as with annual Title IV requirements. As a result, banked Title IV allowances can be used for CAIR compliance, and sources in all states subject to CAIR for SO_2 will be subject to two SO_2 trading programs that share the same currency.

Under CAIR, however, one allowance does not always cover one ton of emissions. Instead, for purposes of CAIR, SO_2 allowances of vintage 2009 and earlier will each cover one ton of emissions; vintage 2010 - 2014 allowances will authorize 0.50 tons of emissions; and vintage 2015 or later allowances will authorize 0.35 tons of emissions. These ratios achieve the more stringent reductions required under CAIR, maintain the value of ARP allowances, and make ARP compliance a foregone conclusion with CAIR compliance.

The NBP will cease to operate with the start of the seasonal NO_X trading program under CAIR in 2009. Sources in most CAIR states will be subject to two separate CAIR NO_X trading programs: an annual NO_X program for $PM_{2.5}$ control and a seasonal NO_X program for ozone control. However, these two programs will not share currency, as CAIR annual and ozone season NO_X allowances are not interchangeable.

EPA will provide NO_X emission allowances to each state according to the state budget for each program. States covered by both programs will allocate both annual and seasonal allowances to sources (or other entities).

The CAIR seasonal NO_X program allows the use of banked allowances from the NO_X SIP Call, just as the CAIR SO_2 program allows the use of banked allowances from the ARP. The annual NO_X trading program includes a limited compliance supplement pool of allowances to be awarded for early reductions in 2007 and 2008, or to address issues of reliability of electricity supply in 2009.

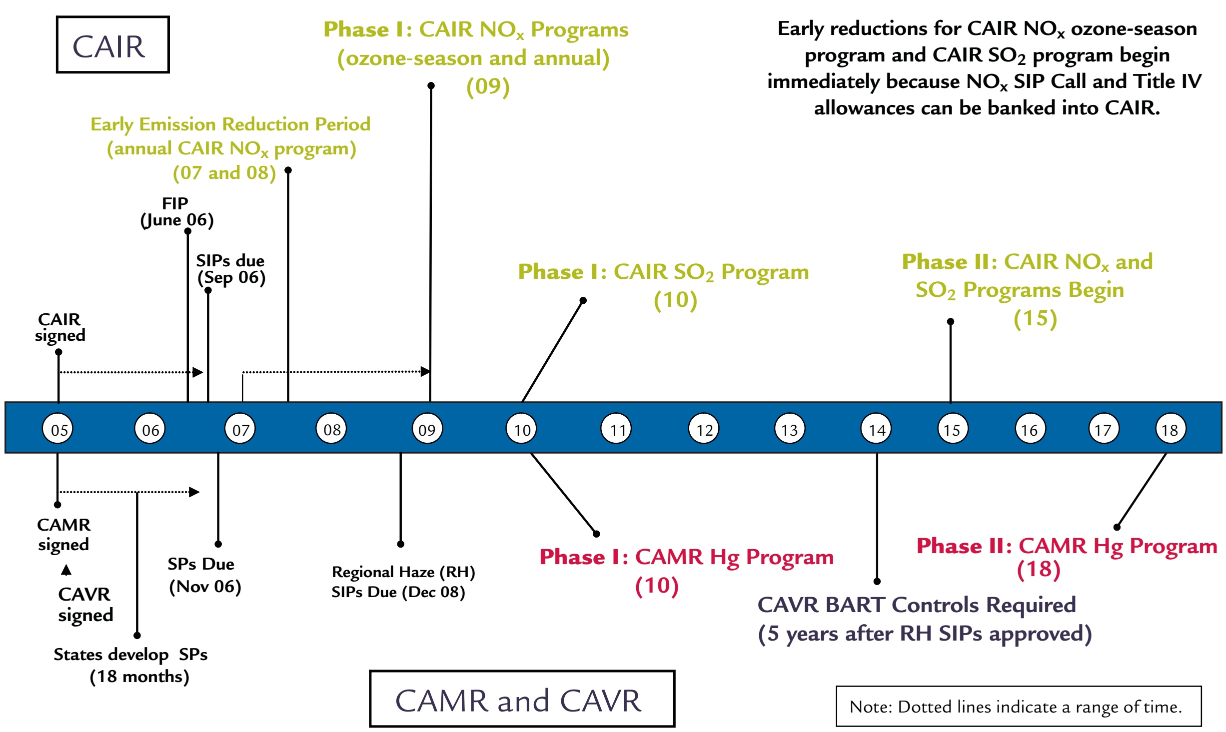
The structure of the CAIR programs and, in particular, the provisions allowing use of banked allowances from ARP and NBP, exemplify EPA's effort to ensure an orderly transition to CAIR's trading programs and strongly encourage early reductions. There is a substantial incentive for sources to begin complying with CAIR immediately, and emissions already have dropped as a result.

CAIR Allowance Market and State Activity

Although there will be two distinct markets, EPA expects that the prices in both the annual and seasonal markets will be established by the cost of controls for annual compliance. There has been trading activity in the 2009 seasonal NO_X market and limited annual NO_X CAIR market trading. Observers expect that active trading will not occur until CAIR SIPs have been approved and NO_X allowance accounts are populated later this year.

For both the SO_2 and NO_X markets, it will take time for buyers and sellers to continue to assess the fundamentals of the changes introduced by CAIR, but this is secondary to the achievement of

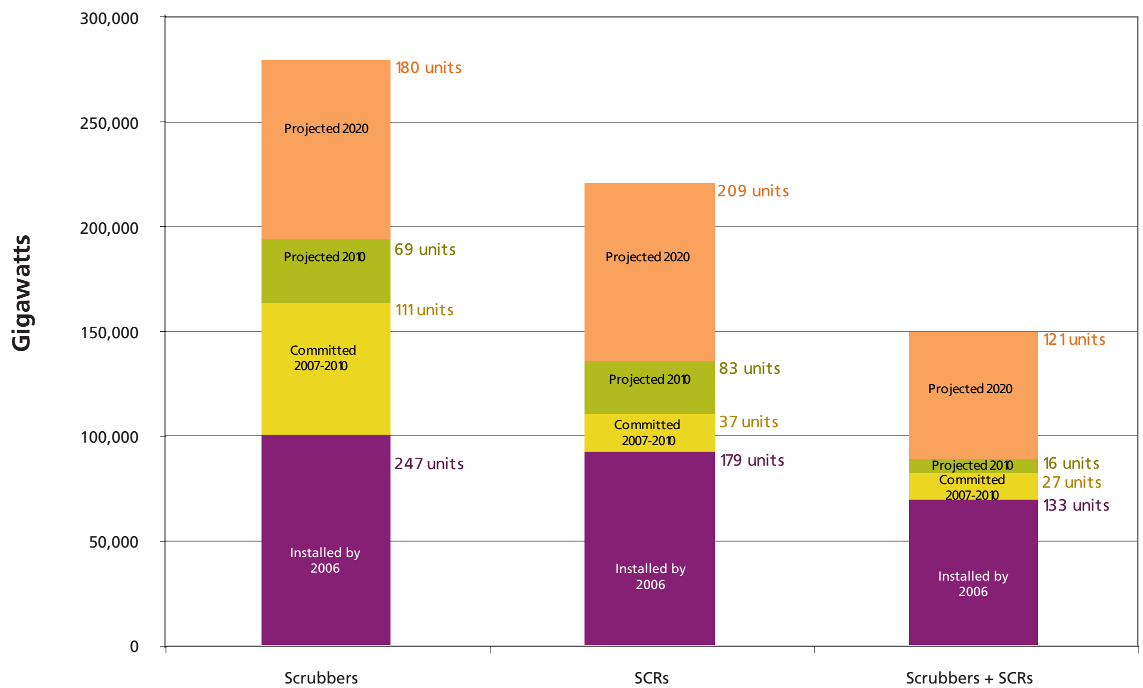
Figure 26: Timeline for Implementation of CAIR/CAMR/CAVR (2005-2018)



Note: During the CAIR annual NO_x program early emission reduction period, owners may earn additional allowances available through a compliance supplement pool established under EPA's CAIR rulemaking.

Source: EPA, 2007

Figure 27: Current and Projected SO_2 Scrubber and NO_X SCR Controls on Coal-fired EGUs



Note: Existing, committed, and projected controls are due to existing programs as well as CAIR, CAMR, and CAVR.

Source: EPA, for IPM, 2007

the environmental accountability and results of the program. CAIR required covered states to submit SIPs to EPA by September 2006. The agency also promulgated a federal implementation plan (FIP) that implements the model trading rules for every CAIR state and offered to leave it in place for states not wishing to submit a SIP. EPA expects all 29 affected jurisdictions to participate in the EPA-run trading programs.

States have some flexibility in participating in the trading programs, including determining NO_X allowance allocations independently. Nearly all states submitting SIPs thus far have established their own allocation methodologies, often including special set-asides for new sources and for various state priorities, like renewable energy or add-on emission controls. In some cases, states roll any unclaimed set-aside allowances back into the main allowance pool; others hold them over for possible distribution in the future.

States may also choose to allow participation by non-EGUs from the NBP and can allow other units to opt-in using methodologies in the CAIR model rules. Of the 19 states plus the District of Columbia that are subject to both the NO_X SIP Call and CAIR (note that Rhode Island was included in the former, but not the latter), all but five have indicated they will include the NBP's non-EGUs in the CAIR NO_X ozone season program. Most states thus far have chosen not to include the model rule provisions that allow sources to opt-in.

Whether sources in a state are subject to a SIP or a FIP, there will be initiation of the allocation of NO_X allowances under CAIR by the end of this year (SO_2 allowances already have been allocated under Title IV).

Figure 27 shows advanced SO_2 and NO_X controls already in place in the CAIR region, as well as those controls that facilities have already committed to install or that are projected under CAIR with additional consideration of CAMR and CAVR requirements.

CAMR

CAMR requires all 50 states, the District of Columbia, and two tribes to regulate mercury emissions from coal-fired EGUs. CAMR establishes "standards of performance" limiting mercury emissions from new and existing coal-fired power plants and, like CAIR, creates a model cap and trade program with two phases of reductions. The first phase cap is 38 tons, taking advantage of "co-benefit" reductions—mercury reductions achieved by reducing SO_2 and NO_X emissions under CAIR—to fulfill EPA's requirement to act on mercury emissions. The second phase, beginning in 2018, goes further to reduce emissions to 15 tons upon full implementation. CAMR sets an emission reduction requirement in the form of an annual budget for each state and two tribes in accordance with the two caps.

New coal-fired power plants will have to meet new source performance standards in addition to being subject to the caps. EPA established annual budgets for each state, and states must ensure that current and future mercury emissions from coal-fired EGUs do not exceed the annual state budget. Like CAIR, CAMR does not exempt the units that may be exempt under the ARP. The summary of applicability across programs in Table 9 on page 40 includes general CAMR applicability for comparison.

Furthermore, under CAMR, affected coal-fired electric utility units will be required to continuously monitor mercury mass emissions for the first time, regardless of whether or not they will be participating in the trading program. Monitoring technologies will be subject to rigorous certification and quality assurance/quality control requirements under 40 CFR Part 75. Affected sources are required to install and certify continuous emissions or sorbent trap monitoring systems by January 1, 2009.

This new requirement is one of the primary areas of focus for EPA's CAMR implementation efforts. Recent work by both EPA and industry has advanced mercury monitoring systems, reference testing methods, and calibration standards to a point that measuring capabilities that had limited feasibility a few years ago now are fully or nearly ready and even commercially available. Over the past year, the performance and reliability of mercury monitoring systems have substantially improved as a result of field demonstrations and testing by EPA and industry. EPA continues to work closely with the regulated community, monitoring equipment and software vendors, academia, and other organizations to ensure timely implementation of a technically sound, effective CAMR mercury monitoring program.

The Mercury Trading Program and State Activity

The trading program under CAMR will work similarly to existing programs and the SO_2 and NO_X programs under CAIR, with two notable differences between the CAMR and CAIR trading programs. First, there are no opt-in provisions included in CAMR; second, allowances under CAMR are measured in ounces rather than tons.

Even with some states choosing to control mercury emissions directly, EPA expects a robust trading program. In July 2006, EPA conducted limited modeling meant to be illustrative of a reduced market based on the states and tribes EPA projected would participate in the national trading program at the time. This more limited market represents states that allocated close to 69 percent of the initial budget of mercury allowances and comprises more than 700 units. These units represent more than 200 GW of capacity—nearly equivalent to the number of coal-fired units in the successful NBP across a larger number of states. As with the NBP, EPA expects a viable market will result.

Based on this modeling, prices for mercury allowances are expected to be the same as or lower than prices in a full national market. This is because several states that would have required relatively large amounts of mercury allowances to comply with CAMR, such as Illinois, will not be participating. Overall, states opting to participate in the trading program generally are characterized by larger percentages of coal-fired generation. Moreover, 21 states submitted state plans to EPA by the November 2006 CAMR deadline, and additional state plans have been received since. The remaining states are actively working on plans. Of all affected jurisdictions, 35 states and two tribes are planning on participating in the CAMR trading program. Twelve states have indicated they will not participate in the trading program, and at least one state is still undecided. Three states (Idaho, Vermont, and Rhode Island) and the District of Columbia do not have any coal-fired EGUs and thus have zero budgets.

States not participating in the trading program must ensure they meet their state budget with other methods. Alternatives often involve control requirements based on percent reduction provisions determined through an analysis of control options that states have evaluated as feasible. Some states have chosen to do this in phases like EPA has, though the start of the second phase is accelerated in some cases. Unlike a capped program, percent reduction programs do not necessarily guarantee emissions will remain below a state's budget, often because of the uncertainty of new source growth over time. Therefore, states are often coupling these programs with caps to ensure the state's budget will be maintained.

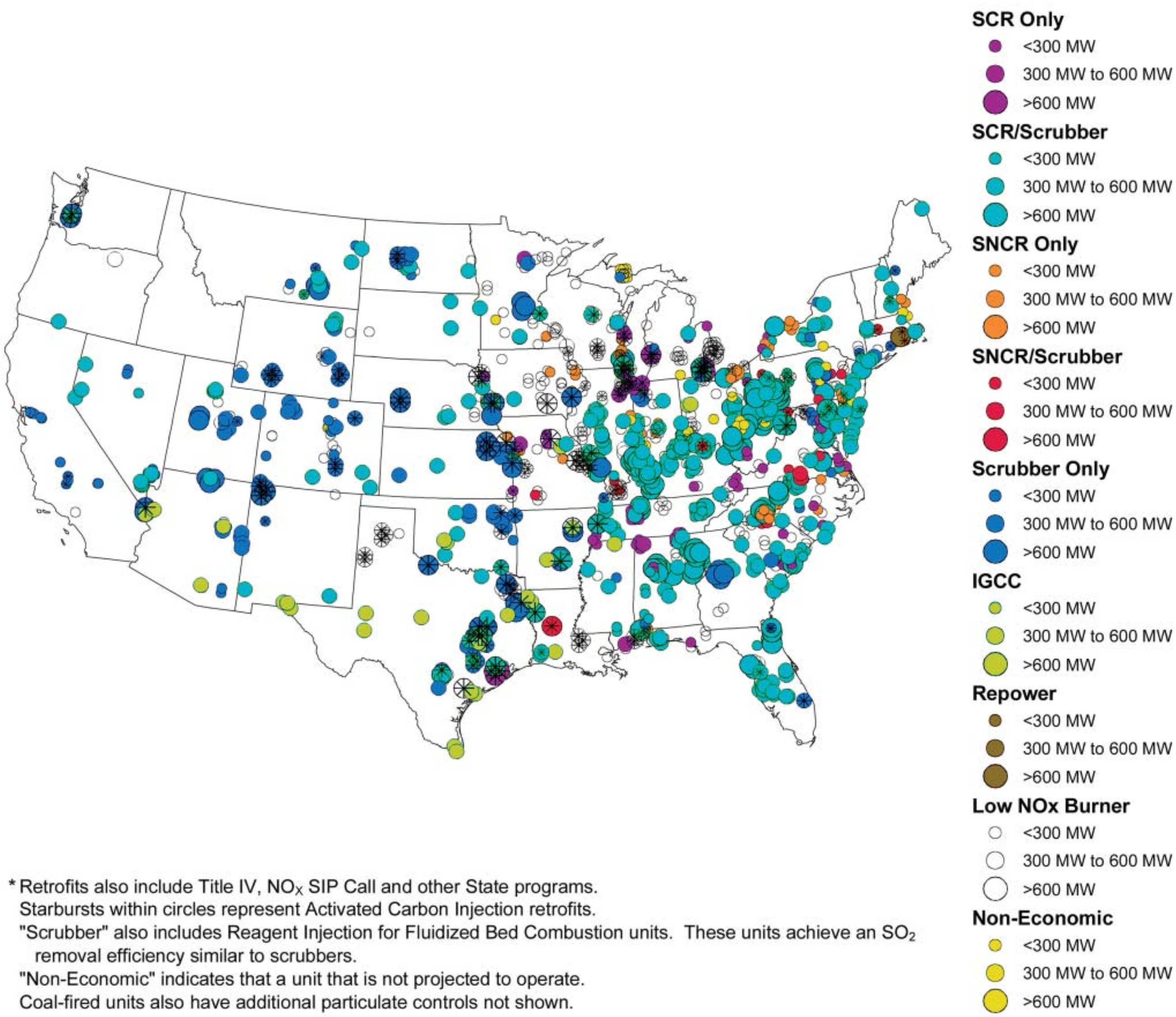
Where mercury trading programs are enacted, EPA expects emission controls to exceed requirements in 2010. This is because sources are likely to optimize the controls installed for CAIR to reduce as much mercury as possible in anticipation of increasing prices for mercury allowances under the lower second phase cap.

In December 2006, EPA proposed a CAMR federal plan to be finalized in states that either fail to submit a CAMR state plan or whose state plan is somehow deficient. EPA is evaluating comments and plans to finalize the CAMR federal plan by the end of 2007 and have it go into effect in the first half of 2008. The plan puts into place a cap and trade program in any state in which the federal plan is finalized and contains provisions to create trading programs for states or regions that could emerge in the future.

CAVR

CAVR supplements the emission reductions of CAIR by requiring emission controls known as best available retrofit technology (BART) for industrial facilities emitting air pollutants that reduce visibility by contributing to regional haze in national parks and wilderness areas. For the electric power industry, CAVR applies outside of the states covered by CAIR. For all other industries, it is a nationwide program. The pollutants include $PM_{2.5}$ and its precursors, such as SO_2, NO_X, volatile organic compounds, and ammonia. The BART requirements apply to facilities built

Figure 28: Projected Coal-fired EGU Retrofits with CAIR/CAMR/CAVR by 2020*



Source: EPA, 2007

between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution. The requirements cover 26 categories, including utility and industrial boilers and large industrial plants such as pulp mills, refineries, and smelters.

Many of these facilities have not been subject to federal pollution control requirements for these pollutants. Under the 1999 regional haze rule, states are required to set periodic goals for improving visibility in the 156 "Class I" natural areas, including national parks. CAVR includes guidelines for states to use in determining which facilities must install controls and the type of controls the facilities must use. States must develop their implementation plans by December 2007, identify the facilities that will have to reduce emissions under BART, set emission limits for those facilities, and require installation of BART in 2014.

For CAIR-affected EGUs, participation in the CAIR programs meets federal source-specific BART requirements because CAIR was determined to be better than BART controls under CAVR in the CAIR region. Specifically, controls for EGUs subject to CAIR will result in more visibility improvement in natural areas than BART would have provided. States could, however, require additional reductions.

Analyzing the Impacts of Rule Implementation

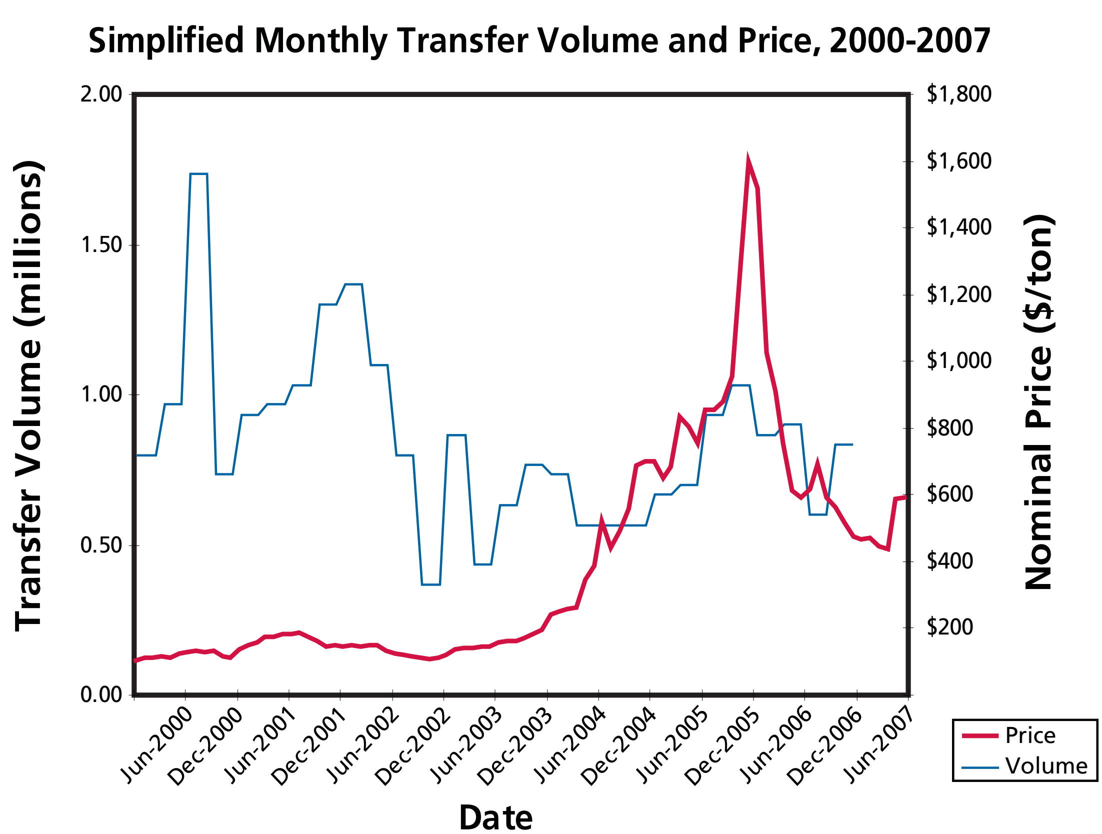
Projected Controls

Although aspects of CAIR and CAMR are in litigation, implementation moves ahead. Having promulgated these environmental programs, EPA has gone on to work with states, which are now working aggressively to put implementing rules in place. The regulated community is going forward with installing equipment for CAIR, entering into contracts for construction of mercury controls, and putting monitoring systems in place.

Sources have begun responding to the new requirements with investments and application of retrofit technology. EPA estimates that in 2010, EGUs accounting for 60 percent of total capacity will have scrubbers, increasing to 73 percent by 2020. Modeling shows that the percentage of advanced controls will go up (with the amount of capacity with advanced controls projected to increase even faster) and the number of units without advanced controls will go down, especially for larger units (see Figure 28 on page 45).

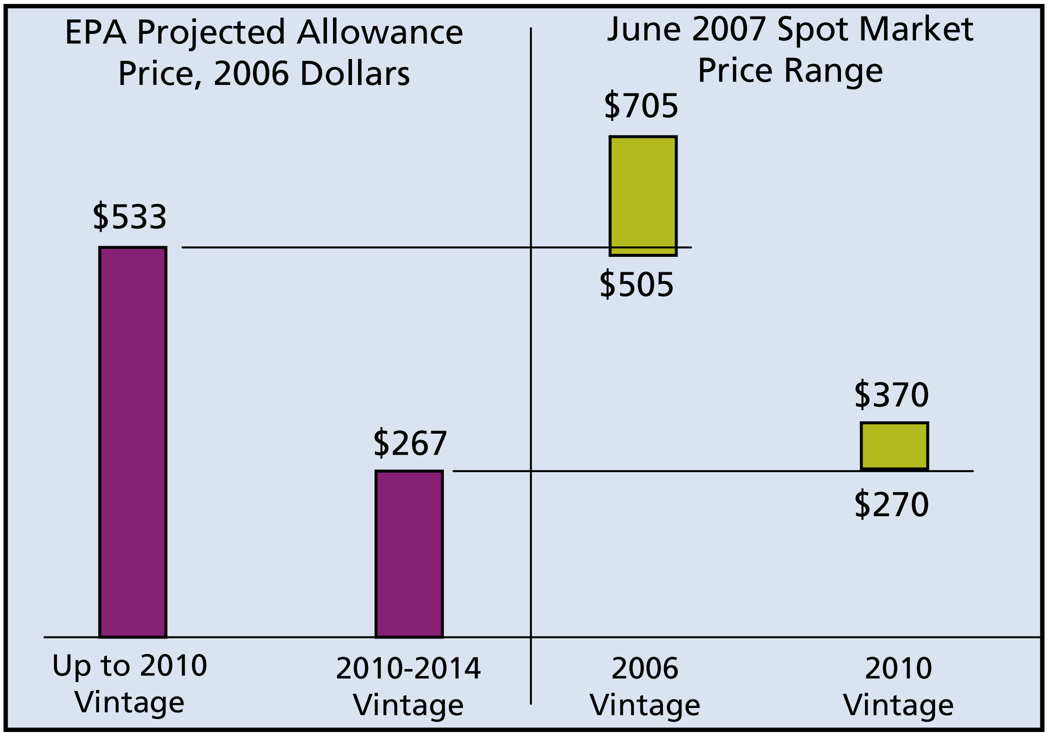
As observed with previous programs, the regulated community responds with a sense of purpose and alacrity to cap and trade programs. EPA, using existing CAA authority, is moving to address interstate transport

Figure 29: SO_2 Allowance Trading Volume and Prices from June 2000 to June 2007



Source: EPA, 2007

Figure 30: Actual and Forecasted SO_2 Allowance Prices



Source: EPA, 2007

of SO_2 and NO_X emissions and lower mercury emissions with CAIR, CAMR, and CAVR. EPA expects these programs to deliver significant human health and environmental improvements in a cost-effective manner by harnessing market forces to achieve substantial required emission reductions.

CAIR and the SO_2 Trading Market

In 2006 trading, prices began the year at nearly $1,500 per ton. As EPA discussed in the *2005 Acid Rain Program Progress Report*, market observers characterized this high price as a result of uncertainty over the implementation of CAIR. However, by mid-2006, prices were lower and had stabilized, generally trading through the second half of 2006 in a band between $400 and $600 per ton. Prices have generally remained at this level through the end of June 2007. EPA also observed that, during the period of peak allowance prices in late-2005 and early-2006, transfer volumes were generally lower in the market, which indicates that many market participants were not trading during this period of high volatility. EPA expects that trade volumes will again increase as the market continues to stabilize in 2007. Figure 29 shows the variation in SO_2 allowance price and transfer volume from June 2000 though June 2007.

Current prices continue to compare favorably with EPA's updated estimate of future SO_2 allowance prices under CAIR. As shown in Figure 30, EPA projected that pre-2010 vintage allowances would be worth $533 per allowance in 2010, and that 2010-2014 vintage allowances would be worth $267 per allowance due to the 2:1 retirement ratio that applies to those vintage allowances in the CAIR region.

Table 10: Aquatic Ecosystem Status Categories for the Adirondacks

Category Label	ANC Levels*	Expected Ecological Effects
Acute Concern	< 0 micro equivalent per Liter (µeq/L)	Complete loss of fish populations is expected. Planktonic communities have extremely low diversity and are dominated by acidophilic forms. The numbers of individuals in plankton species that are present are greatly reduced.
Elevated Concern	0 - 50 µeq/L	Fish species richness is greatly reduced (more than half of expected species are missing). On average, brook trout populations experience sub-lethal effects, including loss of health and reproduction (fitness). During episodes of high acid deposition, brook trout populations may experience lethal effects. Diversity and distribution of zooplankton communities declines.
Moderate Concern	50 - 100 µeq/L	Fish species richness begins to decline (sensitive species are lost from lakes). Brook trout populations are sensitive and variable, with possible sub-lethal effects. Diversity and distribution of zooplankton communities begin to decline as species that are sensitive to acid deposition are affected.
Low Concern	> 100 µeq/L	Fish species richness may be unaffected. Reproducing brook trout populations are expected where habitat is suitable. Zooplankton communities are unaffected and exhibit expected diversity and distribution.

* It is important to note that the wide range of ANC values within these categories makes it likely that substantial improvements in ANC may occur without changing the categorization of a given lake.

Source: EPA, 2007

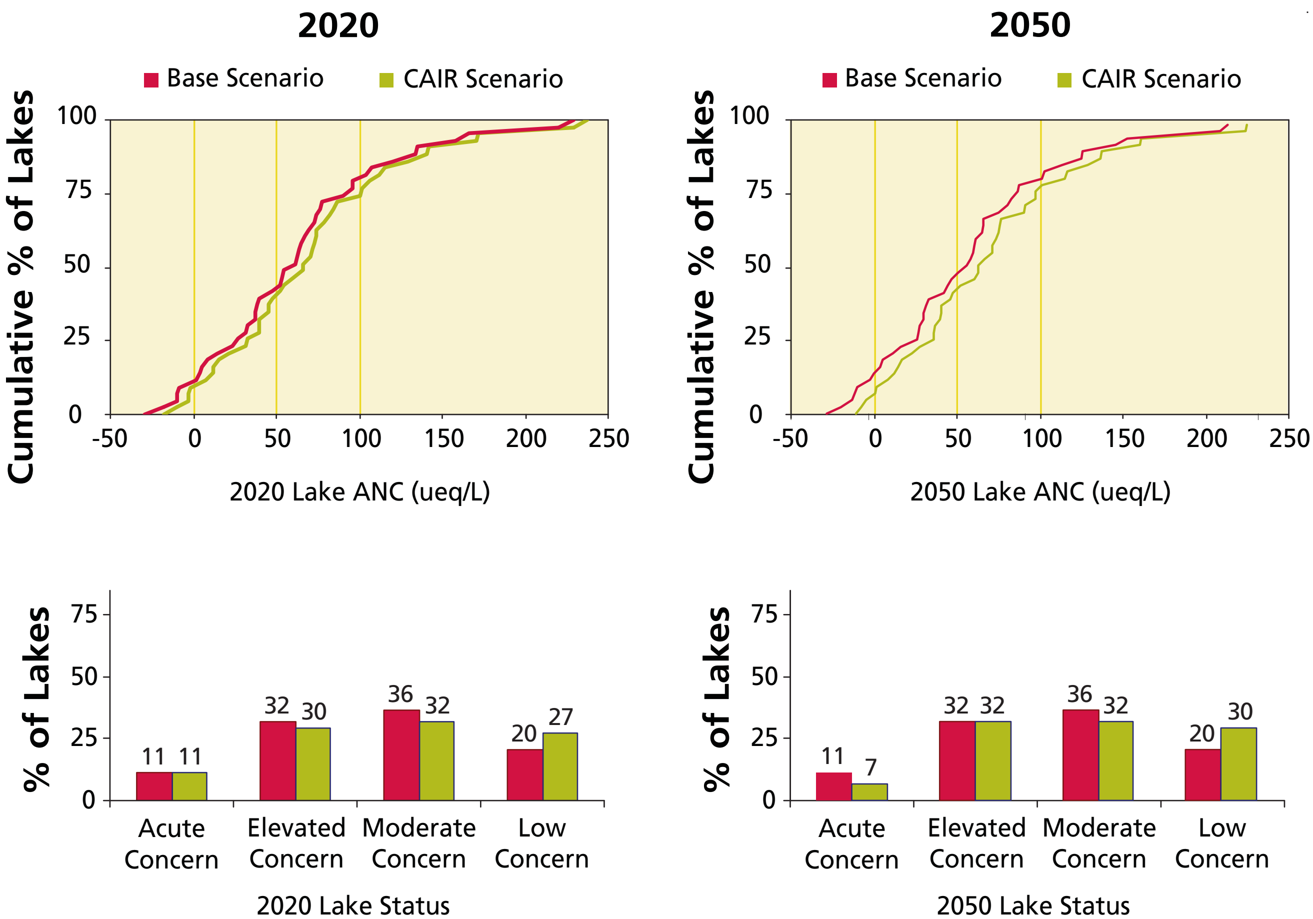
June 2007 spot market prices show that the prices for the earlier vintages are trading for $505 to $705 per ton, and that the later vintages (2010-2014) are trading for $270 to $370 per ton (see Figure 30 on page 47). These market prices compare favorably with, though slightly above, EPA's estimate for the CAIR markets.

Predicting the Response of Acidified Lakes and Streams Under CAIR

In addition to the improvements in lake and stream acidity resulting from implementation of the ARP, CAIR will further reduce SO_2 and NO_x emissions, thereby reducing acid deposition and contributing to improvements in lake and stream conditions. EPA utilized a surface water chemistry model called the Model of Acidification of Groundwater in Catchments (MAGIC) to estimate the response of acidified lakes and streams to these reductions in acid deposition. MAGIC incorporates a small number of processes that are important in influencing the long-term response of surface waters to acidic deposition.

The Adirondack region of New York was selected as the location for this evaluation. Aquatic ecosystem status categories have been defined to track recovery for this area and are presented in Table 10. This analysis uses projected acid deposition scenarios for 2010, 2015, and 2020 that depict acid deposition in the absence (baseline) and presence of CAIR for each year. Using the difference between the baseline and CAIR deposition data, MAGIC projects the response of indicators of stream and lake acidity (such as ANC) to reductions in acid deposition resulting from CAIR implementation.

Figure 31: Simulated Responses in 2020 and 2050 of Adirondack Lakes to Changes in Acid Deposition (Baseline Conditions versus CAIR Scenarios)



Note: Baseline results are shown in red while CAIR results are shown in green - values rounded. The wide range of ANC values within these categories makes it likely that substantial improvements in ANC may occur without changing the categorization of a given lake.

Source: EPA, 2007

The improvements in ANC predicted for lakes in the Adirondacks are depicted in the cumulative distribution plots in Figure 31. The cumulative distribution plots provide information about the change in ANC for all lakes and show that ANC under CAIR is consistently higher than without CAIR. For example in 2020, 59 percent of lakes under CAIR and 56 percent of lakes without CAIR have ANC greater than 50. The bar graphs in Figure 31 show the change in ecosystem status categories for lakes in the Adirondacks between the baseline and CAIR conditions. On average, MAGIC projects that ANC will increase by 7.5 μeq/L in 2020 and 12 μeq/L in 2050 with CAIR. This analysis clearly indicates that improvements in aquatic ecosystem status for the lakes in the Adirondacks should occur as a result of reductions in acid deposition attributable to CAIR emission reductions.

Online Information, Data, and Resources

The availability and transparency of data, from emission measurement to allowance trading to deposition monitoring, is a cornerstone of effective cap and trade programs. The Clean Air Markets Division (CAMD), in the Office of Air and Radiation's Office of Atmospheric Programs, develops and manages programs for collecting these data and assessing the effectiveness of cap and trade programs, including the ARP.

The CAMD Web site provides a public resource for general information on how market-based programs work and what they have accomplished, along with the processes, information, and tools necessary to participate in any of these market-based programs.

For information about EPA's air emissions trading programs, see: <http://www.epa.gov/airmarkets>.

For information about the ARP, see: <http://www.epa.gov/airmarkets/progsregs/arp/index.html>.

Endnotes

1. See <www.epa.gov/ttn/chief/trends> (Total emissions are preliminary projections, based on 2002 National Emissions Inventory).

2. Chestnut, L. G., Mills, D. M. (2005, November). A fresh look at the benefits and costs of the U.S. Acid Rain Program. *Journal of Environmental Management*, Vol. 77, Issue 3, 252-256.

3. For the statutory provisions on allowance allocations, see Section 403 of the CAA, as amended in 1990. See <www.epa.gov/air/caa/caa403.txt>.

4. See <www.epa.gov/ttn/chief/trends>.

5. Detailed emissions and allowance data for ARP sources are available on the Data and Maps portion of EPA's Clean Air Markets Web site, see <http://camddataandmaps.epa.gov/gdm/>.

6. Allowance transfers are posted and updated daily on <www.epa.gov/airmarkets>.

7. See <http://aura.gsfc.nasa.gov/instruments/omi/index.html> for further information. The SO_2 data team includes researchers from a number of locations, including the Goddard Earth Sciences and Technology Center at the University of Maryland Baltimore County; the Joint Center for Earth Systems Technology at the University of Maryland Baltimore County; the National Aeronautics and Space Administration, Goddard Space Flight Center; and the Royal Netherlands Meteorological Institute (KNMI).

8. Kim, S.W., et al. "Satellite-observed U.S. power plant NO_x emission reductions and their impact on air quality." *Geophysical Research Letters*, Vol. 33, No. 22, L22812, doi: 10.1029/2006GL027749, 29 November 2006.

9. Borrell, P., Burrows, J., Platt, U., & Zehner, C. (2001). Determining tropospheric concentrations of trace gases from space. *ESA Bulletin*, 107, 72-81.

10. It should be noted that there has not been a violation of the SO_2 standard at any U.S. monitoring site since 2000.

11. See the EPA Office of Transportation and Air Quality Web site < www.epa.gov/otaq> for information on recent rules to reduce NO_x emissions from mobile sources. Additional NO_x reductions are occurring as a result of the NBP. See EPA's September 2007 report, *NO_x Budget Trading Program: 2006 Program Compliance and Environmental Results*, at <www.epa.gov/airmarkets/progress/nbp06.html>, which discusses these NO_x reduction efforts.

