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Fossil Fuel-Fired Power Plants

Report to the House and Senate Environment and Energy Committees

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Preface

Parts of this report were taken directly from other non-copyrighted resources in the interest of time and comprehensiveness, particularly reports published by the State of Illinois, the federal government, and other states. Some of these portions contain only insignificant wording changes from the original sources. Quotations are not strictly used to distinguish these sections; however, an attempt has been made to accurately reference and acknowledge these sources. The intent is not for the Illinois Environmental Protection Agency to take recognition for the original work of these authors, instead, to include the maximum amount of essential facts as accurately as possible within a constrained time frame.

Executive Summary

The Illinois Environmental Protection Agency (Illinois EPA) was asked by the Illinois General Assembly to examine whether the State should address further potential restrictions on power plant pollution. This request was made under Section 9.10 of the Environmental Protection Act (Act). This is a report of the Illinois EPA's findings.

The Illinois EPA has prepared this report of its findings to date based on consideration of a broad spectrum of issues including health benefits, the impact on the reliability of the power grid, the impact on consumer utility rates and the impact on jobs and Illinois' economy. It provides an overview of the principal issues, presents a review of the information we have gathered that addresses those issues, lists information gaps and uncertainties and finally, lists the work that remains to develop a solution that does not create unintended adverse economic consequences for the people of Illinois.

The information in the report was gathered in a variety of ways including extensive literature reviews, discussions with peers and experts, and meetings and information exchanges with the environmental community, power industry, and other interest groups. The report reflects the fact that, while many questions have been answered, critical information gaps remain that must be addressed before any responsible proposal to reduce power plant emissions can be developed.

Further restricting power plant pollution brings with it four major overarching issues that must be carefully considered and weighed. First among them is the impact on peoples' lives resulting from the pollution allowed by the present air pollution standards. Directly related to this issue are the health and welfare benefits that might accrue with various pollution control scenarios. Responsible consideration of these important public health concerns requires a thorough analysis that examines compliance costs and the associated impacts on employment and related healthcare coverage, electricity system reliability, and electricity rates on Illinois' economy.

The State of Illinois is committed to providing its citizens with sufficient, reliable and affordable electricity. The experience of last year's blackout that affected large parts of the U.S. and Canada clearly demonstrated that the power grid is extremely vulnerable and that energy reliability cannot be taken for granted. Likewise, affordable power has a significant and immediate impact on the lives of the people of Illinois. Indeed, impacts of pollution controls on electricity reliability and rates must be clearly understood before any responsible and final decision can be made. The General Assembly clearly understood these important issues in its drafting of Section 9.10.

The following sections outline Illinois EPA's major findings to-date in the areas of health impacts, electricity reliability, electricity costs and jobs impact and presents outstanding issues that must be addressed before determining the most prudent approach to reducing power plant emissions in Illinois.

Health Impacts

The Illinois EPA reviewed the existing major studies on the health impacts of the emissions from power plants, the technology available to mitigate these effects, and the various pollution control strategies under consideration. We find the following to be reasonable conclusions:

1. Public health is affected to varying degrees by emissions from fossil-fueled power plants. According to U.S. EPA, particulate matter and ozone air pollution resulting from sulfur dioxide and nitrogen oxides emissions are associated with respiratory problems. Human exposure to methyl mercury from eating contaminated fish is associated with adverse health effects.
2. Adverse health impacts can be minimized through the use of technology and renewable energy.
3. Transport of pollutants from other states is a major contributor to the air quality in Illinois, and Illinois itself impacts downwind states. Due to interstate transport of air pollution, this is not an issue that can be contained within or to any single state.
4. While there are numerous proposed emission reduction strategies aimed at controlling power plant pollution at the national and state level, the U.S. EPA currently has two formal regulatory proposals undergoing public scrutiny. U. S. EPA made these proposals in January 2004 and has publicly stated that they intend to propose final sulfur dioxide and nitrogen oxide rules by December 2004 and final mercury reduction rules by March 2005.
5. Significant public health and welfare benefits can be derived by reducing power plant emissions. For example, studies indicate that stricter emission limits would reduce the frequency and severity of asthma attacks and other cardiovascular and respiratory ailments. U.S. EPA predicts that its proposed national program will provide $22 of benefit for every $1 of cost.

What we have not been able to determine is the following:

1. What will be the health benefits of an Illinois-only approach given the significant impact of interstate pollution transport?
2. To what extent would an Illinois-specific emission reduction approach achieve air quality improvements and public health benefits in the absence of a national emission reduction strategy?
3. Would an Illinois-specific approach result in greater reliance on coal-fired power plants in bordering states that lack sufficient pollution controls?
4. If new emissions standards lead to lost jobs and higher consumer rates, what impact would this have on the number of people who lose job-related health coverage, the amount of income consumers can devote to health care costs, and how any potential loss of coverage for individuals weighs against potential health benefits created by new standards?

We need to examine the public health benefits that would accrue from a *state-specific multi-pollutant strategy,* not accompanied by reductions from out-of-state power plants that are upwind and that contribute to measured air pollutant levels in Illinois. The important lesson learned from the planning process to meet U.S. EPA's 1-hour ozone standard is that a state could make very significant emission reduction within its own boundaries, but still not meet the national health-based standards, unless local reductions are also accompanied by significant reductions in transported pollution from upwind sources outside the state. Because power plants have very high stacks, the impact of their emissions is generally felt far downwind, as much as several hundred miles. Since Illinois borders six other states, it is important to take these facts into consideration. Illinois EPA must consider the above issues to achieve the balanced approach requested by the General Assembly.

Electric Reliability

In light of heightened concerns over energy reliability, the Illinois EPA reviewed the major issues that must be addressed when evaluating the impact of power plant emission reduction strategies on reliability. Illinois EPA recognizes that implementation of any state-specific emission reduction strategy must not jeopardize electricity reliability.

We found the following:

1. Transmission constraints represent a major challenge to electric reliability. Since electricity cannot be stored, the transmission system must permit unimpeded movement of electricity from suppliers to consumers at all times, but especially when demand for electricity is at or near its peak.
2. The reliability of the transmission system depends upon critical voltage support and resource capability at key locations in the grid. Actions that lead to reductions in these critical factors can ultimately cause widespread service interruptions or exacerbate a failure of the grid as witnessed in the northern portion of the U.S. and parts of Canada during August 2003. Following the August 2003 blackout, the grid was not completely restored for days to weeks depending on the affected area costing the residents of those eight states an estimated $6.4 billion.
3. As part of the Eastern Interconnect (the regional transmission interconnection), Illinois faces the same electric reliability issues that were highlighted by the August 14, 2003 power outage.
4. Grid congestion problems can become particularly acute where certain generating plants must run because their operation is essential to maintaining grid reliability. Certain of those older power plants would need to remain in operation to maintain grid reliability principally because they supply needed voltage support. Choices would have to be made including installing pollution control technologies on such units, when it might not be economically warranted by the age and efficiency of the units, or the units would need to be repowered.

5. Although several state-sponsored initiatives were launched between 1999 and 2002, no additional base-load generating capacity is under construction. While construction permits were issued for two projects, one has not been able to secure financing due to soft power markets and the construction permit for the other project has been challenged by a number of environmental groups, and the permit is stayed. As a result, at this time we cannot rely on any new baseload generating capacity to ease any potential strain placed upon the grid by new standards.
6. No significant construction to address transmission grid reliability issues is planned within the State or within the MAIN (Mid-America Interconnection Network) electric transmission region of which most of Illinois is a part.

The Illinois EPA has not been able to determine the following:

1. We do not have a firm understanding of how a state-specific emission reduction program would impact power plant closures and electric reliability. Further analysis is needed to investigate whether stricter emission standards for Illinois power generators would put them at a competitive disadvantage relative to out-of-state generators who would not be required to meet the same emission standards. If out-of-state generators can offer their product more competitively, Illinois could lose generation capacity.
2. Additional examination is also needed to explore whether strategies to competitively retain and develop generation capacity and preserve reliability in Illinois are viable. Options that warrant further study include: repowering of power plants using highly efficient combined heat and power systems (CHP), renewable energy, clean coal technologies and energy efficiency.
3. To estimate the impact of a state-specific emission reduction strategy on reliability, a comprehensive resource and transmission planning analysis (that includes detailed production cost information for Illinois and the surrounding interconnect) must be conducted to determine which generating plants might close and which might install pollution controls. In the absence of this analysis, the precise impact of state-specific emission standards on reliability in Illinois is unknown.

Electricity Costs

In addition to ensuring a reliable energy supply, providing affordable electricity is essential to the well being of all Illinois residents. The likely impact of pollution controls on electricity rates must be clearly understood before any responsible emission reduction approach can be determined in Illinois. The Illinois EPA reviewed the available information on the impact of the various national proposals on electricity costs. This effort has been complicated by the state of flux in Illinois' electric supply market due to the shift from a traditional, utility owned and operated, and highly regulated power generation system, to an increasingly deregulated power generation market. One of the major pieces of this shift will occur in January of 2007 when the cap or freeze on retail rates will be lifted.

We have found the following:

1. Illinois is one of the first states to begin the process to become a deregulated state for electric power, but restructuring is not yet complete in Illinois, with the freeze on rates being lifted January 2007. As a result of this market restructuring, most coal-fired power plants in the state now are owned by independent power producers, which are not affiliated with Illinois utilities or by non-utility generation affiliates of Illinois utilities.
2. At the same time as Illinois is going through restructuring, regional transmission organizations have been formed through which power generators are more easily and efficiently able to sell their power across state lines. As a result, Illinois' power generators now compete with generators in several nearby states that have not deregulated their electricity markets.
3. Most of the available information on the impact of emission reductions on electricity costs is based on U.S. EPA's assessment of the Bush Administration's proposed Clear Skies Act, and U.S. EPA's proposed Clean Air Interstate Rule (CAIR). U.S. EPA concluded that the costs of its CAIR program to Illinois and the MAIN (Mid-America Interconnection Network) would increase rates 2.5%-3.5% over those that would occur if no additional pollution controls were implemented.
4. Estimated impacts on electricity rates are based on the assumption of a national approach to emission reductions applied to all power producers in all 29 affected states and the District of Columbia. Imposing more stringent rules in just one state could create further significant upward pressure on rates. However, for Illinois, this assumes that there is a competitive wholesale market for electricity due to deregulation. This competition in wholesale markets has not materialized to any significant degree, such that 2006 power purchase agreements assume no increase in competition in wholesale market that could also impact rates.
5. In most states, the cost of complying with Clear Skies, CAIR or other national proposals to reduce power plant emissions would undoubtedly be passed onto ratepayers by the utilities, whether they still own their power plants or purchase power through wholesale energy markets.

The Illinois EPA has not been able to determine the following:

1. We do not know how the costs of these multi-pollutant proposals will affect competition and consumer rates in a state that is entering full deregulation. However, we do know that compliance costs will ultimately be reflected in electric rates and, very likely, natural gas rates to the extent that coal-fired generation is replaced by natural gas-fired generation.
2. Concern exists that if competition among suppliers of electricity is not robust, then power prices will not remain at reasonable levels. A contributing factor involving California's experience in 2000 and 2001 was the fact that competition

among electric suppliers had yet to take hold. One result was significant price spikes and upheaval in the state's economy.

3. Whether robust competition occurs in 2007 in Illinois will depend on the degree to which competitive forces create an effectively functioning wholesale and retail supply market. If Illinois generators must comply with state-specific regulations that their out-of-state competitors do not, these generators will incur additional costs that cannot be recovered from utility ratepayers and will face a disadvantage in competitive regional power markets.
4. An increase in electric and gas rates may drive greater interest and implementation of renewable energy and energy efficiency projects, but the degree to which Illinois is poised to increase its production of renewable energy and at what cost is not known.
5. The impacts on competition and on rates through a state-specific program have not been evaluated, and must be as part of the overall review of Illinois' deregulated market post-2006. Failure to do so could mean higher rates for consumers.

Impact on Jobs in Illinois

Information on the effects of a state-specific multi-pollution strategy on jobs and the coal industry is lacking. At no time in its history, however, has the Illinois coal industry confronted so many threats to its survival as it now does. Low-priced, lower-sulfur coals, primarily from the Powder River Basin of Wyoming (known as western coal) continue to make inroads in Midwestern and eastern power plant markets.

At the end of 2003, coal production in Illinois totaled 31.1 million tons, down more than 2.3 million tons from 2002. The loss of coal mines and coal mining jobs has negatively impacted the economic structure of southern Illinois. Although mining salaries doubled between 1980 and 2003, from $22,000 a year to $45,500 a year, the total economic payroll of the mining industry in the State of Illinois decreased by 60 percent during the same time period. Moreover, the regulatory climate concerning Illinois coal remained uncertain with mixed signals from the federal government over proposed controversial mercury reduction standards that would serve to benefit western coal, again at the expense of coal mined here in Illinois.

According to industry estimates, there are approximately 4,100 jobs directly involved in running Illinois power plants. In addition, approximately 6,000 more jobs provide skilled contractual labor and miscellaneous support. These jobs produce a combined payroll and benefits that amount to over $700 million a year for employees. There are also another 5,500 retirees whose health insurance could be impacted by the financial viability of the power plants. Furthermore, the approximate value of goods and services purchased locally related to these jobs is over $300 million. Illinois' coal-fired power plants pay nearly $21 million a year in property taxes to local taxing bodies, the majority of which goes to support local school systems.

Understanding the impact on the economy – especially the risk of job losses – is critical in the process used to analyze new emission standards. It is impossible to determine the actual effect of new emission standards in the Illinois economy without knowing what the national standards will ultimately be. It is also worth noting that the potential growth in the renewable energy industry could provide an economic benefit as well, though it is very unclear how significant that impact could be compared to what the coal industry could potentially face. Illinois EPA will work with the Department of Commerce and Economic Opportunity to retain the experts that can work with us to analyze the impacts of any further regulation on the economy of Illinois and Illinois jobs once the national direction is clear.

Other Findings

- For mercury, the Illinois EPA believes that U.S. EPA should move forward in March 2005, pursuant to its Consent Decree, and promulgate national mercury standards for power plants that would not place Illinois at a competitive disadvantage. Although Illinois EPA strongly supports trading programs, mercury reduction cap and trade programs must be carefully designed so as not to create hot spots of elevated mercury.
- The environmental and health benefits from greater use of energy efficient technologies and renewable energy, such as wind power, are also recognized. The pursuit of energy efficient technologies and the use of renewable energy could result in significant economic benefits for Illinois.
- Lastly, a national greenhouse gas registration and trading program under a federal mandate is the most effective strategy to address climate change, and state voluntary efforts should continue to be encouraged.

Recommendations:

It is clear that power plants are a considerable source of air pollution and that reducing emissions will benefit public health. However, moving forward with a state-specific regulatory or legislation strategy without fully understanding all of the critical impacts on jobs and Illinois' economy overall as well as consumer utility rates and reliability of the power grid would be irresponsible.

Illinois EPA recommends that the Governor continue demanding that the federal government act nationally to reduce power plant emissions. Further, Illinois EPA recommends that the Governor and General Assembly insist that the competing issues of health, jobs, electric service reliability and affordable consumer rates be fully and completely reconciled in light of the many unanswered questions presented in this report. While this work is already underway – and will continue – it can ultimately only be completed once the national emission reduction strategy solidifies and the timing and features of a national program are known.

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Chapter 1

Electric Generating Units in Illinois and Their Emissions of Concern

In 2001, the Illinois General Assembly passed legislation regarding fossil fuel-fired electric generating plants. This legislation, found at Section 9.10 of the Illinois Environmental Protection Act and referred within this report as "Section 9.10," requires the Illinois EPA to issue to the House and Senate Committees on Environment and Energy findings that address the potential need for control or reduction of emissions from fossil fuel-fired electric generating units or EGUs. This report presents Illinois EPA's findings to date and recommendations on this very complex mater.

In the State of Illinois, the electric generating units (referred to within this report as "EGUs" or "power plants") that are the subject of this report are those powered by fossil fuel, which includes coal, oil and natural gas. Illinois currently has 214 power plant units, 61 of which are coal-fired boilers.

The General Assembly asked that Illinois EPA focus on sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), mercury, and carbon dioxide. Table 1-1 provides a categorical summary of Illinois' EGUs. Included in the table is total electric generating megawatt capacity, along with NO_x, SO_2, mercury and carbon dioxide emissions for 2002. Detailed unit-by-unit data is provided in Appendix A. Although there are greater numbers of the smaller natural gas units in the State, it is important to note that coal-fired units constitute the greatest power output and heat input, expressed as pounds per million British thermal units or lbs/mmBtu.

Table 1-1
Annual 2002 Summary Data for Coal, Gas, and Oil-fired EGUs Over 25 Megawatts

Unit Category	No. of Units	Capacity MW	Heat Input mmBtu	SO_2 Tons	NO_x Tons	CO_2 Tons	Hg Tons	SO_2 lbs/mmBtu	NO_x lbs/mmBtu
Coal-fired	61	16,905	931,038,484	352,994	170,997	95,505,331	3.7	0.758	0.367
N.Gas-fired	97	6,284	7,576,638	0	315	450,097	0	0	0.083
N.Gas/Oil-Fired	47	8,877	65,824,805	481	2,756	3,925,223	0.4	0.015	0.084
Oil-Fired Units	9	685	611,239	163	107	49,502	0.2	0.534	0.350
Total	214	32,751	1,005,051,166	353,638	174,170	99,931,884	4.3	1.307	0.884

As indicated by Table 1-1 above, coal-fired boilers account for about 51 percent of the non-nuclear electric generating capacity, 92.6 percent of total heat input and 99.8 percent of total SO_2 emissions from all EGUs. In addition, 98.2 percent of total NO_x emissions and 95.6 percent of total carbon dioxide emissions come from coal-fired boilers.

Chapter 2

Human Health Implications from Air Pollution

The General Assembly asked that Illinois EPA focus on the EGU's emissions of the following pollutants: SO_2, NO_x, PM, mercury, and carbon dioxide. This Chapter describes what we currently know about the health implications associated with these emissions. It should be noted that NO_x and SO_2 emissions from power plants are not a concern as direct emissions since Illinois currently meets the national air quality standards for these pollutants. Rather, the concern is the contribution of these emissions to the formation of fine particulate matter and ozone, for which there are federal health-based air quality standards, known as National Ambient Air Quality Standards or NAAQS.

This Chapter briefly explains the pollutants of concern and examines the health implications based on various assumptions projected by U.S. EPA and ABT Associates.

<u>Ground-Level Ozone</u>

Ground-level ozone is formed when NO_x and volatile organic material (VOMs) from cars, trucks, power plants and other sources react in the atmosphere in the presence of sunlight. Ozone levels are highest during the summer months, especially on hot, sunny days with little wind. Ozone is a major component of smog in our cities and in other areas of the country. Naturally occurring ozone in the upper atmosphere protects us from the sun's ultraviolet radiation, while the ozone that we breathe at ground-level can contribute to respiratory illnesses and other health and environmental problems.

Some people are more likely to be adversely affected by ground-level ozone air pollution than others. They include individuals with lung diseases, especially if they are elderly or children, individuals with respiratory illnesses, and children and people who work outdoors.

U.S. EPA has adopted health-based air quality standards for ozone, including standards for 1-hour and 8-hour averages. U.S. EPA has identified metropolitan Chicago and St. Louis/Metro-East as areas that do not meet these standards. Illinois is required to meet the health-based standard for 1-hour ozone by 2007, and the 8-hour ozone standard by 2010.

In Illinois, EGUs are responsible for 27 percent of NO_x emissions and 0.5 percent of VOM emissions. NO_x from power plants and other sources can contribute to ozone formation across a large area extending hundreds of miles downwind.

Particulate Matter

Particulate matter in the atmosphere consists of solids, liquids and liquids-solids in combination. Suspended particulate matter generally refers to particles less than 100 microns (or micrometers) in diameter. Note that human hair is typically 100 microns thick. Particles larger than 100 microns will settle out of the air under the influence of gravity in a short period of time.

A number of scientific studies have linked particulate matter to adverse human health effects. In testimony provided by the U.S. EPA to Congress in 2003 regarding the Clear Skies Initiative, Administrator Whitman stated: "Hundreds of studies in the peer-reviewed literature have found that…exposure to fine [PM] is associated with premature death, as well as asthma attacks, chronic bronchitis, decreased lung function and respiratory disease. Exposure is also associated with aggravation of heart and lung disease, leading to increased hospitalizations, emergency room and doctor visits, and use of medication."[1]

U.S. EPA has adopted health-based standards for fine particulate matter that is 2.5 microns in diameter or less ($PM_{2.5}$), and has identified metropolitan Chicago and St. Louis/Metro-East as areas that do not meet these standards. Illinois is now required to develop plans to ensure that the $PM_{2.5}$ standards are met in these areas by 2010.

EGUs emit particulate matter directly into the air, and they release SO_2 and NO_x that are converted into sulfate and nitrate particulate matter in the atmosphere through complex chemical reactions. These emissions can be transported for hundreds of miles from Illinois and into Illinois. In Illinois, EGUs are responsible for 21 percent of particulate matter emissions, 27 percent of the NO_x emissions, and 68 percent of SO_2 emissions.

Mercury

Mercury (Hg) is a naturally occurring trace contaminant found in the soil, and it is a chemical that is emitted by man-made industrial processes. Although mercury is not a criteria pollutant for which a National Ambient Air Quality Standard exists, it is considered a hazardous air pollutant that can cause adverse health impacts.

Human exposure by direct inhalation of mercury in the air is not the predominant public health concern for this metal. However, the mercury in ambient air eventually can be re-deposited on land surfaces or directly into rivers, lakes and oceans. More than 50 percent of the mercury input to many bodies of water, including Lake Michigan, comes from the air.

Mercury that enters bodies of water by direct deposition from the air or runoff from land surfaces ultimately is transformed by biological processes into a toxic form of mercury (methyl mercury) that concentrates in fish and other organisms living in these waters. A study by the National Academy of Sciences concluded that human exposure to methyl mercury from eating contaminated fish and seafood is associated with adverse health effects related to neurological and developmental damage. Mercury exposure is of particular concern for children, pregnant women and women of childbearing age. Other populations at risk include those who consume a substantial amount of fish.

The severity of these health effects from mercury varies depending on the concentrations of mercury in the ingested food.[2] Mercury contamination is widespread in Illinois' waters, and fish consumption advisories have been issued for every body of water in the State.

In 1999, coal-fired power plants were estimated to have emitted 48 tons of mercury nationally (approximately 37 percent of the manmade total).

Carbon Dioxide

Carbon dioxide is not listed as a "pollutant" under the Clean Air Act, as the concern with carbon dioxide emissions is the relative increase in the so-called greenhouse gases that impact global climate change.

National and State Projections

The remainder of this Chapter discusses two studies on the health implications based on multi-pollutant emission reduction assumptions.

Table 2-1 below summarizes U.S. EPA's estimates of human health benefits for several multi-pollutant emission reduction strategies, including U.S. EPA's Clean Air Interstate Rule (CAIR) and the three leading Congressional legislative proposals for reducing power plant emissions. (These proposals are discussed in more detail in Chapter 4.) While there is not complete agreement on the exact numbers within these tables, there is agreement that reducing air pollution levels will result in health benefits.

Table 2-1
Number of Annual Adverse Health Events Avoided* Through Reductions in Particulate Matter and Ozone

Health Effect	Clear Skies (S. 485)		EPA CAIR	Carper (S. 834)		Jeffords (S. 366)	
	2010	2020	2015	2010	2020	2010	2020
Premature Deaths	7,800	14,100	13,000	9,000	17,000	13,000	18,000
Chronic Bronchitis	5,400	8,800	6,900				
Non-fatal heart attacks	13,100	23,000	18,000				
Hospitalizations/ ER visits for cardiovascular & respiratory symptoms	16,900	30,000	22,500				
Asthma attacks	70,000	180,000	240,000				
Total Health Benefits (in billions)	$55	$110	$82	$70	$140	$90	$140

*Benefits are in addition to reductions required by existing Clean Air Act programs. The benefits of mercury, carbon dioxide or nitrogen load (water, land) reductions are not included.

Attempts to determine the health related benefits resulting from a state-specific approach to power plant emission reductions have produced several competing studies and differing results. However, the data clearly support the contention that a well-designed national approach conveys the greatest health benefits due to the significant impacts of the interstate transport of pollutants.

ABT Associates published a study that provided an estimate of the health-related benefits in Illinois from reducing power plant emissions nationally. A summary of the estimated health benefits is presented in Table 2-2.

Table 2-2
Health Effects of Power Plant Particulate Matter Pollution in Illinois (Cases/Year)[3]

	Mortality	Total Hospitalizations	Asthma ER Visits	Chronic Bronchitis	Asthma Attacks	Lost Work Days	Restricted Activity Days
Health Effects	1,700	1,350	391	1,020	33,100	283,000	1,450,000
Avoided Effects with a 75 % reduction	981	635	222	589	19,000	164,000	848,000

These estimates are based on particulate matter air pollution from all power plants, including those located outside Illinois. Therefore, the ABT study does not estimate the health effects that are due to air pollution from Illinois power plants exclusively. Due to interstate transport of pollutants, a portion of these estimated health benefits would be due to emissions reductions from out-of-state power plants. Other studies have looked at human health impacts from specific power plants located in Illinois. (*See* Appendix D.)

Table 2-3 provides a summary of U.S. EPA's estimate of health benefits from the implementation of a regional (28 states and the District of Columbia) program to reduce emissions from power plants under the Bush Administration's Clear Skies Act (discussed in Chapter 4) that would occur in Illinois.

Table 2-3
Estimated Annual Human Health Benefits for Illinois from Reductions of Particulate Matter and Ozone (Number of Health Effects Avoided): Clear Skies Act (S. 485)[4] *

Health Effect	2020
Premature Deaths	800 avoided
Chronic Bronchitis	500 avoided
Non-fatal heart attacks	1,300 avoided
Hospitalizations/ ER visits for cardiovascular and respiratory symptoms	2,000 avoided
Total Health Benefits	$5.9 billion

* In comparison to reductions and benefits required by existing Clean Air Act programs. Does not include health or economic benefits of mercury, carbon dioxide or nitrogen load (water, land) reductions.

