Shaw® Shaw Environmental, Inc.

A World of **Solutions**™

EMISSIONS IMPACT ASSESSMENT OF THE SUSTAINABLE ENERGY PLAN FOR ILLINOIS

Prepared for:

U.S. Department of Energy

Illinois Department of Commerce and Economic Opportunity

Prepared by:

Shaw Environmental, Inc.

July 24, 2007

444 N. WELLS STREET, CHICAGO, IL 60610
312.499.3500 • FAX 312.499.3505 • THE SHAW GROUP INC.®

TABLE OF CONTENTS

EXECUTIVE SUMMARY **1**

I. INTRODUCTION **3**

II. SUSTAINABLE ENERGY PLAN FOR ILLINOIS **4**
- **A. General** **4**
- **B. Renewable Portfolio Standard** **4**
- **C. Energy Efficiency Portfolio Standard** **4**

III. IMPACT OF ENERGY PLAN ON GENERATION **5**
- **A. General** **5**
- **B. Study Methodology** **6**
- B.1 Study Area 6
- B.2 Study Cases 6
- B.3 Power System Model Assumptions 6
- B.4 Load Forecasts 8
- B.5 Cost Data 9
- **C. Modeling the Energy Efficiency Portfolio** **9**
- **D. Modeling the Renewable Energy Portfolio** **11**
- D.1 Basic Assumptions 11
- D.2 Modeling Wind Generation Plants 12
- **E. Impact of Energy Plan on Generation in Illinois** **15**
- **F. Impact of Energy Plan on Generation Outside Illinois** **17**

IV. IMPACT OF ENERGY PLAN ON AIR EMISSIONS **18**
- **A. General** **18**
- **B. Study Methodology** **18**
- B.1 Impact of Energy Plan on Emissions for Plants in Illinois 19
- B.1.1 Coal-Fired Power Plants 19
- B.1.2 Natural Gas-Fired Power Plants 22
- B.1.3 Oil-Fired Power Plants 24
- B.1.4 All Fossil-Fueled Plants 27
- B.2 Impact of Energy Plan on Emissions in Study Area Outside Illinois 31
- B.3 Impact of Energy Plan on Emissions within the Total Study Area 33
- **C. Impact of Pending Regulations on Emissions Reductions** **36**
- **D. Potential Uncertainties in Emissions Predictions** **38**

V. IMPACT OF ENERGY PLAN ON AIR QUALITY COMPLIANCE **39**
- **A. Pending Federal Regulations and their Relevance to the Energy Plan** **39**
- A.1 Clean Air Interstate Rule (CAIR) 39
- A.2 Clean Air Mercury Rule (CAMR) 40
- A.3 Clean Air Visibility Rule (CAVR) 41
- **B. Considerations on Using EERE as a Tool for Regulatory Compliance** **41**

VI. CONCLUSIONS **42**

TABLES AND FIGURES

Table 3-1: Base Case Load Growth Estimate in Illinois, 2007 - 2013 8

Table 3-2: Base Case Load Growth Estimate Outside Illinois, 2007 - 2013 9

Table 3-3: Actual and Projected Energy Consumption in Illinois without EEPS, 1999 - 2013 10

Table 3-4: Projected Energy Consumption in Illinois with EEPS, 2007 - 2013.....11

Table 3-5: Projected Renewable Energy Implementation in Illinois, 2007 - 2013 12

Table 3-6: Projected Wind Generation Plants in Illinois to Implement Energy Plan Targets, 2007 - 2013 15

Table 3-7: Changes in Energy Production in Illinois Due to Energy Plan Implementation, 2007 - 2013 16

Table 3-8: Changes in Energy Production in Illinois Due to Energy Plan Implementation, 2013 16

Table 3-9: Changes in Energy Production Outside Illinois Due to Energy Plan Implementation, 2007 – 2013.....17

Table 3-10: Changes in Energy Production Outside Illinois Due to Energy Plan Implementation, 2013 18

Table 4-1a: Projected Changes in Electrical Energy Production in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 20

Table 4-1b: Projected Changes in SO_2 Emissions in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 21

Table 4-1c: Projected Changes in NOx Emissions in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013 21

Table 4-1d: Projected Changes in Hg Emissions in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013 21

Table 4-1e: Projected Changes in CO_2 Emissions in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 22

Table 4-2a: Projected Changes in Electrical Energy Production in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013 23

Table 4-2b: Projected Changes in SO_2 Emissions in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 23

Table 4-2c: Projected Changes in NOx Emissions in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 23

Table 4-2d: Projected Changes in Hg Emissions in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 24

Table 4-2e: Projected Changes in CO_2 Emissions in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 24

Table 4-3a: Projected Changes in Electrical Energy Production in Oil-Fired Plants in Illinois Due to Implementation of Energy Plan, 2007 - 2013....25

Table 4-3b: Projected Changes in SO_2 Emissions in Oil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 26

Table 4-3c: Projected Changes in NOx Emissions in Oil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 26

Table 4-3d: Projected Changes in Hg Emissions in Oil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 26

Table 4-3e: Projected Changes in CO_2 Emissions in Oil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013 27

Table 4-4a: Projected Changes in Electrical Energy Production in All Fossil-Fired Plants in Illinois Due to Implementation of Energy Plan, 2007 - 2013....27

Table 4-4b: Projected Changes in SO_2 Emissions in All Fossil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 28

Table 4-4c: Projected Changes in NOx Emissions in All Fossil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 28

Table 4-4d: Projected Changes in Hg Emissions in All Fossil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013 28

Table 4-4e: Projected Changes in CO_2 Emissions in All Fossil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013 29

Figure 4-1a: Projected Net Changes in SO_2 Emissions in Illinois, 2007 - 2013 29

Figure 4-1b: Projected Net Changes in NOx Emissions in Illinois, 2007 - 2013....30

Figure 4-1c: Projected Net Changes in Hg Emissions in Illinois, 2007 - 2013 30

Figure 4-1d: Projected Net Changes in CO_2 Emissions in Illinois, 2007 – 2013....31

Table 4-5: Projected Changes in Emissions in All Fossil Fuel-Fired Plants in the Seven State Area and Study Area Due to Energy Plan Implementation, 2007 - 2013....32

Table 4-6: Projected Changes in Emissions in All Fossil Fuel-Fired Plants in the Seven State Area and Study Area Due to Energy Plan Implementation, 2013....33

Table 4-7: Projected Changes in Emissions in All Fossil Fuel-Fired Plants within the Study Area Due to Energy Plan Implementation, 2007 - 2013 33

Table 4-8: Projected Changes in Emissions in All Fossil Fuel-Fired Plants within the Study Area Due to Energy Plan Implementation, 2013 34

Figure 4-2a: Projected Net Changes in SO_2 Emissions within the Study Area Due to Energy Plan Implementation, 2007 - 2013 34

Figure 4-2b: Projected Net Changes in NOx Emissions within the Study Area Due to Energy Plan Implementation, 2007 - 2013 35

Figure 4-2c: Projected Net Changes in Hg Emissions within the Study Area Due to Energy Plan Implementation, 2007 - 2013 35

Figure 4-2d: Projected Net Changes in CO_2 Emissions within the Study Area Due to Energy Plan Implementation, 2007 – 2013 36

Table 4-9: Projected Changes in Emissions of SO_2 and NOx Considering Implementation of Phase I CAIR within Illinois and the Seven State Area 37

Table 4-10a: Projected Changes in Emissions of SO_2 and NOx Due to Energy Plan Implementation After Phase I CAIR within Illinois and the Seven State Area, 2009 - 2013....38

Table 4-10b: Projected Changes in Hg Emissions Due to Energy Plan Implementation After Illinois Mercury Rule within Illinois, 2010 - 2013....38

APPENDICES

Appendix A: *Study of Emissions Impact by Illinois Sustainable Energy Plan Based on Optimal Power Flow Modeling*, PowerWorld Corporation, January 4, 2007…….. A1

Appendix B: Illinois Commerce Commission Resolution 05-0437, July 19, 2005…….B1

Appendix C: Illinois Power Plants……..……..C1

Appendix D: Emissions Calculations……..……...…….. D1

Appendix E: Description of Existing CAIR Set-Asides for EERE Projects…….……...… E1

Executive Summary

The U.S. Department of Energy (USDOE), in partnership with the U.S. Environmental Protection Agency (USEPA), selected Illinois for a pilot initiative, the Air-Energy Integration Initiative, to demonstrate how state energy and environment officials can work together on policies that improve air quality while addressing energy goals. Under this initiative, energy officials from the Illinois Department of Commerce and Economic Opportunity (DCEO) and environment officials from the Illinois Environmental Protection Agency (IEPA) collaborated to examine the air emissions reductions associated with the Illinois Sustainable Energy Plan proposed by Governor Blagojevich in February 2005. The project not only sought to demonstrate collaborative and innovative approaches to using energy efficiency and renewable energy (EERE) technologies to reduce or prevent air emissions, but also to quantify the avoided emissions and provide replicable tools, models and strategies that other states can implement.

Because of the regional nature of the electrical grid, to analyze the impact of Illinois energy policies the study modeled the economic dispatch of a large portion of the Eastern Interconnect power grid, including most of PJM and the Midwest ISO, and other neighboring control areas. The analysis showed that the Illinois Sustainable Energy Plan will produce significant and measurable environmental benefits:

- The Illinois Sustainable Energy Plan will reduce emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), mercury (Hg), carbon dioxide (CO_2) and other pollutants in Illinois and in numerous other states.

- Less than half of the emissions reductions would occur in Illinois, since many of the marginal plants that would be displaced by energy efficiency and renewable energy technologies in Illinois are located outside of the state.

- More than half of the generation displaced out-of-state, however, is located upwind of Illinois (Iowa, Missouri, Wisconsin), thus contributing toward improved air quality in Illinois.

- Although less than half of the emissions reductions would occur in Illinois, the reductions are still significant. Total Illinois power plant emissions of CO_2 would be reduced by 4.32%, SO_2 emissions would be reduced by 2.87%, NOx emissions would be reduced by 2.11% and Hg emissions would be reduced by 0.71%.

- While the emissions reductions are less in the five-month ozone season than in the rest of the year, the Illinois Sustainable Energy Plan would produce some ozone season benefits and contribute in a modest way towards ozone attainment both in Illinois and across the eastern U.S.

- Coal, which generally yields the highest emissions rates for NOx, SO_2, Hg and CO_2, is the primary fuel displaced, along with some oil and natural gas used in plants serving peak load. Natural gas generation in Illinois, however, increases slightly to address local transmission congestion and short-term changes in availability of wind.

Projected Reductions in Emissions in Fossil Fuel-Fired Plants within the Study Area Due to Energy Plan Implementation, 2007 – 2013*

Area	SO_2 (tons)	NOx (tons)	Hg (lbs)	CO_2 (tons)
Illinois	51,020	4,909	238	16,155,650
Seven State Area**	51,670	7,334	354	18,821,400
Remainder of Study Area	53,062	5,704	168	8,695,001
Total	**155,753**	**17,946**	**760**	**43,672,051**

* Emissions reductions from Illinois' Clean Air Interstate Rule and Illinois' Mercury Rule have been deducted to avoid double counting of emissions benefits
** Includes Iowa, Indiana, Kentucky, Michigan, Missouri, Ohio and Wisconsin

The Illinois Air-Energy Integration Initiative serves as a model for other states in the Midwest and across the country:

- Working cooperatively, energy agencies and environmental agencies can more effectively achieve state energy and environmental goals.

- Energy policies, such as the Renewable Portfolio Standard and Energy Efficiency Portfolio Standard proposed in the Illinois Sustainable Energy Plan, can help states improve air quality and reduce overall environmental compliance costs.

- Other states and regions could employ the dispatch modeling approach used in this study to ensure that the full benefits of energy efficiency and renewable energy measures are understood and to justify claiming credit in their air quality plans for improvements to air quality both within the state and regionally.

- The study found that only by using a regional model of the electrical grid could the impact on air quality be accurately assessed. A simpler state-level analysis would overestimate the in-state benefits but at the same time underestimate the regional air quality benefits.

I. INTRODUCTION

In October 2004, the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy (USDOE) hired Shaw Environmental, Inc. (Shaw) to help implement the FY2005 Midwest Air-Energy Integration Initiative. A new, national program executed at the regional level, the Air-Energy Integration Initiative was sponsored by USDOE and the U.S. Environmental Protection Agency (USEPA) to demonstrate how state energy and environment officials could work together on energy efficiency and renewable energy (EERE) technologies and policies that improve air quality while addressing energy goals. Under the program, USEPA and USDOE regional offices provided technical assistance to selected state pilot projects that supported the use of EERE technologies to reduce or prevent air emissions and verified the resulting air quality, energy and economic benefits.

In the Midwest, USDOE's Midwest Regional Office, USEPA Region 5, energy officials from the Illinois Department of Commerce and Economic Opportunity (DCEO) and environment officials from the Illinois Environmental Protection Agency (IEPA) chose to collaborate on a pilot project that examined air emissions reductions associated with the Sustainable Energy Plan for Illinois (Energy Plan) proposed by Illinois Governor Rod Blagojevich in February 2005. The Energy Plan included a state Renewable Portfolio Standard and Energy Efficiency Portfolio Standard that would require utilities and alternative retail energy suppliers to provide a portion of their electricity from renewable sources and procure energy efficiency and demand reduction services to reduce annual growth in electricity consumption. The goal of the Illinois pilot project was to develop preliminary estimates of the emissions impact of the Energy Plan, with the ultimate intent of incorporating the reductions into Illinois' State Implementation Plan.

A kickoff meeting for Illinois pilot project participants was held in March 2005. Representatives from USDOE, USEPA Region 5, IEPA, DCEO, the National Renewable Energy Lab (NREL) and the University of Illinois at Chicago Energy Resources Center (UIC ERC) participated. DCEO staff gave an overview of the proposed Energy Plan, and told the group that it had contracted with UIC ERC to analyze the environmental and economic benefits of the plan. It was agreed that UIC ERC's findings would be used as a starting point to identify the additional analysis and modeling that would be needed.

In June, UIC ERC released *The Economic and Environmental Impacts of Clean Energy Development in Illinois*, a report that estimated the economic and environmental benefits of the proposed Energy Plan. The report demonstrated through its analysis of Illinois' potential for energy efficiency and renewable power that the Energy Plan standards are achievable. It also predicted significant employment and income benefits and air emissions reductions. Its estimate of environmental benefits was preliminary, however, and it was determined that a regional economic dispatch model was needed before the emissions impact of the proposed plan could be predicted with a comfortable degree of certainty. The model necessitated a regional analysis because economic dispatch does not observe state boundaries; electricity can be exported or imported between states, depending on the least-cost resource that is currently on the margin.

Installation of a renewable generating resource in Illinois, for example, may displace emissions from a power plant in Wisconsin or elsewhere.

With additional project funding from USDOE and DCEO, Shaw engaged PowerWorld Corporation, a nationally-recognized provider of dispatch modeling services, to develop a regional economic dispatch model. The model simulated the economic dispatch of power plants in the region to account for variations in demand throughout the year. This type of model was believed to provide the most accurate assessment of the types of power plants that would be displaced. PowerWorld's report, *Study of Emissions Impact by the Illinois Sustainable Energy Plan Based on Optimal Power Flow Modeling*, was transmitted to Shaw in September 2006 (Appendix A). The findings of that report are presented here, along with a discussion of their regulatory implications.

II. SUSTAINABLE ENERGY PLAN FOR ILLINOIS

A. General

In February 2005, the Governor of Illinois sent to the Illinois Commerce Commission (ICC) a proposal for a Sustainable Energy Plan for Illinois that included a Renewable Portfolio Standard (RPS) and an Energy Efficiency Portfolio Standard (EEPS). After soliciting public comment on the Governor's proposal, the ICC passed a resolution adopting the Governor's proposal, with minor modifications, on July 19, 2005 (Appendix B). The requirements of the Energy Plan adopted by the ICC were used as a basis for the findings presented in this report. It should be noted that the ICC opened three dockets to implement the Energy Plan, but eventually concluded that it did not have the authority to implement it; therefore, implementation awaits legislative action.