12. National Research Council (2004). *Air Quality Management in the United States*. National Academies Press, Washington, DC.

13. Clean Air Act Advisory Committee, Air Quality Management Work Group (2005). "Recommendations to the Clean Air Act Advisory Committee: Phase 1 and Next Steps."

14. The data used to compute trends for the Southern Appalachians include a significant update (over five years of new data), resulting in a substantial change in the magnitude and direction of the trends shown in the *2005 Acid Rain Progress Report*. The trends shown here should be regarded as more accurate estimates of long-term patterns for this region.

15. CAIR (see <www.epa.gov/cair/index.html>), CAMR (see <www.epa.gov/air/mercuryrule>), CAVR (see <www.epa.gov/oar/visibility/index.html>).

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EPA-430-R-07-011

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
AL	AMEA Sylacauga Plant	56018	1, 2	0	1	0		0	1
AL	Barry	3	1, 2, 3, 4, 5, 6A, 6B, 7A, 7B	51872	53823	52622		52622	1201
AL	Calhoun Power Company I, LLC	55409	CT1, CT2, CT3, CT4	0	5	1		1	4
AL	Charles R Lowman	56	1, 2, 3	14774	21240	17879		17879	3361
AL	Colbert	47	1, 2, 3, 4, 5	41776	84487	39943		39943	44544
AL	Decatur Energy Center	55292	CTG-1, CTG-2, CTG-3	0	7	6		6	1
AL	E B Harris Generating Plant	7897	1A, 1B, 2A, 2B	0	12	4		4	8
AL	E C Gaston	26	1, 2, 3, 4, 5	57815	133277	130495		130495	2782
AL	Gadsden	7	1, 2	3981	8422	8203		8203	219
AL	Gorgas	8	6, 7, 8, 9, 10	39880	83366	81267		81267	2099
AL	Greene County	10	1, 2, CT2, CT3, CT4, CT5, CT6, CT7, CT8, CT9, CT10	16411	38820	37862		37862	958
AL	Hog Bayou Energy Center	55241	COG01	0	1	0		0	1
AL	James H Miller Jr	6002	1, 2, 3, 4	57457	54091	53379		53379	712
AL	McIntosh (7063)	7063	**1, **2, **3	938	1903	0		0	1903
AL	McWilliams	533	**4, **V1, **V2	0	26	2		2	24
AL	Morgan Energy Center	55293	CT-1, CT-2, CT-3	0	7	6		6	1
AL	Plant H. Allen Franklin	7710	1A, 1B, 2A, 2B	0	9	6		6	3
AL	SABIC Innovative Plastics - Burkville	7698	CC1	0	8	2		2	6
AL	Tenaska Central Alabama Gen Station	55440	CTGDB1, CTGDB2, CTGDB3	0	8	0		0	8
AL	Tenaska Lindsay Hill	55271	CT1, CT2, CT3	0	6	3		3	3
AL	Theodore Cogeneration	7721	CC1	0	6	3		3	3
AL	Washington County Cogen (Olin)	7697	CC1	0	9	3		3	6
AL	Widows Creek	50	1, 2, 3, 4, 5, 6, 7, 8	35471	54154	33507		33507	20647
AR	Carl Bailey	202	01	10	398	149		149	249
AR	Cecil Lynch	167	2, 3	3	21	0		0	21
AR	Flint Creek Power Plant	6138	1	15192	33737	8526		8526	25211
AR	Fulton	7825	CT1	0	10	0		0	10
AR	Hamilton Moses	168	1, 2	0	4	0		0	4
AR	Harvey Couch	169	1, 2	119	718	0		0	718
AR	Hot Spring Power Co., LLC	55714	SN-01, SN-02	0	6	4		4	2
AR	Independence	6641	1, 2	36556	71236	26172		26172	45064
AR	KGen Hot Spring LLC	55418	CT-1, CT-2	0	5	2		2	3
AR	Lake Catherine	170	1, 2, 3, 4	164	981	0		0	981
AR	McClellan	203	01	15	1229	441		441	788

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AR	Pine Bluff Energy Center	55075	CT-1	0	4	3		3	1
AR	Robert E Ritchie	173	1, 2	2201	1195	0		0	1195
AR	Thomas Fitzhugh	201	2	1	39	0		0	39
AR	Union Power Station	55380	CTG-1, CTG-2, CTG-3, CTG-4, CTG-5, CTG-6, CTG-7, CTG-8	0	50	11		11	39
AR	White Bluff	6009	1, 2	44840	66286	38122		38122	28164
AR	Wrightsville Generating Station	55221	G1, G2, G3, G4, G5, G6, G7	0	70	0		0	70
AZ	Agua Fria Generating Station	141	1, 2, 3	196	1	0		0	1
AZ	Apache Station	160	1, 2, 3, 4	4951	4287	3019		3019	1268
AZ	APS Saguaro Power Plant	118	1, 2, CT3	229	508	0		0	508
AZ	APS West Phoenix Power Plant	117	CC4, CC5A, CC5B	33	25	5		5	20
AZ	Arlington Valley Energy Facility	55282	CTG1, CTG2	0	15	4		4	11
AZ	Cholla	113	1, 2, 3, 4	21147	22847	21148		21148	1699
AZ	Coronado Generating Station	6177	U1B, U2B	11636	13516	13516		13516	0
AZ	De Moss Petrie Generating Station	124	GT1	0	8	0		0	8
AZ	Desert Basin Generating Station	55129	DBG1, DBG2	0	3	3		3	0
AZ	Gila River Power Station	55306	1CTGA, 1CTGB, 2CTGA, 2CTGB, 3CTGA, 3CTGB, 4CTGA, 4CTGB	0	51	12		12	39
AZ	Griffith Energy LLC	55124	P1, P2	0	7	4		4	3
AZ	Irvington Generating Station	126	1, 2, 3, 4	2898	2786	2672		2672	114
AZ	Kyrene Generating Station	147	K-1, K-2, K-7	25	2	2		2	0
AZ	Mesquite Generating Station	55481	1, 2, 5, 6	0	56	16		16	40
AZ	Navajo Generating Station	4941	1, 2, 3	75524	3843	3843		3843	0
AZ	New Harquahala Generating Company, LLC	55372	CTG1, CTG2, CTG3	0	6	3		3	3
AZ	Ocotillo Power Plant	116	1, 2	188	40	0		0	40
AZ	Redhawk Generating Facility	55455	CC1A, CC1B, CC2A, CC2B	0	41	12		12	29
AZ	Santan	8068	5A, 5B, 6A	0	8	8		8	0
AZ	South Point Energy Center, LLC	55177	A, B	0	8	6		6	2
AZ	Springerville Generating Station	8223	1, 2, TS3	12322	5221	4889		4889	332
AZ	Sundance Power Plant	55522	CT01, CT02, CT03, CT04, CT05, CT06, CT07, CT08, CT09, CT10	0	20	0		0	20
AZ	Yuma Axis	120	1	42	273	3		3	270

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CA	AES Alamitos	315	1, 2, 3, 4, 5, 6	9700	415	6		6	409
CA	AES Huntington Beach	335	1, 2, 3A, 4A	2796	299	4		4	295
CA	AES Redondo Beach	356	5, 6, 7, 8, 17	1372	151	2		2	149
CA	Agua Mansa Power	55951	AMP-1	0	0	0		0	0
CA	Almond Power Plant	7315	1	0	6	0		0	6
CA	Anaheim Combustion Turbine	7693	1	0	0	0		0	0
CA	Blythe Energy	55295	1, 2	0	8	2		2	6
CA	Broadway	420	B3	365	78	0		0	78
CA	Cabrillo Power I Encina Power Station	302	1, 2, 3, 4, 5	6800	12	8		8	4
CA	Cal Peak Power - Border LLC	55510	GT-1, GT-2	0	0	0		0	0
CA	Cal Peak Power - El Cajon LLC	55512	GT-1, GT-2	0	0	0		0	0
CA	Cal Peak Power - Enterprise LLC	55513	GT-1, GT-2	0	0	0		0	0
CA	Cal Peak Power - Panoche LLC	55508	GT-1, GT-2	0	0	0		0	0
CA	Cal Peak Power - Vaca Dixon LLC	55499	GT-1, GT-2	0	0	0		0	0
CA	Calpine Gilroy Cogen, LP	10034	S-100	0	1	0		0	1
CA	Calpine Sutter Energy Center	55112	CT01, CT02	0	7	4		4	3
CA	Carson Cogeneration	7527	1, 2	0	9	2		2	7
CA	Carson Cogeneration Company	10169	D1	0	30	1		1	29
CA	Chula Vista Power Plant	55540	1A, 1B	0	2	0		0	2
CA	Contra Costa Power Plant	228	1, 2, 3, 4, 5, 6, 7, 8, 9, 10	4850	209	0		0	209
CA	Coolwater Generating Station	329	1, 2, 31, 32, 41, 42	16	87	3		3	84
CA	Cosumnes Power Plant	55970	2, 3	0	50	6		6	44
CA	Creed Energy Center	55625	UNIT1	0	1	0		0	1
CA	Delta Energy Center, LLC	55333	1, 2, 3	0	13	10		10	3
CA	Donald Von Raesfeld	56026	PCT1, PCT2	0	230	1		1	229
CA	El Centro	389	3, 4, 2-2	1200	4795	2		2	4793
CA	El Segundo	330	3, 4	1082	81	1		1	80
CA	Elk Hills Power	55400	CTG-1, CTG-2	0	26	8		8	18
CA	Escondido Power Plant	55538	CT1A, CT1B	0	2	0		0	2
CA	Etiwanda Generating Station	331	3, 4	1779	187	3		3	184
CA	Feather River Energy Center	55847	UNIT1	0	1	0		0	1
CA	Fresno Cogeneration Partners, LP	10156	GEN1	0	0	0		0	0
CA	Gilroy Energy Center, LLC	55810	S-3, S-4, S-5	0	3	0		0	3
CA	Gilroy Energy Center, LLC for King City	10294	2	0	1	0		0	1
CA	Glenarm	422	16, 17, GT3, GT4	0	293	0		0	293
CA	Goose Haven Energy Center	55627	UNIT1	0	1	0		0	1

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CA	Grayson	377	4, 5, 9	138	957	1		1	956
CA	Hanford Energy Park Peaker	55698	HEP1, HEP2	0	4	0		0	4
CA	Harbor Generating Station	399	10, 11, 12, 13, 14, **10A, **10B	1956	4227	0		0	4227
CA	Haynes Generating Station	400	1, 2, 5, 6, 9, 10	6193	19972	9		9	19963
CA	Henrietta Peaker Plant	55807	HPP1, HPP2	0	4	0		0	4
CA	High Desert Power Project	55518	CTG1, CTG2, CTG3	0	20	9		9	11
CA	Humboldt Bay	246	1, 2	382	641	64		64	577
CA	Hunters Point	247	7	348	34	1		1	33
CA	Indigo Generation Facility	55541	1, 2, 3	0	2	0		0	2
CA	Kern	251	1, 2, 3, 4	16	0	0		0	0
CA	Kings River Conservation District	56239	GT-1, GT-2	0	0	0		0	0
CA	La Paloma Generating Plant	55151	CTG-1, CTG-2, CTG-3, CTG-4	0	20	14		14	6
CA	Lake	7987	01	0	16	0		0	16
CA	Lambie Energy Center	55626	UNIT1	0	1	0		0	1
CA	Larkspur Energy Faciity	55542	1, 2	0	0	0		0	0
CA	Los Esteros Critical Energy Fac	55748	CTG1, CTG2, CTG3, CTG4	0	4	0		0	4
CA	Los Medanos Energy Center, LLC	55217	X724, X725	0	9	7		7	2
CA	LSP South Bay LLC	310	1, 2, 3, 4	7047	21	4		4	17
CA	Magnolia	56046	1	0	6	2		2	4
CA	Malburg Generating Station	56041	M1, M2	0	43	2		2	41
CA	Mandalay Generating Station	345	1, 2	2670	293	1		1	292
CA	Metcalf Energy Center	55393	1, 2	0	7	4		4	3
CA	Miramar Energy Facility	56232	1	0	2	0		0	2
CA	Morro Bay Power Plant, LLC	259	1, 2, 3, 4	8575	10	1		1	9
CA	Moss Landing	260	1, 2, 3, 4, 5, 6, 7, 8, 1A, 2A, 3A, 4A, 6-1, 7-1	10567	53	15		15	38
CA	Mountainview Power Company, LLC	358	3-1, 3-2, 4-1, 4-2	135	21	11		11	10
CA	NCPA Combustion Turbine Project #2	7449	NA1	0	23	0		0	23
CA	Olive	6013	01, 02	158	82	0		0	82
CA	Ormond Beach Generating Station	350	1, 2	9106	1053	1		1	1052
CA	Palomar Energy	55985	CTG1, CTG2	0	6	6		6	0
CA	Pastoria Energy Facility	55656	CT001, CT002, CT004	0	14	11		11	3
CA	Pittsburg Power Plant (CA)	271	5, 6, 7	10937	425	2		2	423
CA	Potrero Power Plant	273	3-1	321	10	2		2	8

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
CA	Redding Power Plant	7307	5	0	67	1		1	66
CA	Ripon Generation Station	56135	1, 2	0	20	0		0	20
CA	Riverside Energy Resource Center	56143	1, 2	0	0	0		0	0
CA	Riverview Energy Center	55963	1	0	1	0		0	1
CA	Sacramento Power Authority Cogen	7552	1	0	13	3		3	10
CA	SCA Cogen II	7551	1A, 1B, 1C	0	23	2		2	21
CA	Scattergood Generating Station	404	1, 2, 3	1672	3394	14		14	3380
CA	Silver Gate	309	1, 2, 3, 4, 5, 6	0	0	0		0	0
CA	Sunrise Power Company	55182	CTG1, CTG2	0	11	8		8	3
CA	Tracy Peaker	55933	TPP1, TPP2	0	8	0		0	8
CA	Valley Gen Station	408	5, 6, 7	1003	29745	5		5	29740
CA	Walnut Energy Center	56078	1, 2	0	12	2		2	10
CA	Wellhead Power Gates, LLC	55875	GT1	0	0	0		0	0
CA	Wolfskill Energy Center	55855	UNIT1	0	1	0		0	1
CA	Woodland Generation Station	7266	1, 2	0	196	1		1	195
CA	Yuba City Energy Center	10349	2	0	1	0		0	1
CO	Arapahoe	465	3, 4	2576	2814	2494		2494	320
CO	Arapahoe Combustion Turbine	55200	CT5, CT6	0	36	0		0	36
CO	Blue Spruce Energy Center	55645	CT-01, CT-02	0	3	2		2	1
CO	Brush 3	10682	GT2	0	7	0		0	7
CO	Brush 4	55209	GT4, GT5	0	7	0		0	7
CO	Cameo	468	2	904	2042	1899		1899	143
CO	Cherokee	469	1, 2, 3, 4	16272	16284	7116		7116	9168
CO	Comanche (470)	470	1, 2	14612	15300	13854		13854	1446
CO	Craig	6021	C1, C2, C3	18665	4357	3586		3586	771
CO	Fort St. Vrain	6112	2, 3, 4	0	18	9		9	9
CO	Fountain Valley Combustion Turbine	55453	1, 2, 3, 4, 5, 6	0	180	0		0	180
CO	Frank Knutson Station	55505	BR1, BR2	0	99	0		0	99
CO	Front Range Power Plant	55283	1, 2	0	10	6		6	4
CO	Hayden	525	H1, H2	15293	2790	2657		2657	133
CO	Limon Generating Station	55504	L1, L2	0	99	1		1	98
CO	Manchief Station	55127	CT1, CT2	0	6	0		0	6
CO	Martin Drake	492	5, 6, 7	6398	9565	8430		8430	1135
CO	Nucla	527	1	1122	1653	1509		1509	144
CO	Pawnee	6248	1	14443	16282	13073		13073	3209
CO	Rawhide Energy Station	6761	A, B, C, D, 101	1800	5010	943		943	4067
CO	Ray D Nixon	8219	1, 2, 3	4477	5019	3878		3878	1141

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
CO	Rocky Mountain Energy Center	55835	1, 2	0	7	6		6	1
CO	Valmont	477	5	3161	3137	748		748	2389
CO	Valmont Combustion Turbine Facility	55207	CT7, CT8	0	60	0		0	60
CO	Zuni	478	1, 2, 3	345	10	1		1	9
CT	Bridgeport Energy	55042	BE1, BE2	0	25	6		6	19
CT	Bridgeport Harbor Station	568	BHB1, BHB2, BHB3	18287	2892	2885		2885	7
CT	Capitol District Energy Center	50498	GT	0	2	0		0	2
CT	Devon	544	7, 8, 11, 12, 13, 14	8340	3	1		1	2
CT	English Station	569	EB13, EB14	271	0	0		0	0
CT	Lake Road Generating Company	55149	LRG1, LRG2, LRG3	0	11	9		9	2
CT	Middletown	562	2, 3, 4	7518	16916	428		428	16488
CT	Milford Power Company LLC	55126	CT01, CT02	0	7	7		7	0
CT	Montville	546	5, 6	6883	17350	226		226	17124
CT	New Haven Harbor	6156	NHB1	13070	676	665		665	11
CT	Norwalk Harbor Station	548	1, 2	10599	709	644		644	65
CT	Wallingford Energy	55517	CT01, CT02, CT03, CT04, CT05	0	42	0		0	42
DC	Benning	603	15, 16	1373	346	310		310	36
DE	Delaware City Refinery	52193	DCPP4	0	56	21		21	35
DE	Edge Moor	593	3, 4, 5	16316	9240	7982		7982	1258
DE	Hay Road	7153	5, 6, 7, **3	158	304	1		1	303
DE	Indian River	594	1, 2, 3, 4	25035	21740	20706		20706	1034
DE	McKee Run	599	3	2585	2586	51		51	2535
DE	NRG Energy Center Dover	10030	2, 3	0	10	0		0	10
DE	Van Sant	7318	**11	138	139	0		0	139
DE	Warren F. Sam Beasley Pwr Station	7962	1	0	5	0		0	5
FL	Anclote	8048	1, 2	27785	32544	23507		23507	9037
FL	Arvah B Hopkins	688	1, 2, HC3, HC4	5605	750	571		571	179
FL	Auburndale Cogeneration Facility	54658	1, 6	0	3	2		2	1
FL	Bayside Power Station	7873	CT1A, CT1B, CT1C, CT2A, CT2B, CT2C, CT2D	0	59	15		15	44
FL	Big Bend	645	BB01, BB02, BB03, BB04	44567	40401	13978		13978	26423
FL	Brandy Branch	7846	1, 2, 3	0	178	3		3	175
FL	C D McIntosh Jr Power Plant	676	1, 2, 3, 5	11867	26990	6128		6128	20862
FL	Cane Island	7238	2, 3, **1	0	39	3		3	36
FL	Cape Canaveral	609	PCC1, PCC2	9188	11184	4046		4046	7138

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
FL	Crist Electric Generating Plant	641	2, 3, 4, 5, 6, 7	25866	71688	35614		35614	36074
FL	Crystal River	628	1, 2, 4, 5	75640	120719	95549		95549	25170
FL	Curtis H. Stanton Energy Center	564	1, 2	11294	27897	8125		8125	19772
FL	Cutler	610	PCU5, PCU6	0	5	0		0	5
FL	Debary	6046	**7, **8, **9, **10	2820	5592	41		41	5551
FL	Deerhaven	663	B1, B2, CT3	8369	10367	8280		8280	2087
FL	Desoto County Generating Co, LLC	55422	CT1, CT2	0	3	0		0	3
FL	Fort Myers	612	PFM3A, PFM3B, FMCT2A, FMCT2B, FMCT2C, FMCT2D, FMCT2E, FMCT2F	12649	14281	25		25	14256
FL	G E Turner	629	2, 3, 4	1872	542	0		0	542
FL	Hardee Power Station	50949	CT2B	0	39	0		0	39
FL	Henry D King	658	7, 8	89	30	0		0	30
FL	Higgins	630	1, 2, 3	1867	418	0		0	418
FL	Hines Energy Complex	7302	1A, 1B, 2A, 2B, 3A, 3B	0	465	17		17	448
FL	Indian River (55318)	55318	1, 2, 3	6408	1458	1329		1329	129
FL	Indian River (683)	683	**C, **D	639	3811	0		0	3811
FL	Intercession City	8049	**7, **8, **9, **10, **11, **12, **13, **14	2820	1398	34		34	1364
FL	J D Kennedy	666	7	2725	60	0		0	60
FL	J R Kelly	664	CC1	58	116	1		1	115
FL	Lansing Smith Generating Plant	643	1, 2, 4, 5	14081	34114	14610		14610	19504
FL	Larsen Power Plant	675	**8	972	2765	1		1	2764
FL	Lauderdale	613	4GT1, 4GT2, 5GT1, 5GT2	3792	4123	15		15	4108
FL	Manatee	6042	PMT1, PMT2, MTCT3A, MTCT3B, MTCT3C, MTCT3D	26478	33639	13358		13358	20281
FL	Martin	6043	PMR1, PMR2, PMR8A, PMR8B, PMR8C, PMR8D, HRSG3A, HRSG3B, HRSG4A, HRSG4B	16235	23855	11985		11985	11870
FL	Mulberry Cogeneration Facility	54426	1	0	2	1		1	1
FL	Northside	667	3, 1A, 2A	23618	9422	7191		7191	2231
FL	Oleander Power Project	55286	O-1, O-2, O-3, O-4	0	6	3		3	3
FL	Orange Cogeneration Facility	54365	1, 2	0	3	0		0	3
FL	Orlando CoGen	54466	1	0	2	2		2	0

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
FL	Osprey Energy Center	55412	CT1, CT2	0	5	4		4	1
FL	P L Bartow	634	1, 2, 3	11198	16302	12569		12569	3733
FL	Payne Creek Generating Station	7380	1, 2	0	165	6		6	159
FL	Polk	7242	**1, **2, **3	0	946	918		918	28
FL	Port Everglades	617	PPE1, PPE2, PPE3, PPE4	16600	20872	9293		9293	11579
FL	Putnam	6246	HRSG11, HRSG12, HRSG21, HRSG22	6424	6900	4		4	6896
FL	Reedy Creek	7254	32432	60	418	1		1	417
FL	Reliant Energy Osceola	55192	OSC1, OSC2, OSC3	0	6	3		3	3
FL	Riviera	619	PRV2, PRV3, PRV4	7214	9377	5239		5239	4138
FL	S O Purdom	689	7, 8	443	298	4		4	294
FL	Sanford	620	PSN3, SNCT4A, SNCT4B, SNCT4C, SNCT4D, SNCT5A, SNCT5B, SNCT5C, SNCT5D	12922	23537	206		206	23331
FL	Santa Rosa Energy Center	55242	CT-1	0	1	0		0	1
FL	Scholz Electric Generating Plant	642	1, 2	4010	36755	3915		3915	32840
FL	Seminole (136)	136	1, 2	36776	47558	22774		22774	24784
FL	Shady Hills	55414	GT101, GT201, GT301	0	2	0		0	2
FL	St. Johns River Power	207	1, 2	22960	20048	17980		17980	2068
FL	Stanton A	55821	25, 26	0	8	4		4	4
FL	Stock Island	6584	CT4	2572	207	18		18	189
FL	Suwannee River	638	1, 2, 3	1156	2282	1182		1182	1100
FL	Tiger Bay	7699	1	0	100	2		2	98
FL	Tom G Smith	673	S-3	89	481	0		0	481
FL	Turkey Point	621	PTP1, PTP2	11783	14410	5237		5237	9173
FL	University of Florida	7345	1	0	17	1		1	16
FL	Vandolah Power Project	55415	GT101, GT201, GT301, GT401	0	30	3		3	27
FL	Vero Beach Municipal	693	3, 4, **5	739	1080	1		1	1079
GA	Baconton	55304	CT1, CT4, CT5, CT6	0	20	0		0	20
GA	Bowen	703	1BLR, 2BLR, 3BLR, 4BLR	109781	210124	206442		206442	3682
GA	Chattahoochee Energy Facility	7917	8A, 8B	0	4	2		2	2
GA	Dahlberg (Jackson County)	7765	1, 2, 3, 4, 5, 6, 7, 8, 9, 10	0	3	0		0	3

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
GA	Doyle Generating Facility	55244	CTG-1, CTG-2, CTG-3, CTG-4, CTG-5	0	50	0		0	50
GA	Effingham County Power, LLC	55406	1, 2	0	7	2		2	5
GA	Hammond	708	1, 2, 3, 4	27835	118663	40579		40579	78084
GA	Harllee Branch	709	1, 2, 3, 4	53485	98664	95990		95990	2674
GA	Hartwell Energy Facility	70454	MAG1, MAG2	0	4	0		0	4
GA	Heard County Power, LLC	55141	CT1, CT2, CT3	0	0	0		0	0
GA	Jack McDonough	710	MB1, MB2	17469	35653	28835		28835	6818
GA	KGen Sandersville LLC	55672	CT1, CT2, CT3, CT4, CT5, CT6, CT7, CT8	0	4	0		0	4
GA	Kraft	733	1, 2, 3, 4	6440	10956	7947		7947	3009
GA	McIntosh (6124)	6124	1, CT1, CT2, CT3, CT4, CT5, CT6, CT7, CT8	5556	6292	5425		5425	867
GA	McIntosh Combined Cycle Facility	56150	10A, 10B, 11A, 11B	0	32	12		12	20
GA	McManus	715	1, 2	2123	7964	567		567	7397
GA	Mid-Georgia Cogeneration	55040	101, 201	0	11	0		0	11
GA	Mitchell (GA)	727	3	5463	6223	5150		5150	1073
GA	MPC Generating, LLC	7764	1, 2	0	0	0		0	0
GA	Murray Energy Facility	55382	CCCT1, CCCT2, CCCT3, CCCT4	0	9	4		4	5
GA	Robins	7348	CT1, CT2	0	4	2		2	2
GA	Scherer	6257	1, 2, 3, 4	84823	115409	74206		74206	41203
GA	Sewell Creek Energy	7813	1, 2, 3, 4	0	8	0		0	8
GA	Smarr Energy Facility	7829	1, 2	0	4	0		0	4
GA	Sowega Power Project	7768	CT2, CT3	0	10	0		0	10
GA	Talbot Energy Facility	7916	1, 2, 3, 4, 5, 6	0	42	2		2	40
GA	Tenaska Georgia Generating Station	55061	CT1, CT2, CT3, CT4, CT5, CT6	0	4	0		0	4
GA	Walton County Power, LLC	55128	T1, T2, T3	0	3	0		0	3
GA	Wansley (6052)	6052	1, 2, 6A, 6B, 7A, 7B	58728	119305	96199		96199	23106
GA	Wansley (7946)	7946	CT9A, CT9B	0	2	2		2	0
GA	Washington County Power, LLC	55332	T1, T2, T3, T4	0	4	0		0	4
GA	West Georgia Generating Company	55267	1, 2, 3, 4	0	5	0		0	5
GA	Yates	728	Y1BR, Y2BR, Y3BR, Y4BR, Y5BR, Y6BR, Y7BR	38220	88299	75476		75476	12823
IA	Ames	1122	7, 8	2237	4334	1291		1291	3043
IA	Burlington (IA)	1104	1	4499	4599	4548		4548	51

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
IA	Council Bluffs	1082	1, 2, 3	18717	19980	17522		17522	2458
IA	Dayton Avenue Substation	6463	GT2	0	17	0		0	17
IA	Dubuque	1046	1, 5, 6	1425	1435	1420		1420	15
IA	Earl F Wisdom	1217	1, 2	379	2719	685		685	2034
IA	Emery Station	8031	11, 12	0	20	3		3	17
IA	Exira Station	56013	U-1, U-2	0	110	0		0	110
IA	Fair Station	1218	2	5575	5587	4124		4124	1463
IA	George Neal North	1091	1, 2, 3	23688	26952	21539		21539	5413
IA	George Neal South	7343	4	15144	18781	16440		16440	2341
IA	Greater Des Moines Energy Center	7985	1, 2	0	29	2		2	27
IA	Lansing	1047	1, 2, 3, 4	5107	5362	5211		5211	151
IA	Lime Creek	7155	**1, **2	510	510	121		121	389
IA	Louisa	6664	101	15593	16316	15397		15397	919
IA	Milton L Kapp	1048	2	5795	3924	3874		3874	50
IA	Muscatine	1167	8, 9	3389	10526	3980		3980	6546
IA	Ottumwa	6254	1	19095	17821	14172		14172	3649
IA	Pella	1175	6, 7, 8	1803	6466	432		432	6034
IA	Pleasant Hill Energy Center	7145	3	0	21	0		0	21
IA	Prairie Creek	1073	3, 4	4159	4059	3681		3681	378
IA	Riverside (1081)	1081	9	1745	2384	2239		2239	145
IA	Sixth Street	1058	2, 3, 4, 5	1530	1530	1221		1221	309
IA	Streeter Station	1131	7	554	2317	1078		1078	1239
IA	Sutherland	1077	1, 2, 3	2766	8569	8454		8454	115
ID	Bennett Mountain Power Project	55733	CT01	0	100	0		0	100
ID	Evander Andrews Power Complex	7953	CT2, CT3	0	400	0		0	400
ID	Rathdrum Combustion Turbine Project	7456	1, 2	0	0	0		0	0
ID	Rathdrum Power, LLC	55179	CTGEN1	0	4	2		2	2
IL	Baldwin Energy Complex	889	1, 2, 3	55620	37458	24977		24977	12481
IL	Calumet Energy Team	55296	**1, **2	0	10	0		0	10
IL	Coffeen	861	01, 02	20466	24488	22007		22007	2481
IL	Cordova Energy Company	55188	1, 2	0	14	0		0	14
IL	Crawford	867	7, 8	17086	10050	9046		9046	1004
IL	Crete Energy Park	55253	GT1, GT2, GT3, GT4	0	0	0		0	0
IL	Dallman	963	31, 32, 33	8152	9297	3125		3125	6172
IL	Duck Creek	6016	1	11201	5780	3849		3849	1931
IL	E D Edwards	856	1, 2, 3	18940	38446	33944		33944	4502

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
IL	Elgin Energy Center	55438	CT01, CT02, CT03, CT04	0	20	0		0	20
IL	Elwood Energy Facility	55199	1, 2, 3, 4, 5, 6, 7, 8, 9	0	225	0		0	225
IL	Fisk	886	19	10032	6350	5641		5641	709
IL	Freedom Power Project	7842	CT1	0	0	0		0	0
IL	Geneva Energy, LLC	55174	1	0	34	34		34	0
IL	Gibson City Power Plant	55201	GCTG1, GCTG2	0	25	0		0	25
IL	Goose Creek Power Plant	55496	CT-01, CT-02, CT-03, CT-04, CT-05, CT-06	0	12	0		0	12
IL	Grand Tower	862	CT01, CT02	3030	153	1		1	152
IL	Havana	891	1, 2, 3, 4, 5, 6, 7, 8, 9	9095	9555	5811		5811	3744
IL	Hennepin Power Station	892	1, 2	9958	10312	4734		4734	5578
IL	Holland Energy Facility	55334	CTG1, CTG2	0	2	2		2	0
IL	Hutsonville	863	05, 06	4525	7739	5780		5780	1959
IL	Interstate	7425	1	0	5	0		0	5
IL	Joliet 29	384	71, 72, 81, 82	28611	16072	14360		14360	1712
IL	Joliet 9	874	5	8676	4536	4075		4075	461
IL	Joppa Steam	887	1, 2, 3, 4, 5, 6	28992	28812	26409		26409	2403
IL	Kendall Energy Facility	55131	GTG-1, GTG-2, GTG-3, GTG-4	0	4	4		4	0
IL	Kincaid Station	876	1, 2	28578	13702	13692		13692	10
IL	Kinmundy Power Plant	55204	KCTG1, KCTG2	0	10	0		0	10
IL	Lakeside	964	7, 8	4000	10079	8985		8985	1094
IL	Lee Energy Facility	55236	CT1, CT2, CT3, CT4, CT5, CT6, CT7, CT8	0	16	0		0	16
IL	Lincoln Generating Facility	55222	CTG-1, CTG-2, CTG-3, CTG-4, CTG-5, CTG-6, CTG-7, CTG-8	0	16	0		0	16
IL	Marion	976	4, 5, 6, 123	13361	21763	6377		6377	15386
IL	MEPI Gt Facility	7858	1, 2, 3, 4, 5	0	25	0		0	25
IL	Meredosia	864	01, 02, 03, 04, 05, 06	7192	9826	7733		7733	2093
IL	Newton	6017	1, 2	29557	27647	20922		20922	6725
IL	NRG Rockford Energy Center	55238	0001, 0002	0	53	0		0	53
IL	NRG Rockford II Energy Center	55936	U1	0	1	0		0	1
IL	Pinckneyville Power Plant	55202	CT01, CT02, CT03, CT04, CT05, CT06, CT07, CT08	0	40	0		0	40
IL	Powerton	879	51, 52, 61, 62	42393	22920	19860		19860	3060

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
IL	PPL University Park Power Project	55640	CT01, CT02, CT03, CT04, CT05, CT06, CT07, CT08, CT09, CT10, CT11, CT12	0	24	0		0	24
IL	Raccoon Creek Power Plant	55417	CT-01, CT-02, CT-03, CT-04	0	8	0		0	8
IL	Reliant Energy - Aurora	55279	AGS01, AGS02, AGS03, AGS04, AGS05, AGS06, AGS07, AGS08, AGS09, AGS10	0	10	0		0	10
IL	Reliant Energy Shelby County	55237	SCE1, SCE2, SCE3, SCE4, SCE5, SCE6, SCE7, SCE8	0	8	0		0	8
IL	Rocky Road Power, LLC	55109	T1, T2, T3, T4	0	0	0		0	0
IL	Southeast Chicago Energy Project	55281	CTG5, CTG6, CTG7, CTG8, CTG9, CTG10, CTG11, CTG12	0	400	0		0	400
IL	Tilton Power Station	7760	1, 2, 3, 4	0	12	0		0	12
IL	University Park Energy	55250	UP1, UP2, UP3, UP4, UP5, UP6, UP7, UP8, UP9, UP10, UP11, UP12	0	0	0		0	0
IL	Venice	913	CT03, CT04, CT05, CT2A, CT2B	62	82	0		0	82
IL	Vermilion Power Station	897	1, 2	6666	7301	2223		2223	5078
IL	Waukegan	883	7, 8, 17	19158	13327	11816		11816	1511
IL	Will County	884	1, 2, 3, 4	30971	19162	17306		17306	1856
IL	Wood River Power Station	898	1, 2, 3, 4, 5	11749	12191	7628		7628	4563
IL	Zion Energy Center	55392	CT-1, CT-2, CT-3	0	1	0		0	1
IN	A B Brown Generating Station	6137	1, 2, 3, 4	10527	9503	8956		8956	547
IN	Alcoa Allowance Management Inc	6705	1, 2, 3, 4	99281	73587	72858		72858	729
IN	Anderson	7336	ACT1, ACT2, ACT3	0	13	0		0	13
IN	Bailly Generating Station	995	7, 8	11683	3319	3309		3309	10
IN	C. C. Perry K Steam Plant	992	11	1796	696	64	489	553	143
IN	Cayuga	1001	1, 2, 4	29105	87332	83173		83173	4159
IN	Clifty Creek	983	1, 2, 3, 4, 5, 6	50488	70371	65371		65371	5000
IN	Dean H Mitchell Generating Station	996	4, 5, 6, 11	11762	0	0		0	0
IN	Edwardsport	1004	6-1, 7-1, 7-2, 8-1	1076	3491	3325		3325	166
IN	F B Culley Generating Station	1012	1, 2, 3	9904	10104	5998		5998	4106

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
IN	Frank E Ratts	1043	1SG1, 2SG1	7253	24760	21638		21638	3122
IN	Georgetown Substation	7759	GT1, GT2, GT3, GT4	0	13	0		0	13
IN	Gibson	6113	1, 2, 3, 4, 5	88393	162732	155056		155056	7676
IN	Harding Street Station (EW Stout)	990	9, 10, 50, 60, 70, GT4, GT5, GT6	13915	46670	46345		46345	325
IN	Henry County Generating Station	7763	1, 2, 3	0	6	0		0	6
IN	Hoosier Energy Lawrence Co Station	7948	1, 2, 3, 4, 5, 6	0	0	0		0	0
IN	IPL Eagle Valley Generating Station	991	1, 2, 3, 4, 5, 6	3858	14978	14828		14828	150
IN	Lawrenceburg Energy Facility	55502	1, 2, 3, 4	0	5	0		0	5
IN	Merom	6213	1SG1, 2SG1	29748	20518	14847		14847	5671
IN	Michigan City Generating Station	997	4, 5, 6, 12	12990	16003	15993		15993	10
IN	Montpelier Electric Gen Station	55229	G1CT1, G1CT2, G2CT1, G2CT2, G3CT1, G3CT2, G4CT1, G4CT2	0	0	0		0	0
IN	Noblesville	1007	CT3, CT4, CT5	160	6	0		0	6
IN	Petersburg	994	1, 2, 3, 4	54094	29714	28986		28986	728
IN	R Gallagher	1008	1, 2, 3, 4	11795	53320	50819		50819	2501
IN	R M Schahfer Generating Station	6085	14, 15, 17, 18	31463	35918	35908		35908	10
IN	Richmond (IN)	7335	RCT1, RCT2	0	9	0		0	9
IN	Rockport	6166	MB1, MB2	66006	94019	83543		83543	10476
IN	State Line Generating Station (IN)	981	3, 4	11650	7368	7348		7348	20
IN	Sugar Creek Power Company, LLC	55364	CT11, CT12	0	2	0		0	2
IN	Tanners Creek	988	U1, U2, U3, U4	20359	58315	35494		35494	22821
IN	Vermillion Energy Facility	55111	1, 2, 3, 4, 5, 6, 7, 8	0	16	0		0	16
IN	Wabash River	1010	1, 2, 3, 4, 5, 6	13140	61733	58794		58794	2939
IN	Wheatland Generating Facility LLC	55224	EU-01, EU-02, EU-03, EU-04	0	8	0		0	8
IN	Whitewater Valley	1040	1, 2	8932	9060	8331		8331	729
IN	Whiting Clean Energy, Inc.	55259	CT1, CT2	0	92	3		3	89
IN	Worthington Generation	55148	1, 2, 3, 4	0	4	0		0	4
KS	Chanute 2	1268	14	0	0	0		0	0
KS	Cimarron River	1230	1	12	2	1		1	1
KS	Coffeyville	1271	4	11	52	0		0	52
KS	East 12th Street	7013	4	10	66	0		0	66
KS	Fort Dodge aka Judson Large	1233	4	39	2	1		1	1
KS	Garden City	1336	S-2	0	68	0		0	68
KS	Gordon Evans Energy Center	1240	1, 2, E1CT, E2CT, E3CT	89	3	1		1	2