Additional sources consulted but not cited in endnotes are listed in Appendix D**.** Illinois EPA found the sources to be useful and encourages those with an interest in this subject to consult them.

Chapter 3

Air Pollution Control Technologies For Reducing Power Plant Emissions

Air pollution reduction and control technologies have advanced substantially over the past 25 years. Many EGUs across the country already employ these technologies to meet existing regulatory requirements. Additionally, under federal and state preconstruction permitting programs, any new EGU is required to employ Best Available Control Technology or BACT before the new unit or units can be constructed.

The control of mercury and other hazardous air pollutants or HAPs from EGUs has only recently become a focus for regulators and the regulated community. While in some instances the control technologies installed for the other pollutants will also help reduce mercury emissions, mercury is generally more difficult to control directly. A number of government and industry-sponsored research projects to improve the technologies needed for mercury reduction from EGUs are under way and Illinois EPA continues to push for advancements.

Applicable emission limits are discussed in this Chapter along with the control technologies available to reduce emissions from EGUs for the pollutants SO_2, NO_x, PM, and mercury. Several reference documents are noted for those desiring additional information.

Also, at the end of this Chapter we provide a brief discussion on U.S. EPA's repository of the most effective air pollution control technologies and methods, and further discussion of Integrated Gasification Combined-Cycle. Although this latter technology is not an air pollution control technology, it is a developing combustion process that is cleaner than traditional coal combustion technologies and holds great promise.

Sulfur Dioxide (SO_2) Controls

The emissions of SO_2 from fuel combustion sources are regulated in Illinois under 35 *Ill. Adm. Code* Part 214. The SO_2 emissions limits for existing sources vary, depending on the type of fuel and geographical location of the emission sources. Emission limits range from 0.3 pounds of SO_2 per million British thermal units (a measure of heat input expressed as lbs/mmBtu) for distillate oil to 6.8 lbs/mmBtu for coal combustion sources in rural areas. All EGUs located in the urbanized areas and burning solid fuels (e.g., coal) are limited to 1.8 lbs/mmBtu. In 1990, the Clean Air Act's Acid Rain Program (Title IV of the Clean Air Act, 42 *U.S.C.* 7651.) imposed much tighter limits. These limits outlined in 63 *Fed. Reg.* 51705 (September 1998) are currently in effect.

U.S. EPA published "*Control Techniques for Sulfur Oxide Emissions from Stationary Sources"* in April 1981, which describes in detail the various control technologies available to reduce sulfur dioxide emissions from EGUs and from other sources.[5] *The Mega Symposium, SO_2 Control Technologies and Continuous Emission Monitors* (August 1997) prepared for a symposium sponsored by the U.S. EPA, the U.S. Department of

Energy, and the Electric Power Research Institute, is a good reference on the various approaches.[6] Techniques used by the industry for achieving compliance with SO_2 emissions limitations include the following:

- Physical coal cleaning to remove pyrites (inorganic sulfur compounds);
- Chemical coal cleaning to remove pyrites and organic sulfur present in coal;
- Switching to either natural gas or to a low sulfur western coal;
- Limestone sorbent injections, or blending coal with limestone before combustion;
- Dry scrubbing with limestone or lime slurry; and
- Flue gas desulfurization, also commonly referred to as scrubbers.

Table 3-1 provides a summary of various SO_2 reduction technologies and the SO_2 reduction potential of each. Illinois' EGUs have employed some of these technologies to reduce SO_2 emissions. Dry scrubber control technology has not been employed on any existing Illinois units thus far, but there is a potential that it will be used on small coal-fired boilers in the future. Blending coal or coal waste with limestone has not yet been used on any existing Illinois source, but permit applications have been received for two new boilers to use this technology. In the absence of regulatory requirements beyond the Acid Rain program that would require the use of these control technologies, sources will not install these technologies because the price of SO_2 allowances is well below the cost of installing these technologies.

We also note that two types of wet scrubber control technologies have been employed in Illinois on coal-fired utility boilers subject to the New Source Performance Standard (NSPS) for Fossil Fuel-Fired Steam Generators, 40 *CFR* 60, Subpart D. A limestone scrubber system has been employed at Marion 4, Duck Creek and Dallman Units 1, 2 and 3. A double-alkali scrubber was employed at Newton Units 1 and 2, but due to its higher operating cost compared to limestone scrubber technology, this scrubber system is no longer in operation.

The technologies listed in Table 3-1 have been proven to be effective in the removal of SO_2, and some are widely used by the industry. The type or types of SO_2 control appropriate for any individual EGU is dependent upon the type of boiler, type of fuel, and the types and staging of other air pollution control devices. In summary, emissions reduction technologies for SO_2 are available and are effective in reducing SO_2 from the gas stream of EGUs.

Table 3-1
SO_2 Reduction Potential of Various Control Technologies

SO_2 Control Technology	SO_2 Reduction Potential
Coal Cleaning to Remove Sulfur Compounds	
Physical Coal Cleaning	10-40%
Chemical Coal Cleaning	50-75%
Fuel Substitution by a Cleaner Fuel	
Switch to Low Sulfur Coal	50-80%
Switch to Distillate Oil	75-90%
Switch to Natural Gas	98-100%
Dry SO_2 Removal Processes	
Combustion of Fuel, Limestone Mixture	~80%
Spray Drying (Dry FGD)	60-85%
Coal + Limestone Mixture + Spray Drying	90-98%
Wet SO_2 Removal Processes	
Limestone Flue Gas Desulfurization (FGD)	90-98%
Wellman-Lord Dual-Alkali FGD	90-95%
Magnesium-Enhanced Lime FGD	90-98%

Nitrogen Oxides (NO_x) Controls

Nitrogen oxides (NO_x) emissions from EGUs are regulated in Illinois under the NSPS, the federal Acid Rain program and under the NO_x SIP Call in 35 *Ill. Adm. Code* Part 217. Under Phase I of the Acid Rain program, NO_x limits are respectively set at 0.45 and 0.50 lbs/mmBtu for certain existing tangential-fired and wall-fired utility boilers burning coal. Under Phase II of the Acid Rain program, NO_x limits are respectively set at 0.40 and 0.46 lbs/mmBtu for the remaining existing tangential-fired and wall-fired units. Some Phase II EGUs opted into the early compliance provisions of the Acid Rain program and are subject to the Phase I limit of the Acid Rain program.

For the cyclone-fired utility boilers at a capacity greater than 155 megawatts, the limit is set at 0.86 lbs/mmBtu. There is no limit set for cyclone-fired boilers smaller than 155 megawatts. There is also no limit set for oil- and gas-fired utility boilers.

New sources must meet Best Available Control Technology or BACT requirements for NO_x. (BACT requirements are discussed in more detail later in this Chapter). U.S. EPA's "*Alternative Control Techniques Document – NO_x Emissions from Utility Boilers*" discusses in detail various control technologies available to reduce emissions of NO_x from EGUs.[7] Control Technologies for NO_x include the following:

- Combustion tuning (CT);
- Burner-out-of-service (BOOS);

- Overfire air (OFA);
- Low NO_x burners (LNB);
- Switching to low nitrogen coal;
- Switching to natural gas;
- Flue gas reburn;
- Selective non-catalytic reduction (SNCR) with ammonia or urea; and
- Selective catalytic reduction (SCR) with ammonia.

In 2001, Illinois adopted NO_x regulations consistent with requirements of the NO_x SIP Call,[8] which are more stringent than the current Acid Rain regulations. The NO_x SIP Call regulations have an initial NO_x emissions budget based on an emission rate of 0.15 lbs/mmBtu. The rule has provisions for the trading of NO_x emissions among sources in the participating states affected by the NO_x SIP Call. To comply with the NO_x emissions trading rule, many sources have installed or plan to install add-on controls or plan to meet the requirement with a combination of the above-mentioned combustion controls.

The NO_x SIP Call was promulgated to address the impacts of NO_x emissions from power plants and other large industrial boilers on ozone. Ozone is seasonal in nature. It is formed by a chemical reaction with other pollution in the presence of sunlight and during warm weather. As a result, the emission reductions are only required during the period May 1 through September 30. However, power plants in many states have installed and are installing control equipment to meet NO_x SIP Call standards. Most facilities do not intend to operate the equipment year-round, especially where they employ selective non-catalytic reduction (SNCR) technology and selective catalytic reduction (SCR) technology for NO_x removal. In fact, to eliminate the cost of operating the equipment other than during the ozone season, some companies are installing equipment to bypass the flue gases before they enter into control equipment. However, annual operation of the control equipment may only add incrementally to the total cost of controlling NO_x.

Some of the NO_x control technologies and their NO_x reduction potentials for coal-fired boilers are provided in Table 3-2. As with SO_2, effective control technologies are readily available and are being widely used by the industry.

Table 3-2
NO_x Reduction Potential for Various Types of Boilers[9,10,11]

Control Technology	NO_x Reduction Potential, %		
	Wall-Fired	Tangential-Fired	Cyclone-Fired
Combustion Tuning (CT)	10-40	10-40	10-40
Burner-Out-Of-Service (BOOS)	10-20	10-20	NA
Overfire Air (OFA)	10-25	10-30	NA
Low NO_x Burner (LNB)	40-50	20-25	NA
LNB+OFA	50-70	30-50	NA
Reburn	50-60	50-60	50-60
Advanced Reburn	70+	70+	70+
Selective Catalytic Reduction (SCR)	80-95	80-95	80-95
Selective Non-Catalytic Reduction (SNCR)	30-60	30-60	30-60
Fuel-Switching (FS)	40-75	40-75	50-75
Repowering	90+	90+	90+

Particulate Matter (PM) Controls

Depending on the type of boiler, uncontrolled primary total particulate emissions from coal combustion range from 0.8 to 4.0 lbs/mmBtu, with PM_{10} emissions of 0.1 to 1.0 lbs/mmBtu and $PM_{2.5}$ emissions of up to 0.6 lbs/mmBtu. Oil combustion generates primary particulate emissions of approximately 0.05 to 0.1 lbs/mmBtu, depending on the quality of oil and its sulfur level, with PM_{10} emissions of 0.03 to 0.08 lbs/mmBtu and $PM_{2.5}$ emissions of 0.025 to 0.06 lbs/mmBtu. Particulate matter emissions from gas combustion, all of which are $PM_{2.5}$, are below 0.01 lbs/mmBtu.

Electrostatic precipitators and fabric filters are commonly used for high-efficiency control of coal-fired boiler particulate emissions. These technologies can provide greater than 99.9 percent control of primary particulates to below 0.03 lbs/mmBtu. They also provide over 99 percent control of PM_{10} and over 95 percent control of $PM_{2.5}$. Most EGUs have installed substantial particulate controls, and the average PM emissions from coal-fired units is 0.043 lbs/mmBtu. Upgrades of existing controls to levels below the NSPS limits of 0.03 lbs/mmBtu, and often to 0.01 lbs/mmBtu or less, are possible through precipitator rebuilding or replacement, augmentation or replacement of precipitators with new fabric filters, or with the use of technologies such as flue gas conditioning. The State and Territorial Air Pollution Program Administrators and Association of Local Air Pollution Control Officials (STAPPA/ALAPCO) has published a document, "*Controlling Particulate Matter Under the Clean Air Act: A Menu of Options*" (July 1996), that describes in detail the available control options to reduce particulate matter emissions.[12]

Mercury Controls

The removal of mercury from coal combustion sources has become a focus in recent years. Only in the last 10 years has the removal process been aggressively studied and advanced technology developed.

Mercury removal itself is made somewhat more complex because of the different forms of mercury present in coal. Mercury is present in coal in elemental (Hg^o), oxidized (Hg^{++}) and organic forms. Relative concentrations of each type of mercury depend on the kind of coal and its constituents. The elemental form is more prevalent in sub-bituminous coals (typically called "western" coal) and the oxidized form is more prevalent in bituminous coals (Illinois and eastern coal). Mean concentrations of mercury in bituminous coal and sub-bituminous coals used by electric generators are 0.12 and 0.07 parts per million (ppm), respectively. Typically, mercury is 25 percent elemental mercury and 75 percent oxidized mercury in bituminous coals, and it is 75 percent elemental mercury and 25 percent oxidized mercury in sub-bituminous coal. Physical coal cleaning processes used for the removal of pyrites can remove an average of 21 percent of mercury present in bituminous coals. The process removes a much smaller amount of mercury from sub-bituminous coals.

The mercury concentration in flue gases is normally 5 to 30 micrograms per dry standard cubic meter (expressed as ug/dscm), the norm being about 10 ug/dscm. Mercury concentration in the flue gases from municipal solid waste boilers is about 200 to 1,000 ug/dscm. The presence of SO_2, moisture, chlorine, hydrogen chloride, and unburned carbon in the flue gases influences conversion of elemental mercury to oxidized mercury.

The greater the porosity of fly ash, the higher the adsorption of mercury by the fly ash. Calcium aids the adsorption of mercury by fly ash. Iron compounds in the coal influence melting and solidification temperatures of fly ash and hence influence its porosity. Hydrogen and oxygen present in coal make it burn faster and make fly ash more porous. Unburned carbon present in the fly ash adsorbs both oxidized and elemental forms of mercury. Cooler temperatures cause better adsorption of mercury by fly ash, carbon, calcium and other materials.

A number of technologies for the removal of mercury are under investigation at the laboratory and pilot-plant stages. Some of these technologies are being tested at full-scale plants. These technologies include the following:

- Adsorption of mercury by treated and untreated activated carbons;

- Oxidation of elemental mercury to oxidized mercury by the use of oxidizing agents such as chlorine, SO_2, aqueous hypochlorite or hydrogen chloride;

- Catalytic oxidation of elemental mercury to oxidized mercury by palladium or iron and with or without the injection of SO_2, NO_x and hydrochloric acid;

- Removal of elemental mercury and oxidized mercury by various types of calcium-based and fly ash sorbents;
- Adsorption of elemental mercury by a noble metal such as gold;
- Capture of elemental mercury by in-situ generated titanium particles in conjunction with ultraviolet irradiation; and
- Addition of activated carbon or fly ash and agglomeration of dust in a circulating fluidized bed.

Activated carbon injected into the flue gas stream is the most commonly studied control technology for removal of elemental mercury and oxidized mercury and, in many cases, has been found to be quite cost effective. Effectiveness of some of these control technologies, as found during the laboratory and pilot-plant studies, is provided in Table 3-3. These levels of effectiveness do not necessarily represent the removal efficiencies that would be guaranteed by vendors to occur in full-scale plant operations. Illinois EPA continues to explore ways to address this challenge.

Table 3-3
Mercury Removal Efficiency for Emerging Mercury Control Technologies[13]

Control Technology	Pollutants Removed	Mercury Removal Efficiency
Activated Carbon (AC)		
Lignite AC (FGD Carbon)	Hg^o, Hg^{++}	Hg^o = 80% Hg^{++}=85%
Lignite AC + 175 ppm SO_2 Gas	Hg^o, Hg^{++}	Hg^o = 75% Hg^{++}=88%
Lime Based Sorbents		
Advacate Lime + no SO_2 injection	Hg^o, Hg^{++}	Hg^o = 3% Hg^{++}=5%
Advacate Lime +175 ppm SO_2 Gas injection	Hg^o, Hg^{++}	Hg^o = 40% Hg^{++}=20%
Gold		
Packed Bed, Monolith, or Filter Bag	Hg^o, Hg^{++}	Hg^o = 95% Hg^{++}= 95%
UV Irradiation + In-Situ Sorbent		
TiO_2 Sorbent + FF for Collection	Hg^o	84.4-96.1%
Circulating Fluidized-Bed		
Activated Carbon + Water Spray*	Hg^o	99%+
Fly Ash + Iodine Impregnated AC + Spray*	Hg^o	99%+
Fly Ash + Water Spray*	Hg^o	50%+

AC=Activated carbon, FF= Fabric Filter, TiO_2= Titanium oxide.
* Water spray is used to cool the gases and allow agglomeration of particles that help mercury removal.

It should be noted that mercury removal is not only boiler specific, but also depends on the type of coal and controls used for removal of PM, SO_2, and NO_x. A cold electrostatic precipitator can remove about 36 percent of mercury while a hot electrostatic precipitator can remove only about nine percent of mercury in a pulverized coal boiler. The document, "*Final Technical Report of September 1, 1996, through August 31, 1997*" (ICCI Project Number 96-1/1.4A-2), provided a correlation of scrubber parameters with mercury removal and mercury species in flue gas.[14]

In summary, technologies do exist to reduce mercury emissions from EGUs. While the control of mercury emissions is more complex than SO_2 or NO_x control, emerging technologies are expected to be effective.

Best Available Control Technology (BACT) for Coal-Fired Boilers

Under the federal and state rules, proposed new and modified EGUs that exceed particular pollutant threshold emissions values for NO_x and SO_2 set forth in the regulations must demonstrate that they will use BACT to minimize the emissions of those pollutants. BACT generally represents the lowest emission rate achieved in practice by a similar or comparable unit, taking into account energy impacts, costs, and other environmental impacts.

As new units are planned and air quality permits are applied for, the control technologies proposed for an EGU must be compared to other plants recently constructed or proposed throughout the country to determine BACT requirements. In addition to setting a standard for new plants, a review of these sources can provide useful insight as to the extent to which Illinois' existing units can and should be controlled in the future.

The U.S. EPA's RACT/BACT/LAER Clearinghouse (BACT Clearinghouse) is a repository of the control technology determinations (e.g., BACT for SO_2 emissions from a pulverized coal boiler) including projects that triggered the requirements of PSD around the country. For recently constructed coal-fired boilers, all of which were new rather than retrofitted units, the BACT limits for NO_x and SO_2 are provided in Appendix B, Tables B-1 and B-2.

Control of mercury has only recently been examined on coal-fired units, so the BACT Clearinghouse has rather incomplete information on the types of technologies that have been used cost effectively to control mercury. Generally, techniques using various forms of activated carbon injection are the accepted technology to reduce mercury. Research is still needed as mercury control technologies are still in their experimental stages, as discussed earlier in this chapter.

Clean Coal Technology, Integrated Gasification Combined-Cycle (IGCC)

Unlike conventional coal-fired boilers, IGCC, sometimes referred to simply as coal gasification, is a relatively new technology as applied to the power generation industry. While Eastman Chemical has most notably and successfully used IGCC in industrial processes, its use for power generation purposes continues to be studied and tested. To provide a reliable alternative to traditional boilers, it must undergo further technical improvement in its operations and reliability.

Coal gasification takes place in the presence of a controlled "shortage" of air/oxygen, thus maintaining reducing conditions. The process is carried out in an enclosed pressurized reactor, and the product is a mixture of carbon monoxide and hydrogen (called synthetic gas, syngas or fuel gas). The product gas is cleaned and then burned with either oxygen or air, generating combustion products at high temperature and pressure.

IGCC utilizes a combined-cycle format with a gas turbine driven by the combusted syngas, while the exhaust gases are heat exchanged with water/steam to generate superheated steam to drive a steam turbine. With an IGCC system typically 60-70 percent of the power is generated by the gas turbine, compared to about 20 percent power generation using a typical fluidized bed combustion system.

Differences in the IGCC demonstration plants are discussed in the "*IEA Coal Research Report OECD Coal-Fired Power Generation – Trends in the 1990s,*" IEAPER/33. Every IGCC plant is required to have a series of large heat exchangers that become major components of the system. In such exchangers, solids deposition, fouling and corrosion may take place. Currently, cooling the syngas to below 100°C is required for conventional cleaning, and it is subsequently reheated before combustion. Substantial heat exchange vessels are required.

There are several technical challenges to operating a successful IGCC unit. Highly integrated plants tend to have long start-up times (compared to pulverized coal combustion units) and hence may only be suitable for base-load operation.

With pressurized gasification (as with fluidized bed combustion units), the supply of coal into the system is considerably more complex than with pulverized coal combustion units. Some gasifiers use bulky and costly lock hopper systems to inject the coal, while others have the coal fed in as a water-based slurry. Similarly, by-product streams have to be depressurized, while heat exchangers and gas cleaning units for the intermediate product syngas must themselves be pressurized.

A number of IGCC power plant demonstration units, mainly around 250 megawatts capacity, are being operated in Europe and the U.S. A 235 megawatt unit at Buggenum in the Netherlands began operation in 1993. The largest unit being evaluated is at Puertollano in Spain, with a capacity of 330 megawatts. In the U.S., there are only two operational plants – Wabash River in Indiana and Polk Power near Tampa, Florida.

All of the current coal-fueled demonstration plants are subsidized. The European plants are part of the Thermie programme. The U.S. Department of Energy is funding the design, construction, and the operating costs for the first few years of the U.S. plants. Some plants are repowering projects, but as far as demonstrating the viability of various systems, they are effectively new plants, even though they are tied to an existing steam turbine.

As gasifiers are pressure vessels, they cannot be fabricated on-site in the same way that pulverized coal combustor boilers can. Large gasifiers are difficult to transport, simply because of their weight and sheer size.

The primary incentive for IGCC development has been that units may be able to achieve higher thermal efficiencies than pulverized coal combustion plants and are able to match the environmental performance of gas-fired plants. During the developmental phase, the thermal efficiencies of new pulverized coal combustion plants using superheated steam have also increased.

When these IGCC units come into general operation, their emissions of particulates, NO_x and SO_2 are expected to meet, and most likely exceed, all current emission standards. Indeed, a major power generator recently pledged to build an IGCC plant within the next decade. Other IGCC proposals continue to be discussed. This is promising technology, and its further development must be encouraged.

Currently, there are only two IGCC plants producing electricity in the U.S. Neither of these plants specifically control mercury emissions. The document "*The Cost of Mercury Removed in an IGCC Plant, Final Report, September 2002"* prepared for the U.S. Department of Energy provides cost estimates for removal of mercury from the IGCC's syngas.[15]

Chapter 4

Overview of National Power Plant Emission Reduction Proposals and Their Estimated Emission Reductions

One of the most prominent national environmental issues during the last two years has been defining appropriate requirements to regulate multiple air pollutants from electric power plants. The desire for improved air quality, while providing a degree of regulatory certainty for the electric power industry, has led to a series of proposals in the U.S. Congress and two related proposals by U.S. EPA. This chapter will provide a brief overview of these proposals, four of which are Congressional legislative proposals and two of which are U.S. EPA proposed rulemakings. This chapter will also discuss the emission reductions expected to be achieved by these proposals.

National Multi-Pollutant Legislation

The Bush Administration and several members of Congress have proposed various versions of "multi-pollutant" legislation for the electric power plant industry. The bills are consistent in the respect that they address requirements for several pollutants simultaneously. All include a requirement for setting a national "cap" on emissions of each pollutant and then add provisions to allow for emissions trading of SO_2 and NO_x allowances between regulated sources. The ability to trade mercury allowances varies among proposals. The proposals typically differ in the number of pollutants regulated, the level of the proposed "cap," and the timeframe for implementation. Depending on each bill's focus, such legislation typically addresses three or four pollutants.

The 3-pollutant bills would set standards for SO_2, NO_x and mercury. The 4-pollutant bills also include requirements to regulate carbon dioxide. The multi-pollutant legislative proposals, whether in 3- or 4-pollutant form, are intended to reduce emissions and to encourage investment in new plants by providing a degree of certainty regarding future regulatory requirements. Some of the these proposals would replace existing regulatory programs, including New Source Review (NSR), New Source Performance Standards (NSPS), Prevention of Significant Deterioration (PSD) of air quality, Lowest Achievable Emission Rate (LAER) standards, Best Available Retrofit Technology (BART), and regulations currently under development to control mercury emissions from electric power plants.

Bush Administration's Clear Skies Act of 2003

In February 2002, President Bush announced a multi-pollutant strategy called the lear Skies Initiative. The strategy was put forth as multi-pollutant legislation that was submitted to the U.S. House of Representatives on July 26, 2002, and to the U.S. Senate two days later. The Administration reintroduced the legislation to the 108th Congress on February 27, 2003, as H.R. 999 and S. 485.

Differences between the 2002 and the 2003 proposals were minimal, inasmuch as the pollutants regulated, the emissions limits and the time frame to implement the proposed requirements, remained the same. However, the bill's name was changed to the Clear Skies Act.

The Clear Skies Act proposes to establish federally enforceable emission limits (caps) for SO_2, NO_x and mercury. The NO_x and SO_2 requirements would apply to all fossil fuel-fired electric generators that sell electricity. The mercury requirements affect only the subset of these units that are coal-fired.

The Clear Skies Act of 2003 would establish new annual caps on total SO_2 emissions and new allocation procedures that would begin January 1, 2010, for power plants in the eastern half of the United States and in 2018 (or later) for power plants in the western U.S. Annual SO_2 emissions for affected power plants would be capped at 4.5 million tons starting in 2010 and 3.0 million tons starting in 2018. During the first year of the program, 99 percent of the total allowances would be allocated to existing regulated units with a national auction being held for the remaining one percent. In each of the next 20 years, an additional one percent of the allowances will be auctioned. An additional 2.5 percent thereafter will be auctioned annually until eventually all the allowances are auctioned. Allowances will be allocated based on each unit's baseline heat input multiplied by standard emission rates that vary depending on the fuel combusted by the units. Standard emission rates are established for three categories of units--coal-fired, oil-fired, and other units.

The Clear Skies Act proposes a separate SO_2 emission limitation and cap-and-trade program for the states in the Western Regional Air Partnership (WRAP) planning organization.[16] The trading program will go into effect if the WRAP states are unable to meet the sulfur dioxide cap (271,000 tons) by 2018. If the 2018 emission cap is exceeded, the back-stop trading program goes into effect three years after 2018. This program is independent of the nationwide cap-and-trade program, and affected emission units would be subject to both.

The proposal also contains new annual caps for NO_x and new allocation procedures starting January 1, 2008. The Clear Skies Act would retain the NO_x requirements in the existing Acid Rain Program and would also retain the requirements in the NO_x SIP Call through December 31, 2007. The new NO_x trading program would apply to the same units in the U.S. and its territories as the new SO_2 trading program, but there would be separate cap-and-trade systems established for Zone 1 (eastern and central U.S. states including the eastern half of Texas) and Zone 2 (western states including the western half of Texas).