B. Renewable Portfolio Standard

The Energy Plan states that "2% of the bundled retail load should be obtained from renewable energy resources in 2007, 3% in 2008, 4% in 2009, 5% in 2010, 6% in 2011, 7% in 2012 and 8% in 2013." Sources of renewable energy are defined to include "wind, solar thermal energy, photovoltaic cells and panels, dedicated crops grown for energy production and organic waste biomass, methane recovered from landfills, hydropower that does not involve the construction of new dams or significant expansion of existing dams, and other such alternative sources of environmentally preferable energy." Additionally, the Energy Plan requires that at least 75% of the renewable energy used to meet the RPS should come from wind power, with the remainder allowed to come from other sources as defined above.

C. Energy Efficiency Portfolio Standard

The Energy Plan's goals for the EEPS are as follows:

- Years 2007 - 2008 at 10% reduction in load growth
- Years 2009 - 2011 at 15% reduction in load growth

- Years 2012 - 2014 at 20% reduction in load growth
- Years 2015 - 2017 at 25% reduction in load growth

These reductions are to be applied to the projected load growth in total customer energy sales by regulated Illinois utilities. The method used to forecast load growth is described in Section III.C.

III. IMPACT OF ENERGY PLAN ON GENERATION

A. General

To predict the emissions impact of the Energy Plan, it was necessary to predict the effect the plan's EERE measures would have on the electrical generation of existing power plants. Intuitively, it would be expected that the construction of a renewable energy resource in the geographic proximity of an existing fossil-fired power plant would act to displace a proportionate amount of energy from that plant. However, because Illinois' transmission system is interconnected with the Eastern Interconnect power grid, power flows across state lines according to economics and the physical constraints of the system. Installation of a renewable generating resource in Illinois may displace emissions from a power plant in Wisconsin or elsewhere. Therefore, to properly assess the impact that the Energy Plan would have on existing power plants, a dispatch model of the regional power system was needed.

A number of different modeling strategies were considered for this assessment. One alternative was to analyze historical system lambda data for the PJM Interconnection and Midwest ISO (MISO) operating areas.[1] System lambda is a product of control area economic dispatch and is closely associated with the marginal cost of producing electricity. As such, it offers a good indicator of the competitive price for electrical energy in that, over a particular hour, it represents the variable cost of the last kilowatt produced. System lambda could be used to determine the type of power plant (i.e., nuclear, coal-fired or natural gas) that was being dispatched over the course of the year. By overlaying the profile of load displaced by new EERE technologies over the same time period, it would be possible to determine the type of fuel being displaced. However, the shortcoming of this methodology is that it does not determine the specific power plants where generation is being displaced. The impact on air quality in various parts of the state – particularly the ozone non-attainment areas – could not be determined.

Therefore, it was decided to prepare a system study that modeled the existing interconnected electrical system over the period of the Energy Plan with and without the Energy Plan's EERE measures to see what changes would be in power plant outputs. The study would need to model a reasonably broad portion of the interconnected grid and simulate the economic dispatch of generation over the course of a "typical" year. After researching alternative system modeling software, the "Simulator Optimal Power Flow" analysis software developed by PowerWorld

[1] PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (http://www.pjm.com/about/territory-served.html). Midwest ISO's service territory consists of all or parts of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Ohio, Pennsylvania, South Dakota, Wisconsin and Manitoba, Canada (http://www.midwestiso.org/page/About%20Us).

Corporation of Champaign, Illinois was selected for the assessment. The following paragraphs present a high-level summary of the analysis performed by PowerWorld; the full PowerWorld report is attached as Appendix A.

B. Study Methodology

B.1 Study Area

The PowerWorld study incorporated an economic dispatch model of the physical and economic operation of a large portion of the Eastern Interconnect power grid (Study Area) for the study period from 2007 through 2013. The model incorporates all of the PJM and MISO markets, except the northwestern extreme of MISO in Manitoba and the eastern corner of PJM in New Jersey and eastern parts of Pennsylvania and Maryland. Other control areas that neighbor Illinois and utilities that operate in Illinois, including TVA, also were incorporated because generation and load patterns throughout these markets and areas affect the operation of Illinois generators.

At the request of Shaw, PowerWorld also estimated generation impacts in Illinois alone and in seven adjacent states—Iowa, Indiana, Kentucky, Michigan, Missouri, Ohio and Wisconsin (Seven State Area).

B.2 Study Cases

The study investigated two cases: a "Base Case" and an "EERE Case."[2] The Base Case modeled generation dispatch in the Study Area for each of the years 2007 through 2013 assuming no new generation from renewable energy resources (as set forth in the RPS) and no load mitigation due to energy efficiency measures (as set forth in the EEPS). The Base Case was used as the baseline for comparison against the EERE Case, which incorporates the EERE measures (i.e., the RPS and EEPS) established by the Energy Plan.

The EERE Case modeled generation dispatch assuming that the targets of both the RPS and the EEPS were attained for each of the years 2007 through 2013. The difference in generation from the power plants being modeled constituted the amount of generation that would be displaced if the EERE targets stipulated in the Energy Plan were realized.

Both the Base Case and the EERE Case were run for each of the study years assuming no new generation would be added to the Study Area other than that stipulated by the Energy Plan. Although this assumption is recognized to be unrealistic, it nevertheless yields accurate results when comparing the relative difference in generation between the two cases.

B.3 Power System Model Assumptions

The power system model used a historical database to configure the interconnected electrical grid and establish the baseline economic dispatch of existing power plants. Load was added into the model in the ensuing years to see how the load flows changed with the addition of the forecast loads. For the EERE Case, the baseline economic dispatch was changed in future years

[2] In the PowerWorld report, this case is called the RPS Case. Though the terminology is different, the RPS Case and EERE Case are identical and include all energy efficiency and renewable energy measures stipulated in the Energy Plan.

to add wind generation and reduce load growth. The difference between the Base Case and the EERE Case was used to define the impact that changes in wind generation and energy efficiency measures have in reducing the electrical output from existing coal-, oil- and natural gas-fired power plants. Both cases used the same grid model that was configured from the historical database. As such, the cases did not include any new generation or transmission lines, other than those associated with the new wind generating plants in Illinois needed to meet the Energy Plan's goals. Other assumptions used in the development of the model are as follows:

- NERC powerflow cases, which are based on FERC 715 filings, were used to develop the system model.
- Only "dispatchable" plants were modeled. Plants that are not dispatched (e.g., cogeneration plants) were not modeled.
- Nuclear power plants were locked-in as "must run" units. Hydroelectric power plants were modeled according to their average historical dispatch pattern. Fossil-fired generating units were varied on the basis of load demand and economic considerations.
- The model assumed that thermal and hydro resources[3] can be dispatched economically around hourly wind and load variations. However, wind intermittence and other uncertainties will likely require operation of additional natural gas and other fast-responding units to provide spinning reserve as a buffer against unanticipated variations. The changes in natural gas production anticipated with the planned increase in wind production cannot be accurately predicted by the modeling.
- The system model utilized a dc powerflow. The dc powerflow is more appropriate than an ac powerflow for cyclic loading studies used for dispatching but does not account for transmission line losses and reactive power flows for voltage support. PowerWorld used interface constraints to adapt the dc model to represent limitations of power flows due to these factors.
- The system was modeled with constraints at the interfaces. The constraints served as "proxies" for certain operating limits.
- The model assumed that the full transmission system is in normal configuration. No forced outage conditions were simulated. Insofar as the study was meant to look at the differential between the Base Case and the EERE Case, this was deemed to be an acceptable modeling approach.
- System load was changed according to historic patterns and averaged over a 6-hour interval called a time step. For each time step, the load was applied to the model and generators dispatched according to the optimal power flow.
- Wind generation in Illinois was located in areas that have the highest potential for wind energy. It is recognized that wind generation is not always placed in the most advantageous geographic location and, as such, the actual energy generated may be less

[3] PowerWorld's dispatch analysis ultimately revealed that hydroelectric dispatch would not be impacted by the Energy Plan, so hydroelectric power plants are not mentioned again in this report.

than the amount forecast. Conversely, the efficiencies of the wind generating units were conservatively estimated and advances in turbine technology are expected to increase actual electrical output. Therefore, the two factors were considered to act in opposition and, for the most part, offset each other.

- It was assumed that existing power plants would continue to operate in the same manner as they did in the baseline study year.[4] That is, the operating costs of the units have been adjusted only to account for changes in fuel costs and labor escalation. It was not possible to predict changes in availability (i.e., major unit outages due to major unit overhauls or capital additions) or shutdowns due to future regulatory constraints.

B.4 Load Forecasts

a. Load Growth in Illinois. According to the Energy Information Administration (EIA), U.S. energy sales are expected to grow at an average 1.8% per year between 2001 and 2025.[5] However, historical indices over a 10-year period from 1991 to 2002 indicate that the load growth in Illinois has lagged the average load growth in the United States by approximately 28%. Therefore, to account for this historical disparity in growth, a value of 72% of the projected average U.S. load growth was used, or 1.3%. Using data published by the ICC for 1999 - 2005, the Base Case loads projected for Illinois over the period 2007 - 2013 are shown in Table 3-1.

Table 3-1: Base Case Load Growth Estimate in Illinois, 2007 - 2013

Illinois Load Estimate	
Year	**Base Case Load (GWh)**
2007	146,857
2008	148,767
2009	150,702
2010	152,662
2011	154,648
2012	156,659
2013	158,697

b. Load Growth Outside Illinois. For the Seven State Area, FERC Form 714 forecasts were used to scale the load for study years 2007 through 2013. The total load for the Study Area outside Illinois used in the modeling study, as received from PowerWorld, is shown in Table 3-2.

[4] After the analysis described in this report was completed, Illinois EPA entered into multi-pollutant agreements with companies that will lead to the retirement of some coal-fired capacity during the study period, which may impact the results of the analysis.

[5] Annual Energy Outlook 2003 (Energy Information Administration, "Energy Annual Outlook 2003", January 2003, DOE/EIA-0383), as cited in *Emissions Impact Assessment for the Illinois Sustainable Energy Plan Based on Economic Dispatch Considerations (Draft)* prepared by UIC ERC, February 9, 2006.

Table 3-2: Base Case Load Growth Estimate Outside Illinois, 2007 - 2013

Load Estimate For Study Area Outside Illinois	
Year	**Base Case Load (GWh)**
2007	1,155,050
2008	1,175,869
2009	1,195,621
2010	1,214,011
2011	1,234,676
2012	1,254,506
2013	1,274,657

B.5 Cost Data

Cost data used for the study were derived as follows:

- Coal fuel costs were provided by DCEO
- All other fuel costs, fuel cost forecasts, heat rates and variable operation and maintenance costs were obtained from EIA databases

C. Modeling the Energy Efficiency Portfolio

The Energy Plan defines targets for energy efficiency measures (i.e., the EEPS) based on total customer energy sales by regulated Illinois utilities and alternative retail electric suppliers (ARES). The amount of electrical energy sold and delivered by regulated electric utilities in Illinois is reported annually by the ICC in its *Comparison of Electric Sales Statistics* for Illinois electric utilities. The ICC's report lists sales of total electrical energy as well as sales of bundled service. Total sales also include sales by ARES for which regulated utilities provide delivery services.

Table 3-3 shows the actual energy consumption reported by the ICC for the period 1999 - 2005 and projected consumption for the period 2006 - 2013.[6] Projected consumption shown in Table 3-3 was calculated using the estimated load growth of 1.3% per year—that is, it does not include the impact of the EEPS on reduction in load growth.

[6] Note that Table 3-1 is a forecast of total load growth in Illinois including sales to customers of regulated utilities, municipal utilities, and electricity cooperatives, as well as industrial/commercial load supplied by self-generation. Table 3-3, on the other hand, only includes sales to customers of regulated utilities and alternative retail electric suppliers (ARES). The Energy Efficiency Portfolio Standard does not apply to municipal utilities, cooperatives, or self-generation.

Table 3-3: Actual and Projected Energy Consumption in Illinois without EEPS, 1999 - 2013

Year	ACTUAL (MWh)		PROJECTED (MWh)	
	Bundled Service	Sales to Ultimate Customers	Bundled Service	Sales to Ultimate Customers
1999	122,141,748	122,141,748		
2000	109,570,988	126,893,517		
2001	102,041,248	127,711,894		
2002	98,220,571	127,339,866		
2003	90,602,012	124,431,464		
2004	88,535,189	126,762,203		
2005	95,432,700	133,098,139		
2006			96,673,325	134,828,415
2007			97,930,078	136,581,184
2008			99,203,169	138,356,740
2009			100,492,811	140,155,377
2010			101,799,217	141,977,397
2011			103,122,607	143,823,103
2012			104,463,201	145,692,804
2013			105,821,222	147,586,810

The targets for energy efficiency savings in the Energy Plan are as follows:

- 10% reduction of the total forecast electricity sales in each of the years 2007 and 2008
- 15% reduction of the total forecast electricity sales in each of the years 2010, 2011 and 2012
- 20% reduction of the total forecast electricity sales in 2013

In applying the energy efficiency targets to electrical consumption, the following assumptions were made:

1. Residential Loads. Approximately 20% of the targeted energy savings were forecast to be in residential electricity consumption. Major potential for savings are in improved technologies in building materials, space heating and cooling, water heating, refrigeration, cooking, lighting and major appliances. The reductions in energy usage were all surcharged against utility company customers that receive bundled service.

2. Commercial Loads. The commercial sector represents about 41% of the total electricity consumption in the state and a proportionate level of savings in electrical energy usage was forecast for this sector. The major areas of savings are similar to that described for residential electricity users, but the modeling of energy consumption was assumed to be predominantly to customers that receive unbundled service. Therefore, energy efficiency savings were not

surcharged against the growth in Bundled Service but acted to reduce the Sales to Ultimate Customers.

3. Industrial Loads. The balance of savings in electrical energy usage was assumed to be made up by industrial users of electrical energy. Similar to the approach cited above for Commercial Loads, the modeling of energy consumption was assumed to be in unbundled service. Therefore, energy efficiency savings were not surcharged against the growth in bundled service.

Applying these factors to the projected energy consumption shown in Table 3-3 yields the forecast savings in electrical consumption from the EEPS shown in Table 3-4.

Table 3-4: Projected Energy Consumption in Illinois with EEPS, 2007 - 2013

Year	Bundled Service			Total Illinois Consumption		
	Savings (MWh)		Forecast with EEPS	Savings (MWh)		Forecast with EEPS
	Annual	Cumulative		Annual	Cumulative	
2007	25,135	25,135	97,904,943	175,277	175,277	146,681,723
2008	25,462	50,597	99,152,572	177,556	352,832	148,414,168
2009	38,689	89,286	100,403,524	269,796	622,628	150,079,372
2010	39,192	128,478	101,670,739	273,303	895,931	151,766,069
2011	39,702	168,180	102,954,427	276,856	1,172,787	153,475,213
2012	53,624	221,804	104,241,397	373,940	1,546,727	155,112,273
2013	54,321	276,125	105,545,098	378,801	1,925,528	156,771,472

D. Modeling the Renewable Energy Portfolio

D.1 Basic Assumptions

The Energy Plan defined targets for renewable energy in Illinois calculated on the basis of the total energy supplied by regulated electric utilities as bundled service. The target for renewable energy is 2% of the bundled service energy consumption in Illinois to be supplied by renewable resources in 2007. The percentage is to increase by 1% per year for each following year until 2013 when 8% of the bundled service energy consumption in Illinois is to be supplied by renewable energy resources.