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
KS	Great Bend Station aka Arthur Mullergren	1235	3	1	1	0		0	1
KS	Holcomb	108	SGU1	4011	5490	1154		1154	4336
KS	Hutchinson Energy Center	1248	1, 2, 3, 4	18	1	0		0	1
KS	Jeffrey Energy Center	6068	1, 2, 3	55835	70524	64483		64483	6041
KS	Kaw	1294	1, 2, 3	1922	7	0		0	7
KS	La Cygne	1241	1, 2	33007	22645	22422		22422	223
KS	Lawrence Energy Center	1250	3, 4, 5	9346	2956	2613		2613	343
KS	McPherson 2	1305	1	1	75	0		0	75
KS	McPherson 3	7515	1	0	38	0		0	38
KS	Murray Gill Energy Center	1242	1, 2, 3, 4	118	3	0		0	3
KS	Nearman Creek	6064	N1, CT4	6930	12618	6027		6027	6591
KS	Neosho Energy Center	1243	7	13	1	0		0	1
KS	Osawatomie Generating Station	7928	1	0	3	0		0	3
KS	Quindaro	1295	1, 2	4111	12143	4584		4584	7559
KS	Riverton	1239	39, 40	2803	7086	5814		5814	1272
KS	Tecumseh Energy Center	1252	9, 10	6172	6535	4126		4126	2409
KS	West Gardner Generating Station	7929	1, 2, 3, 4	0	12	0		0	12
KY	Big Sandy	1353	BSU1, BSU2	26148	47871	46476		46476	1395
KY	Bluegrass Generation Company, LLC	55164	GTG1, GTG2, GTG3	0	0	0		0	0
KY	Cane Run	1363	4, 5, 6	14402	17785	17123		17123	662
KY	Coleman	1381	C1, C2, C3	15714	11979	10899		10899	1080
KY	D B Wilson	6823	W1	12465	10208	9307		9307	901
KY	E W Brown	1355	1, 2, 3, 5, 6, 7, 8, 9, 10, 11	20127	46590	45192		45192	1398
KY	East Bend	6018	2	18322	4144	3947		3947	197
KY	Elmer Smith	1374	1, 2	9018	2539	2525		2525	14
KY	Ghent	1356	1, 2, 3, 4	52666	68979	49912		49912	19067
KY	Green River	1357	4, 5	7923	28414	14177		14177	14237
KY	H L Spurlock	6041	1, 2, 3	26415	61305	38876		38876	22429
KY	Henderson I	1372	6	810	7322	280		280	7042
KY	HMP&L Station 2	1382	H1, H2	11694	11694	4574		4574	7120
KY	John S. Cooper	1384	1, 2	9818	34005	21182		21182	12823
KY	Marshall	55232	CT1, CT2, CT3, CT4, CT5, CT6, CT7, CT8	0	52	0		0	52
KY	Mill Creek	1364	1, 2, 3, 4	40828	115339	25465		25465	89874
KY	Paddy's Run	1366	13	0	5	0		0	5
KY	Paradise	1378	1, 2, 3	48638	97362	83925		83925	13437

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

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KY	R D Green	6639	G1, G2	11672	3206	2566		2566	640
KY	Riverside Generating Company	55198	GTG101, GTG201, GTG301, GTG401, GTG501	0	0	0		0	0
KY	Robert Reid	1383	R1	942	4205	3690		3690	515
KY	Shawnee	1379	1, 2, 3, 4, 5, 6, 7, 8, 9, 10	37929	39289	35815		35815	3474
KY	Smith Generating Facility	54	SCT1, SCT2, SCT3, SCT4, SCT5, SCT6, SCT7	0	1357	0		0	1357
KY	Trimble County	6071	1, 5, 6, 7, 8, 9, 10	9634	24121	829		829	23292
KY	Tyrone	1361	1, 2, 3, 4, 5	1713	2855	2191		2191	664
KY	William C. Dale	1385	1, 2, 3, 4	3831	11874	8624		8624	3250
LA	A B Paterson	1407	3, 4	15	75	0		0	75
LA	Acadia Power Station	55173	CT1, CT2, CT3, CT4	0	5	4		4	1
LA	Arsenal Hill Power Plant	1416	5A	30	186	1		1	185
LA	Bayou Cove Peaking Power Plant	55433	CTG-1, CTG-2, CTG-3, CTG-4	0	4	0		0	4
LA	Big Cajun 1	1464	1B1, 1B2, CTG1, CTG2	54	2	0		0	2
LA	Big Cajun 2	6055	2B1, 2B2, 2B3	44165	48703	46384		46384	2319
LA	Calcasieu Power, LLC	55165	GTG1, GTG2	0	0	0		0	0
LA	Carville Energy Center	55404	COG01, COG02	0	6	5		5	1
LA	D G Hunter	6558	3, 4	32	209	11		11	198
LA	Doc Bonin	1443	1, 2, 3	81	558	0		0	558
LA	Dolet Hills Power Station	51	1	20501	22053	20908		20908	1145
LA	Evangeline Power Station (Coughlin)	1396	6-1, 7-1, 7-2	174	1166	7		7	1159
LA	Hargis-Hebert Electric Generating Statio	56283	U-1, U-2	0	0	0		0	0
LA	Houma	1439	15, 16	24	168	0		0	168
LA	Lieberman Power Plant	1417	3, 4	158	829	3		3	826
LA	Little Gypsy	1402	1, 2, 3	1166	7795	4		4	7791
LA	Louisiana 1	1391	1A, 2A, 3A, 4A, 5A	120	373	105		105	268
LA	Louisiana 2	1392	10, 11, 12	0	6	0		0	6
LA	Michoud	1409	1, 2, 3	668	3341	3		3	3338
LA	Monroe	1448	11, 12	58	406	0		0	406
LA	Morgan City Electrical Gen Facility	1449	4	5	35	0		0	35
LA	Natchitoches	1450	10	0	1	0		0	1
LA	Ninemile Point	1403	1, 2, 3, 4, 5	1891	12668	14		14	12654
LA	Perryville Power Station	55620	1-1, 1-2, 2-1	0	18	4		4	14

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
LA	Plaquemine Cogen Facility	55419	500, 600, 700, 800	0	28	8		8	20
LA	Quachita Power, LLC	55467	CTGEN1, CTGEN2, CTGEN3	0	5	3		3	2
LA	R S Cogen	55117	RS-5, RS-6	0	22	8		8	14
LA	R S Nelson	1393	3, 4, 6	19731	37114	17445		17445	19669
LA	Rodemacher Power Station (6190)	6190	1, 2	22158	39420	10838		10838	28582
LA	Ruston	1458	2, 3	9	28	0		0	28
LA	Sterlington	1404	10, 7C, 7AB	246	1700	0		0	1700
LA	T J Labbe Electric Generating Station	56108	U-1, U-2	0	0	0		0	0
LA	Taft Cogeneration Facility	55089	CT1, CT2, CT3	0	292	3		3	289
LA	Teche Power Station	1400	2, 3	473	928	5		5	923
LA	Waterford 1 & 2	8056	1, 2	8089	25949	1188		1188	24761
LA	Willow Glen	1394	1, 2, 3, 4, 5	967	3249	106		106	3143
MA	ANP Bellingham Energy Project	55211	1, 2	0	8	5		5	3
MA	ANP Blackstone Energy Company	55212	1, 2	0	7	6		6	1
MA	Bellingham	10307	1, 2	0	2	1		1	1
MA	Berkshire Power	55041	1	0	3	2		2	1
MA	Brayton Point	1619	1, 2, 3, 4	48156	32134	25776		25776	6358
MA	Canal Station	1599	1, 2	31234	7563	6842		6842	721
MA	Cleary Flood	1682	8, 9	2822	519	19		19	500
MA	Dartmouth Power	52026	1	0	1	0		0	1
MA	Dighton	55026	1	0	24	1		1	23
MA	Fore River Station	55317	11, 12	0	25	6		6	19
MA	Indeck-Pepperell	10522	CC1	0	14	0		0	14
MA	Kendall Square	1595	1, 2, 3, 4	828	924	13		13	911
MA	Lowell Cogeneration Company	10802	001	0	4	0		0	4
MA	LPG Associates	54586	1	0	6	0		0	6
MA	Masspower	10726	1, 2	0	4	2		2	2
MA	Millennium Power Partners	55079	1	0	5	3		3	2
MA	Mount Tom	1606	1	5611	5838	4150		4150	1688
MA	Mystic	1588	4, 5, 6, 7, 81, 82, 93, 94	26019	9053	2089		2089	6964
MA	New Boston	1589	1	12482	3158	1		1	3157
MA	Salem Harbor	1626	1, 2, 3, 4	24779	19784	8616		8616	11168
MA	Somerset	1613	7, 8	6750	3388	3227		3227	161
MA	West Springfield	1642	3, CTG1, CTG2	3746	947	225		225	722
MD	Brandon Shores	602	1, 2	26305	40872	40467		40467	405

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
MD	C P Crane	1552	1, 2	8392	28160	27881		27881	279
MD	Herbert A Wagner	1554	1, 2, 3, 4	12491	19967	19769		19769	198
MD	Mirant Chalk Point	1571	1, 2, 3, 4, **GT3, **GT4, **GT5, **GT6	37726	51602	49591		49591	2011
MD	Mirant Dickerson	1572	1, 2, 3, GT2, GT3	19358	37506	35954		35954	1552
MD	Mirant Morgantown	1573	1, 2	33121	100386	98073		98073	2313
MD	Panda Brandywine	54832	1, 2	0	3	2		2	1
MD	Perryman	1556	**51	0	4	2		2	2
MD	R. Paul Smith Power Station	1570	9, 11	2948	4788	4388		4388	400
MD	Riverside	1559	4	1463	0	0		0	0
MD	Rock Springs Generating Facility	7835	1, 2, 3, 4	0	20	0		0	20
MD	Vienna	1564	8	3645	150	143		143	7
ME	Androscoggin Energy	55031	CT01, CT02, CT03	0	3	0		0	3
ME	Bucksport Clean Energy	50243	GEN4	0	63	4		4	59
ME	Maine Independence Station	55068	1, 2	0	39	5		5	34
ME	Mason Steam	1496	3, 4, 5	4	19			0	19
ME	Rumford Power Associates	55100	1	0	18	1		1	17
ME	Westbrook Energy Center	55294	1, 2	0	8	7		7	1
ME	William F Wyman	1507	1, 2, 3, 4	11540	2452	306		306	2146
MI	48th Street Peaking Station	7258	9, **7, **8	596	1039	0		0	1039
MI	B C Cobb	1695	1, 2, 3, 4, 5	12862	10738	10631		10631	107
MI	Belle River	6034	1, 2, CTG121, CTG122, CTG131	37274	53931	24128		24128	29803
MI	Conners Creek	1726	15, 16, 17, 18	15951	18949	0		0	18949
MI	Dan E Karn	1702	1, 2, 3, 4	18346	18595	18411		18411	184
MI	Dearborn Industrial Generation	55088	GTP1	0	3	0		0	3
MI	Delray	1728	CTG111, CTG121	40	216	0		0	216
MI	DTE East China	55718	1, 2, 3, 4	0	0	0		0	0
MI	Eckert Station	1831	1, 2, 3, 4, 5, 6	11211	6359	6137		6137	222
MI	Endicott Generating	4259	1	1810	1894	824		824	1070
MI	Erickson	1832	1	6646	2855	2755		2755	100
MI	Greenwood	6035	1, CTG111, CTG112, CTG121	539	556	398		398	158
MI	Harbor Beach	1731	1	3520	2207	1303		1303	904
MI	J B Sims	1825	3	1484	961	607		607	354
MI	J C Weadock	1720	7, 8	9436	9883	9784		9784	99
MI	J H Campbell	1710	1, 2, 3	45264	49536	36790		36790	12746

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

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MI	J R Whiting	1723	1, 2, 3	11374	11091	10981		10981	110
MI	Jackson MI Facility	55270	7EA, LM1, LM2, LM3, LM4, LM5, LM6	0	5	0		0	5
MI	James De Young	1830	5	1048	1784	792		792	992
MI	Kalamazoo River Generating Station	55101	1	0	1	0		0	1
MI	Kalkaska Ct Project #1	7984	1A, 1B	0	0	0		0	0
MI	Livingston Generating Station	55102	1, 2, 3, 4	0	1	0		0	1
MI	Marysville	1732	9, 10, 11, 12	5274	3976	0		0	3976
MI	Michigan Power Limited Partnership	54915	1	0	15	3		3	12
MI	Mistersky	1822	5, 6, 7	1179	8233	1		1	8232
MI	Monroe	1733	1, 2, 3, 4	95364	103575	103570		103570	5
MI	New Covert Generating Project	55297	001, 002, 003	0	4	3		3	1
MI	Presque Isle	1769	2, 3, 4, 5, 6, 7, 8, 9	16850	18205	16514		16514	1691
MI	Renaissance Power	55402	CT1, CT2, CT3, CT4	0	4	0		0	4
MI	River Rouge	1740	1, 2, 3	15505	16055	13307		13307	2748
MI	Shiras	1843	3	500	1915	186		186	1729
MI	St. Clair	1743	1, 2, 3, 4, 5, 6, 7	34931	42374	42373		42373	1
MI	Sumpter Plant	7972	1, 2, 3, 4	0	20	0		0	20
MI	Trenton Channel	1745	16, 17, 18, 19, 9A	22827	29071	29066		29066	5
MI	Wyandotte	1866	5, 7, 8	1913	4141	1703		1703	2438
MI	Zeeland Power Company, LLC	55087	CC1, CC2, CC3, CC4	0	8	0		0	8
MN	Allen S King	1915	1	15628	18494	14361		14361	4133
MN	Black Dog	1904	3, 4, 5	11928	50693	3698		3698	46995
MN	Blue Lake Generating Plant	8027	7, 8	0	20	0		0	20
MN	Boswell Energy Center	1893	1, 2, 3, 4	23817	24229	20406		20406	3823
MN	Cascade Creek	6058	CT2, CT3	0	104	0		0	104
MN	Cottage Grove Cogeneration	55010	01	0	4	1		1	3
MN	Faribault Energy Park	56164	EU006	0	1	1		1	0
MN	Fox Lake	1888	3	2069	1469	129		129	1340
MN	Hibbard Energy Center	1897	3, 4	2081	5740	357		357	5383
MN	High Bridge	1912	3, 4, 5, 6	7622	40001	3406		3406	36595
MN	Hoot Lake	1943	2, 3	3220	5738	3215		3215	2523
MN	Hutchinson - Plant 2	6358	1	0	7	0		0	7
MN	Lakefield Junction Generating	7925	CT01, CT02, CT03, CT04, CT05, CT06	0	59	0		0	59
MN	Laskin Energy Center	1891	1, 2	3341	6092	1611		1611	4481
MN	Mankato Energy Center	56104	CT-2	0	2	1		1	1

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

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MN	Minnesota River Station	7844	U001	0	0	0		0	0
MN	Minnesota Valley	1918	4	938	2339	0		0	2339
MN	Northeast Station	1961	NEPP	1052	3832	2078		2078	1754
MN	Pleasant Valley Station	7843	11, 12, 13	0	23	2		2	21
MN	Riverside (1927)	1927	6, 7, 8	9483	14109	10058		10058	4051
MN	Sherburne County	6090	1, 2, 3	39231	67575	24741		24741	42834
MN	Silver Lake	2008	4	3133	4114	1260		1260	2854
MN	Solway Plant	7947	1	0	9	0		0	9
MN	Taconite Harbor Energy Center	10075	1, 2, 3	0	5702	5388		5388	314
MO	Asbury	2076	1	6975	43611	14517		14517	29094
MO	Audrain Power Plant	55234	CT1, CT2, CT3, CT4, CT5, CT6, CT7, CT8	0	8	0		0	8
MO	Blue Valley	2132	3	4670	6299	5997		5997	302
MO	Chamois Power Plant	2169	2	5457	1117	1112		1112	5
MO	Columbia	2123	6, 7, 8	4659	8147	1204		1204	6943
MO	Columbia Energy Center (MO)	55447	CT01, CT02, CT03, CT04	0	20	0		0	20
MO	Dogwood Energy Facility	55178	CT-1, CT-2	0	0	0		0	0
MO	Empire District Elec Co Energy Ctr	6223	3A, 3B, 4A, 4B	0	36	0		0	36
MO	Essex Power Plant	7749	1	0	10	0		0	10
MO	Hawthorn	2079	6, 7, 8, 9, 5A	12773	2011	1896		1896	115
MO	Holden Power Plant	7848	1, 2, 3	0	98	0		0	98
MO	Iatan	6065	1	16208	17727	17518		17518	209
MO	James River	2161	3, 4, 5, **GT2	12039	8436	4040		4040	4396
MO	Labadie	2103	1, 2, 3, 4	66987	53803	51445		51445	2358
MO	Lake Road	2098	6	605	4096	2287		2287	1809
MO	McCartney Generating Station	7903	MGS1A, MGS1B, MGS2A, MGS2B	0	40	0		0	40
MO	Meramec	2104	1, 2, 3, 4	18756	23213	20662		20662	2551
MO	Montrose	2080	1, 2, 3	11073	11943	11561		11561	382
MO	New Madrid Power Plant	2167	1, 2	26187	14687	14677		14677	10
MO	Nodaway Power Plant	7754	1, 2	0	20	0		0	20
MO	Peno Creek Energy Center	7964	CT1A, CT1B, CT2A, CT2B, CT3A, CT3B, CT4A, CT4B	0	40	0		0	40
MO	Rush Island	6155	1, 2	30612	30975	28674		28674	2301
MO	Sibley	2094	1, 2, 3	8791	27793	11967		11967	15826
MO	Sikeston	6768	1	6791	7790	6351		6351	1439

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

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MO	Sioux	2107	1, 2	20315	47304	44148		44148	3156
MO	South Harper Peaking Facility	56151	1, 2, 3	0	3	0		0	3
MO	Southwest	6195	1	4184	4241	4166		4166	75
MO	St. Francis Power Plant	7604	1, 2	0	48	2		2	46
MO	State Line (MO)	7296	1, 2-1, 2-2	0	233	3		3	230
MO	Thomas Hill Energy Center	2168	MB1, MB2, MB3	30110	18510	18495		18495	15
MS	Attala Generating Plant	55220	A01, A02	0	24	4		4	20
MS	Batesville Generation Facility	55063	1, 2, 3	0	7	5		5	2
MS	Baxter Wilson	2050	1, 2	3924	3950	394		394	3556
MS	BTEC New Albany LLC	13213	AA-001, AA-002, AA-003, AA-004, AA-005, AA-006	0	8	0		0	8
MS	BTEC Southaven LLC	55219	S01, S02, S03, S04, S05, S06, S07, S08	0	8	0		0	8
MS	Caledonia	55197	AA-001, AA-002, AA-003	0	3	3		3	0
MS	Caledonia Power I, LLC	55082	AA-001, AA-002, AA-003, AA-004, AA-005, AA-006	0	18	0		0	18
MS	Chevron Cogenerating Station	2047	5	0	31	11		11	20
MS	Choctaw Gas Generation, LLC	55694	AA-001	0	2	0		0	2
MS	Crossroads Energy Center (CPU)	55395	CT01, CT02, CT03, CT04	0	8	0		0	8
MS	Daniel Electric Generating Plant	6073	1, 2, 3A, 3B, 4A, 4B	25505	33386	31769		31769	1617
MS	Delta	2051	1, 2	76	111	4		4	107
MS	Gerald Andrus	8054	1	3282	3292	2045		2045	1247
MS	Kemper County	7960	KCT1, KCT2, KCT3, KCT4	0	190	0		0	190
MS	KGen Hinds LLC	55218	H01, H02	0	5	2		2	3
MS	Magnolia Facility	55451	CTG-1, CTG-2, CTG-3	0	6	3		3	3
MS	Moselle Generating Plant	2070	1, 2, 3, 5, **4	153	995	2		2	993
MS	Natchez	2052	1	2	14	0		0	14
MS	R D Morrow Senior Generating Plant	6061	1, 2	10054	15538	12465		12465	3073
MS	Red Hills Generation Facility	55076	AA001, AA002	0	2790	2150		2150	640
MS	Reliant Energy Choctaw County Gen	55706	CTG1, CTG2, CTG3	0	15	0		0	15
MS	Rex Brown	2053	3, 4, 1A, 1B	212	635	1		1	634
MS	Silver Creek Generating Plant	7988	1, 2, 3	0	30	0		0	30
MS	Southaven Power, LLC	55269	AA-001, AA-002, AA-003	0	5	3		3	2

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
MS	Sweatt Electric Generating Plant	2048	1, 2	164	25	0		0	25
MS	Sylvarena Generating Plant	7989	1, 2, 3	0	30	0		0	30
MS	Warren Peaking Power Facility	55303	AA-001, AA-002, AA-003, AA-004	0	0	0		0	0
MS	Watson Electric Generating Plant	2049	1, 2, 3, 4, 5	23565	38382	29113		29113	9269
MT	Colstrip	6076	1, 2, 3, 4	23051	15267	14298		14298	969
MT	Glendive Generating Station	2176	GT-2	0	0	0		0	0
MT	Hardin	55749	U1	0	500	316		316	184
MT	J E Corette	2187	2	5062	7187	3473		3473	3714
MT	Lewis & Clark	6089	B1	1444	3967	1201		1201	2766
NC	Asheville	2706	1, 2, 3, 4	11883	15476	2495		2495	12981
NC	Belews Creek	8042	1, 2	63471	99447	95290		95290	4157
NC	Buck	2720	5, 6, 7, 8, 9	7871	10854	9560		9560	1294
NC	Cape Fear	2708	5, 6	8493	15939	13307		13307	2632
NC	Cliffside	2721	1, 2, 3, 4, 5	18406	30002	29128		29128	874
NC	Craven County Wood Energy	10525	ES5A	0	157	118		118	39
NC	Dan River	2723	1, 2, 3	7480	15695	7068		7068	8627
NC	Elizabethtown Power	10380	UNIT1, UNIT2	0	66	56		56	10
NC	G G Allen	2718	1, 2, 3, 4, 5	23076	46790	45396		45396	1394
NC	H F Lee Steam Electric Plant	2709	1, 2, 3, 10, 11, 12, 13	9085	16355	13764		13764	2591
NC	L V Sutton	2713	1, 2, 3	12619	22911	19159		19159	3752
NC	Lincoln	7277	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16	0	221	10		10	211
NC	Lumberton Power	10382	UNIT1, UNIT2	0	84	77		77	7
NC	Marshall	2727	1, 2, 3, 4	49030	91534	85051		85051	6483
NC	Mayo	6250	1A, 1B	25570	47885	24499		24499	23386
NC	Plant Rowan County	7826	1, 2, 3, 4, 5	0	5	3		3	2
NC	Richmond County Plant	7805	1, 2, 3, 4, 6, 7, 8	0	100	7		7	93
NC	Riverbend	2732	7, 8, 9, 10	9158	15711	15148		15148	563
NC	Rockingham County Combustion Turbine	55116	CT1, CT2, CT3, CT4, CT5	0	52	0		0	52
NC	Rosemary Power Station	50555	1, 2	0	4	0		0	4
NC	Roxboro	2712	1, 2, 3A, 3B, 4A, 4B	69736	126824	94627		94627	32197
NC	W H Weatherspoon	2716	1, 2, 3	3873	9534	7385		7385	2149
ND	Antelope Valley	6469	B1, B2	23078	25323	14525		14525	10798
ND	Coal Creek	6030	1, 2	44497	32184	32084		32084	100
ND	Coyote	8222	B1	16182	22244	11472		11472	10772

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
ND	Leland Olds	2817	1, 2	35506	41552	40027		40027	1525
ND	Milton R Young	2823	B1, B2	28836	30156	26880		26880	3276
ND	R M Heskett	2790	B2	3202	7667	1836		1836	5831
ND	Stanton	2824	1, 10	8781	3000	2057		2057	943
NE	Beatrice	8000	1, 2	0	20	0		0	20
NE	C W Burdick	2241	B-3, GT-2, GT-3	0	27	0		0	27
NE	Canaday	2226	1	627	1182	7		7	1175
NE	Cass County Station	55972	CT1, CT2	0	0	0		0	0
NE	Gerald Gentleman Station	6077	1, 2	28377	37161	31135		31135	6026
NE	Gerald Whelan Energy Center	60	1	2335	3099	2331		2331	768
NE	Lon D Wright Power Plant	2240	8, 50T	2044	3109	1401		1401	1708
NE	Nebraska City Station	6096	1	13194	15054	14994		14994	60
NE	North Omaha Station	2291	1, 2, 3, 4, 5	17379	25989	14316		14316	11673
NE	Platte	59	1	2927	6447	2637		2637	3810
NE	Rokeby	6373	2, 3	0	10	0		0	10
NE	Salt Valley Generating Station	7887	SVGS2, SVGS3, SVGS4	0	15	0		0	15
NE	Sarpy County Station	2292	CT3, CT4A, CT4B, CT5A, CT5B	0	7	0		0	7
NE	Sheldon	2277	1, 2	4448	5904	4403		4403	1501
NH	Granite Ridge Energy	55170	0001, 0002	0	8	7		7	1
NH	Merrimack	2364	1, 2	13530	32812	32726		32726	86
NH	Newington	8002	1	11663	2293	2016		2016	277
NH	Newington Power Facility	55661	1, 2	0	80	6		6	74
NH	Schiller	2367	4, 5, 6	4614	5560	5538		5538	22
NJ	AES Red Oak	55239	1, 2, 3	0	13	3		3	10
NJ	B L England	2378	1, 2, 3	11162	11067	10214		10214	853
NJ	Bayonne Plant Holding, LLC	50497	001001, 002001, 004001	0	6	0		0	6
NJ	Bergen	2398	1101, 1201, 1301, 1401, 2101, 2201	4022	17	12		12	5
NJ	Burlington Generating Station	2399	121, 122, 123, 124	561	5	0		0	5
NJ	Calpine Newark Cogeneration	50797	001001	0	0	0		0	0
NJ	Camden Plant Holding, LLC	10751	002001	0	4	0		0	4
NJ	Deepwater	2384	1, 8	5856	1659	1503		1503	156
NJ	EFS Parlin Holdings, LLC	50799	001001, 003001	0	0	0		0	0
NJ	Gilbert Generating Station	2393	9, 04, 05, 06, 07	3191	6	1		1	5
NJ	Hudson Generating Station	2403	1, 2	17169	19714	19709		19709	5

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
NJ	Kearny Generating Station	2404	121, 122, 123, 124	298	8	0		0	8
NJ	Linden Cogeneration Facility	50006	004001	0	13	5		5	8
NJ	Linden Generating Station	2406	5, 6, 7, 8, 1101, 1201, 2101, 2201	3577	13	4		4	9
NJ	Mercer Generating Station	2408	1, 2	15122	14528	14517		14517	11
NJ	Newark Bay Cogen	50385	1001, 2001	0	8	0		0	8
NJ	North Jersey Energy Associates	10308	1001, 1002	0	4	2		2	2
NJ	Ocean Peaking Power, LP	55938	OPP3, OPP4	0	10	0		0	10
NJ	Pedricktown Cogeneration Plant	10099	001001	0	2	0		0	2
NJ	Sewaren Generating Station	2411	1, 2, 3, 4	1285	90	80		80	10
NJ	Sherman Avenue	7288	1	0	10	1		1	9
NJ	Sunoco Power Generation, LLC	50561	0001, 0002	0	2	0		0	2
NM	Afton Generating Station	55210	0001	0	0	0		0	0
NM	Bluffview Power Plant	55977	CTG-1	0	1	1		1	0
NM	Cunningham	2454	121B, 122B, 123T, 124T	311	1365	4		4	1361
NM	Four Corners Steam Elec Station	2442	1, 2, 3, 4, 5	37442	34522	15193		15193	19329
NM	Lordsburg Generating Station	7967	1, 2	0	0	0		0	0
NM	Luna Energy Facility	55343	CTG1, CTG2	0	4	4		4	0
NM	Maddox	2446	051B	170	751	2		2	749
NM	Milagro Cogeneration and Gas Plant	54814	1, 2	0	4	2		2	2
NM	Person Generating Project	55039	GT-1	0	48	0		0	48
NM	Prewitt Escalante Generating Station	87	1	1874	1443	970		970	473
NM	Pyramid Generating Station	7975	1, 2, 3, 4	0	40	1		1	39
NM	Reeves Generating Station	2450	1, 2, 3	115	111	0		0	111
NM	Rio Grande	2444	6, 7, 8	84	570	2		2	568
NM	San Juan	2451	1, 2, 3, 4	40788	43937	14981		14981	28956
NV	Apex Generating Station	55514	CTG01, CTG02	0	5	4		4	1
NV	Chuck Lenzie Generating Station	55322	CTG-1, CTG-2, CTG-3, CTG-4	0	20	10		10	10
NV	El Dorado Energy	55077	EDE1, EDE2	0	27	8		8	19
NV	Fort Churchill	2330	1, 2	948	4709	23		23	4686
NV	Harry Allen	7082	**3, **4	0	23	0		0	23
NV	Las Vegas Cogeneration II, LLC	10761	2, 3, 4, 5	0	40	0		0	40
NV	Mohave	2341	1, 2	53216	70050	0		0	70050
NV	North Valmy	8224	1, 2	11222	19279	7160		7160	12119
NV	REI Bighorn	55687	BHG1, BHG2	0	8	4		4	4

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
NV	Reid Gardner	2324	1, 2, 3, 4	9314	16963	2015		2015	14948
NV	Silverhawk	55841	A01, A03	0	26	8		8	18
NV	Sunrise	2326	1	50	325	0		0	325
NV	Tracy	2336	1, 2, 3, 4, 5, 6	375	1740	5		5	1735
NV	Tri-Center Naniwa Energy	55494	CT1, CT2, CT3, CT4, CT5, CT6	0	31	0		0	31
NY	23rd and 3rd	7910	2301, 2302	0	0	0		0	0
NY	74th Street	2504	120, 121, 122	1343	1343	736		736	607
NY	AES Cayuga, LLC	2535	1, 2	10143	1663	1333		1333	330
NY	AES Greenidge	2527	4, 5, 6	5147	13667	11825		11825	1842
NY	AES Hickling	2529	1, 2, 3, 4	3278	0	0		0	0
NY	AES Jennison	2531	1, 2, 3, 4	2774	0	0		0	0
NY	AES Somerset (Kintigh)	6082	1	13889	2898	2573		2573	325
NY	AES Westover (Goudey)	2526	11, 12, 13	4860	10154	8736		8736	1418
NY	AG - Energy	10803	1, 2	0	1	0		0	1
NY	Allegany Station No. 133	10619	00001	0	3	0		0	3
NY	Arthur Kill	2490	20, 30	3845	4	3		3	1
NY	Astoria Energy	55375	CT1, CT2	0	5	4		4	1
NY	Astoria Generating Station	8906	20, 30, 40, 50	10870	2800	1351		1351	1449
NY	Athens Generating Company	55405	1, 2, 3	0	10	10		10	0
NY	Batavia Energy	54593	1	0	0	0		0	0
NY	Bayswater Peaking Facility	55699	1, 2	0	8	5		5	3
NY	Bethlehem Energy Center (Albany)	2539	10001, 10002, 10003	6637	16	6		6	10
NY	Bethpage Energy Center	50292	GT1, GT2, GT3, GT4	0	3	2		2	1
NY	Binghamton Cogen Plant	55600	1	0	0	0		0	0
NY	Black Rock Facility	10331	1	0	0			0	0
NY	Bowline Generating Station	2625	1, 2	8481	2747	129		129	2618
NY	Brentwood	7912	BW01	0	0	0		0	0
NY	Brooklyn Navy Yard Cogeneration	54914	1, 2	0	22	6		6	16
NY	Carr Street Generating Station	50978	A, B	0	3	0		0	3
NY	Carthage Energy	10620	1	0	3	0		0	3
NY	Charles Poletti	2491	001	6438	1561	671		671	890
NY	Dunkirk	2554	1, 2, 3, 4	17270	17013	10071		10071	6942
NY	Dynegy Danskammer	2480	1, 2, 3, 4	11027	12227	10639		10639	1588
NY	Dynegy Roseton	8006	1, 2	30496	24643	2188		2188	22455
NY	E F Barrett	2511	10, 20	4709	424	173		173	251
NY	East River	2493	1, 2, 60, 70	3859	2463	204		204	2259

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
NY	EPCOR Power (Castleton) LLC	10190	1	0	4	0		0	4
NY	Equus Freeport Power Generating Station	56032	0001	0	7	2		2	5
NY	Far Rockaway	2513	40	469	41	1		1	40
NY	Freeport Power Plant No. 2	2679	5	0	0	0		0	0
NY	Fulton Cogeneration Associates	54138	01GTDB	0	1	0		0	1
NY	Glenwood	2514	40, 50	1842	357	2		2	355
NY	Glenwood Landing Energy Center	7869	UGT012, UGT013	0	4	0		0	4
NY	Harlem River Yard	7914	HR01, HR02	0	0	0		0	0
NY	Hawkeye Energy Greenport, LLC	55969	U-01	0	25	6		6	19
NY	Hell Gate	7913	HG01, HG02	0	0	0		0	0
NY	Huntley Power	2549	63, 64, 65, 66, 67, 68	21899	21582	12299		12299	9283
NY	Ilion Energy Center	50459	1	0	0	0		0	0
NY	Indeck-Corinth Energy Center	50458	1	0	5	1		1	4
NY	Indeck-Olean Energy Center	54076	1	0	52	1		1	51
NY	Indeck-Oswego Energy Center	50450	1	0	67	0		0	67
NY	Indeck-Silver Springs Energy Center	50449	1	0	15	2		2	13
NY	Indeck-Yerkes Energy Center	50451	1	0	27	0		0	27
NY	Independence	54547	1, 2, 3, 4	0	4	4		4	0
NY	Lovett Generating Station	2629	3, 4, 5	9782	9485	9123		9123	362
NY	Massena Energy Facility	54592	001	0	0	0		0	0
NY	Niagara Generation, LLC	50202	1	0	1187	1092		1092	95
NY	North 1st	7915	NO1	0	0	0		0	0
NY	Northport	2516	1, 2, 3, 4	35369	9961	9084		9084	877
NY	Onondaga Cogeneration	50855	1, 2	0	6	0		0	6
NY	Oswego Harbor Power	2594	3, 4, 5, 6	22538	709	675		675	34
NY	Pinelawn Power	56188	00001	0	1	1		1	0
NY	Poletti 500 MW CC	56196	CTG7A, CTG7B	0	10	8		8	2
NY	Port Jefferson Energy Center	2517	1, 2, 3, 4, UGT002, UGT003	10551	4977	1988		1988	2989
NY	Pouch Terminal	8053	PT01	0	0	0		0	0
NY	PPL Edgewood Energy	55786	CT01, CT02	0	0	0		0	0
NY	PPL Shoreham Energy	55787	CT01, CT02	0	5	4		4	1
NY	Project Orange Facility	54425	001, 002	0	2	1		1	1
NY	Ravenswood Generating Station	2500	10, 20, 30, UCC001	10835	2502	1153		1153	1349
NY	Rensselaer Cogen	54034	1GTDBS	0	4	0		0	4
NY	Richard M Flynn (Holtsville)	7314	001	0	21	17		17	4
NY	Rochester 7 - Russell Station	2642	1, 2, 3, 4	6518	25823	19509		19509	6314