The annual NO_x emissions for affected units in Zone 1 are capped at 1.562 million tons starting in 2008 and 1.162 million tons starting in 2018. Zone 2 annual NO_x emissions are capped at 538,000 tons. Each year, the percentages of allowances allocated and auctioned are the same as under the new SO_2 trading program. The Clear Skies Act specifies that sources covered by the new SO_2, NO_x, or mercury trading programs would no longer be subject to NO_x SIP Call requirements, including a seasonal emissions cap, beginning in 2008.

The Clear Skies Act also contains annual caps on total mercury emissions. The allocation of mercury allowances would begin January 1, 2010. The annual mercury emissions would be capped at 34 tons starting in 2010 and 15 tons starting in 2018. The percentage of allowances allocated and auctioned are the same as that proposed for the SO_2 and NO_x trading programs. The allocations will be set on a one-time basis and therefore will remain the same each year. Allowances will be allocated based on the units' baseline heat input, which for units with an operating history is adjusted by a standard factor to reflect the types of coal that were combusted.

The Clear Skies Act also contains a "safety valve" provision. Under the safety valve mechanism, the price of allowances is capped, meaning that if the allowance price exceeds the "safety valve," EPA will borrow allowances from the following year's auction to make more allowances available at that price. The Clear Skies Act "safety valve" provisions for NO_x and SO_2 are $4,000 a ton and $35,000 per pound for mercury.

Other Federal Multi-Pollutant Legislative Proposals: The Carper Bill, the Jeffords Bill and the Waxman Bill

There are three primary legislative proposals in addition to the Clear Skies Act of 2003 for multi-pollutant legislation to regulate emissions from the electric power plants. The three bills, introduced in the 108th Congress, are The Clean Air Planning Act of 2003 (CAPA or the Carper Bill),[17] The Clean Power Act of 2003 (CPA or the Jeffords Bill),[18] and the Clean Smokestacks Act of 2003 (Waxman bill).[19] Figure 4-1 provides a brief summary comparing the provisions of the various bills. A summary table comparing the proposals' regulatory requirements is provided in Appendix C.

While the bills have many elements in common, they also differ substantially. The degrees to which reductions are needed in order to comply with the allowable levels vary among these three bills. The bills would require reduction of NO_x emissions to 1.5 or 1.7 million tons per year (i.e., a 67 to 75 percent reduction from 2000 levels) and reduction of SO_2 emissions to 2.25 million tons per year (i.e., a 75 percent reduction from the Phase II Acid Rain cap). The bills would require mercury reductions of 79 to 90 percent from 1999 levels of emissions (from 48 tons to 10 tons or 5 tons annually, depending on the bill). Under both the Jeffords and the Waxman bills, these reductions would take place by 2008 or 2009. When comparing the three bills with the Clear Skies Act, one striking difference is that the three Congressional bills would establish caps on carbon dioxide emissions, while the Clear Skies Act is silent on carbon dioxide. The Jeffords bill would cap carbon dioxide emissions at 2.1 billion tons beginning in 2009. Senator Carper's bill would cap carbon dioxide's emissions at the 2005 level by 2009 and then at the 2001 level by 2013. The Waxman bill would cap carbon dioxide at 1990 levels by 2009.

Figure 4-1: Emission Cap Levels and Timetables Associated with Federal Multi-Pollutant Legislative Proposals

Proposal	NO_x	SO_2	Mercury	CO_2
Clear Skies Act of 2003 (CSA)	2.1 million tons –2008 (59% reduction from 2000 levels) 1.7 million tons- 2018 (67% reduction from 2000 levels)	4.5 million tons- 2010 (50% reduction from Phase II Acid Rain cap 3.0 million tons – 2018 (67% reduction from Phase II Acid Rain cap	26 tons- 2010 (46% reduction from 1999 levels) Updated in 2003 to 34 tons in 2010 15 tons – 2018 (69% reduction from 1999 levels)	No mandatory CO_2 provisions
Clean Air Planning Act of 2003 (CAPA-Carper Bill)	1.87 million tons – 2009 (63% reduction from 2000 levels) 1.7 million tons – 2013 (67% reduction from 2000 levels)	4.5 million tons – 2009 (50% reduction from Phase II Acid Rain cap) 3.5 million tons – 2013 (61% reduction from Phase II Acid Rain cap) 2.25 million tons – 2016 (75% reduction from Phase II Acid Rain cap)	24 tons – 2009 (50% reduction from 1999 levels) 10 tons – 2013 (79% reduction from 1999 levels)	2005 levels (2.6 billion tons plus flexibility) – 2009 2001 levels (2.4 billion tons plus flexibility) - 2013
Clean Power Act of 2003 (CPA-Jeffords Bill)	1.5 million tons – 2009 (70% reduction from 2000 levels)	2.25 million tons – 2009 (75% reduction from Phase II Acid Rain cap)	5 tons – 2008 (90% reduction from 1999 levels)	2.1 billion tons - 2009
Clean Smokestacks Act of 2003 (Waxman Bill)	75% reduction from 1997 levels – 2009	75% reduction from Phase II Acid Rain cap – 2009	90% reduction from 1999 levels – 2009	1990 levels - 2009

U.S. EPA's Clean Air Interstate Rule (CAIR) Proposal

In addition to the Clear Skies Act, the Bush Administration has pursued a parallel regulatory approach to power plant emissions. U.S. EPA published its *"Proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone"* in the *Federal Register* on January 30, 2004 (69 *Fed. Reg.* 4566). This proposed rule was initially referred to as the Interstate Air Quality Rule or IAQR, and addressed emissions of SO_2 and NO_x from fossil fuel-fired power plants. However, on May 18, 2004, U.S. EPA proposed additions to the rule's provisions and the regulatory text, and renamed the proposal as the Clean Air Interstate Rule or CAIR. (69 *Fed. Reg.* 32684, June 10, 2004, *"Supplemental Proposal for the Rule To Reduce Interstate Transport of Fine Particulate*

Matter and Ozone (Clean Air Interstate Rule)”). One of the findings of this proposal is that emissions of SO_2 and NO_x from power plants from the affected states significantly contribute to a downwind state’s inability to meet national air quality standards for fine particle pollution ($PM_{2.5}$) and/or 8-hour ozone.

As noted by U.S. EPA, as many as 175 metropolitan areas currently do not meet the 8-hour ozone and/or $PM_{2.5}$ standards, exposing almost 160 million people to unhealthful levels of air pollution. U.S. EPA stated that:

> What has become increasingly clear is that it will take a significant regional effort to ameliorate the health and environmental impacts from sources of pollution contributing to these problems. A multi-state and multi-pollutant approach also comports with the recommendations in a recent study by the National Academy of Science, which notes that ozone, $PM_{2.5}$ and regional haze ‘share common precursor emissions and common pathways for the generation of these pollutants and are all to greater or lesser extents affected by long-range transport.’

(U.S. EPA *Fact Sheet on the Interstate Air Quality Rule*, January 30, 2004).

The Clean Air Interstate Rule would require 29 eastern states and the District of Columbia to significantly reduce and permanently cap emissions of SO_2 and/or NO_x, depending on whether the power plant emissions from the state impact the ability of a downwind state to attain the 8-hour ozone or $PM_{2.5}$ standard. Under the emission reduction cap, in 2015, NO_x emissions from the power sector would be 65 percent below the base year levels. SO_2 emissions from that sector would be 50 percent below base year levels by 2010 and approximately 65 percent below base year levels when fully implemented in 2015.

U.S. EPA notes the following in support of its proposal:

> [SO_2 and NO_x] contribute to the formation of fine particles and ground-level ozone, pollutants that, together, are associated with thousands of premature deaths and illnesses each year. Reducing emissions of these pollutants will significantly address these health issues, in addition to improving visibility and protecting sensitive ecosystems. [U.S.] EPA’s modeling predicts that when combined with existing emissions reduction requirements, this rule would [enable] approximately 90 [percent] of “nonattainment areas” meet national air quality standards for ozone and particle pollution. By addressing air pollutants from electric utilities in a cost-effective fashion, EPA’s Clean Air Interstate Rule proposal would protect public health and the environment without interfering with the steady flow of affordable energy for American consumers and businesses.

(*See* U.S. EPA web site, http://www.epa.gov/ interstateairquality/basic).

CAIR provides that the 30 affected states or jurisdictions (Alabama, Arkansas, Connecticut (ozone only), Delaware, Florida (particle pollution only), Georgia, Illinois, Indiana, Iowa, Kansas (particle pollution only), Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota (particle pollution only), Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas (particle pollution only), Virginia, West Virginia, Wisconsin, District of Columbia) would be required to submit a plan to U.S. EPA that demonstrates it will meet its emissions budgets for statewide SO_2 and NO_x, as applicable. States would then be permitted, but would not be required, to meet the emission caps through U.S. EPA's federal cap-and-trade programs for power plants, or achieving reductions through other state-designed emission control measures.

U.S. EPA also proposed that the emissions reductions under CAIR would satisfy the best available retrofit technology (BART) requirements of the Clean Air Act's Regional Haze program for power plants as a "better than BART" alternative. U.S. EPA's justification is that its SO_2 and NO_x model cap-and-trade programs are expected to achieve greater emission reductions from power plants than would otherwise be achieved under BART.

For Illinois power plants, CAIR would cap SO_2 emissions at 192,671 tons per year in 2010, and 134,869 tons per year in 2015. CAIR, as amended by U.S. EPA's "Notice of Data Availability" (August 6, 2001), would cap NO_x emissions at 69,623 tons per year in 2010, and 58,018 tons per year in 2015, for Illinois power plants. However, these caps are not firm caps because U.S. EPA's proposal allows the affected sources to use banked allowances from other programs, such as allowances from the federal Acid Rain Program for compliance with the CAIR. Accordingly, because of banking, affected sources may not have to meet their ultimate compliance deadlines until several years after U.S. EPA's 2015 overall deadline. Illinois EPA has expressed concern that this proposed approach may be inconsistent with the deadline for attaining the 8-hour ozone standard.

U.S. EPA's Mercury Reduction Proposals

In addition to U.S. EPA's CAIR proposal, section 112(n) of the Clean Air Act required U.S. EPA to study the public health effects of air toxic emissions from fossil fuel-fired power plants (coal, oil and natural gas) to determine whether it was necessary to regulate those emissions. Air toxics, also known as hazardous air pollutants, are those pollutants known or suspected to cause cancer or other serious health problems in humans, such as birth defects or neurological effects. In late 1997 and early 1998, U.S. EPA published two reports to Congress: "*The Mercury Study Report to Congress*," (December 1997), and the *"Study of Hazardous Air Pollutant Emissions from Electric Utility Stream Generating Units—Final Report to Congress"* (February 1998).

Data presented within those reports identify coal-fired power plants are the largest source of manmade or anthropogenic mercury emissions in the U.S. -- about 48 tons of mercury each year -- and identify mercury as a toxic pollutant. As a result of these reports, U.S. EPA also provided funding for the National Academy of Sciences in 1999 to review the health effects data associated with methyl mercury and the Agency's "reference dose" for mercury. A "reference dose" is the level at which most people could be exposed to methyl mercury without the risk of health problems.

All of these studies and data gathered led U.S. EPA to develop a rulemaking proposal that presented three alternatives for controlling emissions of mercury from coal-fired power plants. The alternatives presented include:

- A proposed rule requiring power plants to install controls known as "maximum achievable control technologies" (MACT) under section 112 of the Clean Air Act;

- A proposed rule establishing "standards of performance" limiting mercury emissions from new and existing power plants. This proposal, under section 111 of the Clean Air Act, would create a market based "cap-and-trade" program that, if implemented, would reduce nationwide power plant emissions of mercury in two distinct phases. In the first phase, due by 2010, emissions will be reduced by taking advantage of "co-benefit" controls – that is, mercury reductions achieved by reducing SO_2 and NO_x emissions. The expected mercury level would be 34 tons per year. When fully implemented in 2018, mercury emissions will be reduced by 33 tons (69 percent), to a cap of 15 tons per year; and

- A proposal under section 112(n) of the Clean Air Act, which mimics the proposal under section 111.

Although U.S. EPA specifies a 15-ton final cap to be achieved in 2018, under the section 111 or 112(a) approach the agency acknowledges in its proposal that mercury emissions could reach 22 tons (or only a 54 percent reduction) in 2020, when banking and trading credits are utilized.

U.S. EPA makes it clear in its proposal that it does not favor the imposition of a MACT standard. Illinois EPA believes, however, that U.S. EPA incorrectly applied the Clean Air Act in setting the MACT standard in such a way as to penalize the use of eastern or bituminous coal and to favor western coal or sub-bituminous coal. Illinois EPA has challenged U.S. EPA on this approach and believes that U.S. EPA should establish a MACT standard that reflects *at least* "the average emission limitation achieved by the best performing 12 percent of the existing sources" or "the emission control that is achieved in practice by the best controlled similar source." We have stated that the same reduction percentages should be applied to all types of coal, so that fuel switching or blending is not encouraged in lieu of additional controls.

Illinois EPA also expressed great concern that the deadlines in U.S. EPA's section 111 proposal are too extended. Illinois EPA acknowledges that the adoption of controls across this source category may require more time than the traditional three-year compliance time period for MACT sources. However, Illinois EPA believes that, if needed, U.S. EPA can provide the extensions of time for compliance that are already provided in section 112 of the Clean Air Act.

Illinois EPA strongly supports trading programs, but the Agency has commented that there are concerns with the trading of mercury. While mercury emissions can travel great distances, some mercury can also be deposited near its source. In fact, in November 2003, the State of Florida published a study entitled, "*Integrating Atmospheric Mercury Deposition with Aquatic Cycling in South Florida*." This study estimated how quickly fish tissue levels respond to decreased regional mercury emissions.

Thus, the Agency believes any mercury trading program would need to be carefully designed to ensure that it does not have the unintended consequence of creating mercury hot-spots.

Summary

The debate over a multi-pollutant approach to regulating air emissions from electric power plants continues at both the national and state levels. The main differences in competing federal proposals are the pollutants to regulate, the level of the proposed "cap" and the timeframe for implementation. Of the four prominent proposals, the Clear Skies Act is the only proposal that does not propose to cap carbon dioxide emissions.

A well-designed national approach would be superior to a series of diverse individual state rules because there would be more sources in the trading program and it would provide consistency between the states.

Chapter 5

Energy Issues:
Federal and State Policies and Programs and Energy Market Challenges

Over the past two years, several critical events have served as reminders that the United States needs to reinforce its efforts to achieve energy independence, develop alternative fuel sources, reduce emissions from fossil fuels and upgrade its aging electrical distribution system. In addition to the extensive consequences of the terrorists' attacks of September 11, we have the current conflict in Iraq, an unusually cold 2002-2003 winter, the labor strike in Venezuela in December 2002, civil disturbances in Nigeria, and particularly, the August 2003 blackout in the Northeast part of the United States to reveal to us the vulnerabilities of the world energy markets to these wide ranging and disparate pressures.

Illinois citizens are understandably concerned about matters of electric reliability as a result of events such as the California energy crisis, and the dramatic collapse of Enron. The August 2003 electrical blackout that affected over 50 million people in the Northeast was a wake-up call regarding the reliability of our power grid, and it clearly sounded the alarm for change and renovation in our energy policies. In light of these events, policy developments have occurred at both the state and national level, and Illinois has shown its leadership by being proactive in policy-making to address the State's energy issues. At the national and state level, energy policies have been developed to guide efforts to manage our energy resources and programs.

In this section, current government energy policies are briefly described.

<u>The National Energy Policy</u>

In his second week in office, President Bush established the National Energy Policy Development (NEPD) Group, directing it to "develop a national energy policy designed to help the private sector, and, as necessary and appropriate, to help State and local governments to promote dependable, affordable and environmentally sound production and distribution of energy for the future." This overview sets forth the NEPD Group's findings and key recommendations for the National Energy Policy.[20]

The NEPD Group identified the principal energy challenges facing America to be the following: (1) promoting energy conservation; (2) repairing and modernizing our energy infrastructure; and (3) increasing our energy supplies in ways that protect and improve the environment.

The NEPD Group developed several recommendations which included the following:

- Direct federal agencies to take appropriate actions to responsibly conserve energy use at their facilities, especially during periods of peak demand in regions where electricity shortages are possible, and to report to the President on actions taken;

- Provide a tax incentive and streamline permitting to accelerate the development of clean combined heat and power technology;
- Create an income tax credit for the purchase of hybrid and fuel cell vehicles to promote fuel-efficient vehicles;
- Extend the Department of Energy's ENERGY STAR® efficiency program to include schools, retail buildings, health care facilities and homes, and extend the ENERGY STAR® labeling program to additional products and appliances;
- Issue an Executive Order directing federal agencies to expedite permits and coordinate federal, state, and local actions necessary for energy-related project approvals on a national basis in an environmentally sound manner;
- Establish an interagency task force chaired by the Council on Environmental Quality. The task force will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state and local permitting activity in particular regions where increased activity is expected;
- Grant authority to obtain rights-of-way for electricity transmission lines with the goal of creating a reliable national transmission grid;
- Enact comprehensive electricity legislation that promotes competition, encourages new generation, protects consumers, enhances reliability and promotes renewable energy;
- Implement administrative and regulatory changes to improve the reliability of the interstate transmission system and enact legislation to provide for enforcement of electricity reliability standards; and
- Expand the Energy Department's research and development on transmission reliability and superconductivity.

A stated goal of the Bush Administration's National Energy Policy is to add to the energy supply from diverse sources, including domestic oil, gas and coal. It also included evaluating hydropower and nuclear power, and making greater use of non-hydro renewable sources that are now available. President Bush has directed all federal agencies to include a detailed statement on the energy impact of any regulatory action that could significantly and adversely affect energy supplies.

The Bush Administration's National Energy Policy has several elements, which they believe could substantially impact the mix of electric energy sources in Illinois, especially coal. We believe that the federal government must focus attention on efforts to further promote clean coal technology to better use our valuable coal resources, to greatly expand the use of renewable energy, and to make much needed improvements to the vulnerable power grid.

Illinois Energy Policy

The Illinois Energy Cabinet was created in January 2001 to review and coordinate energy issues facing the State of Illinois and to develop a State energy policy. In March 2001, the Energy Cabinet issued a white paper, "*Preparing an Energy Policy for the State of Illinois*." In February 2002, the Energy Cabinet officially released the "*Illinois Energy Policy*" that included 56 recommendations for energy policy improvements in the State of Illinois.[21]

The recommendations addressed five major topics: (1) capitalizing on the rich natural and human resources of Illinois and ensuring that they are used to benefit the State and its citizens; (2) ensuring adequate access to traditional sources of power and heat at a fair price; (3) taking steps toward energy independence by moderating demand and increasing the use of Illinois-based renewable resources; (4) preserving, protecting and improving our environment; and (5) providing that as a major energy consumer, Illinois state government should lead by example.

The recommendations also addressed the underlying economics – supply, demand, affordability and environmental impacts for the energy markets as a whole. While recognizing the inter-related nature of energy issues, the policy split the various energy challenges into the following five separate groupings:

- Electricity Restructuring;
- Coping With Unstable Natural Gas Prices;
- Challenges in Transportation;
- Environmental, Public Health and Safety Challenges; and
- Economic Development and Utilization of Illinois Resources.

The resources of the State are being directed toward achieving the goals outlined in the Illinois Energy Policy. Among those especially pertinent to this report are the efforts to promote renewable energy and increase the use of Illinois' abundant coal resources. Both of these components of the State Energy Policy are the subject of extensive efforts by the Department of Commerce and Economic Opportunity. More information on these programs can be found at www.commerce.state.il.us.

The Partnership for a New Economy

Governor Blagojevich's 2002 Partnership for a New Economy emphasizes helping the economy and protecting the environment, while revitalizing the clean coal industry in Illinois. Recognizing the availability and abundance of coal resources in Illinois, the goal of the Governor's plan is to re-power power plants and to promote mine mouth power generation.[22]

Ultimately, new plants could use new, environmentally friendly technologies such as Integrated Gasification Combined-Cycle that dramatically reduce air pollution at each plant. This clean coal burning technology also increases the efficiency at which coal is burned, emitting 20 percent less carbon dioxide than regular coal-fired plants.

Governor Blagojevich revised the State's $3 billion Clean Coal Bond Program to meet his newly established goals. The Governor's plan, signed into law in July 2003, authorizes a State-backed bonding authority to be created to leverage financing for the upgrading of outdated coal powered plants with advanced coal technology. The backing of the bonds by the State will make them more attractive to financers than the bonding authority available now, giving companies real incentives to build advanced technology power plants.

Governor's Special Task Force on the Condition and Future of the Illinois Energy Infrastructure

As a result of the August 14, 2003 power outage affecting major portions of the northeast United States and southeast Canada, Governor Blagojevich announced the creation of a Special Task Force on the Condition and Future of the Illinois Energy Infrastructure. A committee was formed to analyze the State's existing energy infrastructure, examine Illinois nuclear power plant safety, and to look at ways to relieve pressure on the electric supply grid by promoting energy efficiency and renewable energy.[23]

The Task Force was comprised of the Lieutenant Governor, the Director of the Illinois Emergency Management Agency, the Director of the Illinois EPA, the Governor's Office of Management and Budget, the Governor's Deputy Chief of Staff for Public Safety, the Chairman of the Illinois Commerce Commission, the Director of the DCEO, the General Counsel to the Governor, the Chairman of the Illinois Toll Highway Authority, the Director of Central Management Services, the Director of the Division of Nuclear Safety.

The results of this effort are presented in the final report of the Special Task Force, published in June 2004, entitled *"Blackout Solutions."* In brief, the Special Task Force adopted 32 recommendations to improve system reliability, ensure safety of Illinois' power plants and increase the diversity of Illinois' energy portfolio. While the report focused principally on the immediate need of ensuring protection from power outages, it also includes findings that stress the theme of promoting reliability, efficiency, and safety. The report of the Task Force has helped guide the preparation of this report and helped identify critical issues.

Energy Market Challenges

The remainder of this Chapter provides an overview of the energy market challenges Illinois currently faces.

Restructuring Illinois' Electricity Markets

During the period since restructuring began, Illinois consumers have benefited from rate reductions and rate freezes, and electricity reliability has been improved significantly since major problems occurred in the Chicago-area in the late 1990s. Generation owners have had to invest shareholder dollars in pollution control enhancements required to comply with federal Clean Air Act programs implemented at the state level, most significantly the NO_x SIP Call. Another significant development has been the expansion of regional power transmission organizations through which generation owners are more easily and efficiently able to sell their power across state lines. As a result, owners of Illinois generation facilities are now able to compete with generators in several surrounding and nearby states and generators located outside of Illinois are more capable of providing power to Illinois' consumers. These competitors typically are utilities in states, which have not yet restructured their markets as Illinois has done.

Utility-owned generation outside Illinois can continue to recover the costs of environmental controls through rates paid by consumers. However, non-utility Illinois generators do not have this cost-recovery mechanism. Therefore, if Illinois businesses are encumbered with state-specific regulations that their out-of-state competitors do not face, Illinois businesses will incur additional costs that cannot be recovered directly from utility ratepayers and will face a competitive disadvantage in regional power transmission organizations.

The critical date for the electric restructuring process is January 1, 2007, when the current cap on electricity prices for many Illinois retail customers expires. While the transmission and distribution components will continue to be subject to government regulation, beginning with the above date, prices for the power and electricity portions are expected to be set by the supply and demand conditions of the generation supply market. Restructuring seeks to ensure a low-cost and reliable supply of electricity by injecting competition among suppliers into what has been a highly regulated and vertically integrated industry.

If competition among suppliers of electricity is robust, power prices may remain at reasonable levels. As California's experience in 2000 and 2001 has shown, if competition among electricity suppliers fails to take hold, the price rise could be significant. Whether robust competition occurs in Illinois in 2007 will depend on the degree to which competitive forces create an effectively functioning wholesale and retail supply markets. Retail competition among electricity suppliers has achieved mixed results to date in Illinois.

There have been some encouraging signs of retail market competition in the State. However, there was little or no competition among retail suppliers of electricity in the service territories outside of northern Illinois.

Transmission constraints have a direct impact on the amount of competition among wholesale and retail suppliers. Owners of the transmission system may be reticent to construct transmission lines that would disadvantage their unregulated generation affiliate. Regulatory siting requirements, zoning requirements and resident opposition also act as deterrents in the initiation of transmission improvement projects, making it difficult to eliminate constraints. Uncertainty due to state and federal jurisdiction disputes and shifting federal transmission policy has suppressed investment in new transmission. Recent actions by the Federal Energy Regulatory Commission are recognized as an attempt to cut through the thicket of uncertainty. The task for Illinois legislators, regulators and industry participants is to ensure that the promises of electricity restructuring are fulfilled

Challenges to Reliability

The issue of the reliability of the power system is a major issue throughout the nation, and no less so in Illinois. Ample evidence of the fragility of the grid was especially prominent after the August 2003 blackout. In the Agency's review and discussions, we found that transmission constraints represent a major challenge to electric reliability. Since electricity cannot be stored, the transmission system must permit unimpeded movement of electricity from suppliers to consumers at all times, but especially when demand for electricity is at or near its peak. Likewise, the reliability of the transmission system depends upon critical voltage support and resource capability at key locations in the grid. Actions that lead to reductions in these critical factors can ultimately cause widespread service interruptions or exacerbate a failure of the grid, as witnessed in the northern portion of the U.S. and parts of Canada during August 2003. Following the August 2003 blackout, the grid was not completely restored for days to weeks depending on the affected area. The economic loss and public impact has amounted to approximately $6.4 billion dollars covering eight affected states.[24] As part of the Eastern Interconnect (the regional transmission interconnection), Illinois faces the same electric reliability issues that were highlighted by the power outage.

Grid congestion problems can become particularly acute where the operation of certain generating plants is needed because their operation is essential to maintaining grid reliability. Those older power plants would need to remain operating to maintain grid reliability so they could supply needed voltage support. Their loss, without other units to replace them, could have serious impacts on the reliability of the electric grid. Yet, these same plants may have difficulty meeting new more stringent standards so this factor must be considered in the development and implementation of any new pollution control strategy.

Although several state-sponsored initiatives were launched between 1999 and 2002 to promote new power plants, no additional base-load generating capacity is under construction. Although construction permits were issued for two projects, one has delayed the start of construction and the construction permit for the other project has been challenged by a number of environmental groups and the permit is stayed. No significant construction is planned to address transmission grid reliability issues within the State or within the MAIN (Mid-America Interconnected Network) electric transmission region of which most of Illinois is a part.