The assumptions used for this assessment were as follows:

- Ninety-five percent (95%) of the renewable energy in Illinois will be generated by wind. Wind generation has the highest potential of any renewable energy source for development in Illinois. According to a report by UIC ERC, "new wind resource maps of Illinois have been produced by the Department of Energy's Wind Program and National Renewable Energy Laboratory showing that Illinois has at least 3,000 MW in potential wind capacity from Class 4 wind resource areas and an additional 6,000 MW in upper-range Class 3 resources. Because the map is compiled more from topographical

extrapolations than from specific tower data, the aggregate wind resource projections can be expected to be accurate, though individual sites may have a stronger or lesser resource than the map indicates."[7] Therefore, it is reasonable to assume that the vast majority of new renewable energy sources will be from wind generation.

- Two wind generating stations – the 51 MW Crescent Ridge development and the 50.4 MW wind plant at Mendota Hills – are already in operation in Illinois and contributing to the renewable energy targets set by the Energy Plan. Energy Plan targets for new renewable energy generation must be offset by the energy being generated from these two stations.
- New wind generation stations will be sited in those areas of the state that have the greatest wind capacity and that are located in largely rural areas away from large cities.
- The 5% balance of renewable energy targeted by the Energy Plan will be developed from landfill gas (3%), biomass (1%) and biogas (1%). The location of these new resources in the state is difficult to predict and, for purposes of this study, they have been assumed to be evenly distributed throughout Illinois.

Accordingly, the amount of renewable energy resources modeled for this study is shown in Table 3-5.

Table 3-5: Projected Renewable Energy Implementation in Illinois, 2007 - 2013

Year	Renewable Energy				
	Wind (MWh)			Other (MWh)	Total
	Energy Plan Target	Existing	Annual Additions	Energy Plan Target	
2007	1,858,284	279,987	1,578,297	97,804	1,956,088
2008	2,820,080		961,797	148,425	2,968,506
2009	3,801,762		981,682	200,093	4,001,855
2010	4,804,949		1,003,187	252,892	5,057,841
2012	5,830,057		1,025,108	306,845	6,136,902
2012	6,873,053		1,042,996	361,740	7,234,793
2013	7,937,486		1,064,432	417,762	8,355,248

D.2 Modeling Wind Generation Plants

a. Wind Data. According to the Illinois wind resources maps, the counties that offer the best potential for large-scale development of wind generation are in the following areas of the state:

[7] *The Economic and Environmental Impacts of Clean Energy Development in Illinois*, University of Illinois at Chicago Energy Resources Center, June 2005.

(1) North Region. Approximately 54% of the generated wind energy is assumed to be developed in the following 11 counties:

- Bureau
- Carroll
- Henry
- JoDaviess
- Knox
- LaSalle
- Lee
- Marshall
- Ogle
- Stark
- Stephenson

(2) Central Region. Approximately 42% of the generated wind energy is assumed to be developed in the following 14 counties:

- Champaign
- Coles
- Dewitt
- Edgar
- Ford
- Iroquois
- Knox
- Livingston
- Logan
- Mason
- McLean
- Mercer
- Warren
- Woodford

(3) South Region. Four percent (4%) of the generated wind energy is likely to be developed in the South Region, defined to be counties south of Coles County.

Hour-by-hour profiles of the expected generation output from Illinois wind power stations was derived from wind measurements taken by Professor Roger Brown of Western Illinois University (WIU). WIU took hour-by-hour measurements of wind velocity at two potential wind locations in Henry County in the North Region and Coles County in the Central Region. Measurements were taken over the period of one year and were used as representative data to calculate the expected generation profile from a typical 1.5 MW NEG Micon wind-turbine. PowerWorld used the resultant generation profile in its system model to simulate expected generation of the wind power stations over the course of a year. Since wind production is not dispatchable – that is, it is fixed based on expected wind patterns – the generation produced by wind generation was considered to be base generation that would act to displace regional generation resources that are dispatched by system operators.

b. Wind Generation Plants. In order to model the impact of wind generation on electricity production in Illinois, it was necessary to translate the energy targets for wind generation into a specific number of plants scattered throughout Illinois. The method used to produce the quantity, capacity and location of the wind farms was as follows:

- Capacity factors were based on the WIU wind measurements at the two sites:

  - North Region: 31.4%
  - Central Region: 30.0%

  The South Region was assumed to have a capacity factor equal to that measured for the Central Region.

It should be noted that these plant factors are considered conservative. With current advances in wind turbine technology, plant factors in excess of 35% are considered attainable. Nevertheless, this study used the more conservative estimates for modeling purposes so that hourly energy data as measured by WIU at its two test sites in Cole and Henry Counties could be directly input to the dispatch model without the need for scaling. The impact of this set of assumptions to the modeling study was considered insignificant since the number and capacity of the wind farms was being scaled as necessary to correlate with the target energy values.

- Wind farms were assumed to consist of multiple 1.5 MW wind turbine-generators typically configured in arrays to produce a total installed capacity in the range of 150-200 MW, although it was recognized that wind farms exceeding this range are in the development stages.

The wind generating plants were sited throughout the state to interconnect into the existing 138 kV transmission grid at points that were deemed to be capable of handling the full output of each project. It was assumed that any transmission lines required to deliver power to these points would be built as part of the wind generating plants.

Using the criteria described, the number and capacity of the wind generation plants used in the model to correlate to the Energy Plan targets for wind generation are shown in Table 3-6.

Table 3-6: Projected Wind Generation Plants in Illinois to Implement Energy Plan Targets, 2007 - 2013

NORTH REGION				
Year	**Number of:**			**Capacity**
	1.5 MW TGs	**Wind farms**	**Units/Wind farm**	**MW/Wind farm**
2007	216	2	108	162
2008	126	1	126	189
2009	146	1	146	219
2010	130	1	130	195
2011	132	1	132	198
2012	132	1	132	198
2013	132	1	132	198
Total	**1,014**	**8**		**1,521**
CENTRAL REGION				
Year	**Number of:**			**Capacity**
	1.5 MW TGs	**Wind farms**	**Units/Wind farm**	**MW/Wind farm**
2007	178	1	178	267
2008	124	1	124	186
2009	0	0	0	0
2010	128	1	128	192
2011	130	1	130	195
2012	130	1	130	195
2013	138	1	138	207
Total	**828**	**6**		**1,242**
SOUTH REGION				
Year	**Number of:**			**Capacity**
	1.5 MW TGs	**Wind farms**	**Units/Wind farm**	**MW/Wind farm**
2007				0
2008				0
2009	76	1	76	114
2010				0
2011				0
2012				0
2013				0
Total	**76**	**1**		**114**

E. Impact of Energy Plan on Generation in Illinois

The simulated seven-year energy production values from the PowerWorld Report comparing the energy output from the Base Case with the energy output from the EERE Case is reproduced in Table 3-7, while Table 3-8 contains the changes in energy production for 2013, the final year of

study. The output changes have been segregated into periods coinciding with the ozone season (May through September) and non-ozone season in Illinois.

Table 3-7: Changes in Energy Production in Illinois Due to Energy Plan Implementation, 2007 - 2013

Fuel Type	Energy Production—Base Case (GWh)			Energy Production—EERE Case (GWh)			Change*		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	GWh, Total
Coal	339,569	260,022	599,591	329,999	255,695	585,694	(9,570)	(4,327)	(13,897)
Natural Gas	7,817	7,343	15,160	9,382	7,225	16,607	1,565	(118)	1,447
Fuel Oil	7,396	6,274	13,670	5,077	5,690	10,767	(2,319)	(584)	(2,903)
Wind	1,409	551	1,960	25,169	9,032	34,201	23,760	8,481	32,241
Nuclear	406,386	293,288	699,673	406,386	293,288	699,674	-	-	-
Other RPS**	-	-	-	1,015	782	1,797	1,015	782	1,797
Imports (Exports)	(158,355)	(102,706)	(261,060)	(177,171)	(109,777)	(286,948)	(18,816)	(7,071)	(25,888)
Total Load	604,222	464,772	1,068,994	599,857	461,935	1,061,792	(4,365)	(2,837)	(7,202)

* Negative values in Change columns reflect a decrease in energy production
** Other RPS resources were modeled as load in the EERE Case, but are shown separately from load in this table

Table 3-8: Changes in Energy Production in Illinois Due to Energy Plan Implementation, 2013

Fuel Type	Energy Production—Base Case (GWh)			Energy Production—EERE Case (GWh)			Change*		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	GWh, Total
Coal	53,069	39,968	93,037	50,397	38,793	89,190	(2,672)	(1,175)	(3,847)
Natural Gas	1,855	1,776	3,631	2,192	1,714	3,906	337	(62)	275
Fuel Oil	1,564	1,257	2,821	1,003	1,094	2,097	(561)	(163)	(724)
Wind	201	79	280	5,913	2,113	8,026	5,712	2,034	7,746
Nuclear	58,055	41,898	99,953	58,055	41,898	99,953	-	-	-
Other RPS**	-	-	-	239	184	423	239	184	423
Imports (Exports)	(25,085)	(15,941)	(41,026)	(29,310)	(17,660)	(46,970)	(4,225)	(1,719)	(5,944)
Total Load	89,659	69,037	158,696	88,489	68,136	156,625	(1,170)	(901)	(2,071)

* Negative values in Change columns reflect a decrease in energy production
** Other RPS resources were modeled as load in the EERE Case, but are shown separately from load in this table

The reduction in generation from specific coal-fired generating plants in Illinois is listed in the PowerWorld Report and discussed in more detail in Section IV.

F. Impact of Energy Plan on Generation Outside Illinois

Table 3-7 shows a net increase in exports to other states in the region resulting from implementation of the renewable energy and energy efficiency measures in the Energy Plan over the seven-year period from 2007 through 2013. The net increase is 25,888 GWh over the seven-year period. The impact to fossil-fired generation in the Seven State Area outside Illinois is reproduced from the PowerWorld report in Table 3-9.

Table 3-9: Changes in Energy Production Outside Illinois Due to Energy Plan Implementation, 2007 – 2013*

Resource	Estimated Change (GWh)
Coal, Iowa	(11,000)
Coal, Indiana	(3,000)
Coal, Kentucky	800
Coal, Michigan	400
Coal, Missouri	(3,300)
Coal, Ohio	(600)
Coal, Wisconsin	(1,000)
Natural Gas for Seven State Area	200
Other Out-of-State Resources (all types)	(8,388)
Total	**(25,888)**

* Negative values reflect a decrease in energy production

From Table 3-9, it can be seen that the main impact outside Illinois is to reduce output from coal-fired power plants. Natural gas generation in the Seven State Area remains almost unchanged. The balance of energy production displaced outside the Seven State Area (8,388 GWh) is principally coal and oil-fired generation in the TVA region and parts of Pennsylvania and Virginia. For the final year of the study period, 2013, the impact on generation outside Illinois is shown in Table 3-10.

Table 3-10: Changes in Energy Production Outside Illinois Due to Energy Plan Implementation, 2013*

Resource	Estimated Change (GWh)
Coal, Iowa	(1,678)
Coal, Indiana	(463)
Coal, Kentucky	125
Coal, Michigan	66
Coal, Missouri	(508)
Coal, Ohio	(96)
Coal, Wisconsin	(163)
Natural Gas for Seven State Area	49
Other Out-of-State Resources (all types)	(1,265)
Total	**(3,933)**

* Negative values reflect a decrease in energy production

IV. IMPACT OF ENERGY PLAN ON AIR EMISSIONS

A. General

To assess the impact of the Energy Plan on air emissions, Base Case and EERE Case emissions projections were made for each year from 2007 to 2013 for the following pollutants from existing Illinois power plants (a list of which is attached as Appendix C):

- Sulfur dioxide (SO_2)
- Nitrogen oxides (NOx)
- Mercury (Hg)
- Carbon dioxide (CO_2)

The Energy Plan impact was calculated to be the difference in the projected emissions between the two cases. Emissions changes were reported as the difference between the EERE Case and the Base Case (i.e., Change in emissions = EERE Case emissions – Base Case emissions). Thus, any negative value in the change in emissions column in the following tables reflects a decrease in emissions for the EERE Case over the Base Case.

B. Study Methodology

Coal, natural gas and fuel oil generation are all impacted by the EERE Case, through introduction of the RPS and EEPS. The following sections describe the estimated change in emissions for these three types of fossil fuel power plants from implementing the Energy Plan. Changes in emissions are estimated for: i) Illinois plants, ii) plants in the Seven State Area, iii) plants elsewhere in the Study Area affected by Energy Plan measures in Illinois and iv) all plants within the Study Area, including Illinois plants.

Results of the dispatch modeling indicated that there would be a net export of energy from Illinois to the Seven State Area and beyond. Export of energy from Illinois will result in generation within Illinois and, by the same token, emissions within Illinois. The type of energy exported (e.g., fossil fuel, nuclear, wind) could not be determined in this analysis. Therefore, the impact of the export of energy was not included in the emission analysis in this report. A more detailed dispatch modeling is required to address this issue.

B.1 Impact of Energy Plan on Emissions for Plants in Illinois

B.1.1 Coal-Fired Power Plants

The actual emissions profile for each coal-fired power plant was expected to vary from unit to unit. However, a consistent methodology was needed to evaluate the relative difference in emissions for the EERE Case and the Base Case. Therefore, generally accepted emission factors were used in the analysis for all years of study except where changes were known to affect the emissions. The basic criteria used to develop the power plant characteristics and emission rates were as follows:

- Basic plant data, including plant locations, primary fuels, boiler type (i.e., wet bottom or dry bottom) and boiler efficiencies were obtained from information published by the EIA

- NOx emissions were based on an emission factor of 1.5 lb./MWh-Energy-Output from USEPA's May 2000 guidance document, *Developing and Updating Output-Based NOx Allowance Allocations*.[8] This factor was considered to be applicable for all years of the assessment. It was understood that many of the units would operate at below this emission level. However, this limit was theoretically the maximum allowable and therefore represented maximum emissions from the units.

- SO_2 emissions were based on an emission factor of 1.2 lb/mmBtu-Energy Input from USEPA's *Acid Rain Program SO_2 Allowances Fact Sheet*.[9] This factor was considered applicable for all years of the assessment. Individual plant capacity factors were used to convert from reported MWh-output to mmBtu-input prior to application of the emission factor. It is understood that many of the units would operate at or below this emission level. However, this limit was theoretically the maximum allowable and therefore represented maximum emissions from the units.

- Hg emissions through the end of June 2009 were calculated using a value of 16 lb/10^{12} BTU-Energy Output, taken from USEPA AP-42, Table 1.1-17 – "Emission Factors for Trace Elements, POM, and HCOH from Uncontrolled Bituminous and Sub-bituminous Coal Combustion" (AP-42).

- CO_2 emissions were calculated using the nationwide average carbon dioxide emissions factors of 205.3 lb/mmBtu-Energy-In, for bituminous coal, and 211.9 lb/mmBtu-Energy-

[8] Available at http://www.epa.gov/airmarkets/fednox/april00/finaloutputguidanc.pdf.
[9] Available at http://www.epa.gov/airmarkets/arp/allfact.html.

In, for sub-bituminous coal taken from EIA's "Carbon Dioxide Emission Factors for Coal."[10] Where the type of coal used by the plant was not available, the factor for bituminous coal was used, since this was the most common fuel in Illinois plants.

Plant-by-plant emissions changes were calculated for the years 2007 through 2013 and also separately for 2013 for the ozone and non-ozone seasons in Illinois.

It should be noted that detailed data for the John Deere Harvester Works, Pearl Station and University of Illinois Abbott coal-fired power plants were not available from EIA or IEPA resources. In order to include these small plants in the Energy Plan impacts assessment, a boiler efficiency of 0.301, which is the average of the other plants, and a Hg emission factor of 0.000156 lb./MWh-Energy Out, which is the average for the other plants, were used. In addition, CO_2 emission factors were estimated for each of these plants using the average boiler efficiency and assuming bituminous coal fuel.