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
NY	S A Carlson	2682	9, 10, 11, 12, 20	3037	3570	3045		3045	525
NY	South Glens Falls Energy	10618	1	0	3	0		0	3
NY	Sterling Power Plant	50744	00001	0	0	0		0	0
NY	Vernon Boulevard	7909	VB01, VB02	0	0	0		0	0
NY	WPS Syracuse Generation, LLC	10621	1	0	3	0		0	3
OH	AMP-Ohio Gas Turbines Bowling Green	55262	CT1	0	2	0		0	2
OH	AMP-Ohio Gas Turbines Galion	55263	CT1	0	2	0		0	2
OH	AMP-Ohio Gas Turbines Napoleon	55264	CT1	0	2	0		0	2
OH	Ashtabula	2835	7	15232	5639	5589		5589	50
OH	Avon Lake Power Plant	2836	10, 12	25045	43679	43479		43479	200
OH	Bay Shore	2878	1, 2, 3, 4	20529	15257	15208		15208	49
OH	Cardinal	2828	1, 2, 3	49319	90772	86880		86880	3892
OH	Conesville	2840	3, 4, 5, 6	45744	93316	90541		90541	2775
OH	Darby Electric Generating Station	55247	CT1, CT2, CT3, CT4, CT5, CT6	0	0	0		0	0
OH	Eastlake	2837	1, 2, 3, 4, 5	34273	82756	82706		82706	50
OH	Frank M Tait Station	2847	1, 2, 3	0	12	0		0	12
OH	Gen J M Gavin	8102	1, 2	68837	26048	24787		24787	1261
OH	Greenville Electric Gen Station	55228	G1CT1, G1CT2, G2CT1, G2CT2, G3CT1, G3CT2, G4CT1, G4CT2	0	0	0		0	0
OH	Hamilton Municipal Power Plant	2917	9	1665	2695	1433		1433	1262
OH	Hanging Rock Energy Facility	55736	CTG1, CTG2, CTG3, CTG4	0	10	4		4	6
OH	J M Stuart	2850	1, 2, 3, 4	76200	104686	103649		103649	1037
OH	Killen Station	6031	2	16928	29053	22825		22825	6228
OH	Kyger Creek	2876	1, 2, 3, 4, 5	39155	72157	67157		67157	5000
OH	Lake Road	2908	6	1340	9380	0		0	9380
OH	Lake Shore	2838	18	6336	2888	2838		2838	50
OH	Madison Generating Station	55110	1, 2, 3, 4, 5, 6, 7, 8	0	16	0		0	16
OH	Miami Fort Generating Station	2832	6, 7, 8, 5-1, 5-2	40036	63782	62028		62028	1754
OH	Muskingum River	2872	1, 2, 3, 4, 5	41070	126675	122984		122984	3691
OH	Niles	2861	1, 2	6919	11803	11603		11603	200
OH	O H Hutchings	2848	H-1, H-2, H-3, H-4, H-5, H-6	9923	3382	3287		3287	95
OH	Omega JV2 Bowling Green	7783	P001	0	1	0		0	1
OH	Omega JV2 Hamilton	7782	P001	0	1	0		0	1

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
OH	Picway	2843	9	2128	6635	6441		6441	194
OH	R E Burger	2864	5, 6, 7, 8	17621	17345	17295		17295	50
OH	Richard Gorsuch	7253	1, 2, 3, 4	19500	22266	20483		20483	1783
OH	Richland Peaking Station	2880	CTG4, CTG5, CTG6	0	15	0		0	15
OH	Robert P Mone	7872	1, 2, 3	0	4	0		0	4
OH	Rolling Hills Generating LLC	55401	CT-1, CT-2, CT-3, CT-4, CT-5	0	0	0		0	0
OH	Tait Electric Generating Station	55248	CT4, CT5, CT6, CT7	0	0	0		0	0
OH	Troy Energy, LLC	55348	1, 2, 3, 4	0	2	2		2	0
OH	W H Sammis	2866	1, 2, 3, 4, 5, 6, 7	72492	86441	86391		86391	50
OH	W H Zimmer Generating Station	6019	1	16154	22496	22054		22054	442
OH	Walter C Beckjord Generating Station	2830	1, 2, 3, 4, 5, 6	23268	63728	62480		62480	1248
OH	Washington Energy Facility	55397	CT1, CT2	0	5	0		0	5
OH	Waterford Plant	55503	1, 2, 3	0	7	0		0	7
OH	West Lorain	2869	2, 3, 4, 5, 6	0	25	0		0	25
OH	Woodsdale	7158	**GT1, **GT2, **GT3, **GT4, **GT5, **GT6	1764	12	0		0	12
OK	Anadarko	3006	3, 7, 8	0	13	0		0	13
OK	Arbuckle	2947	ARB	45	90	0		0	90
OK	Chouteau Power Plant	7757	1, 2	0	38	4		4	34
OK	Comanche (8059)	8059	7251, 7252	335	583	3		3	580
OK	Conoco	7185	**1, **2	444	3009	3		3	3006
OK	Grand River Dam Authority	165	1, 2	23038	34015	16801		16801	17214
OK	Green Country Energy, LLC	55146	CTGEN1, CTGEN2, CTGEN3	0	10	6		6	4
OK	Horseshoe Lake	2951	6, 7, 8, 9, 10	717	4935	4		4	4931
OK	Hugo	6772	1	11877	17615	9363		9363	8252
OK	McClain Energy Facility	55457	CT1, CT2	0	80	8		8	72
OK	Mooreland	3008	1, 2, 3	51	338	1		1	337
OK	Muskogee	2952	3, 4, 5, 6	32154	48970	28628		28628	20342
OK	Mustang	2953	1, 2, 3, 4	222	1674	2		2	1672
OK	Northeastern	2963	3302, 3313, 3314, 3301A, 3301B	36394	43921	34646		34646	9275
OK	Oneta Energy Center	55225	CTG-1, CTG-2, CTG-3, CTG-4	0	5	4		4	1
OK	Ponca	762	2, 3, 4	0	0	0		0	0
OK	Redbud Power Plant	55463	CT-01, CT-02, CT-03, CT-04	0	22	8		8	14

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
OK	Riverside (4940)	4940	1501, 1502	804	4215	7		7	4208
OK	Seminole (2956)	2956	1, 2, 3	1359	9339	12		12	9327
OK	Sooner	6095	1, 2	20450	30852	16579		16579	14273
OK	Southwestern	2964	8002, 8003, 801N, 801S	182	428	2		2	426
OK	Spring Creek Power Plant	55651	CT-01, CT-02, CT-03, CT-04	0	1	0		0	1
OK	Tenaska Kiamichi Generating Station	55501	CTGDB1, CTGDB2, CTGDB3, CTGDB4	0	16	12		12	4
OK	Tulsa	2965	1402, 1403, 1404	160	50	2		2	48
OR	Boardman	6106	1SG	13377	8725	8703		8703	22
OR	Coyote Springs	7350	CTG1, CTG2	0	6	6		6	0
OR	Hermiston	54761	1, 2	0	10	6		6	4
OR	Hermiston Power Plant	55328	CTG-1, CTG-2	0	8	6		6	2
OR	Klamath Cogeneration Project	55103	CT1, CT2	0	4	3		3	1
OR	Klamath Energy LLC	55544	GT1, GT2, GT3, GT4	0	8	0		0	8
OR	Morrow Power Project	55683	1	0	0	0		0	0
PA	AES Ironwood	55337	0001, 0002	0	6	4		4	2
PA	Allegheny Energy Hunlock Unit 4	56397	4	0	20	0		0	20
PA	Allegheny Energy Unit 1 and Unit 2	55196	1, 2	0	20	0		0	20
PA	Allegheny Energy Unit 8 and Unit 9	55377	8, 9	0	20	0		0	20
PA	Allegheny Energy Units 3, 4 & 5	55710	3, 4	0	20	0		0	20
PA	Armstrong Energy Ltd Part	55347	1, 2, 3, 4	0	0	0		0	0
PA	Armstrong Power Station	3178	1, 2	12869	27710	27110		27110	600
PA	Bethlehem Power Plant	55690	1, 2, 3, 5, 6, 7	0	16	6		6	10
PA	Bruce Mansfield	6094	1, 2, 3	41259	23482	23431		23431	51
PA	Brunner Island	3140	1, 2, 3	48595	93858	93545		93545	313
PA	Brunot Island Power Station	3096	3, 2A, 2B	0	31	0		0	31
PA	Chambersburg Units 12 and 13	55654	12, 13	0	20	0		0	20
PA	Cheswick	8226	1	16891	32573	32373		32373	200
PA	Conemaugh	3118	1, 2	54690	10747	8037		8037	2710
PA	Cromby	3159	1, 2	4313	4353	3613		3613	740
PA	Eddystone Generating Station	3161	1, 2, 3, 4	9756	9828	6454		6454	3374
PA	Elrama	3098	1, 2, 3, 4	7414	5021	4821		4821	200
PA	Fairless Energy, LLC	55298	1A, 1B, 2A, 2B	0	35	6		6	29
PA	Fayette Energy Facility	55516	CTG1, CTG2	0	4	0		0	4
PA	FPL Energy Marcus Hook, LP	55801	0001, 0002, 0003	0	9	6		6	3

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
PA	Grays Ferry Cogen Partnership	54785	2	0	3	2		2	1
PA	Handsome Lake Energy	55233	EU-1A, EU-1B, EU-2A, EU-2B, EU-3A, EU-3B, EU-4A, EU-4B, EU-5A, EU-5B	0	0	0		0	0
PA	Hatfields Ferry Power Station	3179	1, 2, 3	49772	137182	135082		135082	2100
PA	Homer City	3122	1, 2, 3	61702	126506	106772		106772	19734
PA	Hunlock Power Station	3176	6	2257	4471	4463		4463	8
PA	Hunterstown Combined Cycle	55976	CT101, CT201, CT301	0	12	2		2	10
PA	Keystone	3136	1, 2	58264	164363	164353		164353	10
PA	Liberty Electric Power Plant	55231	0001, 0002	0	16	2		2	14
PA	Lower Mount Bethel Energy	55667	CT01, CT02	0	3	2		2	1
PA	Martins Creek	3148	1, 2, 3, 4	36295	16821	16815		16815	6
PA	Mitchell Power Station	3181	1, 2, 3, 33	3530	1181	931		931	250
PA	Montour	3149	1, 2	48871	129365	129357		129357	8
PA	Mt. Carmel Cogeneration	10343	SG-101	0	498	492		492	6
PA	New Castle	3138	3, 4, 5	12905	13772	13572		13572	200
PA	North East Cogeneration Plant	54571	001, 002	0	0	0		0	0
PA	Ontelaunee Energy Center	55193	CT1, CT2	0	3	3		3	0
PA	PEI Power Power Corporation	50279	2	0	0	0		0	0
PA	Portland	3113	1, 2, 5	6973	30775	30685		30685	90
PA	Schuylkill	3169	1	572	564	95		95	469
PA	Seward	3130	1, 2	7194	7438	7358		7358	80
PA	Shawville	3131	1, 2, 3, 4	21067	47447	47287		47287	160
PA	Springdale Power Station	3182	77, 88	0	0	0		0	0
PA	Sunbury	3152	3, 4, 1A, 1B, 2A, 2B	16550	28322	23876		23876	4446
PA	Titus	3115	1, 2, 3	6617	13459	13339		13339	120
PA	Williams Generation Co (Hazleton)	10870	TURB2, TURB3, TURB4	0	12	0		0	12
PA	WPS Westwood Generation, LLC	50611	031	0	310	300		300	10
RI	Manchester Street	3236	9, 10, 11	1663	1803	3		3	1800
RI	Pawtucket Power Associates, LP	54056	1	0	2	1		1	1
RI	Rhode Island State Energy Partners	55107	RISEP1, RISEP2	0	9	6		6	3
RI	Tiverton Power Associates	55048	1	0	12	2		2	10
SC	Broad River Energy Center	55166	CT-1, CT-2, CT-3, CT-4, CT-5	0	5	0		0	5
SC	Canadys Steam	3280	CAN1, CAN2, CAN3	10450	24886	22984		22984	1902
SC	Cherokee County Cogen	55043	CCCP1	0	8	1		1	7

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
SC	Columbia Energy Center (SC)	55386	CT-1, CT-2	0	2	1		1	1
SC	Cope Station	7210	COP1	2616	4056	2604		2604	1452
SC	Cross	130	1, 2	14544	16096	9412		9412	6684
SC	Darlington County	3250	12, 13	0	40	1		1	39
SC	Dolphus M Grainger	3317	1, 2	3391	13364	13063		13063	301
SC	H B Robinson	3251	1	3815	18410	12503		12503	5907
SC	Hagood	3285	HAG4	2189	452	0		0	452
SC	Jasper County Generating Facility	55927	CT01, CT02, CT03	0	240	4		4	236
SC	Jefferies	3319	1, 2, 3, 4	7630	26601	26299		26299	302
SC	John S. Rainey Generating Station	7834	CT3, CT4, CT5, CT1A, CT1B, CT2A, CT2B	0	20	4		4	16
SC	McMeekin	3287	MCM1, MCM2	8118	14877	13308		13308	1569
SC	Mill Creek Combustion Turbine Sta	7981	1, 2, 3, 4, 5, 6, 7, 8	0	114	0		0	114
SC	Urquhart	3295	URQ3, URQ4, URQ5, URQ6	7036	8823	6738		6738	2085
SC	W S Lee	3264	1, 2, 3	7854	9678	9397		9397	281
SC	Wateree	3297	WAT1, WAT2	18987	34831	32797		32797	2034
SC	Williams	3298	WIL1	15821	29669	28148		28148	1521
SC	Winyah	6249	1, 2, 3, 4	20845	43039	42709		42709	330
SD	Angus Anson	7237	2, 3, 4	1871	13079	1		1	13078
SD	Big Stone	6098	1	13715	19806	11987		11987	7819
SD	Groton Generating Station	56238	CT001	0	100	0		0	100
SD	Huron	3344	**2A, **2B	183	2	0		0	2
SD	Lange	55478	CT1	0	13	0		0	13
TN	Allen	3393	1, 2, 3	20595	22223	17414		17414	4809
TN	Brownsville Power I, LLC	55081	AA-001, AA-002, AA-003, AA-004	0	12	0		0	12
TN	Bull Run	3396	1	25047	30830	27987		27987	2843
TN	Cumberland	3399	1, 2	78282	34534	18352		18352	16182
TN	Dupont Johnsonville	880001	JVD1, JVD2, JVD3, JVD4	7110	0	0		0	0
TN	Gallatin	3403	1, 2, 3, 4, GCT5, GCT6, GCT7, GCT8	32872	44957	23459		23459	21498
TN	Gleason Generating Facility	55251	CTG-1, CTG-2, CTG-3	0	50	0		0	50
TN	John Sevier	3405	1, 2, 3, 4	25907	33219	30126		30126	3093
TN	Johnsonville	3406	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, JCT17, JCT18, JCT19, JCT20	34783	95228	86792		86792	8436

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
TN	Kingston	3407	1, 2, 3, 4, 5, 6, 7, 8, 9	48855	61247	55473		55473	5774
TN	Lagoon Creek	7845	LCT1, LCT2, LCT3, LCT4, LCT5, LCT6, LCT7, LCT8, LCT9, LCT10, LCT11, LCT12	0	1067	5		5	1062
TX	AES Deepwater, Inc.	10670	01001	0	4609	2188		2188	2421
TX	AES Western Power, LLC	3461	DWP9	28	0	0		0	0
TX	Alex Ty Cooke Generating Station	3602	1, 2	130	262	0		0	262
TX	Altura Channelview Cogen Facility	50815	ENG101, ENG201, ENG301, ENG401, ENG501, ENG601	0	12	10		10	2
TX	Barney M. Davis	4939	1, 2	894	904	2		2	902
TX	Bastrop Clean Energy Center	55168	CTG-1A, CTG-1B	0	10	5		5	5
TX	Baytown Energy Center	55327	CTG-1, CTG-2, CTG-3	0	14	10		10	4
TX	Big Brown	3497	1, 2	40863	101574	96221		96221	5353
TX	Blackhawk Station	55064	001, 002	0	10	7		7	3
TX	Bosque County Power Plant	55172	GT-1, GT-2, GT-3	0	4	3		3	1
TX	Brazos Valley Energy, LP	55357	CTG1, CTG2	0	5	5		5	0
TX	Bryan	3561	6	19	127	7		7	120
TX	C E Newman	3574	BW5	3	19	0		0	19
TX	C. R. Wing Cogeneration Plant	52176	1, 2	0	16	2		2	14
TX	Calpine Hidalgo Energy Center	7762	HRSG1, HRSG2	0	7	4		4	3
TX	Cedar Bayou	3460	CBY1, CBY2, CBY3	2460	15880	9		9	15871
TX	Channel Energy Center	55299	CTG1, CTG2	0	18	16		16	2
TX	Coleto Creek	6178	1	14721	17180	14008		14008	3172
TX	Collin	3500	1	92	0	0		0	0
TX	Corpus Christi Energy Center	55206	CU1, CU2	0	8	6		6	2
TX	Cottonwood Energy Project	55358	CT1, CT2, CT3, CT4	0	8	6		6	2
TX	Dansby	6243	1, 2	94	639	1		1	638
TX	Decker Creek	3548	1, 2	323	326	4		4	322
TX	Decordova	8063	1	1018	4	0		0	4
TX	Deer Park Energy Center	55464	CTG1, CTG2, CTG3, CTG4	0	24	20		20	4
TX	Eagle Mountain	3489	1, 2, 3	292	0	0		0	0
TX	Eastman Cogeneration Facility	55176	1, 2	0	99	6		6	93
TX	Ennis-Tractebel Power Company	55223	GT-1	0	7	3		3	4
TX	Exelon Laporte Generating Station	55365	GT-1, GT-2, GT-3, GT-4	0	33	0		0	33

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
TX	Exxonmobil Beaumont Refinery	50625	61STK1, 61STK2, 61STK3	0	20	12		12	8
TX	Fort Phantom Power Station	4938	1, 2	313	0	0		0	0
TX	FPLE Forney, LP	55480	U1, U2, U3, U4, U5, U6	0	37	18		18	19
TX	Freestone Power Generation	55226	GT1, GT2, GT3, GT4	0	14	8		8	6
TX	Frontera Generation Facility	55098	1, 2	0	25	4		4	21
TX	Gibbons Creek Steam Electric Station	6136	1	14414	21545	11913		11913	9632
TX	Graham	3490	1, 2	731	194	95		95	99
TX	Greens Bayou	3464	GBY5	389	2618	1		1	2617
TX	Gregory Power Facility	55086	101, 102	0	27	9		9	18
TX	Guadalupe Generating Station	55153	CTG-1, CTG-2, CTG-3, CTG-4	0	16	10		10	6
TX	H W Pirkey Power Plant	7902	1	20532	33285	2641		2641	30644
TX	Handley Generating Station	3491	2, 3, 4, 5, 1A, 1B	705	3569	3		3	3566
TX	Harrington Station	6193	061B, 062B, 063B	26224	31123	21236		21236	9887
TX	Harrison County Power Project	55664	GT-1, GT-2	0	12	2		2	10
TX	Hays Energy Project	55144	STK1, STK2, STK3, STK4	0	13	9		9	4
TX	Holly Street	3549	3, 4	191	191	2		2	189
TX	J K Spruce	7097	**1	6692	10537	3274		3274	7263
TX	J L Bates	3438	1, 2	172	0	0		0	0
TX	J Robert Massengale Generating Station	3604	GT1	0	2	1		1	1
TX	J T Deely	6181	1, 2	26841	32943	20905		20905	12038
TX	Jack County Generation Facility	55230	CT-1, CT-2	0	8	8		8	0
TX	Johnson County Generation Facility	54817	EAST	0	6	1		1	5
TX	Jones Station	3482	151B, 152B	218	1426	8		8	1418
TX	Knox Lee Power Plant	3476	2, 3, 4, 5	285	1563	65		65	1498
TX	La Palma	3442	7	178	5	2		2	3
TX	Lake Creek	3502	1, 2	230	4	0		0	4
TX	Lake Hubbard	3452	1, 2	774	20	5		5	15
TX	Lamar Power (Paris)	55097	1, 2, 3, 4	0	18	10		10	8
TX	Laredo	3439	1, 2, 3	114	122	4		4	118
TX	Leon Creek	3609	3, 4, CGT1, CGT2, CGT3, CGT4	12	288	0		0	288
TX	Lewis Creek	3457	1, 2	588	2922	6		6	2916
TX	Limestone	298	LIM1, LIM2	37945	38887	15917		15917	22970
TX	Lon C Hill	3440	1, 2, 3, 4	395	0	0		0	0
TX	Lone Star Power Plant	3477	1	0	5	0		0	5

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
TX	Lost Pines 1	55154	1, 2	0	66	8		8	58
TX	Magic Valley Generating Station	55123	CTG-1, CTG-2	0	7	4		4	3
TX	Martin Lake	6146	1, 2, 3	98933	88142	77419		77419	10723
TX	Midlothian Energy	55091	STK1, STK2, STK3, STK4, STK5, STK6	0	24	16		16	8
TX	Monticello	6147	1, 2, 3	81811	82712	77538		77538	5174
TX	Moore County Station	3483	3	0	1	0		0	1
TX	Morgan Creek	3492	5, 6	1070	10	0		0	10
TX	Mountain Creek Generating Station	3453	2, 6, 7, 8, 3A, 3B	669	3561	2		2	3559
TX	Mustang Station	55065	1, 2	0	34	6		6	28
TX	Mustang Station Units 4 and 5	56326	GEN1	0	7	0		0	7
TX	Neches	3458	11, 13, 15, 18	0	0	0		0	0
TX	New Gulf Power Facility	50137	1	0	4	0		0	4
TX	Newman	3456	1, 2, 3, **4, **5	230	1424	4		4	1420
TX	Nichols Station	3484	141B, 142B, 143B	213	1467	4		4	1463
TX	North Lake	3454	1, 2, 3	575	4	0		0	4
TX	North Texas	3627	3	13	11	0		0	11
TX	Nueces Bay	3441	5, 6, 7	637	637	0		0	637
TX	O W Sommers	3611	1, 2	666	3184	5		5	3179
TX	Oak Creek Power Station	3523	1	106	0	0		0	0
TX	Odessa-Ector Generating Station	55215	GT1, GT2, GT3, GT4	0	16	12		12	4
TX	Oklaunion Power Station	127	1	7859	8142	3794		3794	4348
TX	P H Robinson	3466	PHR1, PHR2, PHR3, PHR4	2620	281	0		0	281
TX	Paint Creek Power Station	3524	1, 2, 3, 4	155	0	0		0	0
TX	Pasadena Power Plant	55047	CG-1, CG-2, CG-3	0	9	5		5	4
TX	Permian Basin	3494	5, 6	907	60	20		20	40
TX	Plant X	3485	111B, 112B, 113B, 114B	91	606	5		5	601
TX	Power Lane Steam Plant	4195	2, 3	496	2469	0		0	2469
TX	R W Miller	3628	1, 2, 3, **4, **5	2073	26	2		2	24
TX	Ray Olinger	3576	BW2, BW3, CE1, GE4	181	1238	3		3	1235
TX	Reliant Energy Channelview Cogen	55187	CHV1, CHV2, CHV3, CHV4	0	26	16		16	10
TX	Rio Nogales Power Project, LP	55137	CTG-1, CTG-2, CTG-3	0	20	9		9	11
TX	Rio Pecos Power Station	3526	5, 6	243	0	0		0	0
TX	Sabine	3459	1, 2, 3, 4, 5	1719	8578	15		15	8563
TX	Sabine Cogeneration Facility	55104	SAB-1, SAB-2	0	4	2		2	2

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
TX	Sam Bertron	3468	SRB1, SRB2, SRB3, SRB4	274	1780	2		2	1778
TX	Sam Rayburn Plant	3631	CT7, CT8, CT9	0	2	0		0	2
TX	Sam Seymour	6179	1, 2, 3	43800	37259	27442		27442	9817
TX	San Angelo Power Station	3527	2	161	0	0		0	0
TX	San Jacinto Steam Electric Station	7325	SJS1, SJS2	0	51	5		5	46
TX	San Miguel	6183	SM-1	17216	20455	11827		11827	8628
TX	Sand Hill Energy Center	7900	SH1, SH2, SH3, SH4, SH5	0	14	3		3	11
TX	Sandow	6648	4	25698	28731	23747		23747	4984
TX	Silas Ray	3559	9, 10	0	548	0		0	548
TX	Sim Gideon	3601	1, 2, 3	380	1532	3		3	1529
TX	South Houston Green Power Site	55470	EPN801, EPN802, EPN803	0	191	57		57	134
TX	Spencer	4266	4, 5	42	276	1		1	275
TX	SRW Cogen Limited Partnership	55120	CTG-1, CTG-2	0	18	6		6	12
TX	Stryker Creek	3504	1, 2	695	40	7		7	33
TX	Sweeny Cogeneration Facility	55015	1, 2, 3, 4	0	180	12		12	168
TX	Sweetwater Generating Plant	50615	GT01, GT02, GT03	0	20	0		0	20
TX	T C Ferguson	4937	1	253	737	3		3	734
TX	Tenaska Frontier Generation Station	55062	1, 2, 3	0	12	9		9	3
TX	Tenaska Gateway Generating Station	55132	OGTDB1, OGTDB2, OGTDB3	0	12	9		9	3
TX	Tolk Station	6194	171B, 172B	29225	51859	20642		20642	31217
TX	Tradinghouse	3506	1, 2	1588	25	2		2	23
TX	Trinidad	3507	9	142	30	6		6	24
TX	Twin Oaks Power, LP	7030	U1, U2	5623	7220	5072		5072	2148
TX	V H Braunig	3612	1, 2, 3, CT01, CT02	615	4287	8		8	4279
TX	Valley (TXU)	3508	1, 2, 3	719	30	2		2	28
TX	Victoria Power Station	3443	5, 6	362	30	0		0	30
TX	W A Parish	3470	WAP1, WAP2, WAP3, WAP4, WAP5, WAP6, WAP7, WAP8	66984	128671	56438		56438	72233
TX	W B Tuttle	3613	1, 2, 3, 4	80	560	0		0	560
TX	Webster	3471	WEB3	374	613	0		0	613
TX	Welsh Power Plant	6139	1, 2, 3	41395	43819	27197		27197	16622
TX	Wilkes Power Plant	3478	1, 2, 3	277	1856	16		16	1840
TX	Wise County Power Company	55320	GT-1, GT-2	0	10	8		8	2

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
TX	Wolf Hollow I, LP	55139	CTG1, CTG2	0	14	8		8	6
UT	Bonanza	7790	1-1	10785	1912	864		864	1048
UT	Carbon	3644	1, 2	4412	6979	6779		6779	200
UT	Currant Creek Power Project	56102	CTG1A, CTG1B	0	24	4		4	20
UT	Desert Power Plant	55858	UNT1, UNT2	0	4	0		0	4
UT	Gadsby	3648	1, 2, 3, 4, 5, 6	3979	61	0		0	61
UT	Hunter	6165	1, 2, 3	26668	7628	7338		7338	290
UT	Huntington	8069	1, 2	17678	21095	17396		17396	3699
UT	Intermountain	6481	1SGA, 2SGA	5770	18225	4239		4239	13986
UT	Millcreek Power	56253	MC-1	0	0	0		0	0
UT	Nebo Power Station	56177	U1	0	5	1		1	4
UT	West Valley Generation Project	55622	U1, U2, U3, U4, U5	0	52	0		0	52
VA	Altavista Power Station	10773	1, 2	0	123	112		112	11
VA	Bellemeade Power Station	50966	1, 2	0	5	3		3	2
VA	Bremo Power Station	3796	3, 4	7189	13242	12040		12040	1202
VA	Buchanan -- Units 1 and 2	55738	1, 2	0	20	0		0	20
VA	Chesapeake Energy Center	3803	1, 2, 3, 4	14759	29482	26802		26802	2680
VA	Chesterfield Power Station	3797	3, 4, 5, 6, **8A	34923	71352	64863		64863	6489
VA	Clinch River	3775	1, 2, 3	17112	27949	27134		27134	815
VA	Clover Power Station	7213	1, 2	5876	3580	1854		1854	1726
VA	Commonwealth Chesapeake	55381	CT-001, CT-002, CT-003, CT-004, CT-005, CT-006, CT-007	0	224	10		10	214
VA	Doswell Limited Partnership	52019	CT1	0	4	1		1	3
VA	Elizabeth River Combustion Turbine Sta	52087	CT-1, CT-2, CT-3	0	9	8		8	1
VA	Glen Lyn	3776	6, 51, 52	7800	12899	12522		12522	377
VA	Gordonsville Power Station	54844	1, 2	0	3	0		0	3
VA	Hopewell Power Station	10771	1, 2	0	0	0		0	0
VA	Ladysmith Combustion Turbine Sta	7838	1, 2	0	4	2		2	2
VA	Louisa Generation Facility	7837	EU1, EU2, EU3, EU4, EU5	0	21	1		1	20
VA	Marsh Run Generation Facility	7836	EU1, EU2, EU3	0	17	3		3	14
VA	Mecklenburg Power Station	52007	1, 2	0	622	564		564	58
VA	Mirant Potomac River	3788	1, 2, 3, 4, 5	13349	3578	3179		3179	399
VA	Possum Point Power Station	3804	3, 4, 5, 6A, 6B	13708	1350	1019		1019	331
VA	Remington Combustion Turbine Station	7839	1, 2, 3, 4	0	6	4		4	2
VA	Southampton Power Station	10774	1, 2	0	150	136		136	14

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
VA	Tenaska Virginia Generating Station	55439	CTGDB1, CTGDB2, CTGDB3	0	10	3		3	7
VA	Wolf Hills Energy	55285	WH01, WH02, WH03, WH04, WH05, WH06, WH07, WH08, WH09, WH10	0	0	0		0	0
VA	Yorktown Power Station	3809	1, 2, 3	15650	23855	21686		21686	2169
VT	J C McNeil	589	1	104	63	12		12	51
WA	Centralia	3845	30, 40, 50, 60, BW21, BW22	39413	7567	1667		1667	5900
WA	Chehalis Generation Facility	55662	CT1, CT2	0	15	11		11	4
WA	Encogen Generating Station	7870	CT1, CT2, CT3	0	248	1		1	247
WA	Finley Combustion Turbine	7945	1	0	0	0		0	0
WA	Frederickson Power LP	55818	F1CT	0	8	2		2	6
WA	Fredonia Generating Station	607	CT3, CT4	0	21	0		0	21
WA	Goldendale Generating Station	55482	CT-1	0	2	2		2	0
WA	River Road	7605	1	0	19	4		4	15
WI	Alma	4140	B4, B5	3099	8305	7551		7551	754
WI	Bay Front	3982	1, 2, 5	1889	8047	944		944	7103
WI	Blount Street	3992	3, 5, 6, 7, 8, 9, 11	3810	9743	2622		2622	7121
WI	Columbia	8023	1, 2	24242	29734	22396		22396	7338
WI	Combined Locks Energy Center, LLC	55558	B06	0	19	0		0	19
WI	Concord	7159	**1, **2, **3, **4	504	57	1		1	56
WI	Depere Energy Center	55029	B01	0	18	1		1	17
WI	E J Stoneman Generation Station	4146	B1, B2	400	612	470		470	142
WI	Edgewater (4050)	4050	3, 4, 5	23092	83167	15759		15759	67408
WI	Elk Mound Generating Station	7863	1, 2	0	20	0		0	20
WI	Fox Energy Company LLC	56031	CTG-1, CTG-2	0	2	2		2	0
WI	Genoa	4143	1	8019	15024	13658		13658	1366
WI	Germantown Power Plant	6253	**5	0	3	0		0	3
WI	Island Street Peaking Plant	55836	1A, 1B	0	53	0		0	53
WI	J P Madgett	4271	B1	7436	23081	7807		7807	15274
WI	Manitowoc	4125	6, 7, 8, 9	1724	4299	2548		2548	1751
WI	Neenah Energy Facility	55135	CT01, CT02	0	6	0		0	6
WI	Nelson Dewey	4054	1, 2	5332	14757	14587		14587	170
WI	Paris	7270	**1, **2, **3, **4	496	43	0		0	43
WI	Pleasant Prairie	6170	1, 2	28482	35000	28567		28567	6433
WI	Port Washington Generating Station	4040	21, 22	4283	905	2		2	903

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
WI	Pulliam	4072	3, 4, 5, 6, 7, 8, 32	6935	11412	10868		10868	544
WI	Riverside Energy Center, LLC	55641	CT-01, CT-02	0	3	2		2	1
WI	Rock River	4057	1, 2	3042	6458	2		2	6456
WI	Rockgen Energy Center	55391	CT-1, CT-2, CT-3	0	1	0		0	1
WI	Sheboygan Falls Energy Facility	56166	1, 2	0	0	0		0	0
WI	South Fond Du Lac	7203	**CT1, **CT2, **CT3, **CT4	717	2465	0		0	2465
WI	South Oak Creek	4041	5, 6, 7, 8	21642	24911	13594		13594	11317
WI	Valley (WEPCO)	4042	1, 2, 3, 4	7483	7914	7087		7087	827
WI	West Campus Cogeneration Facility	7991	U1, U2	0	14	2		2	12
WI	West Marinette	4076	**33, **34	765	1718	0		0	1718
WI	Weston	4078	1, 2, 3	12276	13594	12596		12596	998
WI	Whitewater Cogeneration Facility	55011	01	0	4	2		2	2
WV	Albright Power Station	3942	1, 2, 3	8626	16129	15229		15229	900
WV	Big Sandy Peaker Plant	55284	GS01, GS02, GS03, GS04, GS05, GS06, GS07, GS08, GS09, GS10, GS11, GS12	0	0	0		0	0
WV	Ceredo Generating Station	55276	01, 02, 03, 04, 05, 06	0	11	0		0	11
WV	Fort Martin Power Station	3943	1, 2	35702	88765	87565		87565	1200
WV	Harrison Power Station	3944	1, 2, 3	58766	5963	5063		5063	900
WV	John E Amos	3935	1, 2, 3	90000	147823	117299		117299	30524
WV	Kammer	3947	1, 2, 3	23971	41975	40750		40750	1225
WV	Kanawha River	3936	1, 2	8753	13385	12994		12994	391
WV	Mitchell (WV)	3948	1, 2	38585	54466	52006		52006	2460
WV	Mount Storm Power Station	3954	1, 2, 3	54839	4194	3139		3139	1055
WV	Mountaineer (1301)	6264	1	35223	53730	31052		31052	22678
WV	North Branch Power Station	7537	1A, 1B	0	954	867		867	87
WV	Phil Sporn	3938	11, 21, 31, 41, 51	23078	63743	39741		39741	24002
WV	Pleasants Energy, LLC	55349	1, 2	0	1	1		1	0
WV	Pleasants Power Station	6004	1, 2	37797	43768	42868		42868	900
WV	Rivesville Power Station	3945	7, 8	3766	2025	1725		1725	300
WV	Willow Island Power Station	3946	1, 2	6180	4359	3859		3859	500
WY	Dave Johnston	4158	BW41, BW42, BW43, BW44	24912	22647	22351		22351	296
WY	Jim Bridger	8066	BW71, BW72, BW73, BW74	65038	20455	20054		20054	401
WY	Laramie River	6204	1, 2, 3	13239	16795	11540		11540	5255

Appendix A: Acid Rain Program - Year 2006 SO2 Allowance Holdings And Deductions

State	Plant Name	Plant Code	Units	2006 Allowances Allocated	Held in Accounts as of 3/1/2007	2006 Emissions	2006 Underutilization	Allowances Deducted	Allowances Carried Over to 2007
WY	Naughton	4162	1, 2, 3	17162	20964	20664		20664	300
WY	Neil Simpson II	7504	001, CT1	0	1572	633		633	939
WY	Neil Simpson II (CT2)	55477	CT2	0	20	0		0	20
WY	Wygen	55479	001	0	1004	626		626	378
WY	Wyodak	6101	BW91	18317	6614	6514		6514	100

Year 2006 Compliance Summary

State	Facility Name	Facility ID (ORISPL)	Unit ID	Unit Operator(s)	Compliance Approach	Standard Emission Limit	Actual Emission Rate	Early Election Limit (if applicable)	AEL (if applicable)	Averaging Plan Limit (if applicable)	Actual Averaging Plan Rate (if applicable)
AL	Barry	3	1	Alabama Power Company	Averaging Plan	0.40	0.33			0.46	0.28
AL	Barry	3	2	Alabama Power Company	Averaging Plan	0.40	0.33			0.46	0.28
AL	Barry	3	3	Alabama Power Company	Averaging Plan	0.40	0.33			0.46	0.28
AL	Barry	3	4	Alabama Power Company	Averaging Plan	0.40	0.25			0.46	0.28
AL	Barry	3	5	Alabama Power Company	Averaging Plan	0.40	0.33			0.46	0.28
AL	Charles R Lowman	56	1	Alabama Electric Cooperative, Inc.	Standard Limit	0.46	0.43				
AL	Charles R Lowman	56	2	Alabama Electric Cooperative, Inc.	Early Election	0.46	0.47	0.50			
AL	Charles R Lowman	56	3	Alabama Electric Cooperative, Inc.	Early Election	0.46	0.47	0.50			
AL	Colbert	47	1	Tennessee Valley Authority	Averaging Plan	0.50	0.44			0.57	0.38
AL	Colbert	47	2	Tennessee Valley Authority	Averaging Plan	0.50	0.44			0.57	0.38
AL	Colbert	47	3	Tennessee Valley Authority	Averaging Plan	0.50	0.44			0.57	0.38
AL	Colbert	47	4	Tennessee Valley Authority	Averaging Plan	0.50	0.44			0.57	0.38
AL	Colbert	47	5	Tennessee Valley Authority	Averaging Plan	0.50	0.22			0.57	0.38
AL	E C Gaston	26	1	Alabama Power Company	Averaging Plan	0.50	0.36			0.46	0.28
AL	E C Gaston	26	2	Alabama Power Company	Averaging Plan	0.50	0.36			0.46	0.28
AL	E C Gaston	26	3	Alabama Power Company	Averaging Plan	0.50	0.41			0.46	0.28
AL	E C Gaston	26	4	Alabama Power Company	Averaging Plan	0.50	0.41			0.46	0.28
AL	E C Gaston	26	5	Alabama Power Company	Averaging Plan	0.45	0.27			0.46	0.28
AL	Gadsden	7	1	Alabama Power Company	Averaging Plan	0.45	0.59			0.46	0.28
AL	Gadsden	7	2	Alabama Power Company	Averaging Plan	0.45	0.54			0.46	0.28
AL	Gorgas	8	10	Alabama Power Company	Averaging Plan	0.40	0.30			0.46	0.28
AL	Gorgas	8	6	Alabama Power Company	Averaging Plan	0.46	0.44			0.46	0.28
AL	Gorgas	8	7	Alabama Power Company	Averaging Plan	0.46	0.44			0.46	0.28
AL	Gorgas	8	8	Alabama Power Company	Averaging Plan	0.40	0.37			0.46	0.28
AL	Gorgas	8	9	Alabama Power Company	Averaging Plan	0.40	0.38			0.46	0.28
AL	Greene County	10	1	Alabama Power Company	Averaging Plan	0.68	0.29			0.46	0.28
AL	Greene County	10	2	Alabama Power Company	Averaging Plan	0.46	0.34			0.46	0.28
AL	James H Miller Jr	6002	1	Alabama Power Company	Averaging Plan	0.46	0.17			0.46	0.28
AL	James H Miller Jr	6002	2	Alabama Power Company	Averaging Plan	0.46	0.17			0.46	0.28
AL	James H Miller Jr	6002	3	Alabama Power Company	Averaging Plan	0.46	0.21			0.46	0.28
AL	James H Miller Jr	6002	4	Alabama Power Company	Averaging Plan	0.46	0.19			0.46	0.28
AL	Widows Creek	50	1	Tennessee Valley Authority	Averaging Plan	0.46	0.43			0.57	0.38
AL	Widows Creek	50	2	Tennessee Valley Authority	Averaging Plan	0.46	0.43			0.57	0.38
AL	Widows Creek	50	3	Tennessee Valley Authority	Averaging Plan	0.46	0.43			0.57	0.38