Illinois EPA does not yet have adequate information about how a state-specific program would impact plant closures and electric reliability. It can be generalized that if out-of-state generators are not required to meet the same emission standards as Illinois generators, and thus avoid the costs of air pollution control, they could offer their product more competitively, and presumably, Illinois could very well lose generation capacity within the State. A resource and transmission planning model that would include detailed production cost information for Illinois and the surrounding interconnect is needed to determine with reasonable certainty which specific Illinois generation plants might be closed due to the costs of more stringent pollution controls and the effect such closures might have on electric reliability.

Summary

The National Energy Policy and the Illinois Energy Policy identified the challenges and opportunities that exist in formulating a comprehensive and coordinated approach to developing and safeguarding our energy resources. These policies help map the strategies that will guide and harmonize all of our efforts to collectively contribute to the achievement of the policy's critical objectives. Even with these efforts, it is plain to see that our energy future faces significant challenges that are difficult to control or which require long-term and difficult solutions. Any number of events can impede progress or confound the best plans to manage our energy resources. This is the situation the Illinois EPA confronts in its effort to evaluate the benefits of further pollution controls on the power industry in light of the impacts such controls might have on the continued ability of the State's electric energy system to provide safe, sufficient, reliable, and affordable electricity. The Illinois EPA's review of the key issues presented in this Chapter has led to the conclusion that we do not possess sufficient answers to key questions. Without the answers to those key questions, the Illinois EPA cannot be sure that a state-specific approach will not result in unacceptable disruptions in the reliability of electricity in Illinois and that the costs of the plan will not make electricity unaffordable for some. A comprehensive sensitivity analysis must be conducted to estimate the response of Illinois' electric power system to various State-specific pollution control scenarios. This would provide reasonable assurance that all consequences of any proposal could be identified and evaluated in order to avoid unmanageable problems.

Chapter 6

Opportunities Presented Through Renewable Energy and Energy Efficiency

There is an increased level of interest and activity in Illinois in the expanded use of renewable energy sources and energy efficiency, in order to reduce the electrical demands on the existing power generation system and lessen air emissions. More and more emphasis is being focused on utilizing alternative energy sources, combined heat and power, distributed generation, energy conservation, and voluntary initiatives to save energy. The benefits of using these alternatives in Illinois are the production of electric power from non-polluting energy sources, increased operating efficiency of existing power generating equipment, and reduction in current and future demands of conventional fossil fuel-fired electric generating units. While current alternative energy sources and activities account for a minimal portion of the State's electrical power output, Illinois' aggressive approach to creating markets for renewable energy sources could have a substantial impact on the State's energy production.

In their 2004 "*Annual Energy Outlook,"* the U.S. Department of Energy's (U.S. DOE) Energy Information Administration (EIA) forecasts that the national growth rate of energy generation from all renewable energy sources for the 2002 – 2025 timeframe will be approximately 1.8 percent per year.[25] Compounding this annual growth rate from a base year of 2003 equates to a 13 percent increase by 2010, a 35 percent increase by 2020, and a 48 percent increase by 2025 for energy generation from renewable sources. Because Illinois is one of the more progressive states in developing and implementing renewable energy, the growth rate for Illinois is expected to exceed the EIA national growth rate and these growth projections. The current renewable energy sources in Illinois include wind, solar, hydropower, and bioenergy.

Illinois citizens and businesses enjoy many benefits from increased utilization of clean and local energy options, including renewable energy, "recycled energy" (such as Combined Heat and Power or CHP), and energy efficiency. The potential economic and environmental benefits associated with these energy options include:

- New income streams for farmers and rural areas through the production of new renewable "energy crops" such as wind and biogas;

- Retention of manufacturing jobs in Illinois both by reducing energy costs (through energy efficiency or recycled energy) and by the creation of new markets for renewable energy generation in Illinois;

- Reduced cost of doing business for all business classes by expanding customer choice to include distributed energy and energy efficiency;

- Hedging the state's risk against volatile and higher prices for traditional energy sources, especially natural gas;

- Increased electric reliability through cost-effective measures to reduce electric grid congestion during periods of peak usage (through increased reliance on distributed generation and energy efficiency);

- Improved public health and environmental quality by reducing energy waste and stimulating clean energy development; and

- Retention of Illinois dollars in the local economy (instead of exporting dollars while importing coal or natural gas from out-of-state or foreign sources).

This chapter will discuss these energy options and briefly discuss potential policy tools to increase the utilization of these resources.

Renewable Energy Resources

The current renewable energy sources in Illinois with significant potential for growth include wind, solar, and bioenergy. In the following section, each of these various renewable energy sources is discussed.

Wind Energy

Illinois' wind energy resource is found to be the most promising renewable energy resource in the State and can be used to produce electricity at lower cost than new natural gas-fired power plants. The U.S. Department of Energy's National Renewable Energy Laboratory (NREL) in 2001, estimates over 9,000 megawatts of commercial wind energy potential in the State. (*See*, *"The 2001 Illinois Wind Resource Map,"* prepared by the National Renewable Energy Laboratory, at www.eere.energy.gov/windpoweringamerica/.) Wind technology has improved dramatically over the last twenty years, with costs dropping from over 20 cents per kilowatt-hour at that time to generally under 4 cents per kilowatt-hour today. Modern wind generation investments, at current prices, can be competitive with more traditional sources of new electric generation and therefore a valuable hedge against higher electric costs that may result from over-reliance on any of the traditional resources. To date, about 100 megawatts of wind energy capacity has been developed in the state.

This first 100 megawatts of wind energy capacity in Illinois, on an average annual basis, will generate approximately enough power for 30,000 typical homes or approximately 80,000 residents. Based on information from wind energy developers available to the Illinois Department of Commerce and Economic Opportunity (DCEO), approximately 1,500 megawatts of additional wind projects are under active development around the state. If all of this new wind energy capacity were to be built, rural landowners could gain up to $4 to $5 million per year in additional income from wind land-leases and royalty payments, rural communities could benefit from millions of dollars of property tax revenues, and the wind projects could potentially generate enough power annually for over one million residents.

The wind industry indicates that until the federal production tax credit (PTC), currently valued at 1.8 cents per kilowatt-hour, is renewed for an extended period of time, sustained growth in wind energy will not occur. Rather, growth in the industry is likely to experience interval periods of rapid growth and stagnation. The current federal PTC, recently renewed through December 2005, creates an incentive for state policymakers, electric distribution utilities, wind energy developers, and financial supporters such as the Illinois Clean Energy Community Foundation, to cooperate on a wind energy strategy that can bring projects to completion by the end of 2005.

Solar Energy

Illinois has a significant solar energy resource and is using increasingly diverse technologies to capture and utilize the resource. The three technologies experiencing significant market growth in Illinois today include: passive solar daylighting; photovoltaic (PV) electric generation; and solar thermal collectors (both traditional flat-plate collectors as well as compound parabolic collectors).

Illinois has been a leader in the Midwest in the development of its solar resource, and with the partnership of the City of Chicago is the only state in the nation to host two solar panel production facilities: Spire Solar Chicago and Solargenix. Spire Solar Chicago, a manufacturer and turnkey provider for PV systems, provides systems with clear reliability benefits that generate power at periods of peak summer demand, and has enjoyed considerable success as a supplier for public and not-for-profit institutions in the City of Chicago, including installations on the DuSable Museum of African American History, the Reilly School, and the Chicago Center for Green Technology. Spire is now expanding its product line to private sector markets.

Solargenix, a manufacturer and turnkey provider for compound parabolic solar thermal panels, opened its new production facility in Chicago in 2004. Solargenix's products can supply hot water at both traditional domestic hot water temperature ranges and higher temperature ranges suitable for absorption chilling and other applications. The broadening range of solar thermal applications demonstrates its ability to supplement both traditional natural gas loads (domestic hot water) and electric loads (summer cooling through solar absorption chilling).

Illinois is also home to the Midwest's leading retail installer of flat-plate solar thermal collectors, Solar Service of Niles. Solar Service is a 20-year supplier of solar thermal applications for homes (domestic hot water), small businesses (such as commercial laundries), and public facilities (such as heated swimming pools and other applications).

The solar industry in Illinois has demonstrated the environmental benefits and economic development potential of the solar industry in Illinois, but continued financial support will be key to the further stable development of the industry in Illinois.

Bioenergy

Bioenergy, also called biomass, may have the largest long-term energy potential in Illinois. Although much of that resource is, for the near-term, highly cost-constrained, landfill-gas-to-energy systems are cost-effective in Illinois, and "anaerobic digesters" (which produce and capture natural gas from the decomposition of municipal wastewater and livestock operations) are experiencing improving economics. Livestock waste digesters, popularly known as "cow power" systems, have near-term growth potential in Illinois, and offer strong parallel environmental benefits such as odor control, local water quality protection, greenhouse gas capture, and pathogen elimination from the biosolid residues.

Bioenergy can refer to a broad spectrum of organic material feedstocks including agricultural crops and agricultural wastes, forest residues, livestock wastes, municipal wastewater, and any other organic wastes (e.g., those resulting from food production and preparation).

Bioenergy typically enjoys lower air pollutant emissions (including emissions of greenhouse gases) than fossil fuel based electricity. Since biomass absorbs carbon dioxide as it grows, the entire biomass lifecycle of growing, converting to electricity, and regrowing biomass can actually reduce carbon dioxide emissions. Through efficient utilization of biomass resources, through the use of residues and co-products, and by accounting for greenhouse gas emissions avoided by landfills and livestock operations, bioenergy systems can have a positive net impact on Illinois' total greenhouse gas emissions profile.

Biomass co-firing with coal is one option for large-scale use of biomass for electric generation in Illinois. While such systems would likely create new markets for farmers, and reduce pollution levels for all traditional power plant pollutants, the economic feasibility of the systems, particularly in competition with other renewable energy resources such as wind energy, will hinge on further improvements that reduce the costs associated with the collection and delivery of the feedstocks to the co-firing power plant.

Long-term, new technologies such as biomass gasification, the direct conversion of biomass to hydrogen, or the conversion of cellulosic biomass feedstocks to ethanol and then to hydrogen, all offer considerable electric generation opportunities for Illinois' robust agricultural production capacities. While adoption of a Renewable Portfolio Standard for Illinois would likely stimulate the development of further bioenergy development in Illinois, continued financial support, as well as research and development support through the Department of Agriculture and Illinois' universities, will also play key roles in the stable further development of bioenergy in Illinois.

Recycled Energy

"Recycled Energy" refers to the process of recapturing energy that is typically lost in manufacturing, electric generation, or gas pressure-dropping stations, and most typically refers to Combined Heat and Power (CHP) applications. Because all energy associated with the process is used more efficiently, operating efficiencies improve and operating costs and fuel costs are reduced. This section will provide an overview of recycled energy opportunities and challenges.

Combined Heat and Power (CHP)

CHP is the most significant and most common potential recycled energy resource. CHP utilizes the waste heat generated by electricity production to support heating, cooling, dehumidifying, manufacturing thermal process loads, compressed air, or mechanical power. Because the energy streams are produced on-site, electric line losses are eliminated and transmission and distribution system upgrades can frequently be avoided. Furthermore, while the national average efficiency of power generation has remained around 30 to 35 percent for decades, CHP systems can achieve overall energy efficiencies of 70 to 85 percent.

According to the Midwest Combined Heat and Power Application Center, an affiliate of the Energy Resource Center of the University of Illinois at Chicago (Midwest CHP), 32 CHP systems producing approximately 170 megawatts are currently known to be in operation in Illinois, and there are 2,400 megawatts to 7,500 megawatts of additional capacity that could be developed.[26,27]

With rising concerns about electric reliability among industrial energy users, and with long production shut-downs and high costs that can result from even brief electrical outages or voltage reductions, interest in CHP as an electric reliability enhancer is also on the rise. Key issues such as the availability of and appropriate rates (or charges) for standby power, and the need for standardized interconnection procedures for distributed generators, are key policy questions to be addressed to realize the potential benefits that additional CHP systems can bring to Illinois.

Energy Efficiency Efforts

Energy efficiency investments in Illinois' economy brings strong and diverse benefits, including: protecting consumers and businesses from higher energy prices, improving electric reliability by reducing congestion on the electric grid, supporting the retention of manufacturing jobs by reducing manufacturing energy costs and supporting the manufacture of new high-efficiency products, hedging risk against fuel price volatility, supporting public health and the environmental quality by reducing energy waste, and helping to keep Illinois' energy dollars in the local economy.

Illinois has enjoyed considerable success with energy efficiency programs for residential, commercial, and industrial customer classes. This section will provide a brief overview of the State's major energy efficiency programs for the residential, commercial and industrial sectors, as well as the new commercial building code.

- Industrial and Manufacturing Energy Efficiency

  Noting benefits of energy efficiency, and in particular the enormous difficulties caused by the declining number of manufacturing jobs in the State, Governor Blagojevich announced the creation of the new Manufacturing Energy Efficiency Program. Administered by the Illinois DCEO, the new program is charged with helping manufacturers manage their energy costs by making cost-effective efficiency improvements. The program involves key decision-makers in Illinois' manufacturing facilities and focuses on measures that can bring high returns with modest investments. The program helps firms identify best practices in energy management that can be rapidly incorporated. The program then moves to coaching services for the implementation of the new management practices and to operation and maintenance (O&M) improvements implementation, with the State supporting 50 percent of those costs.

- Commercial Sector Energy Efficiency

  Again noting benefits of energy efficiency, in 2003 Governor Blagojevich also announced the creation of a new Small Business $mart Energy Program, administered by DCEO, to help commercial businesses reduce their energy costs. The program, currently in a pilot stage, provides "Design Assistance" to businesses planning on new construction or considering end-of-life heating, ventilating and air conditioning (HVAC) replacement for their facilities, and establishes a Building Operator Certification Program to improve the energy efficiency O&M skills of Illinois' large building operators.

  New construction and reconstruction are key moments when a small amount of incentive and direction can help businesses save on energy costs for many years to come. Larger commercial buildings such as new office buildings, new hotels, and many types of franchise chains that use one template for most new buildings, provide key opportunities. Furthermore, with higher natural gas prices, efficient HVAC technologies such as Geoexchange systems (or ground source heat pumps) are an increasingly attractive option to control long-term energy costs. In the

Small Business $mart Energy pilot program, DCEO provides businesses with Design Assistance services that include an analysis of the energy costs of a traditional building design, as submitted by a business, as well as recommended energy efficiency improvements and an analysis of the return on investment of those improvements. To compliment the Design Assistance program, DCEO is also supporting outreach to Illinois architects, designers, engineers, and contractors, accelerating the market penetration of more efficient design methods.

In addition to Design Assistance, the Small Business $mart Energy program also includes a Building Operator Certification program to improve the energy efficiency O&M skills for Illinois' building operators. The program, in partnership with the Midwest Energy Efficiency Alliance (MEEA), trains building operators at several different levels. Introductory level courses focus on appropriate equipment operation in terms of energy efficiency, air quality, health and safety, and other concerns. Higher-level trainings are also offered to building operators to help them self-identify efficiency improvements and look at the relationship between lighting, HVAC, and the building envelope. DCEO and MEEA have offered the program for several years to institutional building operators such as hospitals and universities, and the program is now being offered to businesses as well.

- Residential Energy Efficiency

  Illinois' residential energy efficiency programs seek to reduce energy costs for consumers by working to improve efficiency practices and products in residential construction, lighting, and appliance markets. In the case of lighting and appliance programs, which are focused simply on reducing energy costs for consumers, the cost per kilowatt-hour saved can be as low as one cent (relative to typical consumer energy costs in Illinois of 8.5 cents per kilowatt-hour). These programs are funded through DCEO's Energy Efficiency Trust Fund, which was established in the 1997 deregulation law and provides $3 million per year for residential energy efficiency programs.

  DCEO's residential efficiency programs have also demonstrated strong parallel benefits in terms of both economic development and economic assistance to low-income communities. For example, DCEO's Energy Efficient Affordable Housing Construction Program, for example, provides assistance to not-for-profit developers of low-income housing developments. The program is not only a cost-effective energy efficiency program (reducing energy consumption by over 50 percent in most cases relative to standard code), but it is also a catalyst for further economic development in low-income neighborhoods. Many projects are gut rehabs in under-served neighborhoods and have led to additional private investment in the adjacent properties. Because not-for-profit developers owning the projects have an affordable housing mission, however, the projects do not cause gentrification or a decline in the available affordable housing stock. Many of these projects occur in low-income neighborhoods across the state, especially in Chicago and Rockford. The return on investment for the efficiency improvements is immediate, as the increase in annual financing costs due to the higher first-costs are less than the annual energy savings from the first year.

Goals of the Energy Efficient Affordable Housing Construction Program include using energy efficiency to create and maintain affordable housing and educating developers, architects and builders on energy efficient building measures and "green" building products so that they can begin using these measures and products on all projects. In State Fiscal Years 2003 and 2004, the program supported 1,259 units of efficient affordable housing, generated over six million dollars in lifetime savings for those units, and cost just over two million dollars in total program costs.

- Energy Efficiency Building Code

  On August 12, 2004, to reduce demand for energy in large commercial buildings, to relieve future strain on the electric distribution grid and to protect the environment, Governor Blagojevich signed into law the Energy Efficient Commercial Building Act. The new law requires the State to draft and enforce the first statewide energy efficient building code. Illinois had been the only major industrial state in the nation without a statewide commercial energy efficiency building code.

  The Energy Efficient Commercial Building Act, requires the Capital Development Board (CDB) and DCEO to write a statewide energy efficiency code for all new commercial buildings and all commercial buildings undergoing significant renovations, alterations, repairs or construction of an addition. CDB will adopt the International Energy Conservation Code (IECC) as the new statewide code for Illinois. The IECC establishes minimum design and installation standards for a building's lighting, windows, walls, roofs, insulation, heating/cooling/ventilation and other building systems. DCEO will provide energy code education programs for local government code officials and for building designers, engineers, and contractors.

Means of Promoting Energy Conservation

Recognizing that demonstration programs are only a step along the way, future efforts should focus on harnessing the power of the marketplace, whether it is promoting energy conservation and efficiency or encouraging renewable and recycled energy efforts.

Illinois has already adopted policies to promote clean power options, but more can be done in this area.

This section will describe the possible policy solutions to consider in addressing constraints to the development of renewable energy and demand side management, including green pricing programs and renewable portfolio standards.

Policy Consideration for Addressing Barriers:

As outlined in "*Repowering the Midwest,*" a document published by the Environmental Law and Policy Center in 2001, key policies for consideration include:

- Evaluate and update Illinois' efficiency standards and building codes;
- Establish or reinforce monitoring and enforcement practices;
- Establish an Illinois Renewable Portfolio Standard that requires all retail electricity suppliers to provide five percent of their power from renewable resources by 2010 and 15 percent by 2020;
- Increase the Illinois Renewable Energy Investment Fund investment to 0.1¢ per kilowatt-hour;
- Increase the Illinois Energy Efficiency Investment Fund by investing 0.3¢ per kilowatt-hour;
- Ensure that transmission pricing policies and power pooling practices treat renewable resources fairly and account for their intermittent nature, remote locations, or smaller scale;
- Remove barriers to clean distributed generation by (1) expanding Commonwealth Edison's net metering program to be offered statewide by all utilities; (2) establishing standard business and interconnection terms; (3) establishing uniform safety and power quality standards to facilitate safe and economic interconnection to the electricity system; and (4) applying clean air standards to small distributed generation sources, thereby promoting clean power technologies and discouraging highly polluting ones; and
- Encourage markets for "NEGA" watts (an overall reduction in wattage) that will promote energy efficiency within demand side management.

<u>Green Pricing Programs</u>

According to market research, some utility customers have expressed a willingness to pay more for renewable energy. "Green pricing" is an option that allows customers to support investment in renewable energy technologies. Participating customers typically agree to pay a premium on their electric bill to cover the incremental increased cost associated with renewable energy. According to a report completed in 2001 by the National Renewable Energy

Laboratory, electric utilities in 29 states have implemented green pricing programs. These green pricing programs were directly responsible for the development of 110 megawatts of new renewable energy capacity to serve these programs, with another 172 megawatts planned or already in development.

Well-designed green pricing programs could also harness the marketplace and accelerate the implementation of renewable energy in Illinois.

Renewable Portfolio Standard Issues

Environmentalists and renewable energy developers recommend a mandated State Renewable Portfolio Standard (RPS) of five percent by 2010 and 15 percent by 2020. Electric utilities indicate that since any cost differential for renewable energy will have to be borne by utilities they must have the flexibility of a voluntary approach until 2007, at which point the freeze on base chargeable rates will be lifted. This issue and its resolution continue to be a point of discussion among the related parties.

Renewable Energy and Energy Efficiency Incentives

This section provides a very brief overview of other renewable energy and energy efficient incentives.

U.S. EPA's ENERGYSTAR® Program in Illinois

Throughout the nation, U.S. EPA's ENERGY STAR® programs establish energy efficiency standards that material and equipment suppliers must meet to be labeled and recognized as energy efficient practices. If merely five percent of the energy efficiency opportunities in Illinois were annually and cumulatively implemented, the American Council for an Energy Efficient Economy predicts that, from 2000 to 2015, businesses could avoid $13.3 billion in utility costs and reduce smog-forming NO_x emissions by about 15 percent.[28] Relating these savings to the electric generating community in Illinois means that if electricity costs $0.07 per kilowatt-hour, approximately 1,450 megawatts less generating capacity would be needed at the five percent implementation level, 2,900 megawatts for a 10 percent implementation level, and 5,800 megawatts for a 20 percent implementation level.

Clean Air Counts and Other Voluntary Initiatives

Voluntary energy conservation programs, such as Clean Air Counts (CAC), also address the demand side of the energy equation. The Clean Air Counts initiative was born in 1999 as a result of the Regional Dialogue Forum, to address the ozone problem in the six county Chicago metropolitan area. The charter of Clean Air Counts aims to identify and implement voluntary measures that not only reduce emissions of volatile organic material (VOM), but also NO_x emissions while also promoting economic development for the Chicago area. Energy savings is a secondary benefit of this initiative, that to date has gone unemphasized.

Although pollution reduction was the primary goal of Clean Air Counts, energy savings of 1.10 million megawatt hours per year by 2007 was also identified in setting goals of reducing VOM emissions by 5.0 tons per day and NO_x by 10.9 tons per day. This energy savings equates to a reduction of nearly 127 megawatts in demand capacity. When setting this initial goal in 1999, Clean Air Counts also recognized the potential to be 6.1 million megawatts hours per year, which translates into approximately 700 megawatts of demand side savings.[29]

Energy Efficiency Programs

Many of the mechanisms necessary to expand the use of renewable and recycled energy, as well as demand side management, have been in place for several years in Illinois. Through various State actions and programs, funds have been made available to enable demonstrations of these new technologies, thereby establishing their feasibility and reliability. The following is a list of some of the existing State energy efficiency and renewable programs currently available in Illinois.

Illinois Clean Energy Development Fund

The Illinois Clean Energy Community Foundation was created as a result of a one-time payment of $225 million by Commonwealth Edison as a public interest environmental condition of its proposed coal plant sale and as part of legislation approved by the Illinois General Assembly in 1999. The Foundation was given $225 million of assets to further its mission of improving energy efficiency, developing renewable energy resources and certain other specified environmental measures.

City of Chicago Clean Energy Development Fund

The City of Chicago Environmental Fund was also created as a result of the settlement of the city's claims against Commonwealth Edison relating to the franchise agreement. This fund had $25 million per year for each of four years beginning in 2000. About half of the funds are devoted to energy efficiency and the other half to renewables.

Energy Efficiency Investment Fund

The Illinois Energy Efficiency Trust Fund was enacted by the Illinois General Assembly and is supported by utility and energy supplier payments that provide $3 million per year for each of 10 years beginning in 1997. The DCEO manages this fund.

Renewable Energy Investment Fund

The Illinois General Assembly enacted the Illinois Renewable Energy Resources Fund in 1997. It has $5 million per year for each of 10 years for renewable energy development projects, and it is supported by (1) residential and small commercial customers payment of a flat monthly fee of $0.50, and (2) by large commercial customers, who have a peak electric demand greater than 10 megawatts and used more than four million therms of gas in the previous calendar year, payments of a flat monthly fee of $37.50.

Commonwealth Edison Renewable Energy Fund

Commonwealth Edison's Renewables Program, also resulting from the settlement of the City of Chicago's claims against Edison relating to the franchise agreement, has $3 million per year for each of four years beginning in 1998. The principal use is for development of solar photovoltaics.

State Grants

State grants of $60,000 to $1 million are available for any renewable energy technology capital projects. Funding is not available for residential projects.

Tax Relief

Property tax assessment for solar energy systems is not to exceed the value of conventional energy systems.

Benefits from Renewable Energy and Energy Efficiency

This section provides an overview of an analysis conducted by the Regional Economics Applications Laboratory (REAL) of the potential economic benefits of renewable energy and energy efficiency in Illinois.

The REAL study applied the assumptions outlined for Illinois in the Environmental Law and Policy Center's "*Repowering the Midwest,*" and found energy efficiency improvements and renewable energy are expected to produce 35,000 net new jobs and $3.6 billion in increased economic output by 2010. By 2020, their study forecasts the creation of 57,000 net new jobs and $6.2 billion in increased economic output. These estimates were based on 3,649 megawatts and 8,358 megawatts of new clean energy in 2010 and 2020, respectively.[30] Table 6-1 shows REAL's predicted economic impacts from clean energy in Illinois.

Table 6-1
Estimated Economic Impacts from Clean Energy in Illinois

	2010			2020		
Forecast of New Clean Energy Generation in Illinois	Electrical Generation (MW)	Net New Jobs	Additional Economic Output (Billion)	Electrical Generation (MW)	Net New Jobs	Additional Economic Output (Billion)
REAL Estimates *	3,649	35,000	$3.6	8,358	57,000	$6.2

* Regional Economics Applications Laboratory forecast based on the Environmental Law and Policy Center's *"Repowering the Midwest."*

According to REAL, these investments in cost-effective energy efficient technologies will produce an estimated one billion dollars in net electricity cost savings for both business and residential consumers.