Detailed calculations are included in Appendix D. Projected changes in energy generation from coal-fired power plants due to implementation of the Energy Plan and corresponding changes in emissions are presented in Table 4-1a through Table 4-1e.

Table 4-1a: Projected Changes in Electrical Energy Production in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	Base Case (MWh)		EERE Case (MWh)		Change in Production (MWh)	
	Non-Ozone	Ozone	Non-Ozone	Ozone	Non-Ozone	Ozone
2007	45,778,714	35,190,464	45,412,196	35,020,310	(366,518)	(170,155)
2008	46,783,061	35,906,598	46,073,066	35,677,822	(709,995)	(228,776)
2009	47,020,534	36,173,816	46,074,021	35,744,609	(946,513)	(429,207)
2010	47,520,214	36,619,228	46,225,227	36,000,219	(1,294,987)	(619,009)
2011	48,859,838	37,550,749	47,253,207	36,768,033	(1,606,632)	(782,716)
2012	50,537,135	38,612,350	48,564,531	37,690,782	(1,972,604)	(921,568)
2013	53,069,365	39,968,465	50,396,712	38,792,887	(2,672,653)	(1,175,579)
Total	**339,568,861**	**260,021,671**	**329,998,959**	**255,694,662**	**(9,569,901)**	**(4,327,009)**

* Negative values reflect a decrease in energy production

[10] Available at http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html.

Table 4-1b: Projected Changes in SO_2 Emissions in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	SO_2 Base Case (tons/yr)			SO_2 EERE Case (tons/yr)			Change in SO_2 Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	285,026	219,947	504,973	282,844	218,882	501,726	(2,182)	(1,065)	(3,247)
2008	291,446	224,552	515,998	287,210	223,130	510,340	(4,236)	(1,422)	(5,658)
2009	293,156	226,429	519,585	287,636	223,778	511,413	(5,520)	(2,651)	(8,171)
2010	296,061	229,121	525,182	288,533	225,267	513,800	(7,528)	(3,854)	(11,383)
2011	304,852	235,232	540,084	295,246	230,343	525,589	(9,606)	(4,889)	(14,495)
2012	315,616	242,029	557,645	303,712	236,263	539,975	(11,904)	(5,766)	(17,670)
2013	331,705	250,636	582,341	315,608	243,270	558,878	(16,096)	(7,366)	(23,463)
Total	**2,117,862**	**1,627,946**	**3,745,808**	**2,060,790**	**1,600,933**	**3,661,722**	**(57,073)**	**(27,013)**	**(84,086)**

* Negative values reflect a decrease in emissions

Table 4-1c: Projected Changes in NOx Emissions in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	NOx Base Case (tons/yr)			NOx EERE Case (tons/yr)			Change in NOx Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	34,334	26,393	60,727	34,059	26,265	60,324	(275)	(128)	(403)
2008	35,087	26,930	62,017	34,555	26,758	61,313	(532)	(172)	(704)
2009	35,265	27,130	62,396	34,556	26,808	61,364	(710)	(322)	(1,032)
2010	35,640	27,464	63,105	34,669	27,000	61,669	(971)	(464)	(1,435)
2011	36,645	28,163	64,808	35,440	27,576	63,016	(1,205)	(587)	(1,792)
2012	37,903	28,959	66,862	36,423	28,268	64,691	(1,479)	(691)	(2,171)
2013	39,802	29,976	69,778	37,798	29,095	66,892	(2,004)	(882)	(2,886)
Total	**254,677**	**195,016**	**449,693**	**247,499**	**191,771**	**439,270**	**(7,177)**	**(3,245)**	**(10,423)**

* Negative values reflect a decrease in emissions

Table 4-1d: Projected Changes in Hg Emissions in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	Hg Base Case (lbs/yr)			Hg EERE Case (lbs/yr)			Change in Hg Emissions (lbs/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	2,499	1,921	4,420	2,479	1,912	4,391	(20)	(9)	(29)
2008	2,554	1,960	4,514	2,515	1,948	4,463	(39)	(12)	(51)
2009	2,567	1,975	4,542	2,515	1,951	4,467	(52)	(23)	(75)
2010	2,594	1,999	4,593	2,524	1,965	4,489	(71)	(34)	(104)
2011	2,667	2,050	4,717	2,580	2,007	4,587	(88)	(43)	(130)
2012	2,759	2,108	4,867	2,651	2,058	4,709	(108)	(50)	(158)
2013	2,897	2,182	5,079	2,751	2,118	4,869	(146)	(64)	(210)
Total	**18,538**	**14,195**	**32,733**	**18,015**	**13,959**	**31,974**	**(522)**	**(236)**	**(759)**

* Negative values reflect a decrease in emissions

Table 4-1e: Projected Changes in CO_2 Emissions in Coal-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	CO_2 Base Case (tons/yr)			CO_2 EERE Case (tons/yr)			Change in CO_2 Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	48,763,207	37,629,277	86,392,484	48,389,846	37,447,089	85,836,935	(373,361)	(182,188)	(555,549)
2008	49,861,569	38,417,078	88,278,648	49,136,851	38,173,849	87,310,700	(724,718)	(243,230)	(967,948)
2009	50,154,088	38,738,177	88,892,266	49,209,697	38,284,612	87,494,308	(944,392)	(453,565)	(1,397,957)
2010	50,651,188	39,198,776	89,849,964	49,363,226	38,539,344	87,902,570	(1,287,962)	(659,432)	(1,947,393)
2011	52,155,127	40,244,252	92,399,379	50,511,718	39,407,865	89,919,583	(1,643,409)	(836,387)	(2,479,797)
2012	53,996,676	41,407,143	95,403,818	51,960,079	40,420,687	92,380,766	(2,036,597)	(986,455)	(3,023,053)
2013	56,749,112	42,879,724	99,628,836	53,995,344	41,619,442	95,614,786	(2,753,768)	(1,260,282)	(4,014,050)
Total	**362,330,968**	**278,514,427**	**640,845,395**	**352,566,760**	**273,892,887**	**626,459,648**	**(9,764,207)**	**(4,621,540)**	**(14,385,747)**

* Negative values reflect a decrease in emissions

B.1.2 Natural Gas-Fired Power Plants

The principal pollutant from the operation of natural gas-fired power plants is NOx. An emission factor of 0.03 lb./mmBtu, per USEPA's AP-42, was used to estimate the overall year-by-year change in NOx emissions due to changes in natural gas-fired generation as a result of the RPS and EEPS measures. Natural gas contains a small percentage of sulfur and negligible amounts of Hg. The SO_2 emissions are typically much lower compared to NOx and Hg emissions are negligible for natural gas combustion. AP-42 was also used to derive emission factors of 0.002 lb./MWh for SO_2 and Hg emissions were neglected.

Both AP-42 and World Resource Institute (WRI) GHG Protocol Initiative documents[11] were reviewed for a CO_2 emission factor from natural gas combustion. The WRI documentation was considered to be more appropriate since it was based on EIA data and more widely used, so the WRI factor of CO_2 emission factor of 1176 lb./MWh was used in the analysis.

Projected changes in energy generation from natural gas-fired power plants due to implementation of the Energy Plan are presented in Table 4-2a. Using the generation values calculated by PowerWorld in its modeling study, projected changes in emissions are presented in Table 4-2b through Table 4-2e.

[11] Available at http://www.ghgprotocol.org/templates/GHG5/layout.asp?MenuID=849.

Table 4-2a: Projected Changes in Electrical Energy Production in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	Base Case (MWh)		EERE Case (MWh)		Change in Production (MWh)	
	Non-Ozone	Ozone	Non-Ozone	Ozone	Non-Ozone	Ozone
2007	0	97,667	0	96,298	--	(1,368)
2008	3,480	224,376	1,478	213,905	(2,002)	(10,472)
2009	284,143	481,849	443,882	511,347	159,739	29,498
2010	1,006,776	1,052,636	1,447,213	1,070,825	440,437	18,190
2011	2,089,152	1,729,671	2,461,112	1,680,394	371,960	(49,277)
2012	2,578,107	1,980,579	2,836,202	1,937,520	258,095	(43,059)
2013	1,854,878	1,776,355	2,192,225	1,714,354	337,348	(62,001)
Total	**7,816,536**	**7,343,134**	**9,382,112**	**7,224,643**	**1,565,577**	**(118,491)**

* Negative values reflect a decrease in production

Table 4-2b: Projected Changes in SO_2 Emissions in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	SO_2 Base Case (tons/yr)			SO_2 EERE Case (tons/yr)			Change in SO_2 Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	--	0.10	0.10	--	0.10	0.10	--	(0.00)	(0.00)
2008	0.00	0.23	0.23	0.00	0.21	0.22	(0.00)	(0.01)	(0.01)
2009	0.29	0.48	0.77	0.45	0.51	0.96	0.16	0.03	0.19
2010	1.01	1.06	2.07	1.45	1.07	2.53	0.44	0.02	0.46
2011	2.10	1.74	3.83	2.47	1.69	4.16	0.37	(0.05)	0.32
2012	2.59	1.99	4.57	2.85	1.94	4.79	0.26	(0.04)	0.22
2013	1.86	1.78	3.64	2.20	1.72	3.92	0.34	(0.06)	0.28
Total	**7.84**	**7.37**	**15.21**	**9.41**	**7.25**	**16.66**	**1.57**	**(0.12)**	**1.45**

* Negative values reflect a decrease in emissions

Table 4-2c: Projected Changes in NOx Emissions in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	NOx Base Case (tons/yr)			NOx EERE Case (tons/yr)			Change in NOx Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	--	5.00	5.00	--	4.93	4.93	--	(0.07)	(0.07)
2008	0.18	11.48	11.66	0.08	10.95	11.02	(0.10)	(0.54)	(0.64)
2009	14.54	24.66	39.20	22.72	26.17	48.89	8.18	1.51	9.69
2010	51.53	53.87	105.40	74.07	54.80	128.87	22.54	0.93	23.47
2011	106.92	88.52	195.45	125.96	86.00	211.96	19.04	(2.52)	16.51
2012	131.95	101.37	233.31	145.16	99.16	244.32	13.21	(2.20)	11.01
2013	94.93	90.91	185.85	112.20	87.74	199.94	17.27	(3.17)	14.09
Total	**400.05**	**375.82**	**775.87**	**480.18**	**369.76**	**849.93**	**80.13**	**(6.06)**	**74.06**

* Negative values reflect a decrease in emissions

Table 4-2d: Projected Changes in Hg Emissions in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 - 2013

Year	Hg Base Case (lbs/yr)			Hg EERE Case (lbs/yr)			Change in Hg Emissions (lbs/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Table 4-2e: Projected Changes in CO_2 Emissions in Natural Gas-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	CO2 Base (tons/yr)			CO2 RPS (tons/yr)			RPS Change (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	0.00	57,428	57,428	0.00	56,623	56,623	0.00	(805)	(805)
2008	2,046	131,933	133,980	869	125,776	126,645	(1,177)	(6,157)	(7,334)
2009	167,076	283,327	450,403	261,003	300,672	561,675	93,926	17,345	111,271
2010	591,984	618,950	1,210,934	850,961	629,645	1,480,607	258,977	10,696	269,672
2011	1,228,422	1,017,047	2,245,468	1,447,134	988,072	2,435,205	218,712	(28,975)	189,737
2012	1,515,927	1,164,581	2,680,507	1,667,687	1,139,262	2,806,948	151,760	(25,319)	126,441
2013	1,090,668	1,044,497	2,135,165	1,289,029	1,008,040	2,297,069	198,361	(36,457)	161,904
Total	**4,596,123**	**4,317,763**	**8,913,886**	**5,516,682**	**4,248,090**	**9,764,772**	**920,559**	**(69,672)**	**850,887**

* Negative values reflect a decrease in emissions

B.1.3 Oil-Fired Power Plants

The principal pollutant from the operation of oil-fired power plants is SO_2. An AP-42 emission factor of 157S lb/1000 gal, where S is the sulfur content of the fuel oil in weight percent, was used to estimate the overall year-by-year change in SO_2 emissions due to changes in oil-fired generation as a result of the RPS scenario. Using an estimated average sulfur concentration of 1.2% (from EIA 906 Summary Data), the net rate of SO_2 emissions is computed to be 188 lb/1000 gal.

Emissions of NOx from oil-fired plants are significantly lower than SO_2. The most commonly used NOx emission factor is from AP-42, which is 10 lb/100 gallons. Though several stack tests in units across the country have shown slightly lower NOx emissions, the AP-42 factors were considered appropriate and used for the analysis. Not many data sources are available for CO_2 emissions from oil fired plants; therefore, the AP-42 factor of 22,300 lbs of CO_2 per 1000 gallons

of fuel oil was used in the analysis. This corresponds well with the WRI emission factor of 10.15 kgs CO_2 per gallon (i.e. 22330 lbs CO_2/1000 gallons).

The AP-42 emission factor of 3 lbs/10^{12} Btu was used for Hg emissions. For 2009 and beyond, a Hg emission factor of 0.008 lb/GWh-Energy-Output was selected to conform to the proposed Illinois mercury control rule.

Assumptions used in the calculations were:

- The plants are external fired combustion sources
- Fuel oil No. 2 would be used at boilers using distillate oil and fuel oil No. 6 would be used at boilers using residual oil
- An average energy output weighted (from EIA 906 Summary data) sulfur content of 1.2% in fuel oil
- Average fuel oil energy content of 140,000 BTU/gal (which is confirmed by EIA data for Illinois plants)
- An average energy output weighted (from EIA 906 Summary Data) energy efficiency of 30.1%

Projected changes in energy generation from oil-fired power plants due to implementation of the Energy Plan are presented in Table 4-3a. Projected changes in emissions are presented in Table 4-3b through Table 4-3e.