State	Facility Name	Facility ID (ORISPL)	Unit ID	Unit Operator(s)	Compliance Approach	Standard Emission Limit	Actual Emission Rate	Early Election Limit (if applicable)	AEL (if applicable)	Averaging Plan Limit (if applicable)	Actual Averaging Plan Rate (if applicable)
AL	Widows Creek	50	4	Tennessee Valley Authority	Averaging Plan	0.46	0.43			0.57	0.38
AL	Widows Creek	50	5	Tennessee Valley Authority	Averaging Plan	0.46	0.43			0.57	0.38
AL	Widows Creek	50	6	Tennessee Valley Authority	Averaging Plan	0.46	0.43			0.57	0.38
AL	Widows Creek	50	7	Tennessee Valley Authority	Averaging Plan	0.40	0.26			0.57	0.38
AL	Widows Creek	50	8	Tennessee Valley Authority	Averaging Plan	0.40	0.26			0.57	0.38
AR	Flint Creek Power Plant	6138	1	Southwestern Electric Power Company	Early Election	0.46	0.29	0.50			
AR	Independence	6641	1	Entergy Corporation	Early Election	0.40	0.24	0.45			
AR	Independence	6641	2	Entergy Corporation	Early Election	0.40	0.24	0.45			
AR	White Bluff	6009	1	Entergy Corporation	Early Election	0.40	0.26	0.45			
AR	White Bluff	6009	2	Entergy Corporation	Early Election	0.40	0.27	0.45			
AZ	Apache Station	160	2	Arizona Electric Power Cooperative	Early Election	0.46	0.46	0.50			
AZ	Apache Station	160	3	Arizona Electric Power Cooperative	Early Election	0.46	0.44	0.50			
AZ	Cholla	113	1	Arizona Public Service Company	Early Election	0.40	0.37	0.45			
AZ	Cholla	113	2	Arizona Public Service Company	Early Election	0.40	0.33	0.45			
AZ	Cholla	113	3	Arizona Public Service Company	Early Election	0.40	0.34	0.45			
AZ	Cholla	113	4	Arizona Public Service Company	Early Election	0.40	0.37	0.45			
AZ	Coronado Generating Station	6177	U1B	Salt River Project	Early Election	0.46	0.37	0.50			
AZ	Coronado Generating Station	6177	U2B	Salt River Project	Early Election	0.46	0.42	0.50			
AZ	Irvington Generating Station	126	4	Tucson Electric Power Company	Standard Limit	0.46	0.41				
AZ	Navajo Generating Station	4941	1	Salt River Project	Early Election	0.40	0.34	0.45			
AZ	Navajo Generating Station	4941	2	Salt River Project	Early Election	0.40	0.39	0.45			
AZ	Navajo Generating Station	4941	3	Salt River Project	Early Election	0.40	0.32	0.45			
AZ	Springerville Generating Station	8223	1	Tucson Electric Power Company	Early Election	0.40	0.19	0.45			
AZ	Springerville Generating Station	8223	2	Tucson Electric Power Company	Early Election	0.40	0.18	0.45			
CO	Arapahoe	465	3	Public Service Company of Colorado	Averaging Plan	0.80	0.79			0.80	0.44
CO	Arapahoe	465	4	Public Service Company of Colorado	Averaging Plan	0.80	0.27			0.80	0.44
CO	Cameo	468	2	Public Service Company of Colorado	Standard Limit	0.46	0.36			0.00	0.00

State	Facility Name	Facility ID (ORISPL)	Unit ID	Unit Operator(s)	Compliance Approach	Standard Emission Limit	Actual Emission Rate	Early Election Limit (if applicable)	AEL (if applicable)	Averaging Plan Limit (if applicable)	Actual Averaging Plan Rate (if applicable)
CO	Cherokee	469	1	Public Service Company of Colorado	Averaging Plan	0.80	0.33			0.80	0.51
CO	Cherokee	469	2	Public Service Company of Colorado	Averaging Plan	0.80	0.70			0.80	0.51
CO	Cherokee	469	3	Public Service Company of Colorado	Early Election	0.46	0.31	0.50			
CO	Cherokee	469	4	Public Service Company of Colorado	Early Election	0.40	0.32	0.45			
CO	Comanche (470)	470	1	Public Service Company of Colorado	Early Election	0.40	0.31	0.45			
CO	Comanche (470)	470	2	Public Service Company of Colorado	Early Election	0.46	0.30	0.50			
CO	Craig	6021	C1	Tri-State Generation & Transmission	Early Election	0.46	0.27	0.50			
CO	Craig	6021	C2	Tri-State Generation & Transmission	Early Election	0.46	0.27	0.50			
CO	Craig	6021	C3	Tri-State Generation & Transmission	Early Election	0.46	0.38	0.50			
CO	Hayden	525	H1	Public Service Company of Colorado	Standard Limit	0.46	0.43				
CO	Hayden	525	H2	Public Service Company of Colorado	Standard Limit	0.40	0.33				
CO	Martin Drake	492	5	Colorado Springs Utilities	Averaging Plan	0.46	0.39			0.46	0.38
CO	Martin Drake	492	6	Colorado Springs Utilities	Averaging Plan	0.46	0.41			0.46	0.38
CO	Martin Drake	492	7	Colorado Springs Utilities	Averaging Plan	0.46	0.35			0.46	0.38
CO	Pawnee	6248	1	Public Service Company of Colorado	Early Election	0.46	0.21	0.50			
CO	Rawhide Energy Station	6761	101	Platte River Power Authority	Early Election	0.40	0.16	0.45			
CO	Ray D Nixon	8219	1	Colorado Springs Utilities	Early Election	0.46	0.26	0.50			
CO	Valmont	477	5	Public Service Company of Colorado	Early Election	0.40	0.34	0.45			
CT	Bridgeport Harbor Station	568	BHB3	PSEG Power Connecticut, LLC	Early Election	0.40	0.14	0.45			
DE	Edge Moor	593	3	Conectiv Delmarva Generation, LLC	Standard Limit	0.40	0.26				
DE	Edge Moor	593	4	Conectiv Delmarva Generation, LLC	Standard Limit	0.40	0.28				
DE	Indian River	594	1	Indian River Operations, Inc.	Standard Limit	0.46	0.35				
DE	Indian River	594	2	Indian River Operations, Inc.	Standard Limit	0.46	0.38				
DE	Indian River	594	3	Indian River Operations, Inc.	Standard Limit	0.46	0.32				
DE	Indian River	594	4	Indian River Operations, Inc.	Standard Limit	0.46	0.34				
FL	Big Bend	645	BB01	Tampa Electric Company	Averaging Plan	0.84	0.70			0.72	0.52

State	Facility Name	Facility ID (ORISPL)	Unit ID	Unit Operator(s)	Compliance Approach	Standard Emission Limit	Actual Emission Rate	Early Election Limit (if applicable)	AEL (if applicable)	Averaging Plan Limit (if applicable)	Actual Averaging Plan Rate (if applicable)
FL	Big Bend	645	BB02	Tampa Electric Company	Averaging Plan	0.84	0.70			0.72	0.52
FL	Big Bend	645	BB03	Tampa Electric Company	Averaging Plan	0.84	0.48			0.72	0.52
FL	Big Bend	645	BB04	Tampa Electric Company	Averaging Plan	0.45	0.27			0.72	0.52
FL	C D McIntosh Jr Power Plant	676	3	City of Lakeland	Early Election	0.46	0.45	0.50			
FL	Crist Electric Generating Plant	641	4	Gulf Power Company	Averaging Plan	0.45	0.34			0.46	0.28
FL	Crist Electric Generating Plant	641	5	Gulf Power Company	Averaging Plan	0.45	0.32			0.46	0.28
FL	Crist Electric Generating Plant	641	6	Gulf Power Company	Averaging Plan	0.50	0.29			0.46	0.28
FL	Crist Electric Generating Plant	641	7	Gulf Power Company	Averaging Plan	0.50	0.09			0.46	0.28
FL	Crystal River	628	1	Progress Energy Corporation	Averaging Plan	0.40	0.40			0.44	0.36
FL	Crystal River	628	2	Progress Energy Corporation	Averaging Plan	0.40	0.40			0.44	0.36
FL	Crystal River	628	4	Progress Energy Corporation	Averaging Plan	0.46	0.48			0.44	0.36
FL	Crystal River	628	5	Progress Energy Corporation	Averaging Plan	0.46	0.45			0.44	0.36
FL	Curtis H. Stanton Energy Center	564	1	Orlando Utilities Commission	Standard Limit	0.46	0.39				
FL	Deerhaven	663	B2	Gainesville Regional Utilities	Early Election	0.46	0.47	0.50			
FL	Lansing Smith Generating Plant	643	1	Gulf Power Company	Averaging Plan	0.40	0.46			0.46	0.28
FL	Lansing Smith Generating Plant	643	2	Gulf Power Company	Averaging Plan	0.40	0.37			0.46	0.28
FL	Scholz Electric Generating Plant	642	1	Gulf Power Company	Averaging Plan	0.50	0.55			0.46	0.28
FL	Scholz Electric Generating Plant	642	2	Gulf Power Company	Averaging Plan	0.50	0.55			0.46	0.28
FL	Seminole (136)	136	1	Seminole Electric Cooperative, Inc.	Early Election	0.46	0.46	0.50			
FL	Seminole (136)	136	2	Seminole Electric Cooperative, Inc.	Early Election	0.46	0.48	0.50			
FL	St. Johns River Power	207	1	JEA	Early Election	0.46	0.41	0.50			
FL	St. Johns River Power	207	2	JEA	Early Election	0.46	0.46	0.50			
GA	Bowen	703	1BLR	Georgia Power Company	Averaging Plan	0.45	0.27			0.46	0.28
GA	Bowen	703	2BLR	Georgia Power Company	Averaging Plan	0.45	0.26			0.46	0.28
GA	Bowen	703	3BLR	Georgia Power Company	Averaging Plan	0.45	0.25			0.46	0.28
GA	Bowen	703	4BLR	Georgia Power Company	Averaging Plan	0.45	0.28			0.46	0.28
GA	Hammond	708	1	Georgia Power Company	Averaging Plan	0.50	0.39			0.46	0.28
GA	Hammond	708	2	Georgia Power Company	Averaging Plan	0.50	0.39			0.46	0.28
GA	Hammond	708	3	Georgia Power Company	Averaging Plan	0.50	0.39			0.46	0.28
GA	Hammond	708	4	Georgia Power Company	Averaging Plan	0.50	0.19			0.46	0.28
GA	Harllee Branch	709	1	Georgia Power Company	Averaging Plan	0.68	0.49			0.46	0.28
GA	Harllee Branch	709	2	Georgia Power Company	Averaging Plan	0.50	0.49			0.46	0.28
GA	Harllee Branch	709	3	Georgia Power Company	Averaging Plan	0.68	0.39			0.46	0.28
GA	Harllee Branch	709	4	Georgia Power Company	Averaging Plan	0.68	0.39			0.46	0.28
GA	Jack McDonough	710	MB1	Georgia Power Company	Averaging Plan	0.45	0.24			0.46	0.28
GA	Jack McDonough	710	MB2	Georgia Power Company	Averaging Plan	0.45	0.24			0.46	0.28
GA	Kraft	733	1	Georgia Power Company	Averaging Plan	0.45	0.48			0.46	0.28

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GA	Kraft	733	2	Georgia Power Company	Averaging Plan	0.45	0.48			0.46	0.28
GA	Kraft	733	3	Georgia Power Company	Averaging Plan	0.45	0.48			0.46	0.28
GA	McIntosh (6124)	6124	1	Georgia Power Company	Averaging Plan	0.50	0.53			0.46	0.28
GA	Mitchell (GA)	727	3	Georgia Power Company	Averaging Plan	0.45	0.64			0.46	0.28
GA	Scherer	6257	1	Georgia Power Company	Averaging Plan	0.40	0.16			0.46	0.28
GA	Scherer	6257	2	Georgia Power Company	Averaging Plan	0.40	0.15			0.46	0.28
GA	Scherer	6257	3	Georgia Power Company	Averaging Plan	0.45	0.13			0.46	0.28
GA	Scherer	6257	4	Georgia Power Company	Averaging Plan	0.40	0.13	0.45		0.46	0.28
GA	Wansley (6052)	6052	1	Georgia Power Company	Averaging Plan	0.45	0.24			0.46	0.28
GA	Wansley (6052)	6052	2	Georgia Power Company	Averaging Plan	0.45	0.22			0.46	0.28
GA	Yates	728	Y1BR	Georgia Power Company	Averaging Plan	0.45	0.42	0.00		0.46	0.28
GA	Yates	728	Y2BR	Georgia Power Company	Averaging Plan	0.45	0.46			0.46	0.28
GA	Yates	728	Y3BR	Georgia Power Company	Averaging Plan	0.45	0.46			0.46	0.28
GA	Yates	728	Y4BR	Georgia Power Company	Averaging Plan	0.45	0.38			0.46	0.28
GA	Yates	728	Y5BR	Georgia Power Company	Averaging Plan	0.45	0.38			0.46	0.28
GA	Yates	728	Y6BR	Georgia Power Company	Averaging Plan	0.45	0.28			0.46	0.28
GA	Yates	728	Y7BR	Georgia Power Company	Averaging Plan	0.45	0.28			0.46	0.28
IA	Ames	1122	7	City of Ames	Early Election	0.40	0.37	0.45			
IA	Ames	1122	8	City of Ames	Early Election	0.46	0.39	0.50			
IA	Burlington (IA)	1104	1	IES Utilities, Inc	Averaging Plan	0.45	0.16			0.46	0.28
IA	Council Bluffs	1082	1	MidAmerican Energy Company	Early Election	0.46	0.35	0.50			
IA	Council Bluffs	1082	2	MidAmerican Energy Company	Early Election	0.40	0.43	0.45			
IA	Council Bluffs	1082	3	MidAmerican Energy Company	Early Election	0.46	0.36	0.50			
IA	Dubuque	1046	1	Interstate Power & Light Company	Averaging Plan	0.46	0.58			0.46	0.28
IA	Dubuque	1046	5	Interstate Power & Light Company	Averaging Plan	0.46	0.72			0.46	0.28
IA	Earl F Wisdom	1217	1	Corn Belt Power Cooperative	Alternative Emissions Limit	0.46	0.57		0.59		
IA	Fair Station	1218	2	Central Iowa Power Cooperative	Standard Limit	0.46	0.43				
IA	George Neal North	1091	2	MidAmerican Energy Company	Early Election	0.46	0.34	0.50			
IA	George Neal North	1091	3	MidAmerican Energy Company	Early Election	0.46	0.22	0.50			
IA	George Neal South	7343	4	MidAmerican Energy Company	Early Election	0.46	0.20	0.50			

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IA	Lansing	1047	1	Interstate Power & Light Company	Averaging Plan	0.46	0.59			0.46	0.28
IA	Lansing	1047	2	Interstate Power & Light Company	Averaging Plan	0.46	0.59			0.46	0.28
IA	Lansing	1047	3	Interstate Power & Light Company	Averaging Plan	0.46	0.69			0.46	0.28
IA	Lansing	1047	4	Interstate Power & Light Company	Early Election	0.46	0.48	0.50			
IA	Louisa	6664	101	MidAmerican Energy Company	Early Election	0.46	0.19	0.50			
IA	Milton L Kapp	1048	2	Interstate Power & Light Company	Averaging Plan	0.45	0.12			0.46	0.28
IA	Muscatine	1167	9	Muscatine Power and Water	Standard Limit	0.40	0.23				
IA	Ottumwa	6254	1	Interstate Power & Light Company	Early Election	0.40	0.32	0.45			
IA	Prairie Creek	1073	3	IES Utilities, Inc	Averaging Plan	0.46	0.53			0.46	0.28
IA	Prairie Creek	1073	4	IES Utilities, Inc	Averaging Plan	0.50	0.36			0.46	0.28
IA	Riverside (1081)	1081	9	MidAmerican Energy Company	Standard Limit	0.45	0.24				
IA	Sixth Street	1058	2	IES Utilities, Inc	Averaging Plan	0.46	0.43			0.46	0.28
IA	Sixth Street	1058	3	IES Utilities, Inc	Averaging Plan	0.46	0.22			0.46	0.28
IA	Sixth Street	1058	4	IES Utilities, Inc	Averaging Plan	0.46	0.22			0.46	0.28
IA	Sixth Street	1058	5	IES Utilities, Inc	Averaging Plan	0.46	0.22			0.46	0.28
IA	Sutherland	1077	1	IES Utilities, Inc	Averaging Plan	0.46	0.29			0.46	0.28
IA	Sutherland	1077	2	IES Utilities, Inc	Averaging Plan	0.46	0.27			0.46	0.28
IL	Baldwin Energy Complex	889	1	Dynegy Midwest Generation, Inc.	Standard Limit	0.86	0.07				
IL	Baldwin Energy Complex	889	2	Dynegy Midwest Generation, Inc.	Standard Limit	0.86	0.07				
IL	Baldwin Energy Complex	889	3	Dynegy Midwest Generation, Inc.	Averaging Plan	0.45	0.09			0.44	0.13
IL	Coffeen	861	01	Ameren Energy Generating Company	Averaging Plan	0.86	0.37			0.75	0.35
IL	Coffeen	861	02	Ameren Energy Generating Company	Averaging Plan	0.86	0.37			0.75	0.35
IL	Crawford	867	7	Midwest Generation EME, LLC	Early Election	0.40	0.16	0.45			
IL	Crawford	867	8	Midwest Generation EME, LLC	Early Election	0.40	0.17	0.45			
IL	Dallman	963	33	City of Springfield, IL	Early Election	0.40	0.25	0.45			
IL	Duck Creek	6016	1	AmerenEnergy Resources Generating Company	Averaging Plan	0.46	0.26			0.46	0.26
IL	E D Edwards	856	1	AmerenEnergy Resources Generating Company	Averaging Plan	0.46	0.28			0.46	0.26

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IL	E D Edwards	856	2	AmerenEnergy Resources Generating Company	Averaging Plan	0.46	0.28			0.46	0.26
IL	E D Edwards	856	3	AmerenEnergy Resources Generating Company	Averaging Plan	0.46	0.23			0.46	0.26
IL	Fisk	886	19	Midwest Generation EME, LLC	Early Election	0.40	0.13	0.45			
IL	Havana	891	9	Dynegy Midwest Generation, Inc.	Standard Limit	0.46	0.05				
IL	Hennepin Power Station	892	1	Dynegy Midwest Generation, Inc.	Averaging Plan	0.40	0.12			0.44	0.13
IL	Hennepin Power Station	892	2	Dynegy Midwest Generation, Inc.	Averaging Plan	0.45	0.12			0.44	0.13
IL	Hutsonville	863	05	Ameren Energy Generating Company	Averaging Plan	0.45	0.29			0.75	0.35
IL	Hutsonville	863	06	Ameren Energy Generating Company	Averaging Plan	0.45	0.27			0.75	0.35
IL	Joliet 29	384	71	Midwest Generation EME, LLC	Standard Limit	0.40	0.12				
IL	Joliet 29	384	72	Midwest Generation EME, LLC	Standard Limit	0.40	0.12				
IL	Joliet 29	384	81	Midwest Generation EME, LLC	Standard Limit	0.40	0.11				
IL	Joliet 29	384	82	Midwest Generation EME, LLC	Standard Limit	0.40	0.11				
IL	Joliet 9	874	5	Midwest Generation EME, LLC	Standard Limit	0.86	0.37				
IL	Joppa Steam	887	1	Electric Energy, Inc.	Standard Limit	0.45	0.13				
IL	Joppa Steam	887	2	Electric Energy, Inc.	Standard Limit	0.45	0.13				
IL	Joppa Steam	887	3	Electric Energy, Inc.	Standard Limit	0.45	0.13				
IL	Joppa Steam	887	4	Electric Energy, Inc.	Standard Limit	0.45	0.13				
IL	Joppa Steam	887	5	Electric Energy, Inc.	Standard Limit	0.45	0.12				
IL	Joppa Steam	887	6	Electric Energy, Inc.	Standard Limit	0.45	0.12				
IL	Kincaid Station	876	1	Dominion Energy Services Company	Standard Limit	0.86	0.38				
IL	Kincaid Station	876	2	Dominion Energy Services Company	Standard Limit	0.86	0.38				
IL	Marion	976	4	Southern Illinois Power Cooperative	Standard Limit	0.86	0.61				
IL	Meredosia	864	01	Ameren Energy Generating Company	Averaging Plan	0.45	0.44			0.75	0.35
IL	Meredosia	864	02	Ameren Energy Generating Company	Averaging Plan	0.45	0.44			0.75	0.35
IL	Meredosia	864	03	Ameren Energy Generating Company	Averaging Plan	0.45	0.44			0.75	0.35
IL	Meredosia	864	04	Ameren Energy Generating Company	Averaging Plan	0.45	0.44			0.75	0.35
IL	Meredosia	864	05	Ameren Energy Generating Company	Averaging Plan	0.45	0.24			0.75	0.35

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IL	Newton	6017	1	Ameren Energy Generating Company	Standard Limit	0.45	0.12				
IL	Newton	6017	2	Ameren Energy Generating Company	Standard Limit	0.45	0.12				
IL	Powerton	879	51	Midwest Generation EME, LLC	Standard Limit	0.86	0.59				
IL	Powerton	879	52	Midwest Generation EME, LLC	Standard Limit	0.86	0.59				
IL	Powerton	879	61	Midwest Generation EME, LLC	Standard Limit	0.86	0.59				
IL	Powerton	879	62	Midwest Generation EME, LLC	Standard Limit	0.86	0.59				
IL	Vermilion Power Station	897	1	Dynegy Midwest Generation, Inc.	Averaging Plan	0.45	0.26			0.44	0.13
IL	Vermilion Power Station	897	2	Dynegy Midwest Generation, Inc.	Averaging Plan	0.45	0.26			0.44	0.13
IL	Waukegan	883	7	Midwest Generation EME, LLC	Early Election	0.40	0.14	0.45			
IL	Waukegan	883	8	Midwest Generation EME, LLC	Early Election	0.40	0.13	0.45			
IL	Will County	884	1	Midwest Generation EME, LLC	Standard Limit	0.86	0.41				
IL	Will County	884	2	Midwest Generation EME, LLC	Standard Limit	0.86	0.42				
IL	Will County	884	3	Midwest Generation EME, LLC	Early Election	0.40	0.15	0.45			
IL	Will County	884	4	Midwest Generation EME, LLC	Early Election	0.40	0.13	0.45			
IL	Wood River Power Station	898	4	Dynegy Midwest Generation, Inc.	Standard Limit	0.40	0.13				
IL	Wood River Power Station	898	5	Dynegy Midwest Generation, Inc.	Averaging Plan	0.40	0.16			0.44	0.13
IN	A B Brown Generating Station	6137	1	Southern Indiana Gas and Electric Company	Early Election	0.46	0.26	0.50			
IN	A B Brown Generating Station	6137	2	Southern Indiana Gas and Electric Company	Early Election	0.46	0.31	0.50			
IN	Alcoa Allowance Management Inc	6705	4	Alcoa Allowance Management, Inc.	Standard Limit	0.68	0.32				
IN	Bailly Generating Station	995	7	Northern Indiana Public Service Company	Averaging Plan	0.86	0.81			0.76	0.45
IN	Bailly Generating Station	995	8	Northern Indiana Public Service Company	Averaging Plan	0.86	0.81			0.76	0.45
IN	Cayuga	1001	1	Duke Energy Shared Services, Inc.	Averaging Plan	0.45	0.32			0.49	0.30
IN	Cayuga	1001	2	Duke Energy Shared Services, Inc.	Averaging Plan	0.45	0.30			0.49	0.30
IN	Clifty Creek	983	1	Indiana Kentucky Electric Corp	Averaging Plan	0.84	0.45			0.84	0.49
IN	Clifty Creek	983	2	Indiana Kentucky Electric Corp	Averaging Plan	0.84	0.45			0.84	0.49
IN	Clifty Creek	983	3	Indiana Kentucky Electric Corp	Averaging Plan	0.84	0.45			0.84	0.49
IN	Clifty Creek	983	4	Indiana Kentucky Electric Corp	Averaging Plan	0.84	0.53			0.84	0.49
IN	Clifty Creek	983	5	Indiana Kentucky Electric Corp	Averaging Plan	0.84	0.53			0.84	0.49

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IN	Clifty Creek	983	6	Indiana Kentucky Electric Corp	Averaging Plan	0.84	0.53			0.84	0.49
IN	Dean H Mitchell Generating Station	996	11	Northern Indiana Public Service Company	Early Election	0.46	0.00	0.50			
IN	Dean H Mitchell Generating Station	996	4	Northern Indiana Public Service Company	Early Election	0.40	0.00	0.45			
IN	Dean H Mitchell Generating Station	996	5	Northern Indiana Public Service Company	Early Election	0.40	0.00	0.45			
IN	Dean H Mitchell Generating Station	996	6	Northern Indiana Public Service Company	Early Election	0.40	0.00	0.45			
IN	Edwardsport	1004	7-1	Duke Energy Shared Services, Inc.	Averaging Plan	0.46	0.65			0.49	0.30
IN	Edwardsport	1004	7-2	Duke Energy Shared Services, Inc.	Averaging Plan	0.46	0.58			0.49	0.30
IN	Edwardsport	1004	8-1	Duke Energy Shared Services, Inc.	Averaging Plan	0.46	0.70			0.49	0.30
IN	F B Culley Generating Station	1012	1	Southern Indiana Gas and Electric Company	Averaging Plan	0.46	0.59			0.50	0.26
IN	F B Culley Generating Station	1012	2	Southern Indiana Gas and Electric Company	Averaging Plan	0.50	0.21			0.50	0.26
IN	F B Culley Generating Station	1012	3	Southern Indiana Gas and Electric Company	Averaging Plan	0.50	0.21			0.50	0.26
IN	Frank E Ratts	1043	1SG1	Hoosier Energy REC, Inc.	Averaging Plan	0.50	0.50			0.47	0.28
IN	Frank E Ratts	1043	2SG1	Hoosier Energy REC, Inc.	Averaging Plan	0.50	0.47			0.47	0.28
IN	Gibson	6113	1	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.27			0.49	0.30
IN	Gibson	6113	2	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.27			0.49	0.30
IN	Gibson	6113	3	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.26			0.49	0.30
IN	Gibson	6113	4	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.28			0.49	0.30
IN	Gibson	6113	5	Duke Energy Shared Services, Inc.	Averaging Plan	0.46	0.29			0.49	0.30
IN	Harding Street Station (EW Stout)	990	50	Indianapolis Power & Light Company	Averaging Plan	0.45	0.28			0.45	0.26
IN	Harding Street Station (EW Stout)	990	60	Indianapolis Power & Light Company	Averaging Plan	0.45	0.26			0.45	0.26
IN	Harding Street Station (EW Stout)	990	70	Indianapolis Power & Light Company	Averaging Plan	0.45	0.21			0.45	0.26
IN	IPL Eagle Valley Generating Station	991	3	Indianapolis Power & Light Company	Averaging Plan	0.45	0.48			0.45	0.26
IN	IPL Eagle Valley Generating Station	991	4	Indianapolis Power & Light Company	Averaging Plan	0.45	0.48			0.45	0.26

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IN	IPL Eagle Valley Generating Station	991	5	Indianapolis Power & Light Company	Averaging Plan	0.45	0.32			0.45	0.26
IN	IPL Eagle Valley Generating Station	991	6	Indianapolis Power & Light Company	Averaging Plan	0.45	0.32			0.45	0.26
IN	Merom	6213	1SG1	Hoosier Energy REC, Inc.	Averaging Plan	0.46	0.22	0.50		0.47	0.28
IN	Merom	6213	2SG1	Hoosier Energy REC, Inc.	Averaging Plan	0.46	0.23	0.50		0.47	0.28
IN	Michigan City Generating Station	997	12	Northern Indiana Public Service Company	Averaging Plan	0.86	0.40			0.76	0.45
IN	Petersburg	994	1	Indianapolis Power & Light Company	Averaging Plan	0.45	0.24			0.45	0.26
IN	Petersburg	994	2	Indianapolis Power & Light Company	Averaging Plan	0.45	0.22			0.45	0.26
IN	Petersburg	994	3	Indianapolis Power & Light Company	Averaging Plan	0.45	0.30			0.45	0.26
IN	Petersburg	994	4	Indianapolis Power & Light Company	Averaging Plan	0.45	0.27			0.45	0.26
IN	R Gallagher	1008	1	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.35			0.49	0.30
IN	R Gallagher	1008	2	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.35			0.49	0.30
IN	R Gallagher	1008	3	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.31			0.49	0.30
IN	R Gallagher	1008	4	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.31			0.49	0.30
IN	R M Schahfer Generating Station	6085	14	Northern Indiana Public Service Company	Averaging Plan	0.86	0.46			0.76	0.45
IN	R M Schahfer Generating Station	6085	15	Northern Indiana Public Service Company	Averaging Plan	0.46	0.18	0.50		0.76	0.45
IN	R M Schahfer Generating Station	6085	17	Northern Indiana Public Service Company	Early Election	0.40	0.17	0.45			
IN	R M Schahfer Generating Station	6085	18	Northern Indiana Public Service Company	Early Election	0.40	0.18	0.45			
IN	Rockport	6166	MB1	Indiana Michigan Power Company	Averaging Plan	0.46	0.28	0.50		0.58	0.37
IN	Rockport	6166	MB2	Indiana Michigan Power Company	Averaging Plan	0.46	0.28	0.50		0.58	0.37
IN	State Line Generating Station (IN)	981	3	State Line Energy, LLC	Averaging Plan	0.40	0.22	0.45		0.67	0.48
IN	State Line Generating Station (IN)	981	4	State Line Energy, LLC	Averaging Plan	0.86	0.66			0.67	0.48
IN	Tanners Creek	988	U1	Indiana Michigan Power Company	Averaging Plan	0.80	0.33			0.58	0.37
IN	Tanners Creek	988	U2	Indiana Michigan Power Company	Averaging Plan	0.80	0.33			0.58	0.37

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IN	Tanners Creek	988	U3	Indiana Michigan Power Company	Averaging Plan	0.80	0.33			0.58	0.37
IN	Tanners Creek	988	U4	Indiana Michigan Power Company	Averaging Plan	0.86	0.25			0.58	0.37
IN	Wabash River	1010	1	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.07			0.49	0.30
IN	Wabash River	1010	2	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.37			0.49	0.30
IN	Wabash River	1010	3	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.37			0.49	0.30
IN	Wabash River	1010	4	Duke Energy Shared Services, Inc.	Averaging Plan	0.46	0.37			0.49	0.30
IN	Wabash River	1010	5	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.37			0.49	0.30
IN	Wabash River	1010	6	Duke Energy Shared Services, Inc.	Averaging Plan	0.45	0.37			0.49	0.30
IN	Whitewater Valley	1040	1	City of Richmond	Early Election	0.46	0.34	0.50			
IN	Whitewater Valley	1040	2	City of Richmond	Early Election	0.40	0.34	0.45			
KS	Holcomb	108	SGU1	Sunflower Electric Power Corporation	Standard Limit	0.46	0.31				
KS	Jeffrey Energy Center	6068	1	Westar Energy, Inc.	Averaging Plan	0.40	0.34			0.40	0.28
KS	Jeffrey Energy Center	6068	2	Westar Energy, Inc.	Averaging Plan	0.40	0.34			0.40	0.28
KS	Jeffrey Energy Center	6068	3	Westar Energy, Inc.	Averaging Plan	0.40	0.15			0.40	0.28
KS	La Cygne	1241	1	Kansas City Power & Light Company	Averaging Plan	0.86	0.93			0.70	0.65
KS	La Cygne	1241	2	Kansas City Power & Light Company	Averaging Plan	0.50	0.31			0.70	0.65
KS	Lawrence Energy Center	1250	3	Westar Energy, Inc.	Averaging Plan	0.40	0.26			0.40	0.28
KS	Lawrence Energy Center	1250	4	Westar Energy, Inc.	Averaging Plan	0.40	0.38			0.40	0.28
KS	Lawrence Energy Center	1250	5	Westar Energy, Inc.	Averaging Plan	0.40	0.19			0.40	0.28
KS	Nearman Creek	6064	N1	Kansas City Bd. of Public Utilities	Early Election	0.46	0.46	0.50			
KS	Quindaro	1295	1	Kansas City Bd. of Public Utilities	Standard Limit	0.86	0.77				
KS	Quindaro	1295	2	Kansas City Bd. of Public Utilities	Standard Limit	0.50	0.29				
KS	Riverton	1239	39	Empire District Electric Company	Early Election	0.46	0.45	0.50			
KS	Riverton	1239	40	Empire District Electric Company	Early Election	0.40	0.41	0.45			
KS	Tecumseh Energy Center	1252	10	Westar Energy, Inc.	Averaging Plan	0.40	0.40			0.40	0.28
KS	Tecumseh Energy Center	1252	9	Westar Energy, Inc.	Averaging Plan	0.40	0.50			0.40	0.28

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KY	Big Sandy	1353	BSU1	Kentucky Power Company	Averaging Plan	0.46	0.41			0.58	0.37
KY	Big Sandy	1353	BSU2	Kentucky Power Company	Averaging Plan	0.46	0.41			0.58	0.37
KY	Cane Run	1363	4	Louisville Gas and Electric Company	Early Election	0.46	0.36	0.50			
KY	Cane Run	1363	5	Louisville Gas and Electric Company	Early Election	0.46	0.40	0.50			
KY	Cane Run	1363	6	Louisville Gas and Electric Company	Early Election	0.40	0.33	0.45			
KY	Coleman	1381	C1	Western Kentucky Energy Corporation	Averaging Plan	0.50	0.31			0.49	0.31
KY	Coleman	1381	C2	Western Kentucky Energy Corporation	Averaging Plan	0.50	0.32			0.49	0.31
KY	Coleman	1381	C3	Western Kentucky Energy Corporation	Averaging Plan	0.50	0.31			0.49	0.31
KY	D B Wilson	6823	W1	Western Kentucky Energy Corporation	Averaging Plan	0.46	0.30			0.49	0.31
KY	E W Brown	1355	1	Louisville Gas and Electric Company	Averaging Plan	0.50	0.48			0.45	0.27
KY	E W Brown	1355	2	Louisville Gas and Electric Company	Averaging Plan	0.45	0.35			0.45	0.27
KY	E W Brown	1355	3	Louisville Gas and Electric Company	Averaging Plan	0.45	0.35			0.45	0.27
KY	East Bend	6018	2	Duke Energy Shared Services, Inc.	Averaging Plan	0.50	0.24			0.49	0.30
KY	Elmer Smith	1374	2	Owensboro Municipal Utilities	Standard Limit	0.45	0.25				
KY	Ghent	1356	1	Kentucky Utilities Company	Averaging Plan	0.45	0.24			0.45	0.27
KY	Ghent	1356	2	Kentucky Utilities Company	Averaging Plan	0.40	0.27			0.45	0.27
KY	Ghent	1356	3	Kentucky Utilities Company	Averaging Plan	0.46	0.21			0.45	0.27
KY	Ghent	1356	4	Kentucky Utilities Company	Averaging Plan	0.46	0.21			0.45	0.27
KY	Green River	1357	4	Kentucky Utilities Company	Averaging Plan	0.46	0.39			0.45	0.27
KY	Green River	1357	5	Kentucky Utilities Company	Averaging Plan	0.50	0.39			0.45	0.27
KY	H L Spurlock	6041	1	East Kentucky Power Cooperative	Standard Limit	0.50	0.32				
KY	H L Spurlock	6041	2	East Kentucky Power Cooperative	Early Election	0.40	0.19	0.45			
KY	HMP&L Station 2	1382	H1	WKE Station Two, Inc.	Averaging Plan	0.50	0.31			0.49	0.31
KY	HMP&L Station 2	1382	H2	WKE Station Two, Inc.	Averaging Plan	0.50	0.30			0.49	0.31
KY	John S. Cooper	1384	1	East Kentucky Power Cooperative	Standard Limit	0.50	0.47				
KY	John S. Cooper	1384	2	East Kentucky Power Cooperative	Standard Limit	0.50	0.47				