<u>Summary</u>

The pursuit of energy efficiency and development of clean renewable energy can result in new jobs and economic benefits for Illinois cities and farming communities. These economic gains could be disseminated to businesses engaged in manufacturing, firms installing and servicing renewable and clean energy equipment, farmers leasing their land for wind turbines or growing and harvesting bioenergy crops, businesses engaged in related marketing and research activities and communities with renewable and clean energy projects. Most importantly, these technologies bring with them the potential for significant environmental and public health benefits.

Chapter 7

Greenhouse Gas Emissions: National, and Nongovernmental Policies and Program, and Challenges

The General Assembly has also asked Illinois EPA to consider the need to establish a system to certify credits for voluntary greenhouse gas reductions. Efforts by the federal government to provide credit for early action on climate change have been considered inadequate by many. In addition to several state actions, President Bush has ordered the Secretary of Energy to improve the existing voluntary national registry for greenhouse gas emission reductions. Based upon these efforts, Illinois has a range of options including adopting one of the approaches worked out by other states or non-governmental organizations, developing its own system, referring entities seeking to certify reductions to one of these other systems, or waiting for and relying on an improved federal system of emission credits. The following sections describe the main greenhouse gas programs that are currently active and evaluates them for potential use by the State of Illinois.

The Federal Energy Policy Act

Section 1605(b) of the Energy Policy Act of 1992 mandated that the U.S. Department of Energy create a Voluntary Reporting of Greenhouse Gases Program to enable any company, organization or individual to establish a public record of their greenhouse gas emissions, reductions or sequestration in a national database. The purpose was to encourage voluntary reductions in greenhouse gases by providing recognition for those reporting reductions. Since a major debate on rewarding "early actors" had just occurred during passage of the Clean Air Act Amendments of 1990, Section 1605(b) was also intended to track early action on climate issues. A program such as the Department of Energy's greenhouse gas registry is important for a variety of reasons, including the following:

- Encourages greenhouse gas emission reductions;
- Ensures credit for those that have made previous reductions if a mandatory program is imposed;
- Provides positive publicity for early participants;
- Raises public awareness of potential climate change;
- Improves the competitive position of companies who participate;
- Provides entities with technical guidance in making and measuring reductions;
- Initiates an infrastructure in the states to carry out a future policy such as cap-and-trade; and

- Facilitates early trading in greenhouse gas credits.

According to the U.S. Department of Energy, in 2001 a total of 228 entities reported to the Energy Information Association that they had voluntarily undertaken 1,705 projects that reduced greenhouse gas emissions by 316 million tons. (*See* U.S. DOE's web page at: http://www.eia.doe.gov/oiaf/1605/vrrpt/) Despite this apparent success, the U. S. Department of Energy's voluntary system was widely criticized for its lack of rigor. The "quality" of the reductions reported varied dramatically. There was a lack of consistency in the methods used to measure the reductions, little or no verification that the reductions actually occurred, and no assurance that emissions reduced in one part of a company were not replaced by increases elsewhere. In response to the current federal Administration's call to improve the existing voluntary national registry, the U.S. Department of Energy has held several public workshops in conjunction with the U.S. Department of Commerce, U.S. EPA and the U.S. Department of Agriculture to obtain input on proposed improvements. On December 5, 2003, the U.S. Department of Energy officially released the proposed revision to the voluntary greenhouse gas reporting system. The public comment period on the revised guidelines remained open until mid-February 2004. The U. S. Department of Energy is planning to simultaneously release a further revision of the greenhouse gas reporting system for public comment and the Technical Guidelines sometime in 2004.

<u>Other Congressional Actions</u>

On the legislative front, numerous bills (nearly 70 bills in 2003) have been introduced in Congress that would either create a national greenhouse gas registry or directly regulate greenhouse gases.

The most notable bill was the Climate Stewardship Act of 2003 (S. 139). U.S. Senators John McCain (R-AZ) and Joseph Lieberman (D-CT) introduced the bill in January 2003 (which was last co-sponsored by seven other senators, including Senator Dick Durbin of Illinois). The bill was last debated in the Senate on October 30, 2003, and then referred again to the Senate Committee on Environment and Public Works, where it currently resides. The Bush Administration has noted that it "strongly opposes" this bill and general opinion suggests that it is unlikely to pass in its current form. However, if it were to be passed in its current state, the bill would mandate the following climate change actions:

- U.S. EPA would be mandated to create regulations that limit greenhouse gas emissions from a number of greenhouse gas source sectors. These sectors account for 85 percent of the year 2000 greenhouse gas emissions from the United States. Agricultural and residential sectors would be excluded, as would other specific sectors where it is deemed too difficult to reduce greenhouse gas emissions.

- One of two possible emissions targets would be enacted (and could be applied according to standard international methodologies):

- By 2010, U.S. emissions will be reduced to year 2000 emission levels
- By 2016, U.S. emissions will be reduced to year 1990 emission levels

- All entities that emit greater than 10,000 metric tons of greenhouse gas per year would be part of the program.

- Trading Units would be issued for each metric ton of greenhouse gas, with an exception for the transportation sector, particularly petroleum refiners and importers. These areas would have units that represent a unit of petroleum product sold per metric ton of emissions produced. At the end of the trading period, companies would be required to turn in allowances equal to the tons of emissions they put out.

- Some allowances would be awarded to companies, while others would be auctioned off. Proceeds from the auctioning of these allowances may be used to offset any possible increase in energy cost to consumers.

- A form of Intersector Trading would be allowed in that companies may satisfy up to 15 percent of their required reduction (reduced to 10 percent after 2016) by sequestration, taking credit for reductions by somebody not in the program, or using tradable allowances from another country's greenhouse gas market system. In addition, credits earned under the Corporate Average Fuel Economy program for passenger vehicles and trucks would be tradable within this system.

- Any company that did not provide enough allowances to meet its emissions would be fined at three times the value of each missing allowance.

- The trading aspect would incorporate the Department of Energy's greenhouse gas registry, discussed above. However, due to the problems already noted, changes would need to be made and any reductions would need to be verified.

- Companies could borrow credits against future expected reductions, up to five years in the future, but with a 10 percent "interest rate" attached to it.

- The bill would also create certain research programs. Most notably, it would:
  - Establish a scholarship program at the National Science Foundation for students who wish to do research in climate change;
  - Require that the Department of Commerce prepare a report on Technology Transfer and establish an "Abrupt" Climate Change program;
  - Require that the Secretary of Commerce submit a report on the effect the Kyoto Protocol would have on U. S. industries' ability to remain competitive, and cooperate with worldwide climate efforts;
  - Alter the structure of the U.S. Global Change Research program; and
  - Require that the National Institute of Standards and Technology create a branch that studies measurement technologies and standards as they relate to climate change.

The Senate vote on the McCain-Lieberman bill marked the first time ever that a bill capping U.S. greenhouse gas emissions and establishing a national greenhouse trading system had been considered. The sponsors intend to put it up for a vote again.

U.S. EPA's Climate Leaders Program

In addition to the Department of Energy registry, the U.S. EPA has created a voluntary industry-government partnership to encourage companies to develop long-term comprehensive strategies to reduce greenhouse gas emissions. The program, called "Climate Leaders," forms partnerships with companies, who then set corporate-wide greenhouse gas reduction goals and inventory their emissions to measure progress. They report this data to the U.S. EPA and thereby create a record of their emissions reductions. As of this writing, 56 companies covering a wide variety of industries have joined Climate Leaders. Some of the companies in Climate Leaders have also joined the Chicago Climate Exchange with the self-determined industry limits being the same for those who belong to both groups. (*See* the Climate Leaders website at http://www.epa.gov/climateleaders/ for more information.)

Greenhouse Gas Efforts in Other States

A few states have decided to undertake climate change action at the state level, with varying approaches. Specifically, some states have emphasized reduction "projects," while others have focused on corporate or company level emissions at a state, national, or even international level. Some state actions include:

California:

California's registry is the most well developed state program in the country. California's Climate Action Registry was launched in October 2002 with the purpose to help companies and organizations with operations in California to measure their greenhouse gas emissions and establish baselines against which any future greenhouse gas emissions reduction requirements may be applied. The registry requires entity-level reporting of emissions from all facilities in the state, but participants may elect to report all national emissions. Entity-level reporting means that a company cannot pick and choose specific operations to report, but instead must report at the corporate level. General reporting requirements and certification protocols have been completed. Reporters must verify that they have met all the general reporting requirements.

The registry system is managed almost entirely through the web; reporters use an online reporting tool known as Climate Action Registry Reporting Online Tool (CARROT). California is offering its system to other states, including its reporting protocols, certification process, online reporting tools, even its server (for a small cost) – which cost several hundred thousand dollars to develop and implement. New England states have been working with California to look at the possibility of using or linking to CARROT. Additionally, Washington and Oregon have also looked at using CARROT.

California has also passed a law capping automobile emissions of greenhouse gases. However, the law must withstand a court challenge from auto manufacturers, who claim only the federal government can make laws governing fuel economy and this is effectively what the California law does.

New Hampshire:

New Hampshire has adopted rules on a greenhouse gas registry. The state allows reporting at the corporate, facility or project level. Verification by a third party or state government is required. New Hampshire also passed a four-pollutant bill. However, indications are that affected companies are already at or below the carbon dioxide requirement and thus no trading will be required. There is also a power-related "tag" system where every megawatt of power has environmental attributes associated with it, and those certificates can be traded. Thus, a company could buy certificates to show that it effectively used only wind power. The program is estimated to cost less than a penny per month for the average home.

Wisconsin:

Wisconsin finalized rules for its registry and started accepting registrants in January 2003. Entities that emit more than 100,000 tons of carbon dioxide annually, of which there are only a few, are mandated to report their carbon dioxide emissions. Verification is encouraged but not required. Reductions can be reported at an entity, facility or project level.

Massachusetts:

Massachusetts has adopted a cap on 1997-1999 utility emissions and emission rates. Offsite emissions offsets and sequestration are allowed. The rule only applies to the six largest power plants in the state.

Oregon:

Oregon limits carbon dioxide emissions for new or expanded power plants to a level that is approximately 17 percent below the most efficient natural gas fired plant in the U.S. Power plants are thereby required to otherwise obtain offsets, for example by giving money to the Climate Trust or engaging in other projects. To date all have chosen to give to the Climate Trust at a specific rate based on the amount of power they will be producing. The Climate Trust then uses that money to purchase greenhouse gas offsets elsewhere. Also, Oregon has promulgated a law regarding forestry registration and reforestry. Oregon's Department of Forestry sells credits under this program, but at last notification the program was on hold.

<u>Non-Governmental Greenhouse Gas Efforts</u>

Chicago Climate Exchange:

The Chicago Climate Exchange is a voluntary greenhouse gas trading program led by CEO and Chairman Dr. Richard L. Sandor, who previously helped design the Acid Rain Program and developed the concept of trading financial futures. Companies who join Chicago Climate Exchange commit to reducing their greenhouse gas emissions by four percent below their baseline (an average of 1998-2001 emissions) by 2006, which is the final planned year of the pilot program.

The gases specifically covered by the Chicago Climate Exchange are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. These emissions will be converted to carbon dioxide-equivalents using the 100-year Global Warming Potential values established by the Intergovernmental Panel on Climate Change. The unit of emissions measurement, reporting, price quotation and trading in the Chicago Climate Exchange will be metric tons carbon dioxide-equivalent, with each trading unit representing 100 metric tons of the carbon dioxide equivalent. The first auction of these trading units was held in September 2003. The majority of the allowances were bought by American Electric Power Company for slightly under a dollar per metric ton. Continuous trading of greenhouse gas emission allowances commenced on December 12, 2003. Through April 2004, trading of Carbon Financial Instruments had increased each month and volumes exceeded expectations. In April, the price per metric ton of carbon dioxide was approximately $0.80-$0.85.

Like the SO_2 trading program and Illinois' trading program for volatile organic material, the Emissions Reduction Market System (ERMS) program (discussed in Chapter 8), the Chicago Climate Exchange expects to operate under a form of cap-and-trade. Participants can reduce their emissions beyond their target levels and sell the extra reductions. Others can avoid having to make reductions at their own facilities by purchasing credits.

Offset projects include some that directly reduce greenhouse gas emissions, such as the capture and use of landfill gas (methane), or that use renewable energy systems like wind and solar power. Other types of projects keep such gases out of the atmosphere through projects like forest expansion or no-till agriculture. Thus, a greenhouse gas trading program would not only provide incentives for industry to reduce emissions, but could provide a secondary income stream for farmers who adopt conservation methods.

There are numerous pros and cons involved in such a voluntary program. Dr. Sandor has indicated that companies will be motivated to join the Chicago Climate Exchange because shareholders and consumers expect them to be more environmentally friendly. Also, he believes that companies will join a voluntary program to reduce the chance of a mandatory one being imposed on them. Currently, several issues are being considered and addressed as the pilot continues.

<u>Other Greenhouse Gas Efforts</u>

The previously discussed federal, state, and private initiatives are the leading greenhouse gas efforts thus far. On a smaller scale, several other states are considering whether to create their own registries and the northeastern states and eastern Canadian provinces have agreed to reduce greenhouse gas emissions on a regional basis, though reports indicate that the New England states are already lagging behind. (*See, Air Daily* September 8, 2003.) Other private trading efforts exist as well. Eight companies, including Alcan, BP, DuPont, Entergy, Ontario Power, Pechiney, Shell and Suncor have set a goal of reducing greenhouse gas emissions by 80 million tons by 2010 and intend to establish a trading system amongst themselves. Shell and BP have already established internal trading programs.

In addition, ten northeastern states (Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont) have agreed to engage in a regional trading program for carbon dioxide emissions from power plants. They hope to have a final agreement in place by April 2005. No details have yet been released on how trading might work. (*See, Daily Environment Report*, September 26, 2003).

Internationally, Denmark and Britain have begun some modest greenhouse gas emission trading. Under the Kyoto Protocol "joint implementation" and the "clean-development mechanism" are two programs to test efforts to create reductions or offsets. Several U.S. states and companies have participated in such projects, but such activity has come to a halt since the Bush Administration's clear rejection of Kyoto. Back in the early 1990s when Illinois still had a sister-state relationship with Liaoning Province in China, the State of Illinois and Illinois Power Company outlined several potential joint implementation projects that never came to fruition.

In more recent international actions, in January 2004, 10 companies announced the start of a Global Greenhouse Gas Registry. Announced at the World Economic Forum Annual meeting, these globally active companies made the commitment to disclose their greenhouse gas emissions from their worldwide operations. Alcoa, Hewlett Packard, the German Utility RWE and Scottish Power are a few of the companies signing on. The 10 companies combined account for approximately 800 million tons of carbon dioxide equivalent annually. This registry was developed with the assistance of a number of environmental and business organizations, most notably the Pew Center on Global Climate Change, Deloitte Touche Tohmatsu and the World Energy Council. The technical infrastructure of the system is modeled after the California Climate Action Registry. The stakeholders of the Registry hope the registry encourages more corporate climate change actions by creating a global standard for disclosure of greenhouse gas emissions and reduction goals. Public access to the emissions information is expected to be available by summer 2004.

Specific Challenges of Greenhouse Gas Trading

Notably, 12 states, three cities, and several environmental groups sued in an attempt to force U.S. EPA to regulate greenhouse gases. U.S. EPA ruled that they do not have the authority to regulate carbon dioxide and other greenhouse gases. However, the lawsuit contends that this ruling contradicts previous statements and testimony from that agency under the Clinton Administration.

If any mandatory program were to be developed in the future, it would likely be a national cap-and-trade program (see Chapter 8 for more information on cap-and-trade programs and emissions trading in general). However, a cap-and-trade program is not as simple with carbon dioxide as it is with pollutants such as volatile organic material (VOM) and NO_x. As such, any cap-and-trade system would probably differ from Illinois EPA's VOM trading program (see Chapter 8) in that it would likely have trading units with an unlimited lifespan. While ozone is a seasonal problem that occurs in specific areas, greenhouse gas issues are a global problem that occur over the course of years or decades. Thus, it is not as important to worry about a single-year "spike" in emissions if everybody should save up all of their credits to use at once. The idea would be to reduce greenhouse gas emissions over a long period of time.

One reason for the difficulty in applying a cap-and-trade to greenhouse gases relates to the difficulty of the possible double counting of emission reductions. One method of accounting for greenhouse gas emissions would be the imposition of a "carbon tax" whereby the fuel producers themselves have the obligation for the carbon they produce. Authorizations or allowances would be sold or auctioned to producers of coal, oil, gas, etc., and the cost would be passed down the line giving companies a monetary incentive to reduce fuel usage and thus greenhouse gas emissions. In such a system, the revenues from the carbon auction could be returned to taxpayers to make up for additional costs to their own home energy bills. While the idea may be workable from a theoretical standpoint, it is unlikely to succeed due to political factors. This is especially true in Illinois, as coal would need a higher cost than other fuels due to its higher greenhouse gas emission potential.

Recommendation for Illinois

Illinois has several options of how to focus its efforts in addressing greenhouse gas emissions. A revised Section 1605(b) registry under the National Energy Policy Act should be up and running soon. While the existing voluntary reporting program contains many tons of reductions from questionable projects that may not deserve to receive early action credit, the improved reporting program should, in theory, be better able to guarantee credit for projects or reductions that are registered. Companies interested in participating in the emissions credit markets can also be directed toward the Chicago Climate Exchange. Finally, for a company wanting to establish their baseline for emissions in preparation for future mandatory programs, they could report their emissions to the California registry or even the newly formed Global Greenhouse Gas Registry.

Alternatively, Illinois could create its own system for reporting emissions on an entity basis. The State could create a voluntary system similar to that being developed by California or perhaps one that could require mandatory emissions reporting for large emitters. Given the existence of various pilot efforts around the country, Illinois should monitor those efforts and learn accordingly.

A final option, which is the option we recommend, is to allow the various ongoing projects to come to fruition before deciding to develop yet another system.

Ultimately, a national trading program with a federal mandate appears to be the most effective way to handle the greenhouse gas issue. While various states have their own independent registry at this time, many do not mesh with each other and will probably be superseded should a federal registry be developed. Thus, it is recommended that Illinois delay development of its own independent registry or greenhouse gas trading program and lend its support to a federal cap-and-trade system like the one proposed in the Climate Stewardship Act of 2003.

Chapter 8

Overview of Emission Trading Programs

This Chapter provides an overview of the application and effectiveness of emission trading programs. During the 1990s, as the need for further control measures became clear, the concept of allowing sources to trade with one another in order to achieve the needed emissions reductions was conceived. Traditionally, however, air pollution control rules and regulations have been written as "command and control" requirements. These rules typically require that every operating unit comply with the applicable rule at all times.

One of the first successful emissions trading programs was part of an air pollution control strategy for the emissions of SO_2 and NO_x from power plants, known as the Acid Rain Program, and implemented by the U.S. EPA pursuant to Title IV of the Clean Air Act.

The Illinois trading program for volatile organic materials, known as the Emissions Reduction Market System (referred to as Illinois EPA's VOM trading program), and the federal NO_x SIP Call trading program followed the Acid Rain Program.

This Chapter will describe the types of emissions trading, the benefits of cap-and-trade programs, an overview of Illinois' VOM Trading Program, the Acid Rain Program, the federal NOx Trading Program, and a very brief description of the trading programs in other states.

Types of Emission Trading

There are three primary types of emissions trading that have been used or considered by those interested in providing industry more flexibility in complying with regulatory requirements. They are Open Market, Cap-and-Trade, and Offset Trading.

Open Market trading, which is the least rigorous of the three, not only allows companies to trade in order to meet a reduced emissions cap, but also allows them to trade in order to avoid compliance with existing air pollution control regulations. U.S. EPA and most environmental groups have opposed the use of open market trading. Therefore, it is not generally seen as a viable trading option for a multi-pollutant strategy.

Cap-and-trade programs set a cap on emissions for a defined region or set of emitters. This cap is a number that represents reductions from previous emission levels, thus reducing overall emissions from the participants. Participants must either reduce their emissions or purchase allowances to meet the overall goal.

Offset Trading was developed as part of U.S. EPA's New Source Review program in the late 1990s. Under such programs, new sources or sources with major modifications must, in addition to installing stringent controls, also obtain offsets at increasing levels of multipliers in the form of permanent emission reductions from other sources in the area at set ratios (e.g., 1.1 to 1.0 , 1.2 to 1.0, etc.). While offset trading has been useful in the preconstruction permitting programs for nonattainment areas, it would not be beneficial for a multi-pollutant control program.

<u>Benefits of Cap-and-Trade Programs</u>

A substantial amount of emissions are already controlled nationally and in Illinois by technology-based rules. Further reductions in emissions using such "command and control" measures are potentially very costly to impose on individual industrial sources. Cap-and-trade programs place a limit on the amount that each facility can emit and allow each individual facility to determine how to best achieve those limits. Some companies will modify their processes, some may add control devices, and others will simply keep their operations the same but purchase credits. In this way, the overall emissions to the air from the area are reduced while providing a variety of mechanisms for sources to use in achieving their individual reductions, presumably at the most cost-effective level. This type of source-by-source flexibility is the major benefit for using cap-and-trade programs rather than command and control rulemaking.

The emissions trading program operates by giving each participating source a baseline consistent with their actual emissions in previous years, adjusted for the source's compliance or noncompliance with existing rules. That baseline is then reduced to the necessary level, and a cap is placed on source-wide emissions. The program allows trading (buying and selling) among participating sources in order to meet that cap on their emissions.

Unlike the situation in some open market trading systems, a cap-and-trade system requires that sources still adhere to all other state and federal emission limitations.

<u>Illinois' VOM Trading Program</u>

Illinois EPA's VOM cap-and-trade program allows major sources of VOM in the Chicago ozone nonattainment area to trade "allotment trading units" to ensure that they meet their specified emissions levels.

Illinois EPA's VOM trading program contains a number of features that distinguish it from traditional command and control programs and other market systems:

- Since ozone is a problem in Illinois only during the summer season, Illinois EPA's VOM trading program is seasonal, restricting emissions from May 1 through September 30 when the ground-level ozone problem exists;

- Illinois EPA's VOM trading program puts a cap on sources based on their actual emissions, which provides certainty that it will reduce VOM in the nonattainment area;

- Illinois EPA's VOM trading program goes beyond "Reasonably Available Control Technology" (RACT). Unlike other emissions trading systems across the country, Illinois does not allow sources to avoid other emission limits by participating in the trading program. Sources must comply with the trading program rule *and* all other applicable limits;

- Some trading programs have created trading units with an unlimited life, which allow them to be accumulated for long periods of time. Illinois EPA's VOM trading program rule provides that allowances have a limited two-year lifespan. This helps to ensure a robust market, allows some saving for companies, but prevents excessive accumulation of active trading units with unlimited life;

- Because Illinois EPA's VOM trading program rule is associated with Illinois' Title V permitting program for major sources, known as the Clean Air Act Permit Program (CAAPP), monitoring and record keeping provisions are linked to avoid duplicative efforts for companies and to ensure the use of standardized methods for determining emissions;

- Illinois has created a specific reduction requirement in the VOM trading program rule, requiring most units to reduce VOM emissions by at least 12 percent. This provides Illinois with a specific, creditable VOM reduction in the Chicago ozone nonattainment area; and

- Sources that fail to reduce their emissions or obtain the proper number of allowances are held accountable for their actions as a part of the VOM trading program rule itself. Indeed, such sources are penalized at a higher rate for repeated failure to hold the required allowances. This discourages noncompliance on the part of participating sources and provides Illinois with some certainty that the VOM reductions will be achieved.

Illinois EPA's VOM trading program has achieved and exceeded the desired emissions reductions. In 2002, there was a reduction of 9.7 percent in the allotment compared to the baseline. There was a further reduction of 48.1 percent in emissions compared to what the allotments would have allowed.

More information about the trading program can be found in the 2002 Illinois Emissions Reduction Market System Annual Performance Review Report.

<u>Federal Acid Rain Program</u>

The Acid Rain Program created a national emissions trading program for SO_2 emissions and required reductions in NO_x emission rates from power plants pursuant to Title IV of the 1990 Clean Air Act Amendments. In their report, *"Latest Findings on National Air Quality: 2002 Status and Trends,"* the U.S. EPA states that acid rain data demonstrate the Acid Rain Program's success in reducing harmful SO_2 and NO_x emissions from power plants. According to the data, SO_2 emissions from power plants were 10.2 million tons in

2002, nine percent lower than in 2000 and 41 percent lower than in 1980. NO_x emissions from power plants also continued downward, measuring 4.5 million tons in 2002, a 13 percent reduction from 2000 and a 33 percent reduction from 1990.

According to the U.S. EPA, the Acid Rain Program is on the way to achieving its goal of a 50 percent reduction from 1980 SO_2 emission levels. They note that trading under the program has created financial incentives for electricity generators to look for new and low-cost ways to reduce emissions. The level of compliance under the program continues to be extremely high, with U.S. EPA estimating the level to be over 99 percent, and allowance prices have generally been much lower than originally anticipated. Refer to http://www.epa.gov/airmarkets/arp/ for additional information on the Acid Rain Program and allowances.

NO_x Trading Program

To allow for use of the most cost-effective emission reduction alternatives, an emission budget trading program is an important component of the federal NO_x SIP Call, which was issued by U.S. EPA on October 27, 1998 (63 *Fed.Reg.*57356) (*See* endnote 8). Each of the states subject to the NO_x SIP Call are encouraged to participate in the NO_x Budget Trading Program, thereby providing a mechanism for sources to achieve cost-effective NO_x reductions. The trading unit, a NO_x allowance, is equal to one ton of emitted NO_x.

Under the NO_x Budget Trading Program that began full implementation in May 2004, each of the participating states determines how its ozone season state trading program budget is allocated among its sources. Each source is given a certain quantity of NO_x allowances. As with other cap-and-trade programs, if a source's actual NO_x emissions exceed its allocated NO_x allowances, the source may purchase additional allowances. Conversely, if a source's actual NO_x emissions are below its allocated NO_x allowances, it may sell the additional NO_x allowances. Such a program creates a competitive market for NO_x allowances and encourages use of the most cost effective and efficient means for reducing NO_x emissions. Trading may occur among any of the sources within the entire NO_x SIP Call region.