Table 4-3a: Projected Changes in Electrical Energy Production in Oil-Fired Plants in Illinois Due to Implementation of Energy Plan, 2007 – 2013*

Year	Base Case (MWh)		EERE Case (MWh)		Change in Production (MWh)	
	Non-Ozone	Ozone	Non-Ozone	Ozone	Non-Ozone	Ozone
2007	76,105	159,007	65,444	152,905	(10,661)	(6,102)
2008	124,439	209,375	76,501	177,799	(47,938)	(31,575)
2009	1,124,235	950,367	808,983	878,284	(315,252)	(72,084)
2010	1,672,931	1,306,706	1,153,700	1,214,946	(519,231)	(91,760)
2011	1,398,546	1,191,674	974,955	1,091,500	(423,591)	(100,174)
2012	1,436,727	1,199,358	995,065	1,080,301	(441,662)	(119,057)
2013	1,563,507	1,257,196	1,002,725	1,094,094	(560,782)	(163,101)
Total	**7,396,491**	**6,273,684**	**5,077,373**	**5,689,829**	**(2,319,117)**	**(583,854)**

* Negative values reflect a decrease in production

Table 4-3b: Projected Changes in SO_2 Emissions in Oil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	SO_2 Base Case (tons/yr)			SO_2 EERE Case (tons/yr)			Change in SO_2 Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	580	1,213	1,793	499	1,166	1,665	(81)	(47)	(128)
2008	949	1,597	2,546	583	1,356	1,940	(366)	(241)	(606)
2009	8,575	7,249	15,823	6,170	6,699	12,869	(2,404)	(550)	(2,954)
2010	12,760	9,967	22,726	8,800	9,267	18,066	(3,960)	(700)	(4,660)
2011	10,667	9,089	19,756	7,436	8,325	15,761	(3,231)	(764)	(3,995)
2012	10,958	9,148	20,106	7,590	8,240	15,829	(3,369)	(908)	(4,277)
2013	11,925	9,589	21,514	7,648	8,345	15,993	(4,277)	(1,244)	(5,521)
Total	**56,415**	**47,851**	**104,265**	**38,726**	**43,397**	**82,124**	**(17,688)**	**(4,453)**	**(22,142)**

* Negative values reflect a decrease in emissions

Table 4-3c: Projected Changes in NOx Emissions in Oil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	NOx Base Case (tons/yr)			NOx EERE Case (tons/yr)			Change in NOx Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	31	64	95	26	62	88	(4)	(2)	(7)
2008	50	85	135	31	72	103	(19)	(13)	(32)
2009	455	385	840	328	356	683	(128)	(29)	(157)
2010	677	529	1,206	467	492	959	(210)	(37)	(247)
2011	566	482	1,049	395	442	837	(171)	(41)	(212)
2012	582	486	1,067	403	437	840	(179)	(48)	(227)
2013	633	509	1,142	406	443	849	(227)	(66)	(293)
Total	**2,994**	**2,540**	**5,534**	**2,056**	**2,303**	**4,359**	**(939)**	**(236)**	**(1,175)**

* Negative values reflect a decrease in emissions

Table 4-3d: Projected Changes in Hg Emissions in Oil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	Hg Base Case (lbs/yr)			Hg EERE Case (lbs/yr)			Change in Hg Emissions (lbs/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	3	5	8	2	5	7	(0)	(0)	(1)
2008	4	7	11	3	6	9	(2)	(1)	(3)
2009	38	32	71	28	30	57	(11)	(2)	(13)
2010	57	44	101	39	41	81	(18)	(3)	(21)
2011	48	41	88	33	37	70	(14)	(3)	(18)
2012	49	41	90	34	37	71	(15)	(4)	(19)
2013	53	43	96	34	37	71	(19)	(6)	(25)
Total	**252**	**213**	**465**	**173**	**193**	**366**	**(79)**	**(20)**	**(99)**

* Negative values reflect a decrease in emissions

Table 4-3e: Projected Changes in CO_2 Emissions in Oil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	CO_2 Base Case (tons/yr)			CO_2 EERE Case (tons/yr)			Change in CO_2 Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	68,708	143,551	212,258	59,083	138,042	197,124	(9,625)	(5,509)	(15,134)
2008	112,343	189,022	301,365	69,065	160,516	229,581	(43,278)	(28,506)	(71,784)
2009	1,014,954	857,987	1,872,942	730,347	792,911	1,523,257	(284,608)	(65,077)	(349,684)
2010	1,510,315	1,179,688	2,690,003	1,041,555	1,096,848	2,138,403	(468,760)	(82,841)	(551,600)
2011	1,262,601	1,075,838	2,338,439	880,185	985,402	1,865,586	(382,416)	(90,437)	(472,853)
2012	1,297,071	1,082,775	2,379,846	898,340	975,291	1,873,631	(398,730)	(107,484)	(506,215)
2013	1,411,527	1,134,991	2,546,518	905,255	987,743	1,892,999	(506,271)	(147,247)	(653,519)
Total	**6,677,518**	**5,663,853**	**12,341,371**	**4,583,829**	**5,136,752**	**9,720,581**	**(2,093,689)**	**(527,101)**	**(2,620,790)**

* Negative values reflect a decrease in emissions

B.1.4 All Fossil-Fueled Plants

The projected total impact on Illinois plants was calculated by summing the impact on three types of fossil fuel power plants, as shown above. Projected changes in energy generation in all fossil-fueled plants due to implementation of the Energy Plan are presented in Table 4-4a Projected changes in emissions are presented in Table 4-4b through Table 4-4e.

Table 4-4a: Projected Changes in Electrical Energy Production in All Fossil-Fired Plants in Illinois Due to Implementation of Energy Plan, 2007 – 2013*

Year	Base Case (MWh)		EERE Case (MWh)		Change in Production (MWh)	
	Non-Ozone	Ozone	Non-Ozone	Ozone	Non-Ozone	Ozone
2007	45,854,819	35,447,138	45,477,639	35,269,513	(377,180)	(177,625)
2008	46,910,980	36,340,349	46,151,045	36,069,526	(759,935)	(270,824)
2009	48,428,911	37,606,032	47,326,886	37,134,240	(1,102,025)	(471,792)
2010	50,199,921	38,978,570	48,826,140	38,285,991	(1,373,781)	(692,579)
2011	52,347,537	40,472,095	50,689,273	39,539,927	(1,658,263)	(932,168)
2012	54,551,969	41,792,288	52,395,798	40,708,603	(2,156,170)	(1,083,685)
2013	56,487,750	43,002,016	53,591,662	41,601,335	(2,896,087)	(1,400,682)
Total	**354,781,887**	**273,638,488**	**344,458,443**	**268,609,135**	**(10,323,441)**	**(5,029,355)**

* Negative values reflect a decrease in production

Table 4-4b: Projected Changes in SO_2 Emissions in All Fossil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	SO_2 Base Case (tons/yr)			SO_2 EERE Case (tons/yr)			Change in SO_2 Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	285,607	221,160	506,766	283,343	220,048	503,391	(2,264)	(1,111)	(3,375)
2008	292,395	226,149	518,544	287,794	224,486	512,280	(4,602)	(1,663)	(6,264)
2009	301,731	233,678	535,409	293,807	230,477	524,283	(7,924)	(3,201)	(11,125)
2010	308,822	239,089	547,911	297,334	234,534	531,868	(11,488)	(4,554)	(16,042)
2011	315,521	244,323	559,844	302,685	238,670	541,355	(12,836)	(5,653)	(18,489)
2012	326,577	251,179	577,756	311,305	244,505	555,809	(15,273)	(6,674)	(21,947)
2013	343,632	260,227	603,859	323,259	251,617	574,875	(20,373)	(8,611)	(28,983)
Total	**2,174,285**	**1,675,805**	**3,850,089**	**2,099,527**	**1,644,337**	**3,743,861**	**(74,760)**	**(31,467)**	**(106,225)**

* Negative values reflect a decrease in emissions

Table 4-4c: Projected Changes in NOx Emissions in All Fossil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	NOx Base Case (tons/yr)			NOx EERE Case (tons/yr)			Change in NOx Emissions (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	34,365	26,462	60,827	34,086	26,332	60,418	(279)	(130)	(409)
2008	35,138	27,026	62,164	34,586	26,841	61,427	(552)	(185)	(737)
2009	35,735	27,540	63,275	34,906	27,190	62,096	(829)	(350)	(1,179)
2010	36,369	28,047	64,416	35,210	27,547	62,757	(1,159)	(500)	(1,659)
2011	37,318	28,734	66,052	35,961	28,104	64,064	(1,357)	(630)	(1,988)
2012	38,616	29,546	68,163	36,971	28,805	65,776	(1,645)	(742)	(2,387)
2013	40,530	30,576	71,106	38,316	29,625	67,941	(2,214)	(951)	(3,165)
Total	**258,071**	**197,931**	**456,003**	**250,036**	**194,444**	**444,479**	**(8,035)**	**(3,488)**	**(11,524)**

* Negative values reflect a decrease in emissions

Table 4-4d: Projected Changes in Hg Emissions in All Fossil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	Hg Base Case (lbs/yr)			Hg EERE Case (lbs/yr)			Change in Hg Emissions (lbs/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	2,502	1,927	4,428	2,481	1,917	4,398	(20)	(9)	(30)
2008	2,558	1,967	4,526	2,518	1,954	4,472	(40)	(14)	(54)
2009	2,605	2,007	4,612	2,543	1,981	4,524	(62)	(26)	(88)
2010	2,651	2,044	4,695	2,563	2,007	4,569	(88)	(37)	(125)
2011	2,715	2,090	4,805	2,613	2,044	4,657	(102)	(46)	(148)
2012	2,808	2,149	4,956	2,685	2,094	4,779	(123)	(54)	(177)
2013	2,950	2,225	5,175	2,785	2,155	4,940	(165)	(70)	(235)
Total	**18,789**	**14,409**	**33,197**	**18,188**	**14,152**	**32,339**	**(600)**	**(256)**	**(857)**

* Negative values reflect a decrease in emissions

Table 4-4e: Projected Changes in CO_2 Emissions in All Fossil-Fired Plants in Illinois Due to Energy Plan Implementation, 2007 – 2013*

Year	Base (tons/yr)			RPS (tons/yr)			RPS Change (tons/yr)		
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total
2007	48,831,915	37,830,256	86,662,171	48,448,928	37,641,754	86,090,682	(382,987)	(188,502)	(571,488)
2008	49,975,958	38,738,034	88,713,992	49,206,785	38,460,141	87,666,926	(769,173)	(277,893)	(1,047,066)
2009	51,336,118	39,879,492	91,215,610	50,201,046	39,378,195	89,579,240	(1,135,073)	(501,297)	(1,636,370)
2010	52,753,487	40,997,414	93,750,901	51,255,743	40,265,837	91,521,579	(1,497,744)	(731,577)	(2,229,321)
2011	54,646,150	42,337,137	96,983,287	52,839,037	41,381,338	94,220,374	(1,807,113)	(955,799)	(2,762,912)
2012	56,809,673	43,654,498	100,464,172	54,526,106	42,535,240	97,061,345	(2,283,568)	(1,119,259)	(3,402,826)
2013	59,251,307	45,059,212	104,310,519	56,189,628	43,615,226	99,804,854	(3,061,679)	(1,443,986)	(4,505,665)
Total	**373,604,608**	**288,496,043**	**662,100,651**	**362,667,272**	**283,277,729**	**645,945,001**	**(10,937,336)**	**(5,218,313)**	**(16,155,650)**

* Negative values reflect a decrease in emissions

For all pollutants for all years, the reduced energy allocations for coal-fired power plants statewide resulted in corresponding emissions reductions. For NOx, SO_2 and CO_2, the emissions reductions increase annually. For Hg, the reductions from 2009 and later were reduced from earlier years due to the dramatically lower mercury emission factor mandated after June 2009.

Figure 4-1a through Figure 4-1d show the projected net changes in emissions of the pollutants in Illinois for the period under study due to implementation of the Energy Plan.

Figure 4-1a: Projected Net Changes in SO_2 Emissions in Illinois, 2007 - 2013

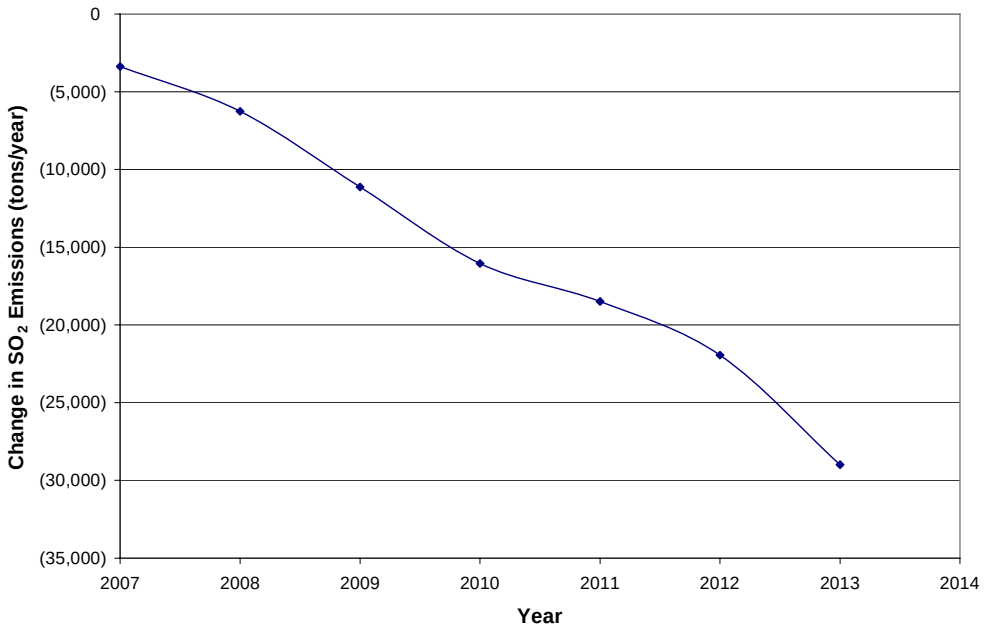


Figure 4-1b: Projected Net Changes in NOx Emissions in Illinois, 2007 - 2013

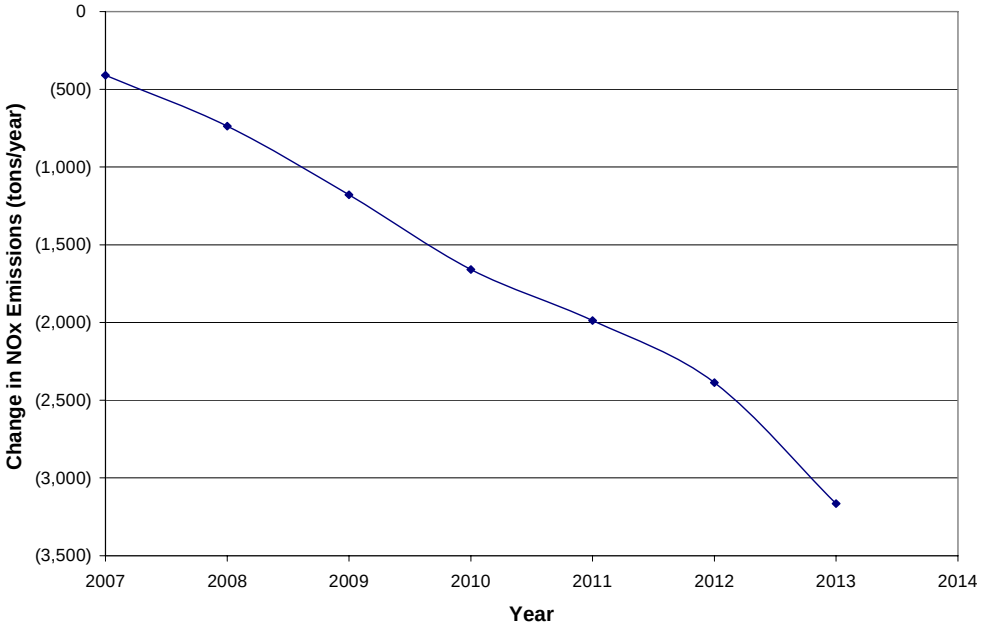


Figure 4-1c: Projected Net Changes in Hg Emissions in Illinois, 2007 - 2013

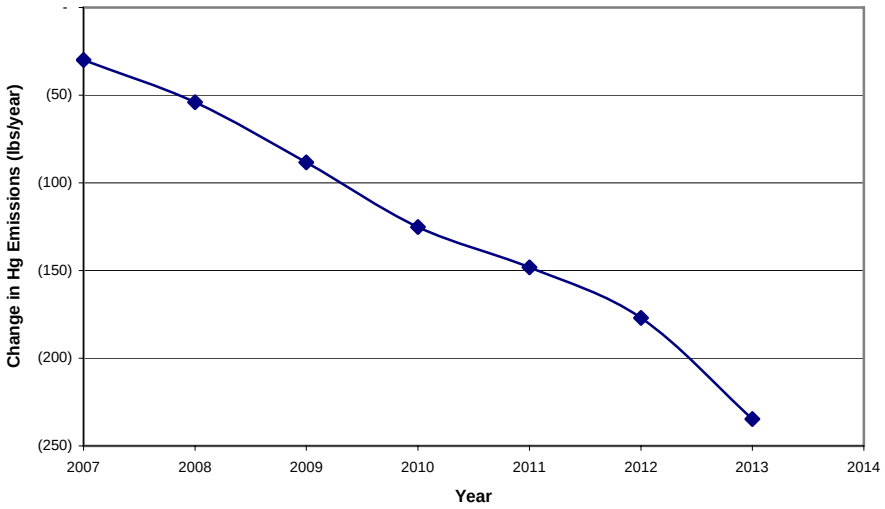
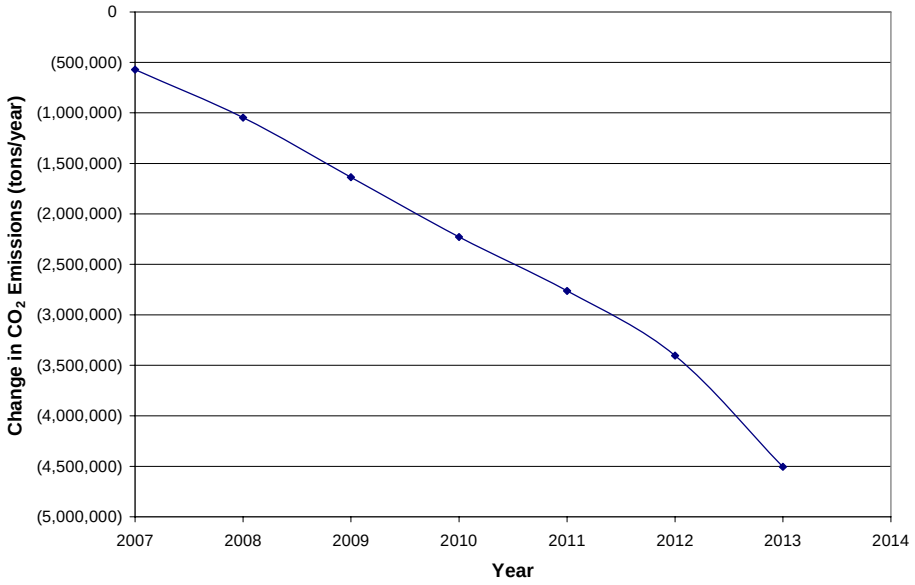