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KY	Mill Creek	1364	1	Louisville Gas and Electric Company	Early Election	0.40	0.33	0.45			
KY	Mill Creek	1364	2	Louisville Gas and Electric Company	Early Election	0.40	0.32	0.45			
KY	Mill Creek	1364	3	Louisville Gas and Electric Company	Early Election	0.46	0.23	0.50			
KY	Mill Creek	1364	4	Louisville Gas and Electric Company	Early Election	0.46	0.19	0.50			
KY	Paradise	1378	1	Tennessee Valley Authority	Averaging Plan	0.86	0.60			0.57	0.38
KY	Paradise	1378	2	Tennessee Valley Authority	Averaging Plan	0.86	0.57			0.57	0.38
KY	Paradise	1378	3	Tennessee Valley Authority	Averaging Plan	0.86	0.45			0.57	0.38
KY	R D Green	6639	G1	Western Kentucky Energy Corporation	Averaging Plan	0.50	0.30			0.49	0.31
KY	R D Green	6639	G2	Western Kentucky Energy Corporation	Averaging Plan	0.50	0.29			0.49	0.31
KY	Robert Reid	1383	R1	WKE Station Two, Inc.	Averaging Plan	0.46	0.54			0.49	0.31
KY	Shawnee	1379	1	Tennessee Valley Authority	Averaging Plan	0.46	0.38			0.57	0.38
KY	Shawnee	1379	2	Tennessee Valley Authority	Averaging Plan	0.46	0.38			0.57	0.38
KY	Shawnee	1379	3	Tennessee Valley Authority	Averaging Plan	0.46	0.38			0.57	0.38
KY	Shawnee	1379	4	Tennessee Valley Authority	Averaging Plan	0.46	0.38			0.57	0.38
KY	Shawnee	1379	5	Tennessee Valley Authority	Averaging Plan	0.46	0.38			0.57	0.38
KY	Shawnee	1379	6	Tennessee Valley Authority	Averaging Plan	0.46	0.36			0.57	0.38
KY	Shawnee	1379	7	Tennessee Valley Authority	Averaging Plan	0.46	0.36			0.57	0.38
KY	Shawnee	1379	8	Tennessee Valley Authority	Averaging Plan	0.46	0.36			0.57	0.38
KY	Shawnee	1379	9	Tennessee Valley Authority	Averaging Plan	0.46	0.36			0.57	0.38
KY	Trimble County	6071	1	Louisville Gas and Electric Company	Early Election	0.40	0.20	0.45			
KY	Tyrone	1361	5	Kentucky Utilities Company	Averaging Plan	0.46	0.39			0.45	0.27
KY	William C. Dale	1385	3	East Kentucky Power Cooperative	Early Election	0.46	0.40	0.50			
KY	William C. Dale	1385	4	East Kentucky Power Cooperative	Early Election	0.46	0.40	0.50			
LA	Big Cajun 2	6055	2B1	Louisiana Generating, LLC	Early Election	0.46	0.20	0.50			
LA	Big Cajun 2	6055	2B2	Louisiana Generating, LLC	Early Election	0.46	0.20	0.50			
LA	Big Cajun 2	6055	2B3	Louisiana Generating, LLC	Early Election	0.46	0.15	0.50			
LA	Dolet Hills Power Station	51	1	CLECO Power, LLC	Early Election	0.46	0.42	0.50			
LA	R S Nelson	1393	6	Entergy Corporation	Early Election	0.40	0.24	0.45			
LA	Rodemacher Power Station (6190)	6190	2	CLECO Power, LLC	Early Election	0.46	0.42	0.50			
MA	Brayton Point	1619	1	Dominion Energy Brayton Point, LLC	Standard Limit	0.40	0.21				

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MA	Brayton Point	1619	2	Dominion Energy Brayton Point, LLC	Standard Limit	0.40	0.23				
MA	Brayton Point	1619	3	Dominion Energy Brayton Point, LLC	Standard Limit	0.46	0.16				
MA	Mount Tom	1606	1	FirstLight Power Resources Services, LLC	Standard Limit	0.46	0.15				
MA	Salem Harbor	1626	1	Dominion Energy Salem Harbor, LLC	Standard Limit	0.46	0.14				
MA	Salem Harbor	1626	2	Dominion Energy Salem Harbor, LLC	Standard Limit	0.46	0.13				
MA	Salem Harbor	1626	3	Dominion Energy Salem Harbor, LLC	Standard Limit	0.46	0.14				
MA	Somerset	1613	7	Somerset Power, LLC	Standard Limit	0.40	0.00				
MA	Somerset	1613	8	Somerset Power, LLC	Standard Limit	0.40	0.17				
MD	Brandon Shores	602	1	Constellation Power Source Generation Inc.	Averaging Plan	0.46	0.29			0.46	0.30
MD	Brandon Shores	602	2	Constellation Power Source Generation Inc.	Averaging Plan	0.46	0.32			0.46	0.30
MD	C P Crane	1552	1	Constellation Power Source Generation Inc.	Standard Limit	0.86	0.53				
MD	C P Crane	1552	2	Constellation Power Source Generation Inc.	Standard Limit	0.86	0.50				
MD	Herbert A Wagner	1554	2	Constellation Power Source Generation Inc.	Standard Limit	0.46	0.44				
MD	Herbert A Wagner	1554	3	Constellation Power Source Generation Inc.	Standard Limit	0.68	0.23				
MD	Mirant Chalk Point	1571	1	Mirant Chalk Point, LLC	Standard Limit	0.50	0.47				
MD	Mirant Chalk Point	1571	2	Mirant Chalk Point, LLC	Standard Limit	0.50	0.47				
MD	Mirant Dickerson	1572	1	Mirant Mid-Atlantic, LLC	Standard Limit	0.40	0.33				
MD	Mirant Dickerson	1572	2	Mirant Mid-Atlantic, LLC	Standard Limit	0.40	0.33				
MD	Mirant Dickerson	1572	3	Mirant Mid-Atlantic, LLC	Standard Limit	0.40	0.33				
MD	Mirant Morgantown	1573	1	Mirant Mid-Atlantic, LLC	Alternative Emissions Limit	0.45	0.44		0.70		
MD	Mirant Morgantown	1573	2	Mirant Mid-Atlantic, LLC	Alternative Emissions Limit	0.45	0.41		0.70		
MD	R. Paul Smith Power Station	1570	11	Allegheny Energy Supply Company, LLC	Averaging Plan	0.45	0.37			0.55	0.33
MD	R. Paul Smith Power Station	1570	9	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.43			0.55	0.33
MI	B C Cobb	1695	1	Consumers Energy Company	Averaging Plan	0.40	0.06			0.47	0.28
MI	B C Cobb	1695	2	Consumers Energy Company	Averaging Plan	0.40	0.06			0.47	0.28
MI	B C Cobb	1695	3	Consumers Energy Company	Averaging Plan	0.40	0.07			0.47	0.28
MI	B C Cobb	1695	4	Consumers Energy Company	Averaging Plan	0.40	0.37	0.45		0.47	0.28

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MI	B C Cobb	1695	5	Consumers Energy Company	Averaging Plan	0.40	0.16	0.45		0.47	0.28
MI	Belle River	6034	1	Detroit Edison Company	Averaging Plan	0.46	0.19			0.54	0.29
MI	Belle River	6034	2	Detroit Edison Company	Averaging Plan	0.46	0.16			0.54	0.29
MI	Dan E Karn	1702	1	Consumers Energy Company	Averaging Plan	0.40	0.25			0.47	0.28
MI	Dan E Karn	1702	2	Consumers Energy Company	Averaging Plan	0.46	0.16			0.47	0.28
MI	Eckert Station	1831	1	Lansing Board of Water and Light	Averaging Plan	0.46	0.20			0.45	0.20
MI	Eckert Station	1831	2	Lansing Board of Water and Light	Averaging Plan	0.40	0.24			0.45	0.20
MI	Eckert Station	1831	3	Lansing Board of Water and Light	Averaging Plan	0.40	0.17			0.45	0.20
MI	Eckert Station	1831	4	Lansing Board of Water and Light	Averaging Plan	0.46	0.20			0.45	0.20
MI	Eckert Station	1831	5	Lansing Board of Water and Light	Averaging Plan	0.46	0.21			0.45	0.20
MI	Eckert Station	1831	6	Lansing Board of Water and Light	Averaging Plan	0.46	0.20			0.45	0.20
MI	Endicott Generating	4259	1	Michigan South Central Power Agency	Standard Limit	0.46	0.21			0.00	0.00
MI	Erickson	1832	1	Lansing Board of Water and Light	Averaging Plan	0.46	0.20			0.45	0.20
MI	Harbor Beach	1731	1	Detroit Edison Company	Averaging Plan	0.46	0.53			0.54	0.29
MI	J B Sims	1825	3	Grand Haven Board of Light and Power	Early Election	0.46	0.23	0.50			
MI	J C Weadock	1720	7	Consumers Energy Company	Averaging Plan	0.40	0.31	0.45		0.47	0.28
MI	J C Weadock	1720	8	Consumers Energy Company	Averaging Plan	0.40	0.30	0.45		0.47	0.28
MI	J H Campbell	1710	1	Consumers Energy Company	Averaging Plan	0.45	0.17			0.47	0.28
MI	J H Campbell	1710	2	Consumers Energy Company	Averaging Plan	0.68	0.31			0.47	0.28
MI	J H Campbell	1710	3	Consumers Energy Company	Averaging Plan	0.46	0.44			0.47	0.28
MI	J R Whiting	1723	1	Consumers Energy Company	Averaging Plan	0.46	0.23	0.50		0.47	0.28
MI	J R Whiting	1723	2	Consumers Energy Company	Averaging Plan	0.46	0.24			0.47	0.28
MI	J R Whiting	1723	3	Consumers Energy Company	Averaging Plan	0.46	0.23	0.50		0.47	0.28
MI	James De Young	1830	5	City of Holland	Standard Limit	0.46	0.39				
MI	Marysville	1732	10	Detroit Edison Company	Averaging Plan	0.40	0.00			0.54	0.29
MI	Marysville	1732	11	Detroit Edison Company	Averaging Plan	0.40	0.00			0.54	0.29
MI	Marysville	1732	12	Detroit Edison Company	Averaging Plan	0.40	0.00			0.54	0.29
MI	Marysville	1732	9	Detroit Edison Company	Averaging Plan	0.40	0.00			0.54	0.29
MI	Monroe	1733	1	Detroit Edison Company	Averaging Plan	0.68	0.35			0.54	0.29
MI	Monroe	1733	2	Detroit Edison Company	Averaging Plan	0.68	0.35			0.54	0.29
MI	Monroe	1733	3	Detroit Edison Company	Averaging Plan	0.68	0.38			0.54	0.29

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MI	Monroe	1733	4	Detroit Edison Company	Averaging Plan	0.68	0.38			0.54	0.29
MI	Presque Isle	1769	2	Wisconsin Electric Power Company	Averaging Plan	0.40	0.32			0.46	0.22
MI	Presque Isle	1769	3	Wisconsin Electric Power Company	Averaging Plan	0.40	0.32			0.46	0.22
MI	Presque Isle	1769	4	Wisconsin Electric Power Company	Averaging Plan	0.40	0.32			0.46	0.22
MI	Presque Isle	1769	5	Wisconsin Electric Power Company	Averaging Plan	0.46	0.35			0.46	0.22
MI	Presque Isle	1769	6	Wisconsin Electric Power Company	Averaging Plan	0.46	0.36			0.46	0.22
MI	Presque Isle	1769	7	Wisconsin Electric Power Company	Averaging Plan	0.46	0.39	0.50		0.46	0.22
MI	Presque Isle	1769	8	Wisconsin Electric Power Company	Averaging Plan	0.46	0.40	0.50		0.46	0.22
MI	Presque Isle	1769	9	Wisconsin Electric Power Company	Averaging Plan	0.46	0.40	0.50		0.46	0.22
MI	River Rouge	1740	2	Detroit Edison Company	Averaging Plan	0.40	0.22			0.54	0.29
MI	River Rouge	1740	3	Detroit Edison Company	Averaging Plan	0.46	0.28			0.54	0.29
MI	Shiras	1843	3	Marquette Board of Light and Power	Standard Limit	0.40	0.15				
MI	St. Clair	1743	1	Detroit Edison Company	Averaging Plan	0.46	0.35			0.54	0.29
MI	St. Clair	1743	2	Detroit Edison Company	Averaging Plan	0.46	0.38			0.54	0.29
MI	St. Clair	1743	3	Detroit Edison Company	Averaging Plan	0.46	0.46			0.54	0.29
MI	St. Clair	1743	4	Detroit Edison Company	Averaging Plan	0.46	0.36			0.54	0.29
MI	St. Clair	1743	6	Detroit Edison Company	Averaging Plan	0.40	0.15			0.54	0.29
MI	St. Clair	1743	7	Detroit Edison Company	Averaging Plan	0.40	0.17			0.54	0.29
MI	Trenton Channel	1745	16	Detroit Edison Company	Averaging Plan	0.40	0.45			0.54	0.29
MI	Trenton Channel	1745	17	Detroit Edison Company	Averaging Plan	0.40	0.45			0.54	0.29
MI	Trenton Channel	1745	18	Detroit Edison Company	Averaging Plan	0.40	0.45			0.54	0.29
MI	Trenton Channel	1745	19	Detroit Edison Company	Averaging Plan	0.40	0.45			0.54	0.29
MI	Trenton Channel	1745	9A	Detroit Edison Company	Averaging Plan	0.40	0.18			0.54	0.29
MI	Wyandotte	1866	7	Wyandotte Municipal Services	Standard Limit	0.46	0.36				
MN	Allen S King	1915	1	NSP (Xcel Energy)	Averaging Plan	0.86	0.78			0.51	0.43
MN	Black Dog	1904	3	NSP (Xcel Energy)	Averaging Plan	0.46	0.78			0.51	0.43
MN	Black Dog	1904	4	NSP (Xcel Energy)	Averaging Plan	0.46	0.78			0.51	0.43
MN	Boswell Energy Center	1893	1	Minnesota Power, Inc.	Averaging Plan	0.46	0.44			0.41	0.36
MN	Boswell Energy Center	1893	2	Minnesota Power, Inc.	Averaging Plan	0.46	0.44			0.41	0.36
MN	Boswell Energy Center	1893	3	Minnesota Power, Inc.	Averaging Plan	0.40	0.34	0.45		0.41	0.36
MN	Boswell Energy Center	1893	4	Minnesota Power, Inc.	Averaging Plan	0.40	0.31			0.41	0.36

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MN	High Bridge	1912	3	NSP (Xcel Energy)	Averaging Plan	0.50	0.57			0.51	0.43
MN	High Bridge	1912	4	NSP (Xcel Energy)	Averaging Plan	0.50	0.57			0.51	0.43
MN	High Bridge	1912	5	NSP (Xcel Energy)	Averaging Plan	0.50	0.57			0.51	0.43
MN	High Bridge	1912	6	NSP (Xcel Energy)	Averaging Plan	0.50	0.57			0.51	0.43
MN	Hoot Lake	1943	2	Otter Tail Power Company	Early Election	0.40	0.44	0.45			
MN	Hoot Lake	1943	3	Otter Tail Power Company	Standard Limit	0.46	0.30				
MN	Laskin Energy Center	1891	1	Minnesota Power, Inc.	Averaging Plan	0.40	0.49			0.41	0.36
MN	Laskin Energy Center	1891	2	Minnesota Power, Inc.	Averaging Plan	0.40	0.49			0.41	0.36
MN	Minnesota Valley	1918	4	NSP (Xcel Energy)	Averaging Plan	0.46	0.00			0.51	0.43
MN	Northeast Station	1961	NEPP	City of Austin	Standard Limit	0.46	0.43				
MN	Riverside (1927)	1927	6	NSP (Xcel Energy)	Averaging Plan	0.46	0.81			0.51	0.43
MN	Riverside (1927)	1927	7	NSP (Xcel Energy)	Averaging Plan	0.46	0.81			0.51	0.43
MN	Riverside (1927)	1927	8	NSP (Xcel Energy)	Averaging Plan	0.86	0.92			0.51	0.43
MN	Sherburne County	6090	1	NSP (Xcel Energy)	Averaging Plan	0.45	0.24			0.51	0.43
MN	Sherburne County	6090	2	NSP (Xcel Energy)	Averaging Plan	0.45	0.24			0.51	0.43
MN	Sherburne County	6090	3	NSP (Xcel Energy)	Averaging Plan	0.46	0.35			0.51	0.43
MN	Silver Lake	2008	4	Rochester Public Utilities	Standard Limit	0.46	0.37				
MN	Taconite Harbor Energy Center	10075	1	Minnesota Power, Inc.	Averaging Plan	0.40	0.40			0.41	0.36
MN	Taconite Harbor Energy Center	10075	2	Minnesota Power, Inc.	Averaging Plan	0.40	0.39			0.41	0.36
MN	Taconite Harbor Energy Center	10075	3	Minnesota Power, Inc.	Averaging Plan	0.40	0.36			0.41	0.36
MO	Asbury	2076	1	Empire District Electric Company	Standard Limit	0.86	0.72				
MO	Blue Valley	2132	3	City of Independence	Standard Limit	0.40	0.30				
MO	Iatan	6065	1	Kansas City Power & Light Company	Standard Limit	0.50	0.29				
MO	James River	2161	3	City Utilities of Springfield, MO	Averaging Plan	0.50	0.37			0.50	0.36
MO	James River	2161	4	City Utilities of Springfield, MO	Averaging Plan	0.50	0.42			0.50	0.36
MO	James River	2161	5	City Utilities of Springfield, MO	Averaging Plan	0.50	0.35			0.50	0.36
MO	Labadie	2103	1	Union Electric Company	Averaging Plan	0.45	0.11			0.52	0.14
MO	Labadie	2103	2	Union Electric Company	Averaging Plan	0.45	0.11			0.52	0.14
MO	Labadie	2103	3	Union Electric Company	Averaging Plan	0.45	0.11			0.52	0.14
MO	Labadie	2103	4	Union Electric Company	Averaging Plan	0.45	0.10			0.52	0.14
MO	Meramec	2104	1	Union Electric Company	Averaging Plan	0.45	0.13			0.52	0.14
MO	Meramec	2104	2	Union Electric Company	Averaging Plan	0.45	0.11			0.52	0.14
MO	Meramec	2104	3	Union Electric Company	Averaging Plan	0.50	0.39			0.52	0.14
MO	Meramec	2104	4	Union Electric Company	Averaging Plan	0.50	0.18			0.52	0.14
MO	Montrose	2080	1	Kansas City Power & Light Company	Standard Limit	0.45	0.32				

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MO	Montrose	2080	2	Kansas City Power & Light Company	Standard Limit	0.45	0.32				
MO	Montrose	2080	3	Kansas City Power & Light Company	Standard Limit	0.45	0.32				
MO	New Madrid Power Plant	2167	1	Associated Electric Cooperative, Inc.	Averaging Plan	0.86	0.82			0.75	0.55
MO	New Madrid Power Plant	2167	2	Associated Electric Cooperative, Inc.	Averaging Plan	0.86	0.68			0.75	0.55
MO	Rush Island	6155	1	Union Electric Company	Averaging Plan	0.45	0.09			0.52	0.14
MO	Rush Island	6155	2	Union Electric Company	Averaging Plan	0.45	0.10			0.52	0.14
MO	Sibley	2094	3	Aquila, Inc.	Standard Limit	0.86	0.58				
MO	Sikeston	6768	1	Sikeston Bd. of Municipal Utilities	Early Election	0.46	0.21	0.50			
MO	Sioux	2107	1	Union Electric Company	Averaging Plan	0.86	0.24			0.52	0.14
MO	Sioux	2107	2	Union Electric Company	Averaging Plan	0.86	0.25			0.52	0.14
MO	Southwest	6195	1	City Utilities of Springfield, MO	Averaging Plan	0.50	0.35			0.50	0.36
MO	Thomas Hill Energy Center	2168	MB1	Associated Electric Cooperative, Inc.	Averaging Plan	0.86	0.57			0.75	0.55
MO	Thomas Hill Energy Center	2168	MB2	Associated Electric Cooperative, Inc.	Averaging Plan	0.86	0.62			0.75	0.55
MO	Thomas Hill Energy Center	2168	MB3	Associated Electric Cooperative, Inc.	Averaging Plan	0.50	0.22			0.75	0.55
MS	Daniel Electric Generating Plant	6073	1	Mississippi Power Company	Averaging Plan	0.45	0.32			0.46	0.28
MS	Daniel Electric Generating Plant	6073	2	Mississippi Power Company	Averaging Plan	0.45	0.29			0.46	0.28
MS	R D Morrow Senior Generating Plant	6061	1	South Missisippi Elec. Power Assoc.	Averaging Plan	0.50	0.47			0.50	0.48
MS	R D Morrow Senior Generating Plant	6061	2	South Missisippi Elec. Power Assoc.	Averaging Plan	0.50	0.49			0.50	0.48
MS	Watson Electric Generating Plant	2049	4	Mississippi Power Company	Averaging Plan	0.50	0.57			0.46	0.28
MS	Watson Electric Generating Plant	2049	5	Mississippi Power Company	Averaging Plan	0.50	0.65			0.46	0.28
MT	Colstrip	6076	1	P P & L Montana, LLC	Early Election	0.40	0.31	0.45			
MT	Colstrip	6076	2	P P & L Montana, LLC	Early Election	0.40	0.28	0.45			
MT	Colstrip	6076	3	P P & L Montana, LLC	Early Election	0.40	0.40	0.45			
MT	Colstrip	6076	4	P P & L Montana, LLC	Early Election	0.40	0.38	0.45			
MT	J E Corette	2187	2	P P & L Montana, LLC	Standard Limit	0.40	0.25				
MT	Lewis & Clark	6089	B1	Montana Dakota Utilities Company	Early Election	0.40	0.39	0.45			
NC	Asheville	2706	1	Carolina Power & Light Company	Averaging Plan	0.46	0.50			0.44	0.36
NC	Asheville	2706	2	Carolina Power & Light Company	Averaging Plan	0.46	0.23			0.44	0.36

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NC	Belews Creek	8042	1	Duke Energy Shared Services, Inc.	Standard Limit	0.68	0.32				
NC	Belews Creek	8042	2	Duke Energy Shared Services, Inc.	Standard Limit	0.68	0.29				
NC	Buck	2720	5	Duke Energy Shared Services, Inc.	Early Election	0.40	0.39	0.45			
NC	Buck	2720	6	Duke Energy Shared Services, Inc.	Early Election	0.40	0.40	0.45			
NC	Buck	2720	7	Duke Energy Shared Services, Inc.	Early Election	0.40	0.41	0.45			
NC	Buck	2720	8	Duke Energy Shared Services, Inc.	Early Election	0.40	0.21	0.45			
NC	Buck	2720	9	Duke Energy Shared Services, Inc.	Early Election	0.40	0.20	0.45			
NC	Cape Fear	2708	5	Carolina Power & Light Company	Averaging Plan	0.40	0.24			0.44	0.36
NC	Cape Fear	2708	6	Carolina Power & Light Company	Averaging Plan	0.40	0.27			0.44	0.36
NC	Cliffside	2721	1	Duke Energy Shared Services, Inc.	Early Election	0.40	0.41	0.45			
NC	Cliffside	2721	2	Duke Energy Shared Services, Inc.	Early Election	0.40	0.35	0.45			
NC	Cliffside	2721	3	Duke Energy Shared Services, Inc.	Early Election	0.40	0.36	0.45			
NC	Cliffside	2721	4	Duke Energy Shared Services, Inc.	Early Election	0.40	0.37	0.45			
NC	Cliffside	2721	5	Duke Energy Shared Services, Inc.	Early Election	0.40	0.17	0.45			
NC	Dan River	2723	1	Duke Energy Shared Services, Inc.	Early Election	0.40	0.37	0.45			
NC	Dan River	2723	2	Duke Energy Shared Services, Inc.	Early Election	0.40	0.36	0.45			
NC	Dan River	2723	3	Duke Energy Shared Services, Inc.	Early Election	0.40	0.38	0.45			
NC	G G Allen	2718	1	Duke Energy Shared Services, Inc.	Early Election	0.40	0.27	0.45			
NC	G G Allen	2718	2	Duke Energy Shared Services, Inc.	Early Election	0.40	0.23	0.45			
NC	G G Allen	2718	3	Duke Energy Shared Services, Inc.	Early Election	0.40	0.26	0.45			
NC	G G Allen	2718	4	Duke Energy Shared Services, Inc.	Early Election	0.40	0.27	0.45			

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NC	G G Allen	2718	5	Duke Energy Shared Services, Inc.	Early Election	0.40	0.30	0.45			
NC	H F Lee Steam Electric Plant	2709	1	Carolina Power & Light Company	Averaging Plan	0.40	0.52			0.44	0.36
NC	H F Lee Steam Electric Plant	2709	2	Carolina Power & Light Company	Averaging Plan	0.46	0.43			0.44	0.36
NC	H F Lee Steam Electric Plant	2709	3	Carolina Power & Light Company	Averaging Plan	0.46	0.36			0.44	0.36
NC	L V Sutton	2713	1	Carolina Power & Light Company	Averaging Plan	0.40	0.46			0.44	0.36
NC	L V Sutton	2713	2	Carolina Power & Light Company	Averaging Plan	0.46	0.46			0.44	0.36
NC	L V Sutton	2713	3	Carolina Power & Light Company	Averaging Plan	0.46	0.38			0.44	0.36
NC	Marshall	2727	1	Duke Energy Shared Services, Inc.	Early Election	0.40	0.24	0.45			
NC	Marshall	2727	2	Duke Energy Shared Services, Inc.	Early Election	0.40	0.27	0.45			
NC	Marshall	2727	3	Duke Energy Shared Services, Inc.	Early Election	0.40	0.26	0.45			
NC	Marshall	2727	4	Duke Energy Shared Services, Inc.	Early Election	0.40	0.25	0.45			
NC	Mayo	6250	1A	Carolina Power & Light Company	Averaging Plan	0.46	0.22			0.44	0.36
NC	Mayo	6250	1B	Carolina Power & Light Company	Averaging Plan	0.46	0.22			0.44	0.36
NC	Riverbend	2732	10	Duke Energy Shared Services, Inc.	Early Election	0.40	0.22	0.45			
NC	Riverbend	2732	7	Duke Energy Shared Services, Inc.	Early Election	0.40	0.25	0.45			
NC	Riverbend	2732	8	Duke Energy Shared Services, Inc.	Early Election	0.40	0.24	0.45			
NC	Riverbend	2732	9	Duke Energy Shared Services, Inc.	Early Election	0.40	0.21	0.45			
NC	Roxboro	2712	1	Carolina Power & Light Company	Averaging Plan	0.46	0.28			0.44	0.36
NC	Roxboro	2712	2	Carolina Power & Light Company	Averaging Plan	0.40	0.29			0.44	0.36
NC	Roxboro	2712	3A	Carolina Power & Light Company	Averaging Plan	0.46	0.30			0.44	0.36
NC	Roxboro	2712	3B	Carolina Power & Light Company	Averaging Plan	0.46	0.30			0.44	0.36

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NC	Roxboro	2712	4A	Carolina Power & Light Company	Averaging Plan	0.46	0.25			0.44	0.36
NC	Roxboro	2712	4B	Carolina Power & Light Company	Averaging Plan	0.46	0.25			0.44	0.36
NC	W H Weatherspoon	2716	1	Carolina Power & Light Company	Averaging Plan	0.46	0.84			0.44	0.36
NC	W H Weatherspoon	2716	2	Carolina Power & Light Company	Averaging Plan	0.46	0.84			0.44	0.36
NC	W H Weatherspoon	2716	3	Carolina Power & Light Company	Averaging Plan	0.40	0.45			0.44	0.36
ND	Antelope Valley	6469	B1	Basin Electric Power Cooperative	Early Election	0.40	0.39	0.45			
ND	Antelope Valley	6469	B2	Basin Electric Power Cooperative	Early Election	0.40	0.35	0.45			
ND	Coal Creek	6030	1	Great River Energy	Standard Limit	0.40	0.24				
ND	Coal Creek	6030	2	Great River Energy	Standard Limit	0.40	0.25				
ND	Coyote	8222	B1	Otter Tail Power Company	Standard Limit	0.86	0.67				
ND	Leland Olds	2817	1	Basin Electric Power Cooperative	Early Election	0.46	0.31	0.50			
ND	Leland Olds	2817	2	Basin Electric Power Cooperative	Standard Limit	0.86	0.50				
ND	Milton R Young	2823	B1	Minnkota Power Cooperative, Inc.	Standard Limit	0.86	0.80				
ND	Milton R Young	2823	B2	Minnkota Power Cooperative, Inc.	Standard Limit	0.86	0.81				
ND	Stanton	2824	1	Great River Energy	Standard Limit	0.46	0.27				
ND	Stanton	2824	10	Great River Energy	Early Election	0.40	0.30	0.45			
NE	Gerald Gentleman Station	6077	1	Nebraska Public Power District	Early Election	0.46	0.28	0.50			
NE	Gerald Gentleman Station	6077	2	Nebraska Public Power District	Early Election	0.46	0.35	0.50			
NE	Gerald Whelan Energy Center	60	1	Nebraska Municipal Energy Agency	Early Election	0.40	0.31	0.45			
NE	Lon D Wright Power Plant	2240	8	City of Fremont	Standard Limit	0.46	0.20				
NE	Nebraska City Station	6096	1	Omaha Public Power District	Early Election	0.46	0.40	0.50			
NE	North Omaha Station	2291	1	Omaha Public Power District	Standard Limit	0.40	0.30				
NE	North Omaha Station	2291	2	Omaha Public Power District	Standard Limit	0.40	0.30				
NE	North Omaha Station	2291	3	Omaha Public Power District	Standard Limit	0.40	0.30				
NE	North Omaha Station	2291	4	Omaha Public Power District	Early Election	0.40	0.33	0.45			
NE	North Omaha Station	2291	5	Omaha Public Power District	Standard Limit	0.46	0.32				
NE	Platte	59	1	Grand Island Utilities Dept.	Early Election	0.40	0.34	0.45			

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NH	Merrimack	2364	2	Public Service of New Hampshire	Standard Limit	0.86	0.26				
NH	Schiller	2367	4	Public Service of New Hampshire	Standard Limit	0.46	0.27				
NH	Schiller	2367	5	Public Service of New Hampshire	Standard Limit	0.46	0.28				
NH	Schiller	2367	6	Public Service of New Hampshire	Standard Limit	0.46	0.29				
NJ	B L England	2378	2	North American Energy Services	Standard Limit	0.86	0.50				
NJ	Deepwater	2384	8	Conectiv Atlantic Generation, LLC	Standard Limit	0.46	0.41				
NJ	Hudson Generating Station	2403	2	PSEG Fossil LLC	Averaging Plan	0.46	0.44			0.65	0.34
NJ	Mercer Generating Station	2408	1	PSEG Fossil LLC	Averaging Plan	0.84	0.20			0.65	0.34
NJ	Mercer Generating Station	2408	2	PSEG Fossil LLC	Averaging Plan	0.84	0.26			0.65	0.34
NM	Four Corners Steam Elec Station	2442	1	Arizona Public Service Company	Averaging Plan	0.46	0.80			0.61	0.55
NM	Four Corners Steam Elec Station	2442	2	Arizona Public Service Company	Averaging Plan	0.46	0.65			0.61	0.55
NM	Four Corners Steam Elec Station	2442	3	Arizona Public Service Company	Averaging Plan	0.46	0.60			0.61	0.55
NM	Four Corners Steam Elec Station	2442	4	Arizona Public Service Company	Averaging Plan	0.68	0.49			0.61	0.55
NM	Four Corners Steam Elec Station	2442	5	Arizona Public Service Company	Averaging Plan	0.68	0.50			0.61	0.55
NM	Prewitt Escalante Generating Station	87	1	Tri-State Generation & Transmission	Early Election	0.40	0.37	0.45			
NM	San Juan	2451	1	PNM Resources	Averaging Plan	0.46	0.43			0.46	0.43
NM	San Juan	2451	2	PNM Resources	Averaging Plan	0.46	0.48			0.46	0.43
NM	San Juan	2451	3	PNM Resources	Averaging Plan	0.46	0.42			0.46	0.43
NM	San Juan	2451	4	PNM Resources	Averaging Plan	0.46	0.42			0.46	0.43
NV	Mohave	2341	1	Southern California Edison Company	Early Election	0.40	0.13	0.45			
NV	Mohave	2341	2	Southern California Edison Company	Early Election	0.40	0.12	0.45			
NV	North Valmy	8224	1	Sierra Pacific Power Company	Early Election	0.46	0.35	0.50			
NV	North Valmy	8224	2	Sierra Pacific Power Company	Early Election	0.46	0.43	0.50			
NV	Reid Gardner	2324	1	Nevada Power Company	Averaging Plan	0.46	0.36			0.46	0.33
NV	Reid Gardner	2324	2	Nevada Power Company	Averaging Plan	0.46	0.39			0.46	0.33
NV	Reid Gardner	2324	3	Nevada Power Company	Averaging Plan	0.46	0.33			0.46	0.33

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NV	Reid Gardner	2324	4	Nevada Power Company	Averaging Plan	0.46	0.30	0.50		0.46	0.33
NY	AES Cayuga, LLC	2535	1	AES Cayuga, LLC	Averaging Plan	0.45	0.21			0.45	0.23
NY	AES Cayuga, LLC	2535	2	AES Cayuga, LLC	Averaging Plan	0.45	0.21			0.45	0.23
NY	AES Greenidge	2527	4	AES Greenidge, LLC	Averaging Plan	0.46	0.71			0.45	0.23
NY	AES Greenidge	2527	5	AES Greenidge, LLC	Averaging Plan	0.46	0.71			0.45	0.23
NY	AES Greenidge	2527	6	AES Greenidge, LLC	Averaging Plan	0.45	0.43			0.45	0.23
NY	AES Somerset (Kintigh)	6082	1	AES Somerset, LLC	Averaging Plan	0.46	0.18	0.50		0.45	0.23
NY	AES Westover (Goudey)	2526	11	AES Westover, LLC	Averaging Plan	0.46	0.39			0.45	0.23
NY	AES Westover (Goudey)	2526	12	AES Westover, LLC	Averaging Plan	0.46	0.39			0.45	0.23
NY	AES Westover (Goudey)	2526	13	AES Westover, LLC	Averaging Plan	0.40	0.39			0.45	0.23
NY	Dunkirk	2554	1	NRG Dunkirk Operations, Inc.	Early Election	0.40	0.16	0.45			
NY	Dunkirk	2554	2	NRG Dunkirk Operations, Inc.	Early Election	0.40	0.17	0.45			
NY	Dunkirk	2554	3	NRG Dunkirk Operations, Inc.	Standard Limit	0.45	0.16				
NY	Dunkirk	2554	4	NRG Dunkirk Operations, Inc.	Standard Limit	0.45	0.16				
NY	Dynegy Danskammer	2480	3	Dynegy Power Corporation	Averaging Plan	0.40	0.24			0.40	0.28
NY	Dynegy Danskammer	2480	4	Dynegy Power Corporation	Averaging Plan	0.40	0.30			0.40	0.28
NY	Huntley Power	2549	63	Huntley Power, LLC	Standard Limit	0.84	0.00				
NY	Huntley Power	2549	64	Huntley Power, LLC	Standard Limit	0.84	0.00				
NY	Huntley Power	2549	65	Huntley Power, LLC	Standard Limit	0.84	0.53				
NY	Huntley Power	2549	66	Huntley Power, LLC	Standard Limit	0.84	0.53				
NY	Huntley Power	2549	67	Huntley Power, LLC	Early Election	0.40	0.15	0.45			
NY	Huntley Power	2549	68	Huntley Power, LLC	Early Election	0.40	0.15	0.45			
NY	Lovett Generating Station	2629	4	Mirant Lovett, LLC	Standard Limit	0.46	0.34				
NY	Lovett Generating Station	2629	5	Mirant Lovett, LLC	Standard Limit	0.46	0.35				
NY	Rochester 7 - Russell Station	2642	1	Rochester Gas & Electric Corporation	Averaging Plan	0.40	0.38			0.40	0.34
NY	Rochester 7 - Russell Station	2642	2	Rochester Gas & Electric Corporation	Averaging Plan	0.40	0.38			0.40	0.34
NY	Rochester 7 - Russell Station	2642	3	Rochester Gas & Electric Corporation	Averaging Plan	0.40	0.29			0.40	0.34
NY	Rochester 7 - Russell Station	2642	4	Rochester Gas & Electric Corporation	Averaging Plan	0.40	0.29			0.40	0.34
NY	S A Carlson	2682	10	Jamestown Board of Public Utilities	Early Election	0.46	0.42	0.50			
NY	S A Carlson	2682	11	Jamestown Board of Public Utilities	Early Election	0.46	0.00	0.50			
NY	S A Carlson	2682	12	Jamestown Board of Public Utilities	Early Election	0.46	0.39	0.50			
NY	S A Carlson	2682	9	Jamestown Board of Public Utilities	Early Election	0.46	0.39	0.50			