Programs in Other States

Illinois EPA's VOM trading program is the first successful cap-and-trade system in the United States for VOM and is currently the only existing U.S. EPA-approved cap-and-trade VOM reduction program in the country. However, there have been several other attempts made at trading programs by other states:

> **Michigan** currently has a voluntary open market statewide emissions trading program that covers VOM, NO_x and carbon monoxide. As of the end of 2001, the Michigan Department of Environmental Quality indicated that creation of allowances had far outpaced their use, which would be expected in a voluntary program.

The **South Coast Air Quality Management District (SCAQMD) of California** began NO_x trading in the "RECLAIM" program in 1994. It covers all sources in the area with emissions greater than four tons per year. Starting in 1994, allocations reduced gradually each year until 2003. Future allocations are expected to remain stable at the 2003 level. As the number of allocations has been reduced, the price of allowances has increased. RECLAIM does not allow banking and has several complicating features due to the local geography and weather patterns.

The **Houston/Galveston area of Texas** has a year-round NO_x cap-and-trade program for all sources in the eight-county area that emit 10 or more tons of NO_x per year. The program is similar to Illinois EPA's VOM trading program in that allocations were based on previous years of operation, new sources receive no allocations and allowances can be banked for one year if not used.

Summary

In general, cap-and-trade programs can be effective tools to meet air pollution requirements if the programs are carefully designed and operated, while also providing sources with an opportunity to seek the most cost-effective compliance option. The federal Acid Rain Program, the NO_x Trading Program and Illinois' VOM trading program are all examples where cap-and-trade programs were well designed, and provide sources with a market that allows for them to make the most cost-effective compliance decisions.

Chapter 9

Costs and Market Impacts of Power Plant Emission Reduction Proposals

The General Assembly made clear that the Agency must consider the effect of any state action on costs – both from the compliance perspective as well as to the consumer. This Chapter summarizes what we know today about the potential costs that Illinois power generators could experience with several of the proposed national multi-pollutant programs, as well as preliminary cost analyses of the proposed U.S. EPA Clean Air Interstate Rule prepared on behalf of the Illinois Energy Association.

This Chapter also briefly describes potential impacts of a state-specific proposal on electric rates, Illinois' coal jobs, and power generator jobs in Illinois. Based on the following information and analyses, we draw some conclusions and recommend a general course of action to better understand these important potential impacts.

National Multi-Pollutant Bill Proposals

As explained in Chapter 4, the primary national multi-pollutant bills before Congress are the Bush Administration's Clear Skies Act, Senator James Jeffords' (I-VT) Clean Power Act of 2003 (Jeffords Bill), and Senator Thomas Carper's (D-DE) Clean Air Planning Act of 2003 (Carper Bill). As summarized in Table 9-1, the U.S. EPA has made estimates of the national costs and benefits associated with each of these bills. The Energy Information Agency (EIA) has also provided analyses of each bill's cost.

U.S. EPA's Clear Skies website outlines an extensive assessment of costs for their proposal as noted in Table 9-1 below. For the cost analyses prepared by U.S. EPA of both the Carper and Jeffords Bills, U.S. EPA used simplified approaches to provide information comparing the different multi-pollutant scenarios. It is important to emphasize these estimates are those of U.S. EPA. U.S. EPA clearly favors the proposal introduced by its own Administration, the Clear Skies Proposal.

Table 9-1
Summary of the U.S. EPA's Cost Estimate of Various National Bills

	Clear Skies	**CAPA (Carper)**	**CPA (Jeffords)**
Annual Costs			
2010	$4.3 Billion	$6.6 Billion	$16.5 Billion
2015	-	-	$17.0 Billion
2020	$6.3 Billion	$9.9 Billion	-
Cumulative Costs			
2005-2030	$52.5 Billion	$82.7 Billion	"Greater"
Electricity Price Increase			
2010	"Small"	4%*	39%
2015	"Small"	-	50%
2020	-	3%*	-

*Significantly higher cost if power plants would have to directly reduce to meet carbon dioxide targets.

According to U.S. EPA, the costs associated with the proposals are very different. U.S. EPA's analyses project that both the Carper and the Jeffords Bills would cost significantly more than the Clear Skies Act.

Clear Skies is the only national bill for which U.S. EPA has made individual state estimates of the cost and benefits. This assessment for Illinois is that Clear Skies will cost $496 million per year beginning in 2020

Federal Clean Air Interstate Rule (CAIR)

U.S. EPA performed an economic and energy impact analysis of the proposed CAIR discussed in Chapter 4. U.S. EPA used the Integrated Planning Model, developed by ICF Consulting, to conduct their analyses.

Because U.S. EPA started its economic analyses before it determined which states the proposed CAIR affected, the final estimates covered a slightly different region than the region actually covered by the rulemaking. The analysis covers the electric power industry, which is a major source of SO_2 and NO_x emissions nationwide, and the industry that U.S. EPA proposes to control in the proposed CAIR cap-and-trade program. Since almost all of the SO_2 emission reductions occur in the proposed region, the larger modeling region still provides a very good estimate of the impacts the SO_2 reductions will have on the smaller proposed region.

For NOx, the caps modeled for this region are very close to those proposed in the CAIR, and U.S. EPA believes that this modeling provides a very good estimate of the impacts the NO_x reductions will have on the proposed region. For the proposed region, U.S. EPA projects that the annual incremental costs of the proposed CAIR are $2.9 billion in 2010, $3.7 billion in 2015 and $4.9 billion in 2020. This represents a 4.5 percent increase in production cost in 2010 and a 5.1 percent increase in 2015 over the base case, which assumes no further pollution requirements on the industry beyond what exists as of March 2002. The cost of electricity production represents roughly 1/3 to 1/2 of total electricity costs with transmission and distribution costs representing the remaining portion.

According to U.S. EPA, the proposed CAIR is projected to require the installation of an additional 63 gigawatts of flue gas desulfurization (scrubbers) on existing capacity for SO_2 control and an additional 46 gigawatts of Selective Catalytic Reduction (SCR) on existing capacity for NO_x control by 2015. The first phase of the proposed CAIR will result in 49 gigawatts of additional scrubbers and 24 gigawatts of SCR by 2010. Most of the NO_x reductions achieved in the first phase of the rule can be attributed to the large pool of existing SCRs that are used during the ozone season in the NO_x SIP Call region that, for relatively little additional cost, can run year-round.

Table 9-2 shows U.S. EPA's projected reductions in SO_2 and NO_x emissions by control option and the associated costs of those reductions in 2015. Some reductions are due to switching to western coal; however, the reductions required by the proposed CAIR must be achieved through the installation of significant pollution controls. For SO_2, most reductions are achieved through new scrubbers, with a small amount of coal switching to lower sulfur sub-bituminous coal or shifts in generation. For NO_x, existing SCRs account for a considerable portion of the reductions with most of the remaining reductions achieved through new SCRs.

Table 9-2
Approximate Regional Emissions Reductions and Incremental Costs by Control Option for the Proposed CAIR from the Base Case (No Further Controls) in 2015

	SO_2 (thousand tons)	NO_x (thousand tons)	Cost (million $1999)
New SCR	-	784	884
New Scrubber	2,958	-	2,370
Annual Use of Existing SCR	-	890	156
Fuel Switching and Generation Shifts	713	39	332
Total	3,671	1,713	3,742

The use of a scrubber and SCR to control emissions of SO_2 and NO_x, respectively, can lead to reductions in mercury emissions. Mercury emissions are projected to decrease to 34 tons in 2010, 22 tons in 2015 and 15 tons in 2020 as a result of the projected scrubber and SCR controls installed on affected units.

It is important to note that U.S. EPA[31] determined that the $3.7 billion annual total social cost to reduce SO_2 and NO_x beginning in 2015 is offset by the $83.8 billion of annual social benefits. Stated another way, there is over $22 of benefit for every $1 of cost. However, it is necessary to consider that the U.S. EPA clearly stated that they did not quantify and monetize all benefits or disbenefits.

U.S. EPA's Mercury Reduction Proposal

A similar cost analysis using the Integrated Planning Model was performed by the U.S. EPA for the Proposed Rule for Fossil fuel-fired Electric Generating Unit (EGU) Maximum Achievable Control Technology (MACT) Standard (EGU MACT Rulemaking). (*See* Chapter 4) This analysis is provided for review in Table 9-5.

Mercury emissions from coal-fired power generators were estimated by U.S. EPA to be 48 tons in 1999. U.S. EPA has projected under its Base Case that mercury emissions from the power generation sector will be further reduced in the coming years due to the NO_x SIP Call and Acid Rain Program. U.S. EPA projects that additional SCR (about 90 gigawatts by 2010) and scrubbers (about 14 gigawatts by 2010) will be installed to meet these program requirements and these installations will also reduce mercury emissions.

Total annual costs of the proposed MACT program, according to U.S. EPA, are projected to be $1.6 billion in 2010 and $1.1 billion in 2020. These costs represent about a 1.9 percent increase in 2010 and 1.1 percent increase in 2020 of total annual electricity production costs.

The lower cost of the MACT program in 2020 stems from total fuel costs being lower than those in the Base Case. As in 2010, coal use reflects a shift away from bituminous and toward sub-bituminous and lignite coal, relative to the Base Case. In addition, there is fuel switching among bituminous coals. Projections for 2010 and 2020 differ in the sulfur content and cost of the bituminous coals that are being displaced. In 2020, the shift is projected to be away from less-expensive, high-sulfur bituminous coals. By 2020, the decrease in bituminous coal use is projected to be toward the more-expensive, lower sulfur coals, which leads to a decrease in the overall fuel costs. Also, while the proposed MACT rule is expected to result in a very slight increase in gas prices in 2010, by 2020 this effect is largely attenuated.

According to U.S. EPA's analysis, by 2020, nationwide retail electricity prices are expected to be 0.2 percent higher with the mercury MACT proposal. In the region that includes Illinois, electricity prices with the mercury MACT are projected to be 0.5 percent higher in 2020.

Preliminary Draft of Economic Analysis of CAIR in Illinois

Included in this report in the following section are the preliminary draft results of an economic analysis, prepared on behalf of the Illinois Energy Association, of the costs of the U.S. EPA's CAIR proposal on Illinois' power plants and the costs of a state-specific proposal that mimicked the emission reduction targets and timing of CAIR. Due to the uncertainty that still exists at the federal level, the only cost analyses performed to address these considerations to date are preliminary, and were commissioned by the power generators.

This draft study predicts, for the national CAIR proposal, higher costs than CAIR for Illinois' power generators, and significantly higher costs for a state-specific CAIR approach. In most states, the cost of CAIR, Clear Skies or other proposals would likely be passed onto ratepayers by the utility, which also owns the power plants. Although this information is being included in this report, Illinois EPA must note again that this is not its study. The information is being included to present one perspective, that of the power industry, on possible economic impacts from CAIR and a state-specific application of CAIR.

The economic assessment is being conducted by James Marchetti, Inc., on behalf of the Illinois Energy Association, of the compliance costs of the U.S. EPA's proposed CAIR rule and the mercury cap-and-trade rule for Illinois' power generators. (*See* Chapter 4 for more discussion on CAIR.) The stated purpose of this analysis is to determine the costs for Illinois generators to comply with the U.S. EPA's CAIR rule and their proposed mercury cap-and-trade requirements. A second analysis is being undertaken to determine the costs for Illinois to comply with the limits of the CAIR rule entirely within Illinois, without the benefit of a regional trading program.

According to Marchetti, the initial modeling of the economic impacts to Illinois power generators of CAIR and the mercury cap-and-trade rule under section 111(d) of the Clean Air Act focused on determining the compliance costs to Illinois power generators of meeting the targets and timetables of the U.S. EPA's proposed CAIR and the version of the Mercury Reduction Rule that allows for a cap-and-trade regime to control mercury. Under the preliminary draft of this analysis shared with Illinois EPA, under this proposed regulatory regime, Illinois power generators would be allowed to trade SO_2 and NO_x allowances within a 28-state CAIR region and mercury allowances nationally. This evaluation used the Emission-Economic Modeling System (EEMS). EEMS identifies a combination of compliance options (i.e., control technology or allowance trading) that approximates the least cost solution for a given power generation facility system. The EEMS database was updated for these analyses using Energy Information Association data and data provided through interviews with power generators to reflect changes in operation (e.g., retire/repowering/fuel switching) and control technology deployments.

Illinois power generation facilities will have to reduce their current SO_2, NO_x and mercury emissions by more than 60 percent to attain the reduction targets outlined in both CAIR and the mercury cap-and-trade rule. The CAIR analysis indicates that states will have a little more flexibility in the allocation of NO_x allowances to units within their borders. Under the current Illinois NO_x rules, a "new" unit becomes classified as an existing unit as control periods move forward. Illinois' NO_x budget in the 28-State CAIR region is 73,622 tons in 2010 through 2014, and 61,352 tons in 2015 and thereafter. The mercury cap-and-trade rule specifies that the 2010 cap for mercury should be set at a level that can be achieved through the installation of SCR controls and flue gas desulfurization devices (scrubbers) needed to meet the 2010 NO_x and SO_2 caps for the CAIR. The 2018 national mercury cap of 15 tons per year is the same as the Bush Administration's Clear Skies proposal. The Base Case SO_2 and NO_x emission forecast for all affected units was based on the assumptions that these units would have to comply with both the federal Acid Rain Program requirements and the NO_x SIP Call requirements.

The Marchetti simulation also took into account future technology deployment and fuel switches planned by Illinois power generators to meet the above regulatory regimes. Assumptions defining the cost and performance of NO_x, SO_2 and mercury control technologies were adopted by Marchetti that reflect experience from operating units as well as those extracted from the public literature. Mercury compliance involved the utilization of EEMS to achieve system-wide NO_x, SO_2 and mercury emission caps for the years 2010 – 2020 at the least possible cost. The system caps were a summation of unit allowances, based upon the allowance allocation system. Under both CAIR and the mercury regulatory regime, power generators were allowed to trade allowances. In addition, all banked Acid Rain Program SO_2 allowances through 2009 could be carried forward on a one-to-one basis to meet the reduction targets of the CAIR. By the end of 2003, Illinois power generators had 5.4 gigawatts of SCR and 1.0 gigawatt of scrubbers operating on their coal-fired units. However, the model predicted that by 2009, 14.4 gigawatts or 84.1 percent of the State's current coal-fired capacity of 17.0 gigawatts will be burning low sulfur sub-bituminous coal, with SO_2 emission rates of 0.7 lbs/mmBtu, or less.

In order for Illinois power generators to meet the CAIR reduction targets for SO_2 in 2010 and 2015, the Marchetti model indicated that they would have to install approximately 1.1 gigawatts of scrubbers, while no power generators would switch to a lower sulfur coal for compliance. The preliminary Marchetti analysis identified three important factors affecting compliance with CAIR in Illinois between 2010 and 2020:

- Sizeable carry-over of banked Acid Rain Program SO_2 allowances (through 2009) that would defer technology deployment and/or allowance purchases;

- 84.1 percent of the state's coal-fired capacity will be burning western, sub-bituminous coal; and

- The aging of some of Illinois' existing coal-fired capacity.

More specifically, Marchetti found that Illinois power generators would carry forward almost 890,300 Acid Rain Program SO_2 allowances, which can be used to meet the CAIR SO_2 caps. To meet the NO_x caps, Illinois power generators would have to install 75 megawatts of SCR and 280 megawatts of Selective Non-Catalytic Reduction Technology (SNCR). However, the 5.4 gigawatts of existing SCR capacity would operate year round in meeting the NO_x reduction targets of CAIR. Unlike CAIR, where SO_2 and NO_x compliance is heavily dependent on allowance purchases, Marchetti modeled compliance under the mercury cap-and-trade program which will result in 10 gigawatts or almost 60 percent of the State's existing coal-fired capacity (17.0 gigawatts) installing some kind of mercury removal technology. To comply with CAIR and the mercury cap-and-trade reduction targets, Marchetti's belief, based on preliminary results, is that Illinois power generators will have to expend $4.2 billion in compliance costs between 2010 and 2020, inclusively. This will equate to an annual cost of approximately $382 million to comply with CAIR and the mercury MACT.

The second economic analysis being conducted by Marchetti evaluated the implications to Illinois power generators of meeting the same targets and timetables as the previous analysis, but with emissions trading being restricted to within the State of Illinois. Again, under this analysis CAIR/Mercury MACT compliance involved the utilization of EEMS to evaluate the cost of achieving system-wide NO_x, SO_2 and mercury emission caps for the years 2010 – 2020 at the least possible cost. Under this regulatory regime, power generators were allowed to trade allowances only within the State of Illinois. In addition, all banked Acid Rain Program allowances through 2009 could be carried forward on a one-to-one basis to meet the reduction targets of the CAIR. This simulation evaluated a State-specific emission market.

The Marchetti model assumed that by the end of 2003, Illinois power generators had 5.4 gigawatts of SCR and 1.0 gigawatt of scrubbers operating on their coal-fired units. It also assumed by 2009, 14.4 gigawatts or 84.1 percent of the State's current coal-fired capacity of 17.0 gigawatts will be burning low sulfur sub-bituminous coal with SO_2 emission rates of 0.7 lbs/mmBtu or less. In addition, Illinois power generators will have almost 890,300 Acid Rain Program SO_2 allowances banked at the end of 2009, which can be used to meet the CAIR reduction targets. For Illinois power generators to meet the SO_2 CAIR reduction targets in 2010 and 2015, in which allowance trading is restricted to Illinois-only, the model predicted they would have to install approximately 8.6 gigawatts of scrubbers, while 334 megawatts would switch to a lower sulfur coal for compliance. Of this total incremental scrubber capacity, 6.3 gigawatts or 73.2 percent will not be installed until 2014 or thereafter.

The primary factor that affects this deferred scrubber deployment, even under this restrictive trading regime, according to Marchetti at this stage of the analysis, is the sizeable Acid Rain Program bank, which does not begin to be significantly drawn down until 2014. Under these same trading restrictions for NO_x, Illinois power generators would install 4.7 gigawatts of SCR technology and 6.7 gigawatts of SNCR technology. In addition, the 5.4 gigawatts of existing SCR technology capacity would operate year round in meeting the NO_x reduction targets of CAIR. Compliance under the mercury MACT cap-and-trade capacity (17.0 gigawatts) would be achieved by installing some kind of mercury removal technology.

According to the preliminary draft of this analysis, the level of coal-fired units requiring major control technology retrofits increases significantly between the two regulatory regimes. This increase is precipitated by the restrictive Illinois-only trading regime, which forces power generators to install technology in order to meet the statewide caps. To comply with CAIR and mercury cap-and-trade reduction targets with Illinois-trading only, Illinois power generators between 2010 and 2020, inclusively, will have to expend $4.8 billion in compliance costs. This would equate to an annual cost of $480 million or 20 percent greater than the cost of complying with these rules as part of the regional program for 28 states and District of Columbia.

Potential Impact to Jobs

Coal Mining Jobs

The state's coal producers and miners have struggled for survival despite a complex series of events that have forestalled a long-awaited revival in the coal fields of Illinois. At the end of 2003, coal production in Illinois totaled 31.1 million tons, down more than 2.3 million tons from 2002. Twenty mines continued to operate in an area stretching south nearly to the tip of Illinois from Danville on the east and Logan and McDonough counties in central Illinois. However, the erosion of employment and tonnage, dating back to the Clean Air Act Amendments of 1990, continued with the closing of the Rend Lake Mine in

Jefferson County (1,682,614 tons) and Illinois Fuels I-1 Mine in Saline County (529,982 tons).

The loss of coal mines and coal mining jobs negatively impacted the economic structure of southern Illinois. Although mining salaries doubled between 1980 and 2003, from $22,000 per year to $45,500 per year, the total economic payroll of the mining industry to the State of Illinois decreased by 60 percent during the same time period (Table 9-3).

Table 9-3
The Economic Impact of the Loss of Coal Mining Jobs in Illinois

	1980	**1990**	**2003**
Mining Industry Employment	18,284	10,129	3,534
Production (million tons mined / year)	62.5	61.6 mil	31.1
Average Mining Industry Yearly Salary	$22,000	$35,000	$45,500
Total Payroll	$402,248,000	$354,515,000	$160,797,000

Source: Department of Mines and Minerals 2004. *Annual Statistical Report 2003*. Illinois Coal Association. *Illinois Census 1980, 1990, and 2003*.

At no time in its history, however, has the Illinois coal industry confronted so many threats to its survival. Lower priced, lower-sulfur coals, primarily from the Powder River Basin (PRB) of Wyoming, continue to make inroads in midwestern and eastern power plant markets. Two of Illinois' largest in-state coal burners – the Edwards Power Station at Bartonville and the Duck Creek Power Station at Canton – have tested PRB coal and were leaning heavily toward a fuel switch. The cost could be two million tons of Illinois coal and the more than 200 jobs that go with it. Moreover, the regulatory climate concerning Illinois coal remained uncertain with the shelving of the proposed Federal Energy Bill and the mixed signals sent by U.S. EPA's controversial mercury reduction standards that would have served to benefit PRB coal, again at the expense of coal mined here in Illinois.

Power Industry Jobs

Although not specifically requested in Section 9.10, Illinois EPA believes a job impacts analysis must be performed in light of the absence of information on the effects of a state-specific multi-pollution strategy on the job market in Illinois.

According to industry estimates, there are approximately 4,100 jobs directly involved in running Illinois power plants. The payroll and benefits for these employees amount to approximately $700 million a year. The service and skilled labor force associated with the power plants adds approximately 6,000 more jobs. The approximate value of goods and services purchased locally and related to these jobs is over $300 million. Illinois' coal-fired power plants pay nearly $21 million a year in property taxes to local taxing bodies, the majority of which goes to support local school systems. A further consideration is the impact that would be felt by the 5,500 or so retirees from these plants whose benefits, including healthcare, could be affected.

Stricter pollution control requirements will undoubtedly have a ripple effect on jobs throughout the power industry and on those jobs that depend indirectly on the viability of the industry. U.S. EPA determined that there would be a vast improvement in the job market for boilermakers under their Clean Air Interstate Rule. Likewise, suppliers of pollution control equipment and other related goods and services will also see an increased demand for their products. The influence on those jobs directly related to the operation of the power plant is less certain.

The major restructuring of the power industry in Illinois is having a negative impact on the job market. A critical part of the power industry's response to restructuring is to reduce the costs of producing electricity in order to allow the companies to remain competitive in the regional and national power markets. This, of course, is part of the purpose of the competitive forces that deregulation promotes. Already, some Illinois companies have reduced their workforce by 20 percent.

Illinois EPA will work with the Department of Commerce and Economic Opportunity to retain the experts that can work with the Illinois EPA to analyze the impacts of any further regulation on the economy of Illinois and Illinois jobs once the national direction is clear.

Impact on Electric Rates

The determination of the costs of pollution control programs on retail electric rates is a difficult process that is made even more difficult by Illinois' transition to a deregulated power market. The Illinois EPA reviewed the available information on the impact of the various national proposals on electricity costs, most notably the work of U.S. EPA for the Clear Skies and Clean Air Interstate Rule as discussed earlier in this Chapter.

The effort to obtain reliable estimates of the future of rates is difficult even without adding the complexity of additional pollution control programs. This effort has been complicated by the state of flux in Illinois' electric supply market due to the shift from a traditional, utility owned and operated, and highly regulated power generation system, to an increasingly deregulated power generation market. One of the major pieces of this shift will occur after December 31, 2006, when the cap or freeze on retail rates will be lifted.

Illinois is undergoing the transition to become a deregulated state for electric power, although restructuring is not yet complete. As a result of this market restructuring, most coal-fired power plants in the State now are owned by independent power producers, which are not affiliated with Illinois utilities or by non-utility, generation affiliates of Illinois utilities. This deregulation has brought about the expansion of regional power transmission organizations through which power generators are more easily and efficiently able to sell their power across state lines. As a result, Illinois' power generators now compete with generators in several surrounding and nearby states. The competitors for Illinois generation are typically utilities in states that have not restructured their markets.

Most of the available information on the impact of new pollution control strategies electricity costs is based on U.S. EPA's assessment of the Bush Administration's proposed Clear Skies Act, and U.S. EPA's proposed Clean Air Interstate Rule. U.S. EPA concluded that the costs of its Clean Air Interstate Rule to Illinois and the MAIN power region would increase 2010 rates by approximately 2.5 percent to 3.5 percent over the inflation adjusted rates that would otherwise occur without further pollution controls. However, for Illinois, U.S. EPA assumed that there is a competitive wholesale market for electricity due to deregulation. This competition in wholesale markets has not materialized to any significant degree, such that 2006 power purchase agreements assume no increase in competition in wholesale markets.

Further work needs to be done in this vital area of costs and retail electric rates. Currently, how the costs of these multi-pollutant proposals will affect competition and consumer rates in a state that is entering full deregulation are not known. But we know that compliance costs will ultimately be reflected in electric and very likely natural gas rates. Concern exists that if competition among suppliers of electricity is not robust, power prices will not remain at reasonable levels. As California's experience in 2000 and 2001 has shown, if competition among electric suppliers fails to take hold, the price rise could be significant.

Whether robust competition occurs in 2007 in Illinois will depend on the degree to which competitive forces create an effectively functioning wholesale and retail supply market. If Illinois generators are encumbered with state-specific regulations that their out-of-state competitors are not, these generators will incur additional costs that cannot be recovered from utility ratepayers and these generators will face a competitive disadvantage in regional power transmission organizations. An increase in electric and gas rates will drive greater interest in and implementation of renewable energy and energy efficiency projects. However, the degree to which Illinois is poised to increase its production of renewable energy and the price points for power generation at which a significant increase in renewable energy production will occur is not known.

The impact on competition and on rates through a state-specific program has not been evaluated. However, this analysis must be a part of the overall review of Illinois' deregulated market post-2006. Without a resource and transmission planning model that would include detailed production cost information for Illinois and the surrounding interconnect, we cannot determine which specific Illinois generation plants might be closed due to the costs of more stringent pollution controls and how electric rates might be affected.