Figure 4-1d: Projected Net Changes in CO_2 Emissions in Illinois, 2007 – 2013



B.2 Impact of Energy Plan on Emissions in Study Area Outside Illinois

Changes in emissions resulting from implementation of the Energy Plan were estimated for Illinois, the Seven State Area and other out-of-state generation resources within the Study Area affected by the change in generation in Illinois. Emissions changes in plants outside Illinois and the Seven State Area could not be performed on an individual plant basis, due to the lack of detailed data. Average values of emissions factors were therefore used as a reasonable approach. Since the types of plants in the Seven State Area are similar to those in Illinois, average emissions factors were derived from the mix of Illinois plants under study. The emissions factors were derived based on output energy, since this data is readily available for the plants outside Illinois. Appendix D shows the derivation of these emissions factors over the period of 2007 - 2013, which are reproduced here for reference:

<u>Coal-Fired Power Plants</u>

- SO_2: 6 tons/GWh
- NOx: 0.75 tons/GWh
- Hg: 0.05 lb./GWh
- CO_2: 1,070 tons/GWh

<u>Natural Gas-Fired Power Plants</u>

- NOx: 0.05 tons/GWh
- CO_2: 588 tons/GWh

Oil-Fired Power Plants

- SO_2 : 7.63 tons/GWh
- NOx: 0.40 tons/GWh
- Hg: 0.03 lb./GWh
- CO_2: 903 tons/GWh

Applying these overall average factors to the reduction in generation in the Seven State Area, an estimate of the change in emissions from power plants in the Seven State Area can be made as indicated in Table 4-5 (cumulative for years 2007 - 2013) and Table 4-6 (for year 2013 only).

Table 4-5: Projected Changes in Emissions in All Fossil Fuel-Fired Plants in the Seven State Area and Study Area Due to Energy Plan Implementation, 2007 – 2013*

Resource	Estimated Change (GWh)	SO_2 (tons)	NOx (tons)	Hg (lbs)	CO_2 (tons)
Coal, Iowa	(11,000)	(66,000)	(8,250)	(550)	(11,770,000)
Coal, Indiana	(3,000)	(18,000)	(2,250)	(150)	(3,210,000)
Coal, Kentucky	800	4,800	600	40	856,000
Coal, Michigan	400	2,400	300	20	428,000
Coal, Missouri	(3,300)	(19,800)	(2,475)	(165)	(3,531,000)
Coal, Ohio	(600)	(3,600)	(450)	(30)	(642,000)
Coal, Wisconsin	(1,000)	(6,000)	(750)	(50)	(1,070,000)
Natural Gas for Seven State Area	200	insignificant	10	insignificant	117,600
Total in Seven State Area	**(17,500)**	**(106,200)**	**(13,265)**	**(885)**	**(18,821,400)**
Other Out-of-State Resources**	(8,388)	(53,062)	(5,704)	(386)	(8,695,001)
Total in Study Area	**(25,888)**	**(159,262)**	**(18,969)**	**(1,271)**	**(27,516,401)**

* Negative values reflect a decrease in emissions
** Assumed to be 80% coal-fired and 20% oil-fired

Table 4-6: Projected Changes in Emissions in All Fossil Fuel-Fired Plants in the Seven State Area and Study Area Due to Energy Plan Implementation, 2013*

Resource	Estimated Change (GWh)	SO_2 (tons)	NOx (tons)	Hg (lbs.)	CO_2 (tons)
Coal, Iowa	(1,678)	(10,068)	(1,259)	(84)	(1,795,460)
Coal, Indiana	(463)	(2,778)	(347)	(23)	(495,410)
Coal, Kentucky	125	750	94	6	133,750
Coal, Michigan	66	396	50	3	70,620
Coal, Missouri	(508)	(3,048)	(381)	(25)	(543,560)
Coal, Ohio	(96)	(576)	(72)	(5)	(102,720)
Coal, Wisconsin	(163)	(978)	(122)	(8)	(174,410)
Natural Gas for Seven State Area	49	insignificant	2	insignificant	28,812
Total in Seven State Area	**(2,668)**	**(16,302)**	**(2,036)**	**(136)**	**(2,878,378)**
Other Out-of-State Resources*	(1,265)	(8,002)	(860)	(58)	(1,311,299)
Total in Study Area	**(3,933)**	**(24,304)**	**(2,896)**	**(194)**	**(4,189,677)**

* Negative values reflect a decrease in emissions
**Assumed to be 80% coal- and 20% oil-fired

B.3 Impact of Energy Plan on Emissions within the Total Study Area

Tables 4-7 and 4-8 show the net change in emissions projected within the Study Area due to implementation of the EERE Case for 2007 through 2013 and for 2013 separately.

Table 4-7: Projected Changes in Emissions in All Fossil Fuel-Fired Plants within the Study Area Due to Energy Plan Implementation, 2007 – 2013*

Area	SO_2 (tons)	NOx (tons)	Hg (lbs)	CO_2 (tons)
Illinois	(106,226)	(11,524)	(857)	(16,155,650)
Seven State Area	(106,200)	(13,265)	(885)	(18,821,400)
Remainder of Study Area	(53,062)	(5,704)	(386)	(8,695,001)
Total	**(265,488)**	**(30,493)**	**(2,128)**	(43,672,051)

* Negative values reflect a decrease in emissions

Table 4-8: Projected Changes in Emissions in All Fossil Fuel-Fired Plants within the Study Area Due to Energy Plan Implementation, 2013*

Area	SO_2 (tons)	NOx (tons)	Hg (lbs)	CO_2 (tons)
Illinois	(28,983)	(3,165)	(235)	(4,505,665)
Seven State Area	(16,302)	(2,036)	(136)	(2,878,378)
Other out-of state sources	(8,002)	(860)	(58)	(1,311,299)
Total	**(53,287)**	**(6,061)**	**(429)**	(8,695,342)

* Negative values reflect a decrease in emissions

Figures 4-2a through 4-2d show the projected net changes in emissions of SO_2, NOx, Hg and CO_2 within the Study Area for 2007 through 2013 due to implementation of the Energy Plan.

Figure 4-2a: Projected Net Changes in SO_2 Emissions within the Study Area Due to Energy Plan Implementation, 2007 – 2013

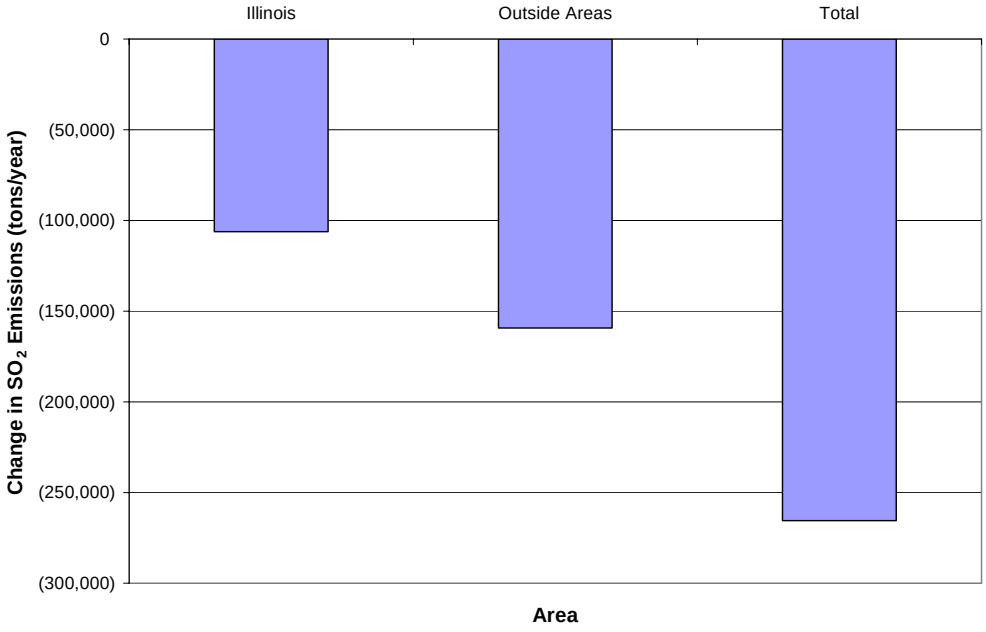


Figure 4-2b: Projected Net Changes in NOx Emissions within the Study Area Due to Energy Plan Implementation, 2007 - 2013

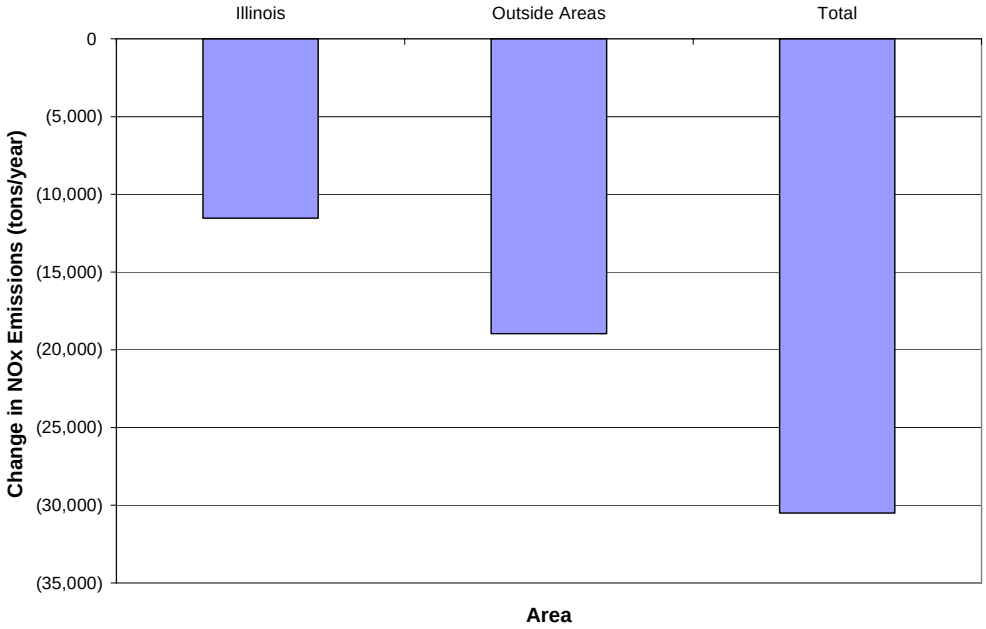


Figure 4-2c: Projected Net Changes in Hg Emissions within the Study Area Due to Energy Plan Implementation, 2007 - 2013

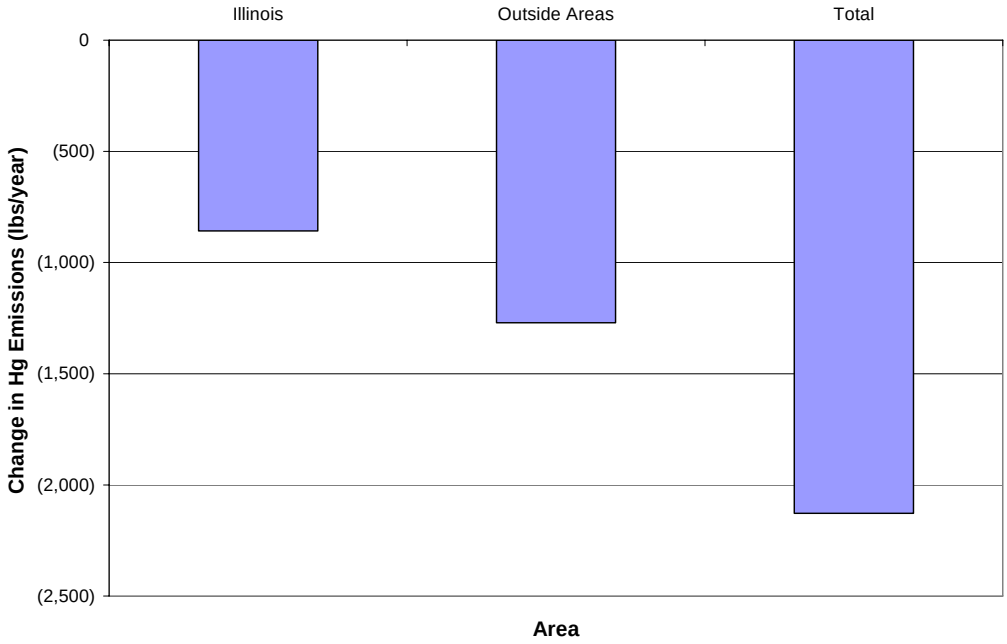
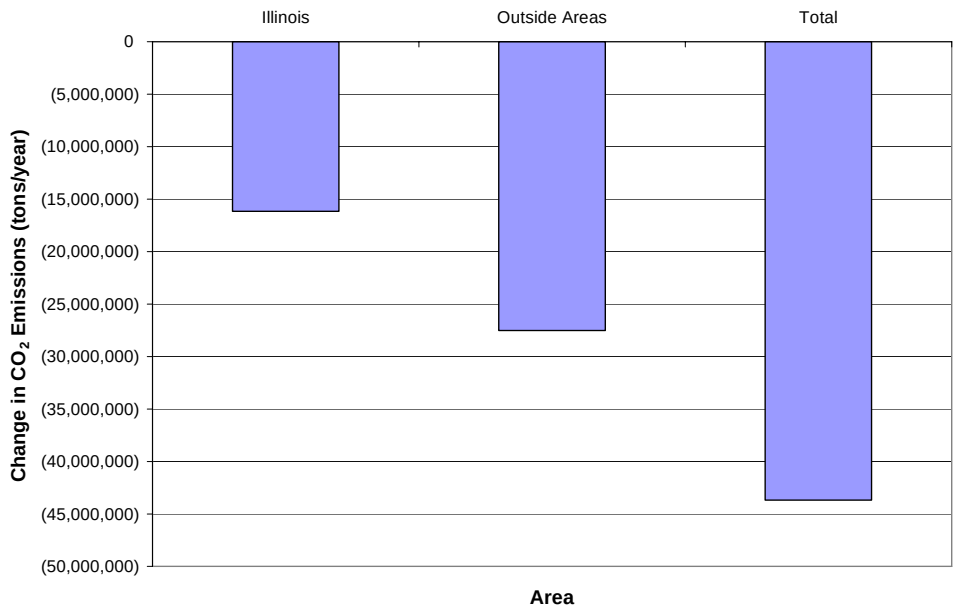


Figure 4-2d: Projected Net Changes in CO_2 Emissions within the Study Area Due to Energy Plan Implementation, 2007 – 2013



C. Impact of Pending Regulations on Emissions Reductions

Several environmental regulations will limit emissions from electric generating units (EGUs)[12] in the next ten to twenty years. Major reductions in emissions are expected from the Clean Air Interstate Rule (CAIR) for SO_2 and NOx and from the Clean Air Mercury Rule (CAMR) for Hg. Other pending regulations such as the Clean Air Visibility Rule (CAVR) and PM 2.5 standard may also limit emissions of criteria pollutants further.