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OH	Ashtabula	2835	7	FirstEnergy Generation Corporation	Averaging Plan	0.45	0.18			0.53	0.29
OH	Avon Lake Power Plant	2836	10	Orion Power Operating Services - Midwest, Inc.	Standard Limit	0.40	0.45				
OH	Avon Lake Power Plant	2836	12	Orion Power Operating Services - Midwest, Inc.	Standard Limit	0.68	0.33				
OH	Bay Shore	2878	1	FirstEnergy Generation Corporation	Averaging Plan	0.80	0.10			0.53	0.29
OH	Bay Shore	2878	2	FirstEnergy Generation Corporation	Averaging Plan	0.80	0.36			0.53	0.29
OH	Bay Shore	2878	3	FirstEnergy Generation Corporation	Averaging Plan	0.46	0.36			0.53	0.29
OH	Bay Shore	2878	4	FirstEnergy Generation Corporation	Averaging Plan	0.46	0.36			0.53	0.29
OH	Cardinal	2828	1	Cardinal Operating Company	Averaging Plan	0.68	0.29			0.58	0.37
OH	Cardinal	2828	2	Cardinal Operating Company	Averaging Plan	0.68	0.33			0.58	0.37
OH	Cardinal	2828	3	Cardinal Operating Company	Averaging Plan	0.46	0.34			0.58	0.37
OH	Conesville	2840	3	Columbus Southern Power Company	Averaging Plan	0.50	0.61			0.58	0.37
OH	Conesville	2840	4	Columbus Southern Power Company	Averaging Plan	0.45	0.38			0.58	0.37
OH	Conesville	2840	5	Columbus Southern Power Company	Averaging Plan	0.40	0.36	0.45		0.58	0.37
OH	Conesville	2840	6	Columbus Southern Power Company	Averaging Plan	0.40	0.36	0.45		0.58	0.37
OH	Eastlake	2837	1	FirstEnergy Generation Corporation	Averaging Plan	0.45	0.27			0.53	0.29
OH	Eastlake	2837	2	FirstEnergy Generation Corporation	Averaging Plan	0.45	0.26			0.53	0.29
OH	Eastlake	2837	3	FirstEnergy Generation Corporation	Averaging Plan	0.45	0.28			0.53	0.29
OH	Eastlake	2837	4	FirstEnergy Generation Corporation	Averaging Plan	0.45	0.22			0.53	0.29
OH	Eastlake	2837	5	FirstEnergy Generation Corporation	Averaging Plan	0.68	0.35			0.53	0.29
OH	Gen J M Gavin	8102	1	Ohio Power Company	Averaging Plan	0.68	0.37			0.58	0.37
OH	Gen J M Gavin	8102	2	Ohio Power Company	Averaging Plan	0.68	0.42			0.58	0.37
OH	Hamilton Municipal Power Plant	2917	9	City of Hamilton	Standard Limit	0.40	0.33				
OH	J M Stuart	2850	1	Dayton Power and Light Company	Averaging Plan	0.68	0.35			0.62	0.37
OH	J M Stuart	2850	2	Dayton Power and Light Company	Averaging Plan	0.68	0.44			0.62	0.37

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OH	J M Stuart	2850	3	Dayton Power and Light Company	Averaging Plan	0.68	0.35			0.62	0.37
OH	J M Stuart	2850	4	Dayton Power and Light Company	Averaging Plan	0.68	0.38			0.62	0.37
OH	Killen Station	6031	2	Dayton Power and Light Company	Averaging Plan	0.46	0.35			0.62	0.37
OH	Kyger Creek	2876	1	Ohio Valley Electric Corporation	Averaging Plan	0.84	0.50			0.84	0.49
OH	Kyger Creek	2876	2	Ohio Valley Electric Corporation	Averaging Plan	0.84	0.50			0.84	0.49
OH	Kyger Creek	2876	3	Ohio Valley Electric Corporation	Averaging Plan	0.84	0.50			0.84	0.49
OH	Kyger Creek	2876	4	Ohio Valley Electric Corporation	Averaging Plan	0.84	0.50			0.84	0.49
OH	Kyger Creek	2876	5	Ohio Valley Electric Corporation	Averaging Plan	0.84	0.50			0.84	0.49
OH	Lake Shore	2838	18	FirstEnergy Generation Corporation	Averaging Plan	0.40	0.30			0.53	0.29
OH	Miami Fort Generating Station	2832	5-1	Duke Energy Shared Services, Inc.	Averaging Plan	0.80	0.41			0.49	0.30
OH	Miami Fort Generating Station	2832	5-2	Duke Energy Shared Services, Inc.	Averaging Plan	0.80	0.41			0.49	0.30
OH	Miami Fort Generating Station	2832	6	Duke Energy Shared Services, Inc.	Averaging Plan	0.45	0.41			0.49	0.30
OH	Miami Fort Generating Station	2832	7	Duke Energy Shared Services, Inc.	Averaging Plan	0.68	0.35			0.49	0.30
OH	Miami Fort Generating Station	2832	8	Duke Energy Shared Services, Inc.	Averaging Plan	0.46	0.30			0.49	0.30
OH	Muskingum River	2872	1	Ohio Power Company	Averaging Plan	0.84	0.61			0.58	0.37
OH	Muskingum River	2872	2	Ohio Power Company	Averaging Plan	0.84	0.61			0.58	0.37
OH	Muskingum River	2872	3	Ohio Power Company	Averaging Plan	0.86	0.61			0.58	0.37
OH	Muskingum River	2872	4	Ohio Power Company	Averaging Plan	0.86	0.61			0.58	0.37
OH	Muskingum River	2872	5	Ohio Power Company	Averaging Plan	0.68	0.42			0.58	0.37
OH	O H Hutchings	2848	H-1	Dayton Power and Light Company	Averaging Plan	0.40	0.63			0.62	0.37
OH	O H Hutchings	2848	H-2	Dayton Power and Light Company	Averaging Plan	0.40	0.63			0.62	0.37
OH	O H Hutchings	2848	H-3	Dayton Power and Light Company	Averaging Plan	0.40	0.41			0.62	0.37
OH	O H Hutchings	2848	H-4	Dayton Power and Light Company	Averaging Plan	0.40	0.41			0.62	0.37
OH	O H Hutchings	2848	H-5	Dayton Power and Light Company	Averaging Plan	0.40	0.40			0.62	0.37

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OH	O H Hutchings	2848	H-6	Dayton Power and Light Company	Averaging Plan	0.40	0.40			0.62	0.37
OH	Picway	2843	9	Columbus Southern Power Company	Averaging Plan	0.50	0.42			0.58	0.37
OH	R E Burger	2864	5	FirstEnergy Generation Corporation	Averaging Plan	0.84	0.00			0.53	0.29
OH	R E Burger	2864	6	FirstEnergy Generation Corporation	Averaging Plan	0.84	0.00			0.53	0.29
OH	R E Burger	2864	7	FirstEnergy Generation Corporation	Averaging Plan	0.50	0.36			0.53	0.29
OH	R E Burger	2864	8	FirstEnergy Generation Corporation	Averaging Plan	0.50	0.36			0.53	0.29
OH	Richard Gorsuch	7253	1	American Municipal Power - Ohio	Standard Limit	0.46	0.38				
OH	Richard Gorsuch	7253	2	American Municipal Power - Ohio	Standard Limit	0.46	0.38				
OH	Richard Gorsuch	7253	3	American Municipal Power - Ohio	Standard Limit	0.46	0.38				
OH	Richard Gorsuch	7253	4	American Municipal Power - Ohio	Standard Limit	0.46	0.38				
OH	W H Sammis	2866	1	FirstEnergy Generation Corporation	Averaging Plan	0.46	0.23			0.53	0.29
OH	W H Sammis	2866	2	FirstEnergy Generation Corporation	Averaging Plan	0.46	0.23			0.53	0.29
OH	W H Sammis	2866	3	FirstEnergy Generation Corporation	Averaging Plan	0.46	0.21			0.53	0.29
OH	W H Sammis	2866	4	FirstEnergy Generation Corporation	Averaging Plan	0.46	0.21			0.53	0.29
OH	W H Sammis	2866	5	FirstEnergy Generation Corporation	Averaging Plan	0.50	0.26			0.53	0.29
OH	W H Sammis	2866	6	FirstEnergy Generation Corporation	Averaging Plan	0.50	0.29			0.53	0.29
OH	W H Sammis	2866	7	FirstEnergy Generation Corporation	Averaging Plan	0.68	0.29			0.53	0.29
OH	W H Zimmer Generating Station	6019	1	Duke Energy Shared Services, Inc.	Early Election	0.46	0.33	0.50			
OH	Walter C Beckjord Generating Station	2830	1	Duke Energy Shared Services, Inc.	Averaging Plan	0.40	0.61			0.49	0.30
OH	Walter C Beckjord Generating Station	2830	2	Duke Energy Shared Services, Inc.	Averaging Plan	0.40	0.62			0.49	0.30
OH	Walter C Beckjord Generating Station	2830	3	Duke Energy Shared Services, Inc.	Averaging Plan	0.46	0.48			0.49	0.30

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OH	Walter C Beckjord Generating Station	2830	4	Duke Energy Shared Services, Inc.	Averaging Plan	0.40	0.40			0.49	0.30
OH	Walter C Beckjord Generating Station	2830	5	Duke Energy Shared Services, Inc.	Averaging Plan	0.45	0.37			0.49	0.30
OH	Walter C Beckjord Generating Station	2830	6	Duke Energy Shared Services, Inc.	Averaging Plan	0.45	0.27			0.49	0.30
OK	Grand River Dam Authority	165	1	Grand River Dam Authority	Averaging Plan	0.46	0.43			0.46	0.39
OK	Grand River Dam Authority	165	2	Grand River Dam Authority	Averaging Plan	0.46	0.35			0.46	0.39
OK	Hugo	6772	1	Western Farmers Electric Cooperative, Inc.	Standard Limit	0.46	0.23				
OK	Muskogee	2952	4	Oklahoma Gas & Electric Company	Early Election	0.40	0.28	0.45			
OK	Muskogee	2952	5	Oklahoma Gas & Electric Company	Early Election	0.40	0.32	0.45			
OK	Muskogee	2952	6	Oklahoma Gas & Electric Company	Early Election	0.40	0.35	0.45			
OK	Northeastern	2963	3313	Public Service Company of Oklahoma	Early Election	0.40	0.42	0.45			
OK	Northeastern	2963	3314	Public Service Company of Oklahoma	Early Election	0.40	0.42	0.45			
OK	Sooner	6095	1	Oklahoma Gas & Electric Company	Early Election	0.40	0.36	0.45			
OK	Sooner	6095	2	Oklahoma Gas & Electric Company	Early Election	0.40	0.35	0.45			
OR	Boardman	6106	1SG	Portland General Electric Company	Early Election	0.46	0.43	0.50			
PA	Armstrong Power Station	3178	1	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.34			0.55	0.33
PA	Armstrong Power Station	3178	2	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.33			0.55	0.33
PA	Bruce Mansfield	6094	1	FirstEnergy Generation Corporation	Averaging Plan	0.50	0.30			0.53	0.29
PA	Bruce Mansfield	6094	2	FirstEnergy Generation Corporation	Averaging Plan	0.50	0.30			0.53	0.29
PA	Bruce Mansfield	6094	3	FirstEnergy Generation Corporation	Averaging Plan	0.46	0.31	0.50		0.53	0.29
PA	Brunner Island	3140	1	PPL Brunner Island, LLC	Standard Limit	0.45	0.31				
PA	Brunner Island	3140	2	PPL Brunner Island, LLC	Standard Limit	0.45	0.31				
PA	Brunner Island	3140	3	PPL Brunner Island, LLC	Standard Limit	0.45	0.32				
PA	Cheswick	8226	1	Orion Power Midwest, LP	Standard Limit	0.45	0.31				
PA	Conemaugh	3118	1	Reliant Energy Northeast Management Company	Standard Limit	0.45	0.36				

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PA	Conemaugh	3118	2	Reliant Energy Northeast Management Company	Standard Limit	0.45	0.32				
PA	Cromby	3159	1	Exelon Generation Company LLC	Early Election	0.46	0.35	0.50			
PA	Eddystone Generating Station	3161	1	Exelon Generation Company LLC	Early Election	0.40	0.32	0.45			
PA	Eddystone Generating Station	3161	2	Exelon Generation Company LLC	Early Election	0.40	0.31	0.45			
PA	Elrama	3098	1	Orion Power Midwest, LP	Averaging Plan	0.80	0.46			0.65	0.46
PA	Elrama	3098	2	Orion Power Midwest, LP	Averaging Plan	0.80	0.46			0.65	0.46
PA	Elrama	3098	3	Orion Power Midwest, LP	Averaging Plan	0.80	0.46			0.65	0.46
PA	Elrama	3098	4	Orion Power Midwest, LP	Averaging Plan	0.46	0.46			0.65	0.46
PA	Hatfields Ferry Power Station	3179	1	Allegheny Energy Supply Company, LLC	Averaging Plan	0.68	0.45			0.55	0.33
PA	Hatfields Ferry Power Station	3179	2	Allegheny Energy Supply Company, LLC	Averaging Plan	0.68	0.45			0.55	0.33
PA	Hatfields Ferry Power Station	3179	3	Allegheny Energy Supply Company, LLC	Averaging Plan	0.68	0.45			0.55	0.33
PA	Homer City	3122	1	EME Homer City Generation, LP	Early Election	0.46	0.24	0.50			
PA	Homer City	3122	2	EME Homer City Generation, LP	Early Election	0.46	0.28	0.50			
PA	Homer City	3122	3	EME Homer City Generation, LP	Early Election	0.46	0.26	0.50			
PA	Keystone	3136	1	Reliant Energy Northeast Management Company	Early Election	0.40	0.19	0.45			
PA	Keystone	3136	2	Reliant Energy Northeast Management Company	Early Election	0.40	0.24	0.45			
PA	Martins Creek	3148	1	PPL Martins Creek, LLC	Standard Limit	0.50	0.42				
PA	Martins Creek	3148	2	PPL Martins Creek, LLC	Standard Limit	0.50	0.42				
PA	Mitchell Power Station	3181	33	Allegheny Energy Supply Company, LLC	Averaging Plan	0.45	0.32			0.55	0.33
PA	Montour	3149	1	PPL Montour, LLC	Early Election	0.40	0.27	0.45			
PA	Montour	3149	2	PPL Montour, LLC	Early Election	0.40	0.29	0.45			
PA	New Castle	3138	3	Orion Power Midwest, LP	Early Election	0.46	0.31	0.50			
PA	New Castle	3138	4	Orion Power Midwest, LP	Early Election	0.46	0.32	0.50			
PA	New Castle	3138	5	Orion Power Midwest, LP	Early Election	0.46	0.37	0.50			
PA	Portland	3113	1	Reliant Energy Mid-Atlantic Power Holdings, LLC	Averaging Plan	0.45	0.25			0.46	0.37
PA	Portland	3113	2	Reliant Energy Mid-Atlantic Power Holdings, LLC	Averaging Plan	0.45	0.34			0.46	0.37

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PA	Shawville	3131	1	Reliant Energy Mid-Atlantic Power Holdings, LLC	Averaging Plan	0.50	0.46			0.46	0.37
PA	Shawville	3131	2	Reliant Energy Mid-Atlantic Power Holdings, LLC	Averaging Plan	0.50	0.46			0.46	0.37
PA	Shawville	3131	3	Reliant Energy Mid-Atlantic Power Holdings, LLC	Averaging Plan	0.45	0.38			0.46	0.37
PA	Shawville	3131	4	Reliant Energy Mid-Atlantic Power Holdings, LLC	Averaging Plan	0.45	0.38			0.46	0.37
PA	Sunbury	3152	3	Sunbury Generation, LP	Standard Limit	0.50	0.28				
PA	Sunbury	3152	4	Sunbury Generation, LP	Standard Limit	0.50	0.27				
PA	Titus	3115	1	Reliant Energy Mid-Atlantic Power Holdings, LLC	Early Election	0.40	0.33	0.45			
PA	Titus	3115	2	Reliant Energy Mid-Atlantic Power Holdings, LLC	Early Election	0.40	0.33	0.45			
PA	Titus	3115	3	Reliant Energy Mid-Atlantic Power Holdings, LLC	Early Election	0.40	0.33	0.45			
SC	Canadys Steam	3280	CAN1	South Carolina Electric & Gas Company	Averaging Plan	0.40	0.39			0.42	0.31
SC	Canadys Steam	3280	CAN2	South Carolina Electric & Gas Company	Averaging Plan	0.40	0.43			0.42	0.31
SC	Canadys Steam	3280	CAN3	South Carolina Electric & Gas Company	Averaging Plan	0.46	0.36			0.42	0.31
SC	Cope Station	7210	COP1	South Carolina Electric & Gas Company	Averaging Plan	0.40	0.26			0.42	0.31
SC	Cross	130	1	Santee Cooper	Averaging Plan	0.46	0.09	0.50		0.46	0.22
SC	Cross	130	2	Santee Cooper	Early Election	0.40	0.09	0.45			
SC	Dolphus M Grainger	3317	1	Santee Cooper	Averaging Plan	0.46	0.45			0.46	0.22
SC	Dolphus M Grainger	3317	2	Santee Cooper	Averaging Plan	0.46	0.42			0.46	0.22
SC	H B Robinson	3251	1	Carolina Power & Light Company	Averaging Plan	0.40	0.51			0.44	0.36
SC	Jefferies	3319	3	Santee Cooper	Averaging Plan	0.46	0.48			0.46	0.22
SC	Jefferies	3319	4	Santee Cooper	Averaging Plan	0.46	0.45			0.46	0.22
SC	McMeekin	3287	MCM1	South Carolina Electric & Gas Company	Averaging Plan	0.40	0.38			0.42	0.31
SC	McMeekin	3287	MCM2	South Carolina Electric & Gas Company	Averaging Plan	0.40	0.36			0.42	0.31
SC	Urquhart	3295	URQ3	South Carolina Electric & Gas Company	Averaging Plan	0.40	0.29			0.42	0.31
SC	W S Lee	3264	1	Duke Energy Shared Services, Inc.	Early Election	0.40	0.28	0.45			
SC	W S Lee	3264	2	Duke Energy Shared Services, Inc.	Early Election	0.40	0.23	0.45			

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SC	W S Lee	3264	3	Duke Energy Shared Services, Inc.	Early Election	0.40	0.25	0.45			
SC	Wateree	3297	WAT1	South Carolina Electric & Gas Company	Averaging Plan	0.46	0.33			0.42	0.31
SC	Wateree	3297	WAT2	South Carolina Electric & Gas Company	Averaging Plan	0.46	0.22			0.42	0.31
SC	Williams	3298	WIL1	South Carolina Generating Company	Averaging Plan	0.40	0.30			0.42	0.31
SC	Winyah	6249	1	Santee Cooper	Averaging Plan	0.46	0.09			0.46	0.22
SC	Winyah	6249	2	Santee Cooper	Alternative Emissions Limit	0.46	0.10		0.61		
SC	Winyah	6249	3	Santee Cooper	Alternative Emissions Limit	0.46	0.13		0.60		
SC	Winyah	6249	4	Santee Cooper	Alternative Emissions Limit	0.46	0.12		0.60		
SD	Big Stone	6098	1	Otter Tail Power Company	Standard Limit	0.86	0.80				
TN	Allen	3393	1	Tennessee Valley Authority	Averaging Plan	0.86	0.49			0.57	0.38
TN	Allen	3393	2	Tennessee Valley Authority	Averaging Plan	0.86	0.53			0.57	0.38
TN	Allen	3393	3	Tennessee Valley Authority	Averaging Plan	0.86	0.42			0.57	0.38
TN	Bull Run	3396	1	Tennessee Valley Authority	Averaging Plan	0.40	0.37			0.57	0.38
TN	Cumberland	3399	1	Tennessee Valley Authority	Averaging Plan	0.68	0.34			0.57	0.38
TN	Cumberland	3399	2	Tennessee Valley Authority	Averaging Plan	0.68	0.40			0.57	0.38
TN	Gallatin	3403	1	Tennessee Valley Authority	Averaging Plan	0.45	0.18			0.57	0.38
TN	Gallatin	3403	2	Tennessee Valley Authority	Averaging Plan	0.45	0.18			0.57	0.38
TN	Gallatin	3403	3	Tennessee Valley Authority	Averaging Plan	0.45	0.19			0.57	0.38
TN	Gallatin	3403	4	Tennessee Valley Authority	Averaging Plan	0.45	0.19			0.57	0.38
TN	John Sevier	3405	1	Tennessee Valley Authority	Averaging Plan	0.40	0.39			0.57	0.38
TN	John Sevier	3405	2	Tennessee Valley Authority	Averaging Plan	0.40	0.39			0.57	0.38
TN	John Sevier	3405	3	Tennessee Valley Authority	Averaging Plan	0.40	0.39			0.57	0.38
TN	John Sevier	3405	4	Tennessee Valley Authority	Averaging Plan	0.40	0.39			0.57	0.38
TN	Johnsonville	3406	1	Tennessee Valley Authority	Averaging Plan	0.45	0.41			0.57	0.38
TN	Johnsonville	3406	10	Tennessee Valley Authority	Averaging Plan	0.50	0.41			0.57	0.38
TN	Johnsonville	3406	2	Tennessee Valley Authority	Averaging Plan	0.45	0.41			0.57	0.38
TN	Johnsonville	3406	3	Tennessee Valley Authority	Averaging Plan	0.45	0.41			0.57	0.38
TN	Johnsonville	3406	4	Tennessee Valley Authority	Averaging Plan	0.45	0.41			0.57	0.38
TN	Johnsonville	3406	5	Tennessee Valley Authority	Averaging Plan	0.45	0.41			0.57	0.38
TN	Johnsonville	3406	6	Tennessee Valley Authority	Averaging Plan	0.45	0.41			0.57	0.38
TN	Johnsonville	3406	7	Tennessee Valley Authority	Averaging Plan	0.50	0.41			0.57	0.38
TN	Johnsonville	3406	8	Tennessee Valley Authority	Averaging Plan	0.50	0.41			0.57	0.38
TN	Johnsonville	3406	9	Tennessee Valley Authority	Averaging Plan	0.50	0.41			0.57	0.38
TN	Kingston	3407	1	Tennessee Valley Authority	Averaging Plan	0.40	0.30			0.57	0.38
TN	Kingston	3407	2	Tennessee Valley Authority	Averaging Plan	0.40	0.30			0.57	0.38

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TN	Kingston	3407	3	Tennessee Valley Authority	Averaging Plan	0.40	0.30			0.57	0.38
TN	Kingston	3407	4	Tennessee Valley Authority	Averaging Plan	0.40	0.30			0.57	0.38
TN	Kingston	3407	5	Tennessee Valley Authority	Averaging Plan	0.40	0.30			0.57	0.38
TN	Kingston	3407	6	Tennessee Valley Authority	Averaging Plan	0.40	0.24			0.57	0.38
TN	Kingston	3407	7	Tennessee Valley Authority	Averaging Plan	0.40	0.24			0.57	0.38
TN	Kingston	3407	8	Tennessee Valley Authority	Averaging Plan	0.40	0.24			0.57	0.38
TN	Kingston	3407	9	Tennessee Valley Authority	Averaging Plan	0.40	0.24			0.57	0.38
TX	Big Brown	3497	1	Luminant Generation Company LLC	Early Election	0.40	0.14	0.45			
TX	Big Brown	3497	2	Luminant Generation Company LLC	Early Election	0.40	0.14	0.45			
TX	Coleto Creek	6178	1	Coleto Creek WLE, LP	Early Election	0.40	0.14	0.45			
TX	Gibbons Creek Steam Electric Station	6136	1	Texas Municipal Power Agency	Early Election	0.40	0.13	0.45			
TX	H W Pirkey Power Plant	7902	1	Southwestern Electric Power Company	Early Election	0.46	0.17	0.50			
TX	Harrington Station	6193	061B	Southwestern Public Service Company	Early Election	0.40	0.29	0.45			
TX	Harrington Station	6193	062B	Southwestern Public Service Company	Early Election	0.40	0.33	0.45			
TX	Harrington Station	6193	063B	Southwestern Public Service Company	Early Election	0.40	0.34	0.45			
TX	J K Spruce	7097	**1	City Public Service	Early Election	0.40	0.17	0.45			
TX	J T Deely	6181	1	City Public Service	Early Election	0.40	0.13	0.45			
TX	J T Deely	6181	2	City Public Service	Early Election	0.40	0.13	0.45			
TX	Limestone	298	LIM1	NRG Texas LP	Early Election	0.40	0.21	0.45			
TX	Limestone	298	LIM2	NRG Texas LP	Early Election	0.40	0.20	0.45			
TX	Martin Lake	6146	1	Luminant Generation Company LLC	Early Election	0.40	0.16	0.45			
TX	Martin Lake	6146	2	Luminant Generation Company LLC	Early Election	0.40	0.17	0.45			
TX	Martin Lake	6146	3	Luminant Generation Company LLC	Early Election	0.40	0.15	0.45			
TX	Monticello	6147	1	Luminant Generation Company LLC	Early Election	0.40	0.14	0.45			
TX	Monticello	6147	2	Luminant Generation Company LLC	Early Election	0.40	0.15	0.45			
TX	Monticello	6147	3	Luminant Generation Company LLC	Early Election	0.46	0.20	0.50			
TX	Oklaunion Power Station	127	1	West Texas Utilities Company	Early Election	0.46	0.33	0.50			

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TX	Sam Seymour	6179	1	Lower Colorado River Authority	Early Election	0.40	0.10	0.45			
TX	Sam Seymour	6179	2	Lower Colorado River Authority	Early Election	0.40	0.11	0.45			
TX	Sam Seymour	6179	3	Lower Colorado River Authority	Early Election	0.40	0.11	0.45			
TX	San Miguel	6183	SM-1	San Miguel Electric Cooperative	Early Election	0.46	0.20	0.50			
TX	Sandow	6648	4	Luminant Generation Company LLC	Early Election	0.40	0.19	0.45			
TX	Tolk Station	6194	171B	Southwestern Public Service Company	Early Election	0.40	0.27	0.45			
TX	Tolk Station	6194	172B	Southwestern Public Service Company	Early Election	0.40	0.26	0.45			
TX	W A Parish	3470	WAP5	NRG Texas LP	Early Election	0.46	0.05	0.50			
TX	W A Parish	3470	WAP6	NRG Texas LP	Early Election	0.46	0.05	0.50			
TX	W A Parish	3470	WAP7	NRG Texas LP	Early Election	0.40	0.04	0.45			
TX	W A Parish	3470	WAP8	NRG Texas LP	Early Election	0.40	0.04	0.45			
TX	Welsh Power Plant	6139	1	Southwestern Electric Power Company	Early Election	0.46	0.18	0.50			
TX	Welsh Power Plant	6139	2	Southwestern Electric Power Company	Early Election	0.46	0.17	0.50			
TX	Welsh Power Plant	6139	3	Southwestern Electric Power Company	Early Election	0.46	0.20	0.50			
UT	Bonanza	7790	1-1	Deseret Generation & Transmission	Early Election	0.46	0.33	0.50			
UT	Carbon	3644	1	PacifiCorp	Averaging Plan	0.40	0.46			0.45	0.38
UT	Carbon	3644	2	PacifiCorp	Averaging Plan	0.40	0.45	0.45		0.45	0.38
UT	Hunter	6165	1	PacifiCorp	Early Election	0.40	0.38	0.45			
UT	Hunter	6165	2	PacifiCorp	Early Election	0.40	0.34	0.45			
UT	Hunter	6165	3	PacifiCorp	Averaging Plan	0.46	0.34			0.45	0.38
UT	Huntington	8069	1	PacifiCorp	Early Election	0.40	0.37	0.45			
UT	Huntington	8069	2	PacifiCorp	Averaging Plan	0.40	0.37			0.45	0.38
UT	Intermountain	6481	1SGA	Intermountain Power Service Corporation	Early Election	0.46	0.40	0.50			
UT	Intermountain	6481	2SGA	Intermountain Power Service Corporation	Early Election	0.46	0.33	0.50			
VA	Bremo Power Station	3796	3	Dominion Generation	Averaging Plan	0.46	0.62			0.41	0.26
VA	Bremo Power Station	3796	4	Dominion Generation	Averaging Plan	0.46	0.36			0.41	0.26
VA	Chesapeake Energy Center	3803	1	Dominion Generation	Early Election	0.40	0.39	0.45			
VA	Chesapeake Energy Center	3803	2	Dominion Generation	Early Election	0.40	0.44	0.45			

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VA	Chesapeake Energy Center	3803	3	Dominion Generation	Averaging Plan	0.46	0.26			0.41	0.26
VA	Chesapeake Energy Center	3803	4	Dominion Generation	Early Election	0.40	0.28	0.45			
VA	Chesterfield Power Station	3797	3	Dominion Generation	Early Election	0.40	0.40	0.45			
VA	Chesterfield Power Station	3797	4	Dominion Generation	Early Election	0.40	0.24	0.45			
VA	Chesterfield Power Station	3797	5	Dominion Generation	Averaging Plan	0.40	0.23			0.41	0.26
VA	Chesterfield Power Station	3797	6	Dominion Generation	Averaging Plan	0.40	0.22			0.41	0.26
VA	Clinch River	3775	1	Appalachian Power Company	Averaging Plan	0.80	0.42			0.58	0.37
VA	Clinch River	3775	2	Appalachian Power Company	Averaging Plan	0.80	0.42			0.58	0.37
VA	Clinch River	3775	3	Appalachian Power Company	Averaging Plan	0.80	0.39			0.58	0.37
VA	Clover Power Station	7213	1	Dominion Generation	Averaging Plan	0.40	0.26			0.41	0.26
VA	Clover Power Station	7213	2	Dominion Generation	Averaging Plan	0.40	0.27			0.41	0.26
VA	Glen Lyn	3776	51	Appalachian Power Company	Averaging Plan	0.40	0.42			0.58	0.37
VA	Glen Lyn	3776	52	Appalachian Power Company	Averaging Plan	0.40	0.40	0.45		0.58	0.37
VA	Glen Lyn	3776	6	Appalachian Power Company	Averaging Plan	0.46	0.47			0.58	0.37
VA	Mirant Potomac River	3788	1	Mirant Potomac River, LLC	Early Election	0.40	0.34	0.45			
VA	Mirant Potomac River	3788	2	Mirant Potomac River, LLC	Early Election	0.40	0.31	0.45			
VA	Mirant Potomac River	3788	3	Mirant Potomac River, LLC	Early Election	0.40	0.26	0.45			
VA	Mirant Potomac River	3788	4	Mirant Potomac River, LLC	Early Election	0.40	0.24	0.45			
VA	Mirant Potomac River	3788	5	Mirant Potomac River, LLC	Early Election	0.40	0.26	0.45			
VA	Possum Point Power Station	3804	3	Dominion Generation	Early Election	0.40	0.11	0.45			
VA	Possum Point Power Station	3804	4	Dominion Generation	Averaging Plan	0.40	0.08			0.41	0.26
VA	Yorktown Power Station	3809	1	Dominion Generation	Early Election	0.40	0.41	0.45			
VA	Yorktown Power Station	3809	2	Dominion Generation	Early Election	0.40	0.41	0.45			
WA	Centralia	3845	BW21	TransAlta Centralia Generation, LLC	Early Election	0.40	0.27	0.45			
WA	Centralia	3845	BW22	TransAlta Centralia Generation, LLC	Early Election	0.40	0.24	0.45			
WI	Alma	4140	B4	Dairyland Power Cooperative	Averaging Plan	0.50	0.78			0.48	0.39
WI	Alma	4140	B5	Dairyland Power Cooperative	Averaging Plan	0.50	0.78			0.48	0.39
WI	Blount Street	3992	7	Madison Gas & Electric Company	Standard Limit	0.68	0.43				
WI	Blount Street	3992	8	Madison Gas & Electric Company	Early Election	0.46	0.34	0.50			
WI	Blount Street	3992	9	Madison Gas & Electric Company	Early Election	0.46	0.35	0.50			
WI	Columbia	8023	1	Wisconsin Power & Light Company	Early Election	0.40	0.15	0.45			
WI	Columbia	8023	2	Wisconsin Power & Light Company	Early Election	0.40	0.12	0.45			
WI	E J Stoneman Generation Station	4146	B1	WPS Power Development, Inc.	Averaging Plan	0.46	0.35			0.46	0.35

State	Facility Name	Facility ID (ORISPL)	Unit ID	Unit Operator(s)	Compliance Approach	Standard Emission Limit	Actual Emission Rate	Early Election Limit (if applicable)	AEL (if applicable)	Averaging Plan Limit (if applicable)	Actual Averaging Plan Rate (if applicable)
WI	E J Stoneman Generation Station	4146	B2	WPS Power Development, Inc.	Averaging Plan	0.46	0.35			0.46	0.35
WI	Edgewater (4050)	4050	4	Wisconsin Power & Light Company	Averaging Plan	0.86	0.18			0.66	0.20
WI	Edgewater (4050)	4050	5	Wisconsin Power & Light Company	Averaging Plan	0.46	0.21	0.50		0.66	0.20
WI	Genoa	4143	1	Dairyland Power Cooperative	Averaging Plan	0.45	0.35			0.48	0.39
WI	J P Madgett	4271	B1	Dairyland Power Cooperative	Averaging Plan	0.50	0.31			0.48	0.39
WI	Pleasant Prairie	6170	1	Wisconsin Electric Power Company	Averaging Plan	0.46	0.18			0.46	0.22
WI	Pleasant Prairie	6170	2	Wisconsin Electric Power Company	Averaging Plan	0.46	0.19			0.46	0.22
WI	Pulliam	4072	3	Wisconsin Public Service Corporation	Averaging Plan	0.46	0.76			0.47	0.41
WI	Pulliam	4072	4	Wisconsin Public Service Corporation	Averaging Plan	0.46	0.76			0.47	0.41
WI	Pulliam	4072	5	Wisconsin Public Service Corporation	Averaging Plan	0.46	0.95			0.47	0.41
WI	Pulliam	4072	6	Wisconsin Public Service Corporation	Averaging Plan	0.46	0.95			0.47	0.41
WI	Pulliam	4072	7	Wisconsin Public Service Corporation	Averaging Plan	0.50	0.38			0.47	0.41
WI	Pulliam	4072	8	Wisconsin Public Service Corporation	Averaging Plan	0.50	0.27			0.47	0.41
WI	South Oak Creek	4041	5	Wisconsin Electric Power Company	Averaging Plan	0.50	0.17			0.46	0.22
WI	South Oak Creek	4041	6	Wisconsin Electric Power Company	Averaging Plan	0.50	0.17			0.46	0.22
WI	South Oak Creek	4041	7	Wisconsin Electric Power Company	Averaging Plan	0.45	0.13			0.46	0.22
WI	South Oak Creek	4041	8	Wisconsin Electric Power Company	Averaging Plan	0.45	0.13			0.46	0.22
WI	Valley (WEPCO)	4042	1	Wisconsin Electric Power Company	Averaging Plan	0.50	0.34			0.46	0.22
WI	Valley (WEPCO)	4042	2	Wisconsin Electric Power Company	Averaging Plan	0.50	0.34			0.46	0.22
WI	Valley (WEPCO)	4042	3	Wisconsin Electric Power Company	Averaging Plan	0.50	0.38			0.46	0.22
WI	Valley (WEPCO)	4042	4	Wisconsin Electric Power Company	Averaging Plan	0.50	0.38			0.46	0.22
WI	Weston	4078	1	Wisconsin Public Service Corporation	Averaging Plan	0.50	0.68			0.47	0.41
WI	Weston	4078	2	Wisconsin Public Service Corporation	Averaging Plan	0.50	0.33			0.47	0.41

State	Facility Name	Facility ID (ORISPL)	Unit ID	Unit Operator(s)	Compliance Approach	Standard Emission Limit	Actual Emission Rate	Early Election Limit (if applicable)	AEL (if applicable)	Averaging Plan Limit (if applicable)	Actual Averaging Plan Rate (if applicable)
WI	Weston	4078	3	Wisconsin Public Service Corporation	Averaging Plan	0.45	0.25			0.47	0.41
WV	Albright Power Station	3942	1	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.54			0.55	0.33
WV	Albright Power Station	3942	2	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.42			0.55	0.33
WV	Albright Power Station	3942	3	Allegheny Energy Supply Company, LLC	Averaging Plan	0.45	0.30			0.55	0.33
WV	Fort Martin Power Station	3943	1	Allegheny Energy Supply Company, LLC	Averaging Plan	0.45	0.27			0.55	0.33
WV	Fort Martin Power Station	3943	2	Allegheny Energy Supply Company, LLC	Averaging Plan	0.68	0.26			0.55	0.33
WV	Harrison Power Station	3944	1	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.33			0.55	0.33
WV	Harrison Power Station	3944	2	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.32			0.55	0.33
WV	Harrison Power Station	3944	3	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.30			0.55	0.33
WV	John E Amos	3935	1	Appalachian Power Company	Averaging Plan	0.46	0.32			0.58	0.37
WV	John E Amos	3935	2	Appalachian Power Company	Averaging Plan	0.46	0.32			0.58	0.37
WV	John E Amos	3935	3	Appalachian Power Company	Averaging Plan	0.68	0.43			0.58	0.37
WV	Kammer	3947	1	Ohio Power Company	Averaging Plan	0.86	0.64			0.58	0.37
WV	Kammer	3947	2	Ohio Power Company	Averaging Plan	0.86	0.64			0.58	0.37
WV	Kammer	3947	3	Ohio Power Company	Averaging Plan	0.86	0.64			0.58	0.37
WV	Kanawha River	3936	1	Appalachian Power Company	Averaging Plan	0.80	0.36			0.58	0.37
WV	Kanawha River	3936	2	Appalachian Power Company	Averaging Plan	0.80	0.36			0.58	0.37
WV	Mitchell (WV)	3948	1	Ohio Power Company	Averaging Plan	0.50	0.46			0.58	0.37
WV	Mitchell (WV)	3948	2	Ohio Power Company	Averaging Plan	0.50	0.46			0.58	0.37
WV	Mount Storm Power Station	3954	1	Dominion Generation	Alternative Emissions Limit	0.45	0.34		0.76		
WV	Mount Storm Power Station	3954	2	Dominion Generation	Alternative Emissions Limit	0.45	0.35		0.69		
WV	Mount Storm Power Station	3954	3	Dominion Generation	Alternative Emissions Limit	0.45	0.41		0.74		
WV	Mountaineer (1301)	6264	1	Appalachian Power Company	Averaging Plan	0.46	0.24	0.50		0.58	0.37
WV	Phil Sporn	3938	11	Appalachian Power Company	Averaging Plan	0.80	0.37			0.58	0.37
WV	Phil Sporn	3938	21	Central Operating Company	Averaging Plan	0.80	0.37			0.58	0.37
WV	Phil Sporn	3938	31	Appalachian Power Company	Averaging Plan	0.80	0.37			0.58	0.37
WV	Phil Sporn	3938	41	Central Operating Company	Averaging Plan	0.80	0.37			0.58	0.37
WV	Phil Sporn	3938	51	Central Operating Company	Averaging Plan	0.46	0.36			0.58	0.37
WV	Pleasants Power Station	6004	1	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.25			0.55	0.33
WV	Pleasants Power Station	6004	2	Allegheny Energy Supply Company, LLC	Averaging Plan	0.50	0.23			0.55	0.33