<u>Conclusion</u>

Illinois EPA believes that independent, full and complete economic assessments should be performed on the full economic impacts in Illinois of the final CAIR proposal, the Mercury Reduction Rule, the Carper and Jeffords Bills, and any others that surface in the next several months. The impact to Illinois' coal jobs and power industry jobs must be fully understood. Certainly, with the deregulated electricity market that exists in Illinois, the cost impacts on generation and, ultimately, to Illinois citizens and businesses needs to be fully understood. Such assessments can only be properly performed once certainty exists at the federal level. These cost analyses will be vital in fully assessing the appropriate timing and scope of additional emission reductions from power plants in Illinois.

List of Appendices, Figures and Tables

Appendices

Tables

Figures

Acronyms

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CAAPP	Clean Air Act Permit Program
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
EGU	Electric Generating Units
EIA	Energy Information Administration
ERMS	Emissions Reduction Market System
Hg	Mercury
HAP	Hazardous Air Pollutant
IGCC	Integrated Gasification Combined-Cycle
Illinois EPA	Illinois Environmental Protection Agency
kWhr	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
MACT	Maximum Achievable Control Technology
mmBtu	Million British Thermal Units
MW	Megawatts
N_2	Nitrogen Gas
NAAQS	National Ambient Air Quality Standards
NEPD	National Energy Policy Development
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
$PM_{2.5}$	Particulate Matter 2.5 microns in diameter
PM_{10}	Particulate Matter 10 microns in diameter
ppb	Parts per billion
ppm	Parts per million
PSD	Prevention of Significant Deterioration
SNCR	Selective non-catalytic reduction
SIP	State Implementation Plan
SNR	Selective non-catalytic reduction
SO_2	Sulfur Dioxide
TPD	Tons Per Day
U. S. DOE	U.S. Department of Energy
U.S. EPA	United States Environmental Protection Agency
VOM	Volatile Organic Material

[1] Christine Todd Whitman, testimony on the Clear Skies Act before the U.S. Senate Environment and Public Works Committee. April 8, 2003.

[2] National Research Council. "Toxicological Effects of Methyl mercury". Committee on the Toxicological Effects on Methyl mercury Board and National Academy Press, Washington, D.C., 2000.

[3] ABT Associates, Inc. Particulate-Related Health Impacts of Eight Electric Utility Systems. April 2002.

[4] U.S. EPA. *The Clear Skies Act of 2003. Illinois and Clear Skies*. http://www.epa.gov/air/clearskies/state/il.html.

[5] U.S. EPA. *Control Techniques for Sulfur Oxide Emissions from Stationary Sources* (EPA-450/3-81-004). Office of Air Quality Planning and Standards. April 1981.

[6]Electric Power Research Institute, U.S> Dept. of Energy and U.S. EPA. *Combined Utility Air Pollutant Control Symposium, The Mega Symposium SO_2 Control Technologies and Continuous Emission Monitors* (TR-108683-V2). August 1997.

[7] U.S. EPA. *Alternative Control Techniques Document – NOx Emissions from Utility Boilers* (EPA-453/R-94-023). Office of Air Quality Planning and Standards. March 1994.

[8] In October 1998, U.S. EPA issued a rulemaking that found that EGUs (in 22 states and the District of Columbia) emit NO_x in amounts that significantly contribute to nonattainment of the 1-hour ozone standard in one or more downwind states, and issued a call for revisions to the state implementation plans to address these contributions. As part of that rulemaking, U.S. EPA developed a federal NO_x Trading Program that applied to EGUs and certain large industrial boilers in the affected states to allow for the most cost-effective compliance options to be utilized. (*See* 63 *Fed. Reg.57356*, October 27, 1998).

[9] STAPPA/ALAPCO Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options. July 1994.

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[14] Illinois Clean Coal Institute. Final Technical Report: Correlate Coal/Scrubber Parameters with Hg Removal and Hg Species in Flue Gas/96-1/2.UA-2). September 1, 1996, through August 31, 1997.

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[16] The WRAP states consist of Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah and Wyoming.

[17] The Clean Planning Act of 2003 (CAPA) was introduced as S. 843 on April 9, 2003 by Senator Thomas Carper (D-DE) and in the House as H.R. 3093 on September 19, 2003 by Congressman Charles Bass (R-NH).

[18] The Clean Power Act of 2003 (CPA) was introduced as S. 366 on February 12, 2003 by Senator James Jeffords (I-VT).

[19] The Clean Smokestacks Act of 2003 was introduced as H.R. 2042 on May 8, 2003 by Congressman Henry Waxman (D-CA).

[20] Report of the National Energy Policy Development Group. *National Energy Policy*, U.S. Government Printing Office (ISBN 0—16-050814-2), May 2001. http://www.whitehouse.gov/energy/National-Energy-Policy.pdf

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26 Midwest CHP Application Center, *BCHP Baseline Analysis for Illinois Market 2002 UPDATE*, University of Illinois at Chicago Energy Resource Center, Chicago, IL, August 2002.

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[30] Environmental Law and Policy Center. Repowering the Midwest*. 2001. http://www.repowermidwest.org*.

[31] U.S. EPA. *Benefits of the Proposed Inter-State Air Quality Rule* (EPA-452/03-001). Office of Air Quality Planning and Standards. January 2004.

APPENDIX A

2002 Annual Data

For

Fossil Fuel-Fired

Electrical Generating Units

In Illinois

2002 Annual Data For Illinois EGUs

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
1	000889	Baldwin	157851AAA	1	**623**	Coal	43,883,642	9053	12119	4502460	0.55	0.41
2	000889	Baldwin	157851AAA	2	**635**	Coal	37,134,739	7283	7405	3810021	0.40	0.39
3	000889	Baldwin	157851AAA	3	**602**	Coal	46,402,730	9931	2850	4760923	0.12	0.43
4	000861	Coffeen	135803AAA	01	**389**	Coal	18,569,744	14008	4745	1905255	0.51	1.51
5	000861	Coffeen	135803AAA	02	**616**	Coal	37,545,026	28323	9594	3852118	0.51	1.51
6	000867	Crawford	031600AIN	7	**240**	Coal	11,626,898	3142	1187	1192922	0.20	0.54
7	000867	Crawford	031600AIN	8	**358**	Coal	17,347,866	4453	1663	1779892	0.19	0.51
8	000963	Dallman	167120AAO	31	**80**	Coal	4,528,281	772	2498	464597	1.10	0.34
9	000963	Dallman	167120AAO	32	**80**	Coal	4,787,079	816	2640	491150	1.10	0.34
10	000963	Dallman	167120AAO	33	**205**	Coal	13,274,189	1831	2892	1361463	0.44	0.28
11	006016	Duck Creek	057801AAA	1	**416**	Coal	22,635,088	11026	5328	2322122	0.47	0.97
13	000856	Edwards Station	143805AAG	1	**136**	Coal	6,416,602	11399	1306	651130	0.41	3.55
14	000856	Edwards Station	143805AAG	2	**281**	Coal	17,222,007	14666	3901	1771396	0.45	1.70
12	000856	Edwards Station	143805AAG	3	**364**	Coal	15,971,436	9683	3639	1604354	0.46	1.21
15	000886	Fisk	031600AMI	19	**374**	Coal	14,649,555	3843	2462	1503046	0.34	0.52
16	000891	Havana	125804AAB	9	**429**	Coal	28,513,578	12815	3901	2919450	0.27	0.90
17	000892	Hennepin	155010AAA	1	**75**	Coal	4,684,352	1008	762	480620	0.33	0.43
18	000892	Hennepin	155010AAA	2	**231**	Coal	17,575,289	3784	2859	1803245	0.33	0.43
19	000863	Hutsonville	033801AAA	05	**78**	Coal	3,160,847	7163	897	324303	0.57	4.53
20	000863	Hutsonville	033801AAA	06	**78**	Coal	3,442,889	7792	902	353240	0.52	4.53
21	000384	Joliet 29	197809AAO	71	**330**	Coal	15,034,236	5264	879	1542510	0.12	0.70
22	000384	Joliet 29	197809AAO	72	**330**	Coal	13,824,017	4840	808	1418342	0.12	0.70
23	000384	Joliet 29	197809AAO	81	**330**	Coal	15,585,483	5311	1067	1599072	0.14	0.68
24	000384	Joliet 29	197809AAO	82	**330**	Coal	15,403,146	5249	1055	1580364	0.14	0.68
25	000874	Joliet 9	197809AAO	5	**360**	Coal	14,368,937	4560	2562	1474252	0.36	0.63
26	000887	Joppa Steam	127855AAC	1	**183**	Coal	13,547,956	3446	874	1389886	0.13	0.51
27	000887	Joppa Steam	127855AAC	2	**183**	Coal	16,256,930	4135	1049	1667800	0.13	0.51
28	000887	Joppa Steam	127855AAC	3	**183**	Coal	15,395,686	3975	1034	1578891	0.13	0.52
29	000887	Joppa Steam	127855AAC	4	**183**	Coal	13,401,870	3460	900	1374417	0.13	0.52
30	000887	Joppa Steam	127855AAC	5	**183**	Coal	15,093,451	3930	939	1548600	0.12	0.52
31	000887	Joppa Steam	127855AAC	6	**183**	Coal	16,062,809	4183	999	1648057	0.12	0.52

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
32	000876	Kincaid	021814AAB	1	**660**	Coal	32,264,830	8836	10457	3310371	0.65	0.55
33	000876	Kincaid	021814AAB	2	**660**	Coal	32,238,113	8829	10448	3307630	0.65	0.55
34	000964	Lakeside	167120AAO	7	**38**	Coal	1,001,318	2783	469	102726	0.94	5.56
35	000964	Lakeside	167120AAO	8	**38**	Coal	1,593,064	4428	746	163434	0.94	5.56
36	000976	Marion	199856AAC	1	**33**	Coal	1,043,046	2522	426	100444	0.82	4.84
37	000976	Marion	199856AAC	2	**33**	Coal	203,706	493	83	19617	0.82	4.84
38	000976	Marion	199856AAC	3	**33**	Coal	1,420,902	3354	736	145029	1.04	4.72
39	000976	Marion	199856AAC	4	**173**	Coal	12,935,289	2626	5457	1364004	0.84	0.41
40	000864	Meredosia	137805AAA	01	**34**	Coal	1,133,979	2846	288	116346	0.51	5.02
41	000864	Meredosia	137805AAA	02	**34**	Coal	1,336,982	3355	339	137174	0.51	5.02
42	000864	Meredosia	137805AAA	03	**34**	Coal	1,069,118	2683	271	109691	0.51	5.02
43	000864	Meredosia	137805AAA	04	**34**	Coal	1,406,308	3529	357	144287	0.51	5.02
44	000864	Meredosia	137805AAA	05	**240**	Coal	10,810,415	12639	2524	1109146	0.47	2.34
45	006017	Newton	079808AAA	1	**617**	Coal	40,631,096	9046	3037	4168749	0.15	0.45
46	006017	Newton	079808AAA	2	**650**	Coal	38,533,185	8823	2215	3953506	0.11	0.46
47	000879	Powerton	179801AAA	51	**447**	Coal	20,936,258	4487	7264	2148061	0.69	0.43
48	000879	Powerton	179801AAA	52	**447**	Coal	21,136,861	4530	7333	2168642	0.69	0.43
49	000879	Powerton	179801AAA	61	**447**	Coal	18,293,368	3921	6347	1876900	0.69	0.43
50	000879	Powerton	179801AAA	62	**447**	Coal	18,087,823	3877	6276	1855811	0.69	0.43
51	000897	Vermilion	183814AAA	1	**75**	Coal	5,304,579	7277	977	544141	0.37	2.74
52	000897	Vermilion	183814AAA	2	**102**	Coal	6,735,448	9240	1240	690919	0.37	2.74
53	000883	Waukegan	097190AAC	17	**121**	Coal	7,502,045	1642	2365	769710	0.63	0.44
54	000883	Waukegan	097190AAC	7	**326**	Coal	16,116,575	3754	1092	1653562	0.14	0.47
55	000883	Waukegan	097190AAC	8	**355**	Coal	21,950,142	5385	1488	2252084	0.14	0.49
56	000884	Will County	197810AAK	1	**188**	Coal	9,398,486	1969	4000	964284	0.85	0.42
57	000884	Will County	197810AAK	2	**184**	Coal	8,292,831	1617	3310	850842	0.80	0.39
58	000884	Will County	197810AAK	3	**299**	Coal	15,559,101	3636	1300	1596358	0.17	0.47
59	000884	Will County	197810AAK	4	**598**	Coal	27,584,774	6462	2009	2830196	0.15	0.47
60	000898	Wood River	119020AAE	4	**103**	Coal	5,561,263	1536	521	570588	0.19	0.55
61	000898	Wood River	119020AAE	5	**387**	Coal	17,611,221	5726	1903	1806910	0.22	0.65
		Total Coal-Fired Units			**16,905**		**931,038,484**	**352,994**	**170,997**	**95,507,062**	**0.37**	**0.76**

2002 Annual Data For Illinois EGUs

2002 Annual Data For Illinois EGUs

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
1	055296	Calumet Energy Team	031600GHA	**1	**153**	N.Gas	65,208	0	1.70	3875	0.05	0.00
2	055296	Calumet Energy Team	031600GHA	**2	**153**	N.Gas	8,384	0	0.30	498	0.07	0.00
3	055253	Crete Energy Park	197030AAO	GT1	**89**	N.Gas	87,321	0	1.30	5189	0.03	0.00
4	055253	Crete Energy Park	197030AAO	GT2	**89**	N.Gas	86,926	0	1.10	5166	0.03	0.00
5	055253	Crete Energy Park	197030AAO	GT3	**89**	N.Gas	75,077	0	1.00	4462	0.03	0.00
6	055253	Crete Energy Park	197030AAO	GT4	**89**	N.Gas	61,334	0	0.80	3645	0.03	0.00
7	055236	Duke Energy Lee	103817AAH	CT1	**83**	N.Gas	71,847	0	0.90	4270	0.03	0.00
8	055236	Duke Energy Lee	103817AAH	CT2	**83**	N.Gas	73,748	0	1.00	4382	0.03	0.00
9	055236	Duke Energy Lee	103817AAH	CT3	**83**	N.Gas	108,212	0	1.70	6431	0.03	0.00
10	055236	Duke Energy Lee	103817AAH	CT4	**83**	N.Gas	111,819	0	1.90	6645	0.03	0.00
11	055236	Duke Energy Lee	103817AAH	CT5	**83**	N.Gas	71,008	0	1.10	4220	0.03	0.00
12	055236	Duke Energy Lee	103817AAH	CT6	**83**	N.Gas	70,684	0	1.50	4201	0.04	0.00
13	055236	Duke Energy Lee	103817AAH	CT7	**83**	N.Gas	60,681	0	1.10	3606	0.04	0.00
14	055236	Duke Energy Lee	103817AAH	CT8	**83**	N.Gas	127,773	0	2.30	7593	0.04	0.00
15	055438	Elgin Energy Center	031438ABC	CT01	**135**	N.Gas	2,076	0	0.10	123	0.10	0.00
16	055201	Gibson City Power	053803AAL	GCTG1	**135**	N.Gas	204,499	0	6.90	12153	0.07	0.00
17	055201	Gibson City Power	053803AAL	GCTG2	**135**	N.Gas	185,068	0	5.80	11021	0.06	0.00
18	055204	Kinmundy Power Pl	121803AAA	KCTG1	**250**	N.Gas	218,277	0	7.90	12971	0.07	0.00
19	055204	Kinmundy Power Pl	121803AAA	KCTG2	**250**	N.Gas	208,278	0	6.60	12378	0.06	0.00
20	055222	Lincoln Generating	197811AAH	CTG-1	**83**	N.Gas	206,000	0	2.50	12242	0.02	0.00
21	055222	Lincoln Generating	197811AAH	CTG-2	**83**	N.Gas	204,224	0	2.10	12137	0.02	0.00
22	055222	Lincoln Generating	197811AAH	CTG-3	**83**	N.Gas	180,522	0	2.20	10728	0.02	0.00
23	055222	Lincoln Generating	197811AAH	CTG-4	**83**	N.Gas	160,394	0	1.80	9532	0.02	0.00
24	055222	Lincoln Generating	197811AAH	CTG-5	**83**	N.Gas	165,500	0	2.40	9836	0.03	0.00
25	055222	Lincoln Generating	197811AAH	CTG-6	**83**	N.Gas	111,782	0	1.40	6643	0.03	0.00
26	055222	Lincoln Generating	197811AAH	CTG-7	**83**	N.Gas	83,383	0	1.40	4956	0.03	0.00
27	055222	Lincoln Generating	197811AAH	CTG-8	**83**	N.Gas	84,453	0	1.20	5019	0.03	0.00
28	055417	MEP Flora Power	025803AAD	CT-01	**94.5**	N.Gas	3,985	0	0.10	237	0.05	0.00
29	055417	MEP Flora Power	025803AAD	CT-02	**94.5**	N.Gas	3,985	0	0.10	237	0.05	0.00
30	055417	MEP Flora Power	025803AAD	CT-03	**95**	N.Gas	3,985	0	0.10	237	0.05	0.00
31	055417	MEP Flora Power	025803AAD	CT-04	**95**	N.Gas	3,985	0	0.10	237	0.05	0.00
32	007858	MEPI GT Facility	127899AAA	1	**72**	N.Gas	100,522	0	6.60	5974	0.13	0.00

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
33	007858	MEPI GT Facility	127899AAA	2	**72**	N.Gas	94,976	0	6.00	5645	0.13	0.00
34	007858	MEPI GT Facility	127899AAA	3	**72**	N.Gas	95,813	0	6.20	5694	0.13	0.00
35	007858	MEPI GT Facility	127899AAA	4	**72**	N.Gas	46,778	0	2.50	2781	0.11	0.00
36	007858	MEPI GT Facility	127899AAA	5	**72**	N.Gas	43,368	0	2.10	2578	0.10	0.00
37	055202	Pinckneyville Power	145842AAA	CT05	**49**	N.Gas	64,026	0	1.20	3805	0.04	0.00
38	055202	Pinckneyville Power	145842AAA	CT06	**49**	N.Gas	73,870	0	1.40	4391	0.04	0.00
39	055202	Pinckneyville Power	145842AAA	CT07	**49**	N.Gas	69,816	0	1.30	4150	0.04	0.00
40	055202	Pinckneyville Power	145842AAA	CT08	**49**	N.Gas	66,572	0	1.10	3956	0.03	0.00
41	055640	PPL University Park	197899AAC	CT01	**44**	N.Gas	16,484	0	0.90	980	0.11	0.00
42	055640	PPL University Park	197899AAC	CT02	**44**	N.Gas	13,854	0	0.60	823	0.09	0.00
43	055640	PPL University Park	197899AAC	CT03	**44**	N.Gas	13,663	0	1.60	812	0.23	0.00
44	055640	PPL University Park	197899AAC	CT04	**44**	N.Gas	14,500	0	0.70	862	0.10	0.00
45	055640	PPL University Park	197899AAC	CT05	**44**	N.Gas	33,685	0	0.20	2002	0.01	0.00
46	055640	PPL University Park	197899AAC	CT06	**44**	N.Gas	27,397	0	0.20	1628	0.01	0.00
47	055640	PPL University Park	197899AAC	CT07	**44**	N.Gas	29,699	0	1.20	1765	0.08	0.00
48	055640	PPL University Park	197899AAC	CT08	**44**	N.Gas	26,111	0	1.60	1551	0.12	0.00
49	055640	PPL University Park	197899AAC	CT09	**44**	N.Gas	18,221	0	0.70	1083	0.08	0.00
50	055640	PPL University Park	197899AAC	CT10	**44**	N.Gas	15,744	0	0.60	936	0.08	0.00
51	055640	PPL University Park	197899AAC	CT11	**44**	N.Gas	10,763	0	1.00	640	0.19	0.00
52	055640	PPL University Park	197899AAC	CT12	**44**	N.Gas	12,614	0	0.90	750	0.14	0.00
53	055279	Reliant Energy - Aurora	043407AAF	AGS05	**45**	N.Gas	211,157	0	7.70	12549	0.07	0.00
54	055279	Reliant Energy - Aurora	043407AAF	AGS06	**45**	N.Gas	203,388	0	7.80	12088	0.08	0.00
55	055279	Reliant Energy - Aurora	043407AAF	AGS07	**45**	N.Gas	198,741	0	8.10	11811	0.08	0.00
56	055279	Reliant Energy - Aurora	043407AAF	AGS10	**45**	N.Gas	209,367	0	8.80	12441	0.08	0.00
57	055237	Reliant Energy Shelby	173801AAA	SCE1	**41**	N.Gas	134,636	0	5.60	8001	0.08	0.00
58	055237	Reliant Energy Shelby	173801AAA	SCE2	**41**	N.Gas	147,174	0	6.10	8746	0.08	0.00
59	055237	Reliant Energy Shelby	173801AAA	SCE3	**41**	N.Gas	156,480	0	6.00	9300	0.08	0.00

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
60	055237	Reliant Energy Shelby	173801AAA	SCE4	**41**	N.Gas	148,595	0	6.20	8831	0.08	0.00
61	055237	Reliant Energy Shelby	173801AAA	SCE5	**41**	N.Gas	154,951	0	6.50	9208	0.08	0.00
62	055237	Reliant Energy Shelby	173801AAA	SCE6	**41**	N.Gas	150,121	0	6.10	8922	0.08	0.00
63	055237	Reliant Energy Shelby	173801AAA	SCE7	**41**	N.Gas	202,340	0	8.20	12026	0.08	0.00
64	055237	Reliant Energy Shelby	173801AAA	SCE8	**41**	N.Gas	192,091	0	7.60	11416	0.08	0.00
65	055109	Rocky Road Power	089425AAC	T2	**121**	N.Gas	206,143	0	8.30	12251	0.08	0.00
66	055109	Rocky Road Power	089425AAC	T3	**35**	N.Gas	53,829	0	4.10	3199	0.15	0.00
67	055281	Southeast Chicago Energy	031600GKE	CTG10	**44**	N.Gas	7,059	0	1.20	418	0.34	0.00
68	055281	Southeast Chicago Energy	031600GKE	CTG11	**44**	N.Gas	7,191	0	1.10	426	0.31	0.00
69	055281	Southeast Chicago Energy	031600GKE	CTG12	**44**	N.Gas	3,885	0	0.60	231	0.31	0.00
70	055281	Southeast Chicago Energy	031600GKE	CTG5	**44**	N.Gas	6,890	0	1.10	407	0.32	0.00
71	055281	Southeast Chicago Energy	031600GKE	CTG6	**44**	N.Gas	6,806	0	1.10	403	0.32	0.00
72	055281	Southeast Chicago Energy	031600GKE	CTG7	**44**	N.Gas	7,011	0	1.10	415	0.31	0.00
73	055281	Southeast Chicago Energy	031600GKE	CTG8	**44**	N.Gas	6,453	0	1.10	382	0.34	0.00
74	055281	Southeast Chicago Energy	031600GKE	CTG9	**44**	N.Gas	6,147	0	1.00	363	0.33	0.00
75	055250	University Park Energy	197899AAB	UP1	**25**	N.Gas	35,111	0	2.60	2072	0.15	0.00
76	055250	University Park Energy	197899AAB	UP10	**25**	N.Gas	34,602	0	2.50	2041	0.14	0.00
77	055250	University Park Energy	197899AAB	UP11	**25**	N.Gas	35,825	0	2.70	2114	0.15	0.00

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
78	055250	University Park Energy	197899AAB	UP12	**25**	N.Gas	34,320	0	2.60	2025	0.15	0.00
79	055250	University Park Energy	197899AAB	UP2	**25**	N.Gas	35,276	0	2.60	2082	0.15	0.00
80	055250	University Park Energy	197899AAB	UP3	**25**	N.Gas	33,465	0	2.40	1974	0.14	0.00
81	055250	University Park Energy	197899AAB	UP4	**25**	N.Gas	36,100	0	2.70	2129	0.15	0.00
82	055250	University Park Energy	197899AAB	UP5	**25**	N.Gas	37,334	0	2.80	2202	0.15	0.00
83	055250	University Park Energy	197899AAB	UP6	**25**	N.Gas	36,963	0	2.80	2180	0.15	0.00
84	055250	University Park Energy	197899AAB	UP7	**25**	N.Gas	38,231	0	2.90	2256	0.15	0.00
85	055250	University Park Energy	197899AAB	UP8	**25**	N.Gas	37,900	0	2.80	2236	0.15	0.00
86	055250	University Park Energy	197899AAB	UP9	**25**	N.Gas	36,851	0	2.70	2174	0.15	0.00
87	000913	Venice	119105AAA	1	**45**	N.Gas	0	0	0.00	0	-	-
88	000913	Venice	119105AAA	2	**45**	N.Gas	0	0	0.00	0	-	-
89	000913	Venice	119105AAA	3	**45**	N.Gas	116,293	0	14.10	6912	0.24	0.00
90	000913	Venice	119105AAA	4	**45**	N.Gas	126,576	0	12.60	7522	0.20	0.00
91	000913	Venice	119105AAA	5	**45**	N.Gas	122,681	0	13.20	7291	0.22	0.00
92	000913	Venice	119105AAA	6	**45**	N.Gas	131,155	0	14.30	7795	0.22	0.00
93	000913	Venice	119105AAA	7	**104**	N.Gas	89,639	0	6.00	5328	0.13	0.00
94	000913	Venice	119105AAA	8	**104**	N.Gas	122,766	0	15.90	7297	0.26	0.00
95	000898	Wood River	119020AAE	1	**46**	N.Gas	4,091	0	0.59	243	0.29	0.00
96	000898	Wood River	119020AAE	2	**46**	N.Gas	5,873	0	0.85	348	0.29	0.00
97	000898	Wood River	119020AAE	3	**46**	N.Gas	6,237	0	0.90	371	0.29	0.00
		Total Gas-Fired Units			**6284**		**7,576,638**	**0**	**315**	**450097**	**0.08**	**0.00**