The impacts of all of these rules were not considered in the above analysis mainly because the implementation of the rules was not complete and therefore compliance strategies by EGUs were not finalized. Of all the above regulations, CAIR seems to have been in the most advanced stages of implementation and therefore this section considers its impact on the overall change in emissions due to implementation of the Energy Plan.

Using a cap-and-trade approach, CAIR reduces the emissions of SO_2 and NOx from EGUs in 28 eastern states and the District of Columbia drastically from 2003 levels. The reductions will be realized by EGUs via installation of control devices (FGD, SCR, SNCR), thus decreasing the lbs/MWh of emissions from the units. After CAIR is implemented, any displaced generation due to Energy Plan implementation will reduce the emissions by this emission factor.

[12] This report refers to both "power plants" and "electric generating units (EGUs)". An EGU is a distinct generating unit, while a power plant may be comprised of one or more EGUs. EGUs with a nameplate capacity of 25 MW or higher are subject to the Clean Air Interstate Rule and other federal air quality regulations. All of the power plants considered in the analysis described in this report have a nameplate capacity of 25 MW or higher.

CAIR allows for cap-and-trade across the region. Thus, the net decrease due to CAIR is realized over the entire region and cannot be calculated on a state-by-state basis. Considering that the allowance trading will occur within Illinois and the Seven State Area, this area was selected for estimating the impact of CAIR. CAIR impacts in other parts of the Study Area affected by Energy Plan measures in Illinois were not considered. Also, the CAIR impacts are shown for the period under consideration in this analysis.

Table 4-9 shows the estimated emissions of SO_2 and NOx with and without CAIR for Illinois and the Seven State Area, as estimated by USEPA. These reductions were used to derive overall factors for reduction, which then could be applied to the analysis.

Approximately 40.3% reduction in SO_2 emission is predicted due to CAIR in Illinois from 2010 to 2015 (first control period for SO_2). NOx emissions reduction in Illinois due to CAIR is estimated to be 52.7% from 2009 to 2015 (first control period). For the same time period, the overall reduction of SO_2 and NOx emissions from the Seven State Area are 44.8% and 46.9%, respectively. The second control period for CAIR starts in 2015 and is outside the time period considered in this analysis.

Table 4-9: Projected Changes in Emissions of SO_2 and NOx Considering Implementation of Phase I CAIR within Illinois and the Seven State Area*

State	SO_2 Emissions (tons) without CAIR, 2010 – 2013**	SO_2 Emissions (tons) with CAIR, 2010 – 2013**	% Reduction in SO_2 with CAIR, 2010 – 2013**	NOx Emissions (tons) without CAIR, 2009 – 2013**	NOx Emissions (tons) with CAIR, 2009 – 2013**	% Reduction in NOx with CAIR, 2009 – 2013**
Illinois	**402,000**	**240,000**	**40.3**	**146,000**	**69,000**	**52.7**
Seven State Area:						
Iowa	127,000	118,000	7.1	76,000	44,000	42.1
Indiana	651,000	429,000	34.1	234,000	121,000	48.3
Kentucky	447,000	341,000	23.7	176,000	107,000	39.2
Michigan	387,000	381,000	1.6	117,000	88,000	24.8
Minnesota	83,000	69,000	16.9	72,000	36,000	50.0
Ohio	1,373,000	298,000	78.3	264,000	93,000	64.8
Wisconsin	143,000	137,000	4.2	71,000	47,000	33.8
Total in Seven State Area	**3,211,000**	**1,773,000**	**44.8**	**1,010,000**	**536,000**	**46.9**

* Source: USEPA CAIR Implementation Document
** Figures shown are cumulative for time period specified.

These reductions will be reflected in any displaced generation when CAIR is implemented. Thus, EGUs displaced due to Energy Plan measures after CAIR implementation will reduce emissions at these lower rates. Based on this assumption, the net impact of CAIR implementation on reduction of emissions of SO_2 and NOx are shown in Table 4-10a.

Table 4-10a: Projected Changes in Emissions of SO_2 and NOx Due to Energy Plan Implementation After Phase I CAIR within Illinois and the Seven State Area, 2009 – 2013*

Year	SO_2 Emissions (tons)			NOx Emissions (tons)		
	Total w/o CAIR	CAIR Impact	Net Total	Total w/o CAIR	CAIR Impact	Net Total
2009	N/A	N/A	N/A	(3,844)	(1,871)	(1,973)
2010	(38,627)	(16,583)	(22,044)	(4,348)	(2,136)	(2,213)
2011	(41,567)	(17,790)	(23,777)	(4,735)	(2,336)	(2,399)
2012	(45,588)	(19,436)	(26,152)	(5,201)	(2,578)	(2,623)
2013	(53,285)	(22,568)	(30,718)	(6,060)	(3,026)	(3,034)
Total	**(179,067)**	**(76,377)**	**(102,691)**	**(24,188)**	**(11,947)**	**(12,242)**

* Negative values reflect a decrease in emissions

Implementation of CAIR will increase the compliance cost for EGUs in dollars per ton. Therefore, though the reductions in emissions due to the Energy Plan's RPS and EEPS measures are less after implementation of CAIR, the avoided compliance cost is higher.

The Illinois Mercury Rule is expected to take effect in June 2009, requiring all affected facilities to reduce mercury emissions to 0.008 lbs/GWH. Based on this, the impact of this rule on Hg emissions reductions is shown in Table 4-10b.

Table 4-10b: Projected Changes in Hg Emissions Due to Energy Plan Implementation After Illinois Mercury Rule within Illinois, 2010 – 2013*

Year	Hg Emissions (lbs)		
	Total w/o Hg Rule	Hg Rule Impact	Net Total
2010	(125)	(105)	(20)
2011	(148)	(125)	(23)
2012	(177)	(149)	(28)
2013	(235)	(198)	(37)
Total	**(685)**	**(577)**	**(108)**

* Negative values reflect a decrease in emissions

D. Potential Uncertainties in Emissions Predictions

The emissions presented in Section IV.B above are based on industry emission factors, which are estimated from several sources of data across the industry. Each combustion unit, however, operated differently and industry–wide emission factors, while applicable over a large number of units, might not be appropriate for individual units. Thus, there is a degree of uncertainty introduced in the calculations by using the industry-averaged emission factors.

A second source of uncertainty in projected emissions calculations is due to lack of information on potential upgrades and modifications in the existing plants over the period of study. For reasons completely unrelated to environmental issues, a plant may change operations (e.g., fuel switches, voluntary emissions controls, etc.) which may affect future year emissions.

Finally, various environmental regulations have been proposed by USEPA and states (e.g., CAIR, CAMR and CAVR) that will affect the emission profiles from the EGUs in each state and nationwide. The implications of these regulations on overall emissions from the EGUs through the end of the study period of this report is not clear at this time and the analysis was based on information known at this time (i.e., CAIR reductions in Illinois and the Seven State Area and IEPA mercury regulations). As these regulations are finalized and EGUs respond with a variety of compliance options, the projected emissions calculations may change.

In spite of these uncertainties, the basic conclusion that the Energy Plan measures (EERE) will result in significant reduction of air pollution (both criteria and hazardous air pollutants) is without question.

V. IMPACT OF ENERGY PLAN ON AIR QUALITY COMPLIANCE

A. Pending Federal Regulations and their Relevance to the Energy Plan

Currently, several environmental regulations are in various stages of development and implementation, with the goal of improving air quality in the nation. This section describes the most important regulations facing the EGUs and their relevance to the Energy Plan.

A.1 Clean Air Interstate Rule (CAIR)

Brief Description of Rule: On March 10, 2005, USEPA finalized the Clean Air Interstate Rule (CAIR) aiming at reducing SO_2 and NOx from EGUs in 28 eastern states and the District of Columbia. Through a cap-and-trade approach, CAIR will achieve substantial reduction in these two pollutants from EGUs in three phases. Starting in 2010, the estimated emission of SO_2 is expected to be reduced to 2.5 million tons from 9.4 million tons in 2003. Similarly, NOx emission are expected to be reduced to 1.3 million tons from 3.2 million tons in 2003. After the first control period (2010 for SO_2 and 2009 for NOx), CAIR will replace all other cap-and-trade programs for these pollutants (e.g., NOx Budget SIP call). Each state will be allocated a fixed number of allowances which can be divided between covered EGUs. The allowances can be used, sold or traded by the EGUs, depending on individual compliance strategy.

Energy Plan Impact: The main purpose of CAIR is to reduce long-range transport of pollutants and help states to achieve the national ambient air quality goals. CAIR reduction will occur even without any Energy Plan at federal or state levels. However, the Energy Plan measures would help the goals of CAIR in following ways:

1. Any MWh saved by energy efficiency or generated by renewable energy are actual emissions reductions, since these measures displace more polluting electric generation.

2. The Energy Plan allows the EGUs to have the flexibility to meet the energy demand of the state without requiring additional allowances, thus maintaining the CAIR caps.

3. The federal CAIR model plan provides allowance set-asides for EERE projects. At this time, seven states—Missouri, Indiana, Massachusetts, Maryland, New Jersey, New York and Ohio—have already incorporated NOx allowance set-asides for EERE in their state CAIR plans, ranging from 1% of total allowances (Ohio) to 5% of total allowances (Massachusetts). Several other states, including Minnesota, Pennsylvania, Virginia and Illinois, are planning various levels of NOx allowance set-asides (5% to 15%) from EERE projects. Georgia is also planning to adopt such a plan after finalizing its state energy plan. Illinois has proposed a 12% set-aside for EERE. A more detailed description of these EERE set-asides is included in Appendix E.

   USEPA has estimated that if all states in the NOx SIP call area set aside 5% of their NOx allowances for EERE projects, the region could see annual savings of $5 billion in consumers' energy bills and $150 million in air quality compliance costs.

   The Energy Plan's EERE measures qualify for these set-aside NOx allowances. Thus, the Energy Plan provides a vehicle to EGUs to obtain the set-aside NOx allowances. The Energy Plan can help EGUs meet energy demand without increasing emissions and lower the overall cost of compliance for the fleet. Though not mandatory, these set-asides provide EGUs with an incentive to reduce generation costs and compliance costs, and promote Energy Plan measures.

   Energy Plan measures earning set-aside NOx allowances under CAIR may also be bought by municipalities and non-governmental organizations (NGOs) and retired. This results in a permanent reduction of the CAIR cap for the state and forces the reduction of pollutants even beyond CAIR to improve air quality goals.

As the EGUs' compliance strategies for CAIR compliance in Illinois and in other states in the study are finalized, a more accurate estimate of the net emission change from the rule can be prepared.

A.2 Clean Air Mercury Rule (CAMR)

Brief Description of Rule: The Clean Air Mercury Rule was promulgated by USEPA on March 15, 2005 and requires drastic reductions in mercury emissions from coal-fired EGUs nationwide. The reductions will come in two phases. The first phase reduction in 2010 is expected to reduce annual mercury emissions from 48 tons to 26 tons. In the second phase, annual mercury emissions will be reduced further to 15 tons by 2018. It is generally believed that most of the Phase I reductions will come out of the wet scrubbers installed at the EGUs for compliance with CAIR.

While USEPA has proposed a cap-and-trade program for mercury reduction, several states, such as Pennsylvania and New Jersey, are either proposing or adopting individual plant controls. In addition, some states are proposing more stringent and reduced timelines for control. IEPA has proposed a plant-based emission cap of 0.008 lbs/GWh for EGUs, effective in June 2009.

Energy Plan Impact: Since the implementation of CAMR is in flux at this time, the only impact considered in this analysis is IEPA's proposed emission cap of 0.008 lbs/GWh from 2009 and beyond. All calculations shown in Section 4 of this report reflect this emission cap. Once mercury control legislation in the Seven State Area considered in this study is finalized, the emissions reduction calculations of this report may be revised. However, since Energy Plan measures reflect actual reduction of emissions from more polluting EGUs, these help in lowering the overall mercury emissions nationwide.

A.3 Clean Air Visibility Rule (CAVR)

Brief Description of Rule: This rule, also known as the Regional Haze Rule, requires emissions controls at large sources of SO_2, NOx and particulate emissions to improve visibility in Class I areas such as National Parks. EGUs installed between 1962 and 1977 are primary targets for the controls. Controls are required for visibility-impairing pollutants such as SO_2, NOx and PM10. It is generally believed at this time that control of SO_2 and NOx by EGUs as part of CAIR compliance will be adequate to meet the requirements of the Regional Haze Rule. Control of PM10 may be necessary at many covered EGUs.

Energy Plan Impact: Since the required controls are still being investigated by regional planning organizations and will take some time to finalize, impact of this rule has not been considered in this analysis. It is generally believed that CAIR-affected EGUs will not need further controls to comply with this regulation. However, the Energy Plan measures are expected to help achieve the visibility goals of CAVR by avoiding installation of more polluting units.

B. Considerations on Using EERE as a Tool for Regulatory Compliance

A significant challenge in crediting EERE measures towards compliance with air quality regulations is allocating emissions reductions to specific geographic areas, such as states and non-attainment areas. As noted earlier, this challenge is tied directly to two factors. First the electrical grid is regional, covering multiple states, and interconnected. Second, electrical power is dispatched to the grid based upon economics and technical requirements. Air quality regulations and EERE portfolio mandates can impact the order in which power is dispatched by either imposing regulatory requirements that impact the economics of electric generating units or by adding EERE resources to meet a given demand.

The mix of EERE resources that are deployed to the grid impacts both the extent and timing of emissions reductions, and changes in that mix can be used to target specific emissions reduction outcomes. For example, the EERE resource mix that was modeled in this study was dominated by wind generation. Wind generation in Illinois is greatest in the non-ozone season. A different resource mix that increased the deployment of such strategies as higher levels of energy efficiency, demand response, solar or other resources could change the timing and extent of emissions reductions.

In developing EERE portfolio programs, a number of states have established preferences to encourage specific types of EERE measures (e.g., wind, solar, efficiency, biomass) or a specific

composition of energy resources within the portfolio. The Illinois Energy Plan, for example, sets minimum requirements for in-state wind generation and includes energy efficiency goals to reduce load growth. Portfolio preferences like these often tie to specific policy objectives, such as managing the overall cost and rate impact of the portfolio requirement, promoting economic development opportunities that result from the EERE measures and diversifying the mix of power to ensure that it meets the energy performance requirements of the electrical system. A state's portfolio can also be structured to address specific air quality objectives using the modeling approach employed in this study. This approach can be achieved, in part, through increased collaboration between a state's energy office and air quality program, as happened with the Illinois project. This collaboration focused on developing accurate projections of the type and timing of EERE resources that would be deployed under the Energy Plan prior to modeling emissions impacts.