State	Facility Name	Facility ID (ORISPL)	Unit ID	Unit Operator(s)	Compliance Approach	Standard Emission Limit	Actual Emission Rate	Early Election Limit (if applicable)	AEL (if applicable)	Averaging Plan Limit (if applicable)	Actual Averaging Plan Rate (if applicable)
WV	Rivesville Power Station	3945	7	Allegheny Energy Supply Company, LLC	Averaging Plan	0.80	0.73			0.55	0.33
WV	Rivesville Power Station	3945	8	Allegheny Energy Supply Company, LLC	Averaging Plan	0.80	0.63			0.55	0.33
WV	Willow Island Power Station	3946	1	Allegheny Energy Supply Company, LLC	Averaging Plan	0.80	0.46			0.55	0.33
WV	Willow Island Power Station	3946	2	Allegheny Energy Supply Company, LLC	Averaging Plan	0.86	0.66			0.55	0.33
WY	Dave Johnston	4158	BW41	PacifiCorp	Early Election	0.46	0.47	0.50			
WY	Dave Johnston	4158	BW42	PacifiCorp	Early Election	0.46	0.46	0.50			
WY	Dave Johnston	4158	BW43	PacifiCorp	Averaging Plan	0.68	0.51			0.45	0.38
WY	Dave Johnston	4158	BW44	PacifiCorp	Averaging Plan	0.40	0.37			0.45	0.38
WY	Jim Bridger	8066	BW71	PacifiCorp	Averaging Plan	0.45	0.41			0.45	0.38
WY	Jim Bridger	8066	BW72	PacifiCorp	Averaging Plan	0.45	0.22			0.45	0.38
WY	Jim Bridger	8066	BW73	PacifiCorp	Averaging Plan	0.45	0.41			0.45	0.38
WY	Jim Bridger	8066	BW74	PacifiCorp	Early Election	0.40	0.40	0.45			
WY	Laramie River	6204	1	Basin Electric Power Cooperative	Early Election	0.46	0.26	0.50			
WY	Laramie River	6204	2	Basin Electric Power Cooperative	Early Election	0.46	0.27	0.50			
WY	Laramie River	6204	3	Basin Electric Power Cooperative	Early Election	0.46	0.26	0.50			
WY	Naughton	4162	1	PacifiCorp	Averaging Plan	0.40	0.54			0.45	0.38
WY	Naughton	4162	2	PacifiCorp	Averaging Plan	0.40	0.54			0.45	0.38
WY	Naughton	4162	3	PacifiCorp	Averaging Plan	0.40	0.44			0.45	0.38
WY	Wyodak	6101	BW91	PacifiCorp	Averaging Plan	0.50	0.27			0.45	0.38

Year 2006 Averaging Plan Summary

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
7	E W Brown	1355	1	0.45	0.27
7	E W Brown	1355	2	0.45	0.27
7	E W Brown	1355	3	0.45	0.27
7	Ghent	1356	1	0.45	0.27
7	Ghent	1356	2	0.45	0.27
7	Ghent	1356	3	0.45	0.27
7	Ghent	1356	4	0.45	0.27
7	Green River	1357	4	0.45	0.27
7	Green River	1357	5	0.45	0.27
7	Tyrone	1361	5	0.45	0.27
10	Clifty Creek	983	1	0.84	0.49
10	Clifty Creek	983	2	0.84	0.49
10	Clifty Creek	983	3	0.84	0.49
10	Clifty Creek	983	4	0.84	0.49
10	Clifty Creek	983	5	0.84	0.49
10	Clifty Creek	983	6	0.84	0.49
10	Kyger Creek	2876	1	0.84	0.49
10	Kyger Creek	2876	2	0.84	0.49
10	Kyger Creek	2876	3	0.84	0.49
10	Kyger Creek	2876	4	0.84	0.49
10	Kyger Creek	2876	5	0.84	0.49
11	Harding Street Station (EW Stout)	990	50	0.45	0.26
11	Harding Street Station (EW Stout)	990	60	0.45	0.26
11	Harding Street Station (EW Stout)	990	70	0.45	0.26
11	IPL Eagle Valley Generating Station	991	3	0.45	0.26
11	IPL Eagle Valley Generating Station	991	4	0.45	0.26
11	IPL Eagle Valley Generating Station	991	5	0.45	0.26
11	IPL Eagle Valley Generating Station	991	6	0.45	0.26
11	Petersburg	994	1	0.45	0.26
11	Petersburg	994	2	0.45	0.26
11	Petersburg	994	3	0.45	0.26
11	Petersburg	994	4	0.45	0.26
21	Bailly Generating Station	995	7	0.76	0.45
21	Bailly Generating Station	995	8	0.76	0.45
21	Michigan City Generating Station	997	12	0.76	0.45
21	R M Schahfer Generating Station	6085	14	0.76	0.45
21	R M Schahfer Generating Station	6085	15	0.76	0.45
28	New Madrid Power Plant	2167	1	0.75	0.55
28	New Madrid Power Plant	2167	2	0.75	0.55
28	Thomas Hill Energy Center	2168	MB1	0.75	0.55
28	Thomas Hill Energy Center	2168	MB2	0.75	0.55
28	Thomas Hill Energy Center	2168	MB3	0.75	0.55
33	Martin Drake	492	5	0.46	0.38
33	Martin Drake	492	6	0.46	0.38
33	Martin Drake	492	7	0.46	0.38
34	Grand River Dam Authority	165	1	0.46	0.39

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
34	Grand River Dam Authority	165	2	0.46	0.39
35	R D Morrow Senior Generating Plant	6061	1	0.50	0.48
35	R D Morrow Senior Generating Plant	6061	2	0.50	0.48
41	Big Bend	645	BB01	0.72	0.52
41	Big Bend	645	BB02	0.72	0.52
41	Big Bend	645	BB03	0.72	0.52
41	Big Bend	645	BB04	0.72	0.52
47	State Line Generating Station (IN)	981	3	0.67	0.48
47	State Line Generating Station (IN)	981	4	0.67	0.48
51	Frank E Ratts	1043	1SG1	0.47	0.28
51	Frank E Ratts	1043	2SG1	0.47	0.28
51	Merom	6213	1SG1	0.47	0.28
51	Merom	6213	2SG1	0.47	0.28
53	Bremo Power Station	3796	3	0.41	0.26
53	Bremo Power Station	3796	4	0.41	0.26
53	Chesapeake Energy Center	3803	3	0.41	0.26
53	Chesterfield Power Station	3797	5	0.41	0.26
53	Chesterfield Power Station	3797	6	0.41	0.26
53	Clover Power Station	7213	1	0.41	0.26
53	Clover Power Station	7213	2	0.41	0.26
53	Possum Point Power Station	3804	4	0.41	0.26
57	Coleman	1381	C1	0.49	0.31
57	Coleman	1381	C2	0.49	0.31
57	Coleman	1381	C3	0.49	0.31
57	D B Wilson	6823	W1	0.49	0.31
57	HMP&L Station 2	1382	H1	0.49	0.31
57	HMP&L Station 2	1382	H2	0.49	0.31
57	R D Green	6639	G1	0.49	0.31
57	R D Green	6639	G2	0.49	0.31
57	Robert Reid	1383	R1	0.49	0.31
61	Rochester 7 - Russell Station	2642	1	0.40	0.34
61	Rochester 7 - Russell Station	2642	2	0.40	0.34
61	Rochester 7 - Russell Station	2642	3	0.40	0.34
61	Rochester 7 - Russell Station	2642	4	0.40	0.34
62	Hudson Generating Station	2403	2	0.65	0.34
62	Mercer Generating Station	2408	1	0.65	0.34
62	Mercer Generating Station	2408	2	0.65	0.34
63	Burlington (IA)	1104	1	0.46	0.28
63	Dubuque	1046	1	0.46	0.28
63	Dubuque	1046	5	0.46	0.28
63	Lansing	1047	1	0.46	0.28
63	Lansing	1047	2	0.46	0.28
63	Lansing	1047	3	0.46	0.28
63	Milton L Kapp	1048	2	0.46	0.28
63	Prairie Creek	1073	3	0.46	0.28
63	Prairie Creek	1073	4	0.46	0.28
63	Sixth Street	1058	2	0.46	0.28
63	Sixth Street	1058	3	0.46	0.28

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
63	Sixth Street	1058	4	0.46	0.28
63	Sixth Street	1058	5	0.46	0.28
63	Sutherland	1077	1	0.46	0.28
63	Sutherland	1077	2	0.46	0.28
67	Edgewater (4050)	4050	4	0.66	0.20
67	Edgewater (4050)	4050	5	0.66	0.20
68	Alma	4140	B4	0.48	0.39
68	Alma	4140	B5	0.48	0.39
68	Genoa	4143	1	0.48	0.39
68	J P Madgett	4271	B1	0.48	0.39
71	La Cygne	1241	1	0.70	0.65
71	La Cygne	1241	2	0.70	0.65
72	F B Culley Generating Station	1012	1	0.50	0.26
72	F B Culley Generating Station	1012	2	0.50	0.26
72	F B Culley Generating Station	1012	3	0.50	0.26
89	Allen S King	1915	1	0.51	0.43
89	Black Dog	1904	3	0.51	0.43
89	Black Dog	1904	4	0.51	0.43
89	High Bridge	1912	3	0.51	0.43
89	High Bridge	1912	4	0.51	0.43
89	High Bridge	1912	5	0.51	0.43
89	High Bridge	1912	6	0.51	0.43
89	Minnesota Valley	1918	4	0.51	0.43
89	Riverside (1927)	1927	6	0.51	0.43
89	Riverside (1927)	1927	7	0.51	0.43
89	Riverside (1927)	1927	8	0.51	0.43
89	Sherburne County	6090	1	0.51	0.43
89	Sherburne County	6090	2	0.51	0.43
89	Sherburne County	6090	3	0.51	0.43
90	B C Cobb	1695	1	0.47	0.28
90	B C Cobb	1695	2	0.47	0.28
90	B C Cobb	1695	3	0.47	0.28
90	B C Cobb	1695	4	0.47	0.28
90	B C Cobb	1695	5	0.47	0.28
90	Dan E Karn	1702	1	0.47	0.28
90	Dan E Karn	1702	2	0.47	0.28
90	J C Weadock	1720	7	0.47	0.28
90	J C Weadock	1720	8	0.47	0.28
90	J H Campbell	1710	1	0.47	0.28
90	J H Campbell	1710	2	0.47	0.28
90	J H Campbell	1710	3	0.47	0.28
90	J R Whiting	1723	1	0.47	0.28
90	J R Whiting	1723	2	0.47	0.28
90	J R Whiting	1723	3	0.47	0.28
92	Big Sandy	1353	BSU1	0.58	0.37
92	Big Sandy	1353	BSU2	0.58	0.37
92	Cardinal	2828	1	0.58	0.37
92	Cardinal	2828	2	0.58	0.37

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
92	Cardinal	2828	3	0.58	0.37
92	Clinch River	3775	1	0.58	0.37
92	Clinch River	3775	2	0.58	0.37
92	Clinch River	3775	3	0.58	0.37
92	Conesville	2840	3	0.58	0.37
92	Conesville	2840	4	0.58	0.37
92	Conesville	2840	5	0.58	0.37
92	Conesville	2840	6	0.58	0.37
92	Gen J M Gavin	8102	1	0.58	0.37
92	Gen J M Gavin	8102	2	0.58	0.37
92	Glen Lyn	3776	51	0.58	0.37
92	Glen Lyn	3776	52	0.58	0.37
92	Glen Lyn	3776	6	0.58	0.37
92	John E Amos	3935	1	0.58	0.37
92	John E Amos	3935	2	0.58	0.37
92	John E Amos	3935	3	0.58	0.37
92	Kammer	3947	1	0.58	0.37
92	Kammer	3947	2	0.58	0.37
92	Kammer	3947	3	0.58	0.37
92	Kanawha River	3936	1	0.58	0.37
92	Kanawha River	3936	2	0.58	0.37
92	Mitchell (WV)	3948	1	0.58	0.37
92	Mitchell (WV)	3948	2	0.58	0.37
92	Mountaineer (1301)	6264	1	0.58	0.37
92	Muskingum River	2872	1	0.58	0.37
92	Muskingum River	2872	2	0.58	0.37
92	Muskingum River	2872	3	0.58	0.37
92	Muskingum River	2872	4	0.58	0.37
92	Muskingum River	2872	5	0.58	0.37
92	Phil Sporn	3938	11	0.58	0.37
92	Phil Sporn	3938	21	0.58	0.37
92	Phil Sporn	3938	31	0.58	0.37
92	Phil Sporn	3938	41	0.58	0.37
92	Phil Sporn	3938	51	0.58	0.37
92	Picway	2843	9	0.58	0.37
92	Rockport	6166	MB1	0.58	0.37
92	Rockport	6166	MB2	0.58	0.37
92	Tanners Creek	988	U1	0.58	0.37
92	Tanners Creek	988	U2	0.58	0.37
92	Tanners Creek	988	U3	0.58	0.37
92	Tanners Creek	988	U4	0.58	0.37
100	Albright Power Station	3942	1	0.55	0.33
100	Albright Power Station	3942	2	0.55	0.33
100	Albright Power Station	3942	3	0.55	0.33
100	Armstrong Power Station	3178	1	0.55	0.33
100	Armstrong Power Station	3178	2	0.55	0.33
100	Fort Martin Power Station	3943	1	0.55	0.33
100	Fort Martin Power Station	3943	2	0.55	0.33

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
100	Harrison Power Station	3944	1	0.55	0.33
100	Harrison Power Station	3944	2	0.55	0.33
100	Harrison Power Station	3944	3	0.55	0.33
100	Hatfields Ferry Power Station	3179	1	0.55	0.33
100	Hatfields Ferry Power Station	3179	2	0.55	0.33
100	Hatfields Ferry Power Station	3179	3	0.55	0.33
100	Mitchell Power Station	3181	33	0.55	0.33
100	Pleasants Power Station	6004	1	0.55	0.33
100	Pleasants Power Station	6004	2	0.55	0.33
100	R. Paul Smith Power Station	1570	11	0.55	0.33
100	R. Paul Smith Power Station	1570	9	0.55	0.33
100	Rivesville Power Station	3945	7	0.55	0.33
100	Rivesville Power Station	3945	8	0.55	0.33
100	Willow Island Power Station	3946	1	0.55	0.33
100	Willow Island Power Station	3946	2	0.55	0.33
102	Belle River	6034	1	0.54	0.29
102	Belle River	6034	2	0.54	0.29
102	Harbor Beach	1731	1	0.54	0.29
102	Marysville	1732	10	0.54	0.29
102	Marysville	1732	11	0.54	0.29
102	Marysville	1732	12	0.54	0.29
102	Marysville	1732	9	0.54	0.29
102	Monroe	1733	1	0.54	0.29
102	Monroe	1733	2	0.54	0.29
102	Monroe	1733	3	0.54	0.29
102	Monroe	1733	4	0.54	0.29
102	River Rouge	1740	2	0.54	0.29
102	River Rouge	1740	3	0.54	0.29
102	St. Clair	1743	1	0.54	0.29
102	St. Clair	1743	2	0.54	0.29
102	St. Clair	1743	3	0.54	0.29
102	St. Clair	1743	4	0.54	0.29
102	St. Clair	1743	6	0.54	0.29
102	St. Clair	1743	7	0.54	0.29
102	Trenton Channel	1745	16	0.54	0.29
102	Trenton Channel	1745	17	0.54	0.29
102	Trenton Channel	1745	18	0.54	0.29
102	Trenton Channel	1745	19	0.54	0.29
102	Trenton Channel	1745	9A	0.54	0.29
108	J M Stuart	2850	1	0.62	0.37
108	J M Stuart	2850	2	0.62	0.37
108	J M Stuart	2850	3	0.62	0.37
108	J M Stuart	2850	4	0.62	0.37
108	Killen Station	6031	2	0.62	0.37
108	O H Hutchings	2848	H-1	0.62	0.37
108	O H Hutchings	2848	H-2	0.62	0.37
108	O H Hutchings	2848	H-3	0.62	0.37
108	O H Hutchings	2848	H-4	0.62	0.37

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
108	O H Hutchings	2848	H-5	0.62	0.37
108	O H Hutchings	2848	H-6	0.62	0.37
109	Arapahoe	465	3	0.80	0.44
109	Arapahoe	465	4	0.80	0.44
111	Reid Gardner	2324	1	0.46	0.33
111	Reid Gardner	2324	2	0.46	0.33
111	Reid Gardner	2324	3	0.46	0.33
111	Reid Gardner	2324	4	0.46	0.33
116	San Juan	2451	1	0.46	0.43
116	San Juan	2451	2	0.46	0.43
116	San Juan	2451	3	0.46	0.43
116	San Juan	2451	4	0.46	0.43
121	Portland	3113	1	0.46	0.37
121	Portland	3113	2	0.46	0.37
121	Shawville	3131	1	0.46	0.37
121	Shawville	3131	2	0.46	0.37
121	Shawville	3131	3	0.46	0.37
121	Shawville	3131	4	0.46	0.37
123	Carbon	3644	1	0.45	0.38
123	Carbon	3644	2	0.45	0.38
123	Dave Johnston	4158	BW43	0.45	0.38
123	Dave Johnston	4158	BW44	0.45	0.38
123	Hunter	6165	3	0.45	0.38
123	Huntington	8069	2	0.45	0.38
123	Jim Bridger	8066	BW71	0.45	0.38
123	Jim Bridger	8066	BW72	0.45	0.38
123	Jim Bridger	8066	BW73	0.45	0.38
123	Naughton	4162	1	0.45	0.38
123	Naughton	4162	2	0.45	0.38
123	Naughton	4162	3	0.45	0.38
123	Wyodak	6101	BW91	0.45	0.38
125	Canadys Steam	3280	CAN1	0.42	0.31
125	Canadys Steam	3280	CAN2	0.42	0.31
125	Canadys Steam	3280	CAN3	0.42	0.31
125	Cope Station	7210	COP1	0.42	0.31
125	McMeekin	3287	MCM1	0.42	0.31
125	McMeekin	3287	MCM2	0.42	0.31
125	Urquhart	3295	URQ3	0.42	0.31
125	Wateree	3297	WAT1	0.42	0.31
125	Wateree	3297	WAT2	0.42	0.31
125	Williams	3298	WIL1	0.42	0.31
126	Boswell Energy Center	1893	1	0.41	0.36
126	Boswell Energy Center	1893	2	0.41	0.36
126	Boswell Energy Center	1893	3	0.41	0.36
126	Boswell Energy Center	1893	4	0.41	0.36
126	Laskin Energy Center	1891	1	0.41	0.36
126	Laskin Energy Center	1891	2	0.41	0.36
126	Taconite Harbor Energy Center	10075	1	0.41	0.36

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
126	Taconite Harbor Energy Center	10075	2	0.41	0.36
126	Taconite Harbor Energy Center	10075	3	0.41	0.36
127	Barry	3	1	0.46	0.28
127	Barry	3	2	0.46	0.28
127	Barry	3	3	0.46	0.28
127	Barry	3	4	0.46	0.28
127	Barry	3	5	0.46	0.28
127	Bowen	703	1BLR	0.46	0.28
127	Bowen	703	2BLR	0.46	0.28
127	Bowen	703	3BLR	0.46	0.28
127	Bowen	703	4BLR	0.46	0.28
127	Crist Electric Generating Plant	641	4	0.46	0.28
127	Crist Electric Generating Plant	641	5	0.46	0.28
127	Crist Electric Generating Plant	641	6	0.46	0.28
127	Crist Electric Generating Plant	641	7	0.46	0.28
127	Daniel Electric Generating Plant	6073	1	0.46	0.28
127	Daniel Electric Generating Plant	6073	2	0.46	0.28
127	E C Gaston	26	1	0.46	0.28
127	E C Gaston	26	2	0.46	0.28
127	E C Gaston	26	3	0.46	0.28
127	E C Gaston	26	4	0.46	0.28
127	E C Gaston	26	5	0.46	0.28
127	Gadsden	7	1	0.46	0.28
127	Gadsden	7	2	0.46	0.28
127	Gorgas	8	10	0.46	0.28
127	Gorgas	8	6	0.46	0.28
127	Gorgas	8	7	0.46	0.28
127	Gorgas	8	8	0.46	0.28
127	Gorgas	8	9	0.46	0.28
127	Greene County	10	1	0.46	0.28
127	Greene County	10	2	0.46	0.28
127	Hammond	708	1	0.46	0.28
127	Hammond	708	2	0.46	0.28
127	Hammond	708	3	0.46	0.28
127	Hammond	708	4	0.46	0.28
127	Harllee Branch	709	1	0.46	0.28
127	Harllee Branch	709	2	0.46	0.28
127	Harllee Branch	709	3	0.46	0.28
127	Harllee Branch	709	4	0.46	0.28
127	Jack McDonough	710	MB1	0.46	0.28
127	Jack McDonough	710	MB2	0.46	0.28
127	James H Miller Jr	6002	1	0.46	0.28
127	James H Miller Jr	6002	2	0.46	0.28
127	James H Miller Jr	6002	3	0.46	0.28
127	James H Miller Jr	6002	4	0.46	0.28
127	Kraft	733	1	0.46	0.28
127	Kraft	733	2	0.46	0.28
127	Kraft	733	3	0.46	0.28

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
127	Lansing Smith Generating Plant	643	1	0.46	0.28
127	Lansing Smith Generating Plant	643	2	0.46	0.28
127	McIntosh (6124)	6124	1	0.46	0.28
127	Mitchell (GA)	727	3	0.46	0.28
127	Scherer	6257	1	0.46	0.28
127	Scherer	6257	2	0.46	0.28
127	Scherer	6257	3	0.46	0.28
127	Scherer	6257	4	0.46	0.28
127	Scholz Electric Generating Plant	642	1	0.46	0.28
127	Scholz Electric Generating Plant	642	2	0.46	0.28
127	Wansley (6052)	6052	1	0.46	0.28
127	Wansley (6052)	6052	2	0.46	0.28
127	Watson Electric Generating Plant	2049	4	0.46	0.28
127	Watson Electric Generating Plant	2049	5	0.46	0.28
127	Yates	728	Y1BR	0.46	0.28
127	Yates	728	Y2BR	0.46	0.28
127	Yates	728	Y3BR	0.46	0.28
127	Yates	728	Y4BR	0.46	0.28
127	Yates	728	Y5BR	0.46	0.28
127	Yates	728	Y6BR	0.46	0.28
127	Yates	728	Y7BR	0.46	0.28
128	Cherokee	469	1	0.80	0.51
128	Cherokee	469	2	0.80	0.51
129	AES Cayuga, LLC	2535	1	0.45	0.23
129	AES Cayuga, LLC	2535	2	0.45	0.23
129	AES Greenidge	2527	4	0.45	0.23
129	AES Greenidge	2527	5	0.45	0.23
129	AES Greenidge	2527	6	0.45	0.23
129	AES Somerset (Kintigh)	6082	1	0.45	0.23
129	AES Westover (Goudey)	2526	11	0.45	0.23
129	AES Westover (Goudey)	2526	12	0.45	0.23
129	AES Westover (Goudey)	2526	13	0.45	0.23
130	Baldwin Energy Complex	889	3	0.44	0.13
130	Hennepin Power Station	892	1	0.44	0.13
130	Hennepin Power Station	892	2	0.44	0.13
130	Vermilion Power Station	897	1	0.44	0.13
130	Vermilion Power Station	897	2	0.44	0.13
130	Wood River Power Station	898	5	0.44	0.13
132	James River	2161	3	0.50	0.36
132	James River	2161	4	0.50	0.36
132	James River	2161	5	0.50	0.36
132	Southwest	6195	1	0.50	0.36
133	Eckert Station	1831	1	0.45	0.20
133	Eckert Station	1831	2	0.45	0.20
133	Eckert Station	1831	3	0.45	0.20
133	Eckert Station	1831	4	0.45	0.20
133	Eckert Station	1831	5	0.45	0.20
133	Eckert Station	1831	6	0.45	0.20

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
133	Erickson	1832	1	0.45	0.20
134	Pleasant Prairie	6170	1	0.46	0.22
134	Pleasant Prairie	6170	2	0.46	0.22
134	Presque Isle	1769	2	0.46	0.22
134	Presque Isle	1769	3	0.46	0.22
134	Presque Isle	1769	4	0.46	0.22
134	Presque Isle	1769	5	0.46	0.22
134	Presque Isle	1769	6	0.46	0.22
134	Presque Isle	1769	7	0.46	0.22
134	Presque Isle	1769	8	0.46	0.22
134	Presque Isle	1769	9	0.46	0.22
134	South Oak Creek	4041	5	0.46	0.22
134	South Oak Creek	4041	6	0.46	0.22
134	South Oak Creek	4041	7	0.46	0.22
134	South Oak Creek	4041	8	0.46	0.22
134	Valley (WEPCO)	4042	1	0.46	0.22
134	Valley (WEPCO)	4042	2	0.46	0.22
134	Valley (WEPCO)	4042	3	0.46	0.22
134	Valley (WEPCO)	4042	4	0.46	0.22
135	Cayuga	1001	1	0.49	0.30
135	Cayuga	1001	2	0.49	0.30
135	East Bend	6018	2	0.49	0.30
135	Edwardsport	1004	7-1	0.49	0.30
135	Edwardsport	1004	7-2	0.49	0.30
135	Edwardsport	1004	8-1	0.49	0.30
135	Gibson	6113	1	0.49	0.30
135	Gibson	6113	2	0.49	0.30
135	Gibson	6113	3	0.49	0.30
135	Gibson	6113	4	0.49	0.30
135	Gibson	6113	5	0.49	0.30
135	Miami Fort Generating Station	2832	5-1	0.49	0.30
135	Miami Fort Generating Station	2832	5-2	0.49	0.30
135	Miami Fort Generating Station	2832	6	0.49	0.30
135	Miami Fort Generating Station	2832	7	0.49	0.30
135	Miami Fort Generating Station	2832	8	0.49	0.30
135	R Gallagher	1008	1	0.49	0.30
135	R Gallagher	1008	2	0.49	0.30
135	R Gallagher	1008	3	0.49	0.30
135	R Gallagher	1008	4	0.49	0.30
135	Wabash River	1010	1	0.49	0.30
135	Wabash River	1010	2	0.49	0.30
135	Wabash River	1010	3	0.49	0.30
135	Wabash River	1010	4	0.49	0.30
135	Wabash River	1010	5	0.49	0.30
135	Wabash River	1010	6	0.49	0.30
135	Walter C Beckjord Generating Station	2830	1	0.49	0.30
135	Walter C Beckjord Generating Station	2830	2	0.49	0.30
135	Walter C Beckjord Generating Station	2830	3	0.49	0.30

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
135	Walter C Beckjord Generating Station	2830	4	0.49	0.30
135	Walter C Beckjord Generating Station	2830	5	0.49	0.30
135	Walter C Beckjord Generating Station	2830	6	0.49	0.30
137	Jeffrey Energy Center	6068	1	0.40	0.28
137	Jeffrey Energy Center	6068	2	0.40	0.28
137	Jeffrey Energy Center	6068	3	0.40	0.28
137	Lawrence Energy Center	1250	3	0.40	0.28
137	Lawrence Energy Center	1250	4	0.40	0.28
137	Lawrence Energy Center	1250	5	0.40	0.28
137	Tecumseh Energy Center	1252	10	0.40	0.28
137	Tecumseh Energy Center	1252	9	0.40	0.28
138	Labadie	2103	1	0.52	0.14
138	Labadie	2103	2	0.52	0.14
138	Labadie	2103	3	0.52	0.14
138	Labadie	2103	4	0.52	0.14
138	Meramec	2104	1	0.52	0.14
138	Meramec	2104	2	0.52	0.14
138	Meramec	2104	3	0.52	0.14
138	Meramec	2104	4	0.52	0.14
138	Rush Island	6155	1	0.52	0.14
138	Rush Island	6155	2	0.52	0.14
138	Sioux	2107	1	0.52	0.14
138	Sioux	2107	2	0.52	0.14
139	Coffeen	861	01	0.75	0.35
139	Coffeen	861	02	0.75	0.35
139	Hutsonville	863	05	0.75	0.35
139	Hutsonville	863	06	0.75	0.35
139	Meredosia	864	01	0.75	0.35
139	Meredosia	864	02	0.75	0.35
139	Meredosia	864	03	0.75	0.35
139	Meredosia	864	04	0.75	0.35
139	Meredosia	864	05	0.75	0.35
140	Brandon Shores	602	1	0.46	0.30
140	Brandon Shores	602	2	0.46	0.30
141	Cross	130	1	0.46	0.22
141	Dolphus M Grainger	3317	1	0.46	0.22
141	Dolphus M Grainger	3317	2	0.46	0.22
141	Jefferies	3319	3	0.46	0.22
141	Jefferies	3319	4	0.46	0.22
141	Winyah	6249	1	0.46	0.22
142	Elrama	3098	1	0.65	0.46
142	Elrama	3098	2	0.65	0.46
142	Elrama	3098	3	0.65	0.46
142	Elrama	3098	4	0.65	0.46
145	Asheville	2706	1	0.44	0.36
145	Asheville	2706	2	0.44	0.36
145	Cape Fear	2708	5	0.44	0.36
145	Cape Fear	2708	6	0.44	0.36

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
145	Crystal River	628	1	0.44	0.36
145	Crystal River	628	2	0.44	0.36
145	Crystal River	628	4	0.44	0.36
145	Crystal River	628	5	0.44	0.36
145	H B Robinson	3251	1	0.44	0.36
145	H F Lee Steam Electric Plant	2709	1	0.44	0.36
145	H F Lee Steam Electric Plant	2709	2	0.44	0.36
145	H F Lee Steam Electric Plant	2709	3	0.44	0.36
145	L V Sutton	2713	1	0.44	0.36
145	L V Sutton	2713	2	0.44	0.36
145	L V Sutton	2713	3	0.44	0.36
145	Mayo	6250	1A	0.44	0.36
145	Mayo	6250	1B	0.44	0.36
145	Roxboro	2712	1	0.44	0.36
145	Roxboro	2712	2	0.44	0.36
145	Roxboro	2712	3A	0.44	0.36
145	Roxboro	2712	3B	0.44	0.36
145	Roxboro	2712	4A	0.44	0.36
145	Roxboro	2712	4B	0.44	0.36
145	W H Weatherspoon	2716	1	0.44	0.36
145	W H Weatherspoon	2716	2	0.44	0.36
145	W H Weatherspoon	2716	3	0.44	0.36
148	Allen	3393	1	0.57	0.38
148	Allen	3393	2	0.57	0.38
148	Allen	3393	3	0.57	0.38
148	Bull Run	3396	1	0.57	0.38
148	Colbert	47	1	0.57	0.38
148	Colbert	47	2	0.57	0.38
148	Colbert	47	3	0.57	0.38
148	Colbert	47	4	0.57	0.38
148	Colbert	47	5	0.57	0.38
148	Cumberland	3399	1	0.57	0.38
148	Cumberland	3399	2	0.57	0.38
148	Gallatin	3403	1	0.57	0.38
148	Gallatin	3403	2	0.57	0.38
148	Gallatin	3403	3	0.57	0.38
148	Gallatin	3403	4	0.57	0.38
148	John Sevier	3405	1	0.57	0.38
148	John Sevier	3405	2	0.57	0.38
148	John Sevier	3405	3	0.57	0.38
148	John Sevier	3405	4	0.57	0.38
148	Johnsonville	3406	1	0.57	0.38
148	Johnsonville	3406	10	0.57	0.38
148	Johnsonville	3406	2	0.57	0.38
148	Johnsonville	3406	3	0.57	0.38
148	Johnsonville	3406	4	0.57	0.38
148	Johnsonville	3406	5	0.57	0.38
148	Johnsonville	3406	6	0.57	0.38

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
148	Johnsonville	3406	7	0.57	0.38
148	Johnsonville	3406	8	0.57	0.38
148	Johnsonville	3406	9	0.57	0.38
148	Kingston	3407	1	0.57	0.38
148	Kingston	3407	2	0.57	0.38
148	Kingston	3407	3	0.57	0.38
148	Kingston	3407	4	0.57	0.38
148	Kingston	3407	5	0.57	0.38
148	Kingston	3407	6	0.57	0.38
148	Kingston	3407	7	0.57	0.38
148	Kingston	3407	8	0.57	0.38
148	Kingston	3407	9	0.57	0.38
148	Paradise	1378	1	0.57	0.38
148	Paradise	1378	2	0.57	0.38
148	Paradise	1378	3	0.57	0.38
148	Shawnee	1379	1	0.57	0.38
148	Shawnee	1379	2	0.57	0.38
148	Shawnee	1379	3	0.57	0.38
148	Shawnee	1379	4	0.57	0.38
148	Shawnee	1379	5	0.57	0.38
148	Shawnee	1379	6	0.57	0.38
148	Shawnee	1379	7	0.57	0.38
148	Shawnee	1379	8	0.57	0.38
148	Shawnee	1379	9	0.57	0.38
148	Widows Creek	50	1	0.57	0.38
148	Widows Creek	50	2	0.57	0.38
148	Widows Creek	50	3	0.57	0.38
148	Widows Creek	50	4	0.57	0.38
148	Widows Creek	50	5	0.57	0.38
148	Widows Creek	50	6	0.57	0.38
148	Widows Creek	50	7	0.57	0.38
148	Widows Creek	50	8	0.57	0.38
149	Pulliam	4072	3	0.47	0.41
149	Pulliam	4072	4	0.47	0.41
149	Pulliam	4072	5	0.47	0.41
149	Pulliam	4072	6	0.47	0.41
149	Pulliam	4072	7	0.47	0.41
149	Pulliam	4072	8	0.47	0.41
149	Weston	4078	1	0.47	0.41
149	Weston	4078	2	0.47	0.41
149	Weston	4078	3	0.47	0.41
150	E J Stoneman Generation Station	4146	B1	0.46	0.35
150	E J Stoneman Generation Station	4146	B2	0.46	0.35
151	Duck Creek	6016	1	0.46	0.26
151	E D Edwards	856	1	0.46	0.26
151	E D Edwards	856	2	0.46	0.26
151	E D Edwards	856	3	0.46	0.26
200	Dynegy Danskammer	2480	3	0.40	0.28

Averaging Plan ID	Facility Name	Facility ID (ORISPL)	Unit ID	Plan Limit	Plan Rate
200	Dynegy Danskammer	2480	4	0.40	0.28
201	Four Corners Steam Elec Station	2442	1	0.61	0.55
201	Four Corners Steam Elec Station	2442	2	0.61	0.55
201	Four Corners Steam Elec Station	2442	3	0.61	0.55
201	Four Corners Steam Elec Station	2442	4	0.61	0.55
201	Four Corners Steam Elec Station	2442	5	0.61	0.55
202	Ashtabula	2835	7	0.53	0.29
202	Bay Shore	2878	1	0.53	0.29
202	Bay Shore	2878	2	0.53	0.29
202	Bay Shore	2878	3	0.53	0.29
202	Bay Shore	2878	4	0.53	0.29
202	Bruce Mansfield	6094	1	0.53	0.29
202	Bruce Mansfield	6094	2	0.53	0.29
202	Bruce Mansfield	6094	3	0.53	0.29
202	Eastlake	2837	1	0.53	0.29
202	Eastlake	2837	2	0.53	0.29
202	Eastlake	2837	3	0.53	0.29
202	Eastlake	2837	4	0.53	0.29
202	Eastlake	2837	5	0.53	0.29
202	Lake Shore	2838	18	0.53	0.29
202	R E Burger	2864	5	0.53	0.29
202	R E Burger	2864	6	0.53	0.29
202	R E Burger	2864	7	0.53	0.29
202	R E Burger	2864	8	0.53	0.29
202	W H Sammis	2866	1	0.53	0.29
202	W H Sammis	2866	2	0.53	0.29
202	W H Sammis	2866	3	0.53	0.29
202	W H Sammis	2866	4	0.53	0.29
202	W H Sammis	2866	5	0.53	0.29
202	W H Sammis	2866	6	0.53	0.29
202	W H Sammis	2866	7	0.53	0.29