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
1	006025	Collins Station	063806AAF	1	**554**	N.Gas/Oil	2,874,427	48	187	172987	0.13	0.03
2	006025	Collins Station	063806AAF	2	**554**	N.Gas/Oil	6,442,082	108	419	387694	0.13	0.03
3	006025	Collins Station	063806AAF	3	**530**	N.Gas/Oil	6,720,399	113	437	396110	0.13	0.03
4	006025	Collins Station	063806AAF	4	**530**	N.Gas/Oil	6,451,251	108	456	388401	0.14	0.03
5	006025	Collins Station	063806AAF	5	**530**	N.Gas/Oil	5,579,148	93	395	335895	0.14	0.03
6	055188	Cordova Energy Center	161807AAN	1	**250**	N.Gas/Oil	3,211,814	0.90	25.00	190870	0.02	0.00
7	055188	Cordova Energy Center	161807AAN	2	**250**	N.Gas/Oil	3,173,713	0.90	20.40	188607	0.01	0.00
8	055199	Elwood Energy Facility	197808AAG	1	**172**	N.Gas/Oil	632,950	0.10	12.90	37616	0.04	0.00
9	055199	Elwood Energy Facility	197808AAG	2	**172**	N.Gas/Oil	627,722	0.10	12.70	37304	0.04	0.00
10	055199	Elwood Energy Facility	197808AAG	3	**172**	N.Gas/Oil	617,460	0.10	14.60	36695	0.05	0.00
11	055199	Elwood Energy Facility	197808AAG	4	**172**	N.Gas/Oil	615,336	0.10	14.40	36569	0.05	0.00
12	055199	Elwood Energy Facility	197808AAG	5	**172**	N.Gas/Oil	731,332	0.20	10.60	43463	0.03	0.00
13	055199	Elwood Energy Facility	197808AAG	6	**170**	N.Gas/Oil	609,295	0.20	9.00	36208	0.03	0.00
14	055199	Elwood Energy Facility	197808AAG	7	**170**	N.Gas/Oil	722,715	0.20	11.30	42951	0.03	0.00
15	055199	Elwood Energy Facility	197808AAG	8	**170**	N.Gas/Oil	536,966	0.10	8.40	31910	0.03	0.00
16	055199	Elwood Energy Facility	197808AAG	9	**170**	N.Gas/Oil	651,943	0.10	10.90	38744	0.03	0.00
17	000862	Grand Tower	077806AAA	CT01	**300**	N.Gas/Oil	4,378,973	1.30	160.20	260235	0.07	0.00
18	000862	Grand Tower	077806AAA	CT02	**300**	N.Gas/Oil	4,613,402	1.30	182.30	274167	0.08	0.00
19	055334	Holland Energy Facility	173807AAG	CTG1	**168**	N.Gas/Oil	588,414	0.20	6.80	34969	0.02	0.00
20	055334	Holland Energy Facility	173807AAG	CTG2	**168**	N.Gas/Oil	857,090	0.20	11.10	50936	0.03	0.00
21	055238	Indeck Rockford Energy	201030BCG	0001	**150**	N.Gas/Oil	361,575	0.10	18.80	21488	0.10	0.00

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Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
22	055238	Indeck Rockford	201030BCG	0002	**150**	N.Gas/Oil	368,239	0.10	9.50	21889	0.05	0.00
23	007425	Interstate	167822ABG	1	**139**	N.Gas/Oil	116,657	0.00	13.50	6933	0.23	0.00
24	055131	Kendall County Generation	093808AAD	GTG-1	**250**	N.Gas/Oil	2,531,946	0.70	34.40	150471	0.03	0.00
25	055131	Kendall County Generation	093808AAD	GTG-2	**250**	N.Gas/Oil	2,276,507	0.70	30.90	135288	0.03	0.00
26	055131	Kendall County Generation	093808AAD	GTG-3	**250**	N.Gas/Oil	1,838,860	0.50	22.90	109280	0.02	0.00
27	055131	Kendall County Generation	093808AAD	GTG-4	**250**	N.Gas/Oil	1,263,341	0.40	16.10	75081	0.03	0.00
28	055202	Pinckneyville Power	145842AAA	CT01	**49**	N.Gas/Oil	325,594	0.10	14.50	19350	0.09	0.00
29	055202	Pinckneyville Power	145842AAA	CT02	**49**	N.Gas/Oil	321,781	0.10	14.60	19124	0.09	0.00
30	055202	Pinckneyville Power	145842AAA	CT03	**49**	N.Gas/Oil	301,332	0.10	13.80	17908	0.09	0.00
31	055202	Pinckneyville Power	145842AAA	CT04	**49**	N.Gas/Oil	303,177	0.10	13.50	18019	0.09	0.00
32	055279	Reliant Energy - Aurora	043407AAF	AGS01	**170**	N.Gas/Oil	197,081	0.10	3.10	11713	0.03	0.00
33	055279	Reliant Energy - Aurora	043407AAF	AGS02	**170**	N.Gas/Oil	215,836	0.10	3.10	12827	0.03	0.00
34	055279	Reliant Energy - Aurora	043407AAF	AGS03	**170**	N.Gas/Oil	334,729	0.10	5.10	19892	0.03	0.00
35	055279	Reliant Energy - Aurora	043407AAF	AGS04	**170**	N.Gas/Oil	218,547	0.00	3.50	12988	0.03	0.00
36	055279	Reliant Energy - Aurora	043407AAF	AGS08	**45**	N.Gas/Oil	230,331	0.10	9.10	13689	0.08	0.00
37	055279	Reliant Energy - Aurora	043407AAF	AGS09	**45**	N.Gas/Oil	232,688	0.10	8.90	13828	0.08	0.00
38	055109	Rocky Road Power	089425AAC	T1	**121**	N.Gas/Oil	254,364	0.10	10.00	15117	0.08	0.00
39	055109	Rocky Road Power	089425AAC	T4	**121**	N.Gas/Oil	248,155	0.10	6.50	14748	0.05	0.00
40	007760	Tilton	183090AAE	1	**44**	N.Gas/Oil	396,027	0.10	17.70	23537	0.09	0.00
41	007760	Tilton	183090AAE	2	**44**	N.Gas/Oil	415,357	0.10	18.20	24684	0.09	0.00
42	007760	Tilton	183090AAE	3	**44**	N.Gas/Oil	368,708	0.10	16.20	21912	0.09	0.00

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
43	007760	Tilton	183090AAE	4	**44**	N.Gas/Oil	478,624	0.10	21.90	28442	0.09	0.00
44	000913	Venice	119105AAA	CT2A	**30**	N.Gas/Oil	30,758	0.10	1.50	1941	0.10	0.01
45	000913	Venice	119105AAA	CT2B	**30**	N.Gas/Oil	32,090	0.10	1.90	2023	0.12	0.01
46	055392	Zion Energy Center	097200ABB	CT-1	**160**	N.Gas/Oil	1,005,831	0.30	14.90	59800	0.03	0.00
47	055392	Zion Energy Center	097200ABB	CT-2	**160**	N.Gas/Oil	520,238	0.20	8.50	30924	0.03	0.00
		Total N.Gas/Oil-Fired Units					**65,824,805**	**481**	**2,756**	**3,925,223**	0.08	0.01

Sr. No.	ORISPL	Plant Name	ID No.	UNIT ID	Unit Capacity MW	Fuel Used	Heat Input mmBtu	SO2 Tons	NOx Tons	CO2 Tons	NOx lbs/ mmBtu	SO2 lbs/ mmBtu
1	000891	Havana	125804AAB	1	**30**	Oil	30,637	12.60	14.70	2486	0.96	0.82
2	000891	Havana	125804AAB	2	**30**	Oil	7,585	1.70	1.60	614	0.42	0.45
3	000891	Havana	125804AAB	3	**30**	Oil	26,865	10.60	12.60	2180	0.94	0.79
4	000891	Havana	125804AAB	4	**30**	Oil	29,215	11.20	13.10	2370	0.90	0.77
5	000891	Havana	125804AAB	5	**30**	Oil	12,916	3.70	2.80	1049	0.43	0.57
6	000891	Havana	125804AAB	6	**30**	Oil	3,765	1.40	1.60	296	0.85	0.74
7	000891	Havana	125804AAB	7	**30**	Oil	46,418	16.60	15.10	3767	0.65	0.72
8	000891	Havana	125804AAB	8	**30**	Oil	23,621	8.60	8.60	1917	0.73	0.73
9	000864	Meredosia	137805AAA	06	**447**	Oil	430,217	96.90	36.80	34823	0.17	0.45
		Total Oil-Fired Units					**611,239**	**163**	**107**	**49,502**	**0.35**	**0.53**

Appendix B

Best Available Control Technology

Clearinghouse Results

Table B-1

Summary of Results of the BACT Clearing House Search for NOx Controls

RBLC #	Date	Source	Boiler Type	MDHI* mmBtu/hr	BACT Technology**	NOx Limits lbs/mmBtu
IL	**10/10/03**	**Indeck-Elwood**	**CFB**	**5,800**	**SNCR**	**0.10**
IA-0067	06/17/03	Midamerican Energy-Council Bluffs		7,675	LNB/OFA/SCR	0.07
WY-0057	09/25/02	Black Hills Corporation		5,146	LNB/SCR	0.07
PR-007	10/29/01	AES Puerto Rico	CFB	4,923	SNCR	0.10
PA-0182	04/23/01	Reliant Energy Mid-Atlantic	CFB	2,532	SNCR	0.15
PA-0275	04/14/95	Northhampton Gen. Company		1,146		0.1
MD-0022	06/03/94	AES Warrior Run	CFB	2,070	SNCR	0.07
MO-		Kansas City P & L – Hawthorne			SCR	0.12
MA-0009		Energy New Bedford Cogen.	CFB	3,342	SNCR	0.15
MA-0011		Taunton Energy Center		1,604		0.15
WY-0047	10/10/97	Encoal Corp. North Rochelle		3,960	LNB/OFA + SCR	0.15
WY-0039	02/27/98	Two Elk Gen. Part, Lim. Part.		250	LNB/OFA + SCR	0.15
PA-0089	06/01/93	Inter-Power of PA	CFB	1,120	SNCR	0.2
WY-0048	09/06/96	Wygen, Inc.				0.22
NY-0078	03/31/95	UDG/Goodyear		576	NA	0.5
OH-0231	08/11/97	Toledo Edison-Bayshore		1,764	NA	0.2
NY-0070	03/01/94	Fort Drum HTW Cogen.		651		0.6
UT-0053	03/16/98	Deseret Gen. & Transmission Co.				0.55
PA-0132	07/25/95	York County Energy Partners		2,500		0.125
PA		Edison-Mission Energy			SCR	0.15
PA-0110	11/27/95	Gilberton Power		520	NA	0.3
PA-0124	11/27/95	Westwood Energy Properties		423	NA	0.3

*MDHI = Maximum Design Heat Input
**LNB = Low NOx Burner; OFA = Over Fire Air; SCR = Selective Catalytic Reduction; SNCR = Selective Non-Catalytic Reduction

Table B-2

Summary of Results of the BACT Clearinghouse Search for SO_2

RBLC I.D. #	Date	Source	Boiler Type	MDHI (1)	BACT Technology	Limit (2)
IL	**10/10/03**	**Indeck-Elwood**	**CFB**	**5,800**	**Bed Injection/Polishing Scrubber**	**0.15**
WY-0057	09/25/02	Black Hills Corporation		5,146	Semi-Dry Lime Spray Absorber	0.1
PA-0183	11/21/01	AES Beaver Valley, L.L.C.	CFB	2,155	Hydrated Ash Re-Injection	0.14
PR-0007	10/29/01	AES Puerto Rico Congen.	CFB	4,923	Low Sulfur Coal/Dry Scrubber	0.022
TX-0275	12/21/00	Reliant Energy		6,700	FGD	0.36
MO-0050	08/17/99	Kansas City Power & Light		5,606*	Low Sulfur Coal/Dry Scrubber	0.12
FL-0178	07/14/99	JEA North Side Generation	CFB	2,764	Bed Injection/Dry Absorber	0.2
MS-0036	08/24/98	Choctaw Generation Limited	CFB	2,476	Bed Injection	0.25
UT-0060	03/16/98	Deseret Gen. and Trans.		500 MW	Wet Scrubber	0.15
WY-0030	02/27/98	Two Elk Gen. Partners LTD.		250 MW	Lime Spray Dry Scrubber	0.17
PA-0132	07/25/95	York County Energy Partners		2,500	Lime Injection/Sulfur Lt.	0.25
MD-0022	06/03/94	AES Warrior Run, Inc.	CFB	2,070	Bed Injection	0.16
VA-0213	08/23/93	SEI Birchwood, Inc.		2,200	Lime Spray Drying System	0.10
MA-0009	04/30/93	Energy New Bedford Cogen.		3,342	Limestone Injection	0.23

* Estimated MDHI based on using Lignite

(1) Units in mmBtu/hr

(2) lbs/mmBtu

(3) 3-Hour Average

(4) 24-Hour Average

(5) 12 Month Rolling Average

Appendix C

Multi-Pollutant Strategy

Legislation Comparison Chart

Multi-Pollutant Strategy Legislation Comparison Chart

	<u>Clean Smokestacks Act of 2003-H.R. 2042</u> **(Congressman Waxman, D-CA)**	**<u>Clean Power Act of 2003 -S.366</u>** **(Senator James Jeffords I-VT)**	**Clean Air Planning Act of 2003 <u>-S. 843</u>** **(Senator Tom Carper, D-DE)**	**Clear Skies Act of 2003 <u>S. 485/H.R. 999</u>** **(Senators James Inhofe, R-OK & George Voinovich, R-OH, Reps. Joe Barton, R-TX & Billy Tauzin, R-LA)**
Caps	Within 2 years of enactment the Administrator must promulgate regulations to achieve the caps	National, annual caps for 4 pollutants	National, annual caps for 4 pollutants	National, annual caps for 3 pollutants
Sulfur Dioxide	75% reduction from Phase II Acid Rain cap beginning 2009	2.25 million tons beginning 2009-1.975 million tons in East and 275,000 tons in West(AZ, CA, CO, ID, MT, NV, NM, OR, UT, WA, WY)	4.5 million tons beginning in 2009; 3.5 million tons beginning in 2013; 2.25 million tons beginning in 2016	4.5 million tons beginning 2010; 3.0 million tons beginning 2018. Includes provisions for a second emission limit and cap-and-trade program for WRAP states.
Nitrogen Oxides	75% reduction from 1997 levels beginning 2009	1.51 million tons beginning 2009	1.87 million tons beginning 2009; 1.7 million tons beginning 2013	2.1 million tons beginning 2008-1.562 million tons in Zone 1 (eastern and some central states) and 538, 000 tons in Zone 2 (western and remainder of central states); 1.7 million tons beginning 2018-1.162 million tons in Zone 1 and 538,000 tons in Zone 2 **(*Oklahoma is now included to Zone 2, as opposed to being in Zone 1 in 2002 version*)**

Multi-Pollutant Strategy Legislation Comparison Chart

	<u>Clean Smokestacks Act of 2003-H.R. 2042</u> **(Congressman Waxman, D-CA)**	**<u>Clean Power Act of 2003 -S.366</u>** **(Senator James Jeffords I-VT)**	**Clean Air Planning Act of 2003 <u>-S. 843</u>** **(Senator Tom Carper, D-DE)**	**Clear Skies Act of 2003 <u>S. 485/H.R. 999</u>** **(Senators James Inhofe, R-OK & George Voinovich, R-OH, Reps. Joe Barton, R-TX & Billy Tauzin, R-LA)**
Mercury	90% reduction from 1999 levels beginning 2009	5 tons beginning 2008, based on unit-by-unit emissions rate limit not to exceed 2.4g/MW-hr	24 tons beginning 2009 and facility-specific emissions cannot exceed either (1) 50% of the total quantity of Hg in its coal; or (2) an annual out-put based emission rate for Hg, as determined by EPA based on an input rate of 4 lbs/tBtu. 10 tons beginning 2013 Plus facility-specific emissions cannot exceed either: (1) 30% of the total quantity of Hg present in the coal used; or (2) an annual out-put based emission rate for Hg, as determined by EPA	26 tons beginning 2010; 15 tons beginning 2018
Carbon Dioxide	1990 levels beginning 2009	2.05 billion tons beginning 2009	Emissions equal to 2006 levels, beginning 2009; emission equal to 2001 beginning 2013	No limits
<u>Emissions Trading</u>	May include trading for SO2, NOx and CO2. Not allowed for Hg.	Allowed for SO2, NOx and CO2 (no trading with other sectors, with some exceptions for CO2) Not allowed for Hg	Allowed SO2, NOx, Hg and CO2 (international CO2 trading allowed)	Allowed for SO2, NOx and Hg

Multi-Pollutant Strategy Legislation Comparison Chart

	Clean Smokestacks Act of 2003-H.R. 2042 (Congressman Waxman, D-CA)	**Clean Power Act of 2003 -S.366** (Senator James Jeffords I-VT)	**Clean Air Planning Act of 2003 -S. 843** (Senator Tom Carper, D-DE)	**Clear Skies Act of 2003 S. 485/H.R. 999** (Senators James Inhofe, R-OK & George Voinovich, R-OH, Reps. Joe Barton, R-TX & Billy Tauzin, R-LA)
Allocation of Allowances		Allowances to be allocated annually starting in 2009 among 5 categories: consumers/households; transition assistance; renewable energy-efficiency and cleaner energy; carbon sequestration; and existing units Total annual allocation will be reduced by an amount equal to emission from electric generators with <15 MW capacity Allows use of market-oriented mechanisms, such as emission trading based on generation performance standards, auctions or other allocation methods EPA to establish allowance tracking and transfer program within 1 yr of enactment	EPA to issue regs to implement SO2 cap through CAA Title IV; includes provisions for allocating SO2 allowances to new units Allowances for NOx, Hg and CO2 to be allocated, based on output of affect units, by 12/31/05 for 2009 and, thereafter, updated annually, 4 yrs in advance. Provisions included for allocating NOx, Hg and CO2 allowances to new units. EPA to issue regs establishing NOx, Hg and CO2 allowance trading programs by 1/1/05, including requirements for generation, allocation, recording, tracking, transfer and use of allowances, monitoring and reporting of emissions, excess emissions penalties and enforcement and compliance Allowances created and placed	Allowances to be allocated to existing units, with an increasing portion reserved for auction (in 1st yr, 99% for existing units and 1% for auction; an additional 1% for auction in each of next 20 yrs; thereafter, an additional 2.5% for auction each year until all allowances are auctioned) SO2 allowances allocated to existing units based on their proportion of total post-2009 Acid Rain SO2 allowances currently in their accounts (if they received allowances under Acid Rain program) or based on product of baseline heat input and a standard emission rate reflective of fuel type; pre-2010 allowances under Acid Rain program may be used to meeting new holding requirements Separate NOx cap-and-trade programs for Zone 1 and Zone 2 NOx allowances allocated to existing units based on

	<u>Clean Smokestacks Act of 2003-H.R. 2042</u> **(Congressman Waxman, D-CA)**	**<u>Clean Power Act of 2003 -S.366</u>** **(Senator James Jeffords I-VT)**	**Clean Air Planning Act of 2003** **<u>-S. 843</u>** **(Senator Tom Carper, D-DE)**	**Clear Skies Act of 2003** **<u>S. 485/H.R. 999</u>** **(Senators James Inhofe, R-OK & George Voinovich, R-OH, Reps. Joe Barton, R-TX & Billy Tauzin, R-LA)**
Allocation of Allowances (continued) s			in reserve under an emission limit imposed under CAA Title I before 1/1/08 have ½ the value of allowances under new program	proportionate share of their baseline heat input to total heat input of all affected units in their perspective zones; pre-2008 NOx allowances may be carried forward Hg allowances allocated to existing units based on proportionate share of their baseline heat input to total heat input of all affected units; for purposes of allocating the allowances, each unit's baseline heat input is adjusted to reflect the types of coal combusted by the unit during the baseline period. EPA to issue regs establishing system, similar to that for existing Acid Rain Program, for issuing, recording and tracking allowances
Impact on Current Clean Air Act Requirements		No existing CAA requirements replaced or removed	Exempts affected units from Hg MACT. Exempts affected units from visibility protection requirements in Section 169(A) for 20 years after enactment.	Existing NSPS program for new and modified units repealed and replaced with fixed, statutory performance standards to apply only to new, not modified, sources; modified sources have option of meeting new performance standard or case-by case

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Impact on Current Clean Air Act Requirements (continued)			NSR and NSPS will apply only to those new (including boiler replacement) affected units and renewable energy units where maximum hourly emissions rates increase, after netting among covered units at a source. Establishes SO2 and NOx performance standards for affected units that commence construction before August 17, 1971. EPA will identify BACT and LAER biannually for affected units and renewable energy units. LAER for the electric generating sector cannot require technology costing more than twice the BACT guidelines or more than a smaller amount determined by EPA. No offsets are required for electricity generating sector	BACT Major sources exempted from existing NSR and BART requirements, and many PSD requirements EPA authorized to designate as "transitional" those areas for which modeling shows legislation or legislation plus federal /state measures result in attainment; such areas avoid non-attainment area requirements. CAA Title I amended to provide transitional areas until 12/20/15 to attain and to address the timing of designations Consequence of failure of a transitional area to attain by 2015 is redesignation to non-attainment (by 6/30/16) and requirement to submit SIP within 3 years CAA amended to postpone until 2012 application of any

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Impact on Current Clean Air Act Requirements (continued)			sources located in non-attainment areas after 2008. Each state must identify areas in the state that adversely affect local air quality and impose measures necessary to remedy such adverse effects in accordance with the SO2, NOx, Hg and CO2 caps.	Section 126 rule; requires a demonstration that downwind area has implemented all more cost-effective measures CAA amended to preclude regulation under Section 112 of HAPs from EGUs; prevents EPA from conduction residual risk assessment fro mercury from EGUs (EPA authorized to address residual risk from non-mercury HAPs) Exempts certain “clean coal technology” projects from requirements under CAA Section 111 (for new sources) and Parts C & D of Title I

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Impact on State/Local Authority		States may adopt or enforce more stringent requirements	States and political subdivisions may adopt and enforce more stringent requirements, including requiring further reductions from specific units to address local air quality problems	States unable to apply NSR or PSD to affected units as part of SIP
Review/Revision of Cap Levels		EPA may reduce caps if its is determined that they will not protect public health or the environment EPA may limit emissions from an individual facility if they are anticipated to cause or contribute to a significant adverse local impact	Caps to remain in effect until 20 yrs after enactment; within 16 ½ years of enactment, EPA must determine whether any caps should be revised and set revised caps if necessary.	EPA, in consultation with DOE, to study whether the total allowances available beginning in 2018 should be adjusted and make a recommendation to Congress by 7/1/09
Other Key Provisions	The later of the date that is 30 years after a power plant commenced operation or that is 5 years after the date of enactment, the power plant must comply with the most recent NSPS under section 111 and the requirements under parts C and D that are applicable to modified sources.	By the later of 2014, or 40 years after commencing operation, each facility must achieve emission limits that reflect BACT for new units Coal-fired-units >50 MW required to monitor HAPs and SO_2 w/in 30-mile radius EPA must propose MACT	Provides for establishment of an Independent Review Board to assist EPA with CO_2 allowance program, including developing standards for certifying CO_2 reduction programs, such as early action, sequestration and reduction of other greenhouse gases	EPA to study and report to Congress on 1) environmental and economic consequences of allowing SO_2 for NO_x trading and 2) feasibility of international trading of SO_2, NO_x and Hg allowances Codifies emission reduction requirements of NO_x SIP

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		regulations to cover non-Hg HAPs from facilities by 2005 and enforce them by 2008. EPA to develop emissions inventory for electric generators w/capacity <15 MW Facilities that contribute to ozone non-attainment in a state may be required to submit 3 allocations for every 1 ton of pollution emitted during periods of NAAQS exceedance Does not affect any regional seasonal NOx control programs established by EPA under CAA Title I	EPA must report to Congress 18 months after enactment on health and environmental impacts of mercury that is captured or recovered EPA to issue regs for monitoring	Call for eastern US. Requires full implementation of required emission control measures by May 1, 2003 for northeastern states and by May 1, 2004 for remaining states. Allows units to petition for 2-yr extension to meet emission limitations (SO2) Provides for a reserve of 250,000 SO2 allowances for units that used bituminous coal and installed and operated technology before 2008 to continue to use such coal Requires installation and operation of CEMS on, and quality assurance of data for, each affected unit
Status	Proposed 5/8/2003 (5/20/2003 referred to House Subcommittee on Energy and Air Quality)	Proposed 2/12/2003 (referred to Senate EPW Committee)	Proposed 4/9/2003 (referred to Senate EPW Committee)	Proposed 2/27/03 in the House (referred to House Energy and Commerce Committee) and 2/27/03 in the Senate (referred to Senate EPW Committee)

Appendix D

List of Health Studies Addressing Emissions from Power Plants

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1. C. Arden Pope III, PhD; Richard T. Burnett, PhD; Michael J. Thun, MD; Eugenia E. Calle, PhD; Daniel Krewski, PhD; Kazuhiko Ito, PhD; George D. Thurston, ScD., " Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *JAMA*. 2002; 287:1132-1141.

2. Electric Power Research Institute. Power Plants and Particulate Matter. 2003

3. U.S. EPA. Response to request from Senators Carper and Jeffords for analysis of S.366, The Clean Power Act, and S.843, The Clean Air Planning Act. October 28, 2003. Note: In a November 5, 2003 letter to Administrator Leavitt, the Senators asked that the analysis be redone because it does not "allow for a fair comparison of the costs and benefits of the three major legislative proposals."

4. Senator Jack Reed Press Release about co-sponsoring S. 366. http://www.senate.gov/~reed/press108th/Environment/pressreleaseCleanPowerAct2-12-03.htm.

5. Calculations based on findings from: Levy JI, Spengler JD, Hlnika D, Sullivan D, Moon D. Using CALPUFF to Evaluate the Impacts of Power Plant Emissions in Illinois: Model Sensitivity and Implications. Atmospheric Environment 36 (6): 1063-1075 (2002). Provided by the researchers on request.

6. Lippman, Morton. Health Effects of Power Plant Emissions on Downwind Populations. March 2002.

7. Levy, Jonathan I., Susan L. Greco, and John D. Spengler. The Influence of Population Heterogeneity on Air Pollution Risk Assessment: A Case Study of Power Plants Near Washington, DC. Environmental Health Perspectives (2003).

8. Levy, Jonathan I. Briefing on Health Impacts of Power Plants: Case Studies in Massachusetts, Illinois, and Washington DC. United States Senate Environment and Public Works Committee. Senate Office Building. May 17, 2002.