Collaboration, using the dispatch modeling approach employed in this study, is also appropriate on a multi-state basis to ensure that the full benefits of EERE measures are understood and incorporated into air quality plans. The modeling results demonstrate that EERE policies in one state can result in measurable emissions reductions in another state. For example, the Illinois Energy Plan displaces fossil fuel generation in multiple states and results in significant emissions reductions outside of Illinois for all of the pollutants analyzed in this study. More detailed modeling of how specific state energy policies impact regional economic dispatch would both highlight additional opportunities for emissions reductions and provide a reasonable basis for allocating regulatory credit for producing the benefits. Increased collaboration is consistent with both regional air quality efforts, such as the CAIR rule, and the interconnected nature of the electrical grid. In addition to state energy and air quality officials, state utility commissions, local utilities and multi-state transmission organizations can provide important information to ensure accurate modeling results and identify the methods by which modeled emission reductions can be guaranteed.

The analysis described in this report modeled the delivery of emissions reductions through a state mandated RPS/EEPS. The portfolio requirement helps to guarantee the delivery of EERE resources at sufficient scale to have a measurable impact on economic dispatch of existing fossil fuel generation. While this study focuses on portfolio requirements, other methods of guaranteeing performance may also be effective in producing and verifying a measurable impact on economic dispatch and overall emission levels. These approaches generally use regulatory, contractual or utility tariff obligations to deliver and verify measurable amounts of EERE resources to the grid. Compliance with these regulatory or contractual obligations often requires the tracking of EERE performance and can be a valuable source of data to verify performance.

VI. CONCLUSIONS

The Illinois Air-Energy Integration Initiative successfully demonstrated collaborative and innovative approaches to using energy efficiency and renewable energy technologies to reduce or prevent air emissions. The analysis showed that the Illinois Sustainable Energy Plan will produce significant and measurable environmental benefits. The project also helped to quantify the

avoided emissions and to provide replicable tools, models and strategies that other states can implement.

The following general conclusions can be drawn from the analysis:

- The Illinois Sustainable Energy Plan will reduce emissions of NOx, SO_2, Hg, CO_2 and other pollutants in Illinois and in numerous other states.
- Less than half of the emission reductions would occur in Illinois, since many of the marginal plants that would be displaced by energy efficiency and renewable energy technologies in Illinois are located outside of the state.
- More than half of the generation displaced out-of-state, however, is located upwind of Illinois (Iowa, Missouri, Wisconsin), thus contributing toward improved air quality in Illinois.
- While the emission reductions are less in the five-month ozone season than in the rest of the year, the Illinois Sustainable Energy Plan would produce some ozone season benefits and contribute in a modest way towards ozone attainment both in Illinois and across the eastern US.
- Coal, which generally yields the highest emissions rates for NOx, SO_2, Hg and CO_2, is the primary fuel displaced, along with some oil and natural gas used in plants serving peak load. Natural gas generation in Illinois, however, increases slightly to address local transmission congestion and short-term changes in availability of wind.

The Illinois Air-Energy Integration Initiative serves as a model for other states in the Midwest and across the country:

- Working cooperatively, energy agencies and environmental agencies can more effectively achieve state energy and environmental goals.
- Energy policies, such as the Renewable Portfolio Standard and Energy Efficiency Portfolio Standard proposed in the Illinois Sustainable Energy Plan, can help states improve air quality and reduce overall environmental compliance costs.
- Other states and regions could employ the dispatch modeling approach used in this study to ensure that the full benefits of energy efficiency and renewable energy measures are understood and to justify claiming credit in their air quality plans for improvements to air quality both within the state and regionally.

- The study found that only by using a regional model of the electrical grid, could the impact on air quality be accurately assessed. A simpler state-level analysis would overestimate the in-state benefits but at the same time underestimate the regional air quality benefits.

APPENDIX A

Study of Emissions Impact by the Illinois Sustainable Energy Plan Based on Optimal Power Flow Modeling

Author:	PowerWorld Corporation Scott R. Dahman, P.E.
Client:	Shaw Environmental
Original Date:	August 18, 2006 (draft)
Revised:	January 4, 2007

Table of Contents

Purpose 1
Study Definitions and Assumptions 1
Study Limitations 1
Generator Operation 1
Wind Operation 2
Cost Modeling and Economics 2
System Size and Electrical Modeling 3
Wind Projects 4
Energy Efficiency Portfolio Standard 6
Modeling Results 8
Conclusions 14
Appendix A A1

Purpose

The study seeks to investigate the electric power generation changes that are anticipated by implementing the Renewable Portfolio Standard (RPS) and the Energy Efficiency Portfolio Standard (EEPS) in the Illinois Sustainable Energy Plan (SEP). It is anticipated that the RPS will involve a significant growth in wind energy generation in the state. Because the state's transmission system is interconnected with the Eastern Interconnect power grid, power flows across state lines according to the physics and economics of the system. Energy from new resources such as wind may displace existing energy generation outside Illinois as well as within Illinois. This study seeks to estimate how energy production will change across the spectrum of existing coal, oil, and natural gas fired resources in the state of Illinois.

Study Definitions and Assumptions

This study incorporates a model of the physical and economic operation of a large portion of the Eastern Interconnect power grid. Forecast customer demand or load by electric utility control area is modeled for the study period ranging from 2007 through 2013. The load is changed according to observed historical patterns and averaged every 6 hours. The 6-hour intervals are divided along prevailing diurnal peak, valley, and shoulder periods that occur in electrical system operation. Each 6-hour interval is called a time step. For each time step, the electrical load is applied to the model and generators are dispatched according to the optimal power flow. The optimal power flow seeks the lowest cost operation, subject to physical system limits. Such limits include the current carrying capacity of transmission lines, the production capacity of generators, and power transfer limits to maintain the stability of the network. Such limits may dictate operation of generators that are more costly than others which must be curtailed, due to the location of the units in the transmission network, relative to the locations of customer load.

The study will first model the operation of the system without any new RPS wind generation or EEPS load reduction. The results will form a baseline for comparison, called the base case. The system will then be modeled with proposed wind developments added over time, as well as EEPS load reduction. These results are called the RPS case.

Study Limitations

Generator Operation

Some real-world constraints are beyond the scope and capabilities of the model and the study. Time-based parameters such as generator ramp rates, minimum up time, and minimum down time are not generally known and cannot be incorporated in the model. Short-term effects such as these are approximated through the 6-hour duration of each time step. If a unit is running during a time step, it is assumed to be running for the entire 6-hour interval.

Longer-term resource planning constraints also cannot be fully modeled. Scheduled maintenance, forced outages, spinning reserve requirements, reliability-must-run, and other ancillary services may dictate that certain units are or are not in operation for certain periods. Our model assumes that base load units such as nuclear and coal are always available. Nuclear

units are assumed to run 100% of the time. True modeling of the consequences of long-term constraints would require stochastic simulations that incorporate probabilities, which are beyond the scope of the project.

The ability to model coordination of hydro and thermal resources is also limited. Hydro is unique in that the fuel is essentially free, but the energy supply is limited by non-electrical constraints such as rainfall totals, reservoir levels for navigation and recreation, and discharges for fish populations. Many of these constraints vary from year to year and across a region within a year. Hydro is priced in this model assuming that the entire system will generate close to historically observed system averages. Hydro resources tend to supply energy when the value of the energy is highest, so assumptions about hydro availability influence the operation of peaking resources.

Wind Operation

The study assumes that wind units will operate to fullest extent of the availability of wind. Historic observations of wind availability at a point within the Northern region and a point within the Central region of Illinois were applied to all existing and planned developments in each respective region. The Southern region was assumed to have the same wind pattern as the Central region. Wind units outside Illinois are assumed to operate at static levels in the summer peak planning power flow cases that form the basis of the electrical model. The study assumes that all non-wind resources can be economically dispatched around available wind. In reality, wind is intermittent and difficult to predict and short-term fluctuations would likely be followed by hydro and simple cycle gas turbines. The ability to dispatch resources around wind can be done only to the extent that the wind can be forecast.

Planned wind developments are assumed to be interconnected at specific points within the 138-kV network that exhibited transmission capacity to handle the full output of each project. It is assumed that any transmission required to deliver power to those points will be built. The actual size and interconnection point of each product may affect the optimal dispatch of other resources to accommodate the wind.

Cost Modeling and Economics

All thermal resources are assumed to be dispatched according to average production costs. Coal fuel costs were provided by the Illinois Department of Commerce and Economic Opportunity (DCEO). Other fuel costs, fuel cost forecasts, heat rates, variable operations and maintenance costs, and load forecasts were obtained or inferred from U.S. Energy Information Administration (EIA) databases. Such databases often do not contain figures for non-utility merchant generation. Furthermore, actual bids for generation in ISO markets may deviate from production costs, especially during peak periods. The EIA forecast of the relative costs between coal, oil, and natural gas, may also impact the modeled operation in future years.

The simulated least-cost dispatch assumes that the ISOs and utilities performing the dispatch have complete and perfect information and that all power is scheduled according to an ideal spot market. It also assumes completely liquid trading of power across control area and ISO boundaries. However, from hour to hour and over short-term periods, trade volumes are likely fixed. Some units may also operate according to long-term energy supply contracts, for which information was not available for the simulation. Finally, transmission operators may need to

dispatch some resources uneconomically for reliability, to meet environmental restrictions, or other reasons which cannot be predicted by the model. Thus the simulated energy production will not necessarily correlate to actual historic production.

System Size and Electrical Modeling

The electrical model incorporates most of the MISO and PJM markets, in which most Illinois control areas participate. Exceptions include the northwestern extreme of MISO in Manitoba and the eastern extreme of PJM in New Jersey and eastern parts of Pennsylvania and Maryland. Other control areas that neighbor Illinois and utilities that operate in Illinois, including TVA were also incorporated. Generation and load patterns throughout these markets and areas affect the operation of Illinois generators. The region of the Eastern Interconnect not incorporated in the model is approximated by a system equivalent, which assumes that the flows due to generators and loads outside the model are held constant.

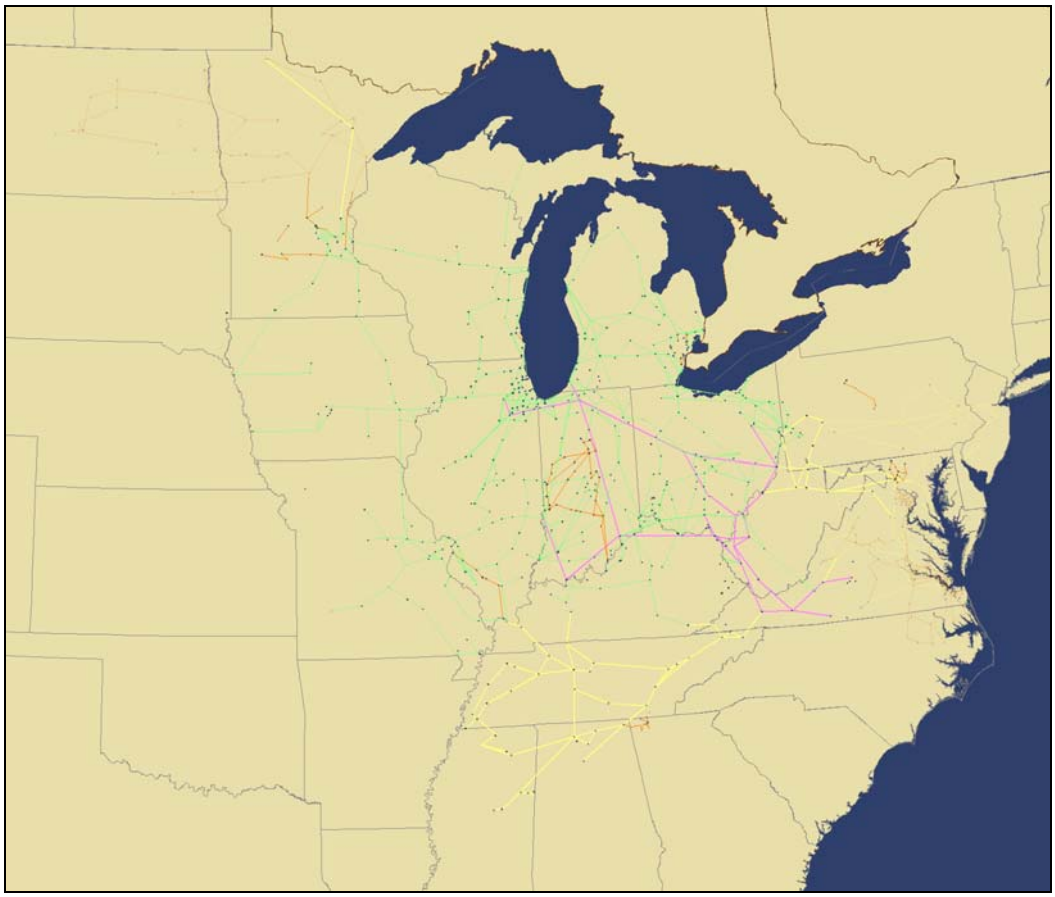


Figure 1 - Study System:
230 kV and above are shown. Transmission constraints are enforced on emphasized lines.

The electrical model makes use of the DC power flow, which incorporates some simplifying assumptions necessary to model the system over the range of anticipated daily and seasonal fluctuations. The DC model cannot fully incorporate system losses, reactive power flow, and

voltage constraints. These shortcomings are mitigated to some extent by the fact that forecast loads include system losses and that flowgates establish boundaries for reactive power and voltage requirements.

Secure operation of the electrical system is approximated in the model by flowgate modeling. Some flowgates stipulate that the flow on certain transmission paths, plus any additional flow that would appear due to specific forced outages or contingencies, may not exceed a certain threshold. Flowgates help define the reliability margins required to safely operate the system.

The model also assumes no upgrades in the transmission network or new generation developments, except for the RPS wind developments. It is possible that future expansion may alleviate existing physical and economic constraints.

The limitations in modeling time-dependent variables, the assumption of cost-based generation bids, and wide-area optimization tends to underestimate the absolute production from peaking resources such as natural gas and oil. However, because both the base and RPS cases incorporate identical assumptions and limitations, the model should be able to capture the differences in Illinois energy production between the cases. As a result, the predicted RPS savings should be considered more reliable than the absolute numbers predicted for each type of resource and specific plants.

Wind Projects

Two existing and 18 proposed wind developments are incorporated into the model, as shown in Figure 2 and Table 1. The actual locations of the proposed developments are unknown, but are assumed as shown for this study.

Table 1 - Illinois Wind Developments

Development	County	Region	Capacity (MW)	Capacity Factor	Annual Production (MWh)	Status
Crescent Ridge	Bureau	North	51	35.0%	156,365	Operating
Mendota Hills	Lee	North	50.4	28.0%	123,619	Operating
Wind 3	Boone	North	162	31.4%	445,130	Proposed, 2007
Wind 4	La Salle	North	162	31.4%	445,130	Proposed, 2007
Wind 11	Coles	Central	267	30.0%	702,194	Proposed, 2007
Wind 5	Knox	North	189	31.4%	519,318	Proposed, 2008
Wind 12	McLean	Central	186	30.0%	489,168	Proposed, 2008
Wind 6	Marshall	North	219	31.4%	601,750	Proposed, 2009

Development	County	Region	Capacity (MW)	Capacity Factor	Annual Production (MWh)	Status
Wind 17	Effingham	South	114	30.0%	299,812	Proposed, 2009
Wind 7	Stephenson	North	195	31.4%	535,802	Proposed, 2010
Wind 13	Woodford	Central	192	30.0%	504,947	Proposed, 2010
Wind 8	Carroll	North	198	31.4%	544,049	Proposed, 2011
Wind 14	Ford	Central	195	30.0%	512,833	Proposed, 2011
Wind 9	Ogle	North	198	31.4%	544,049	Proposed, 2012
Wind 15	McLean	Central	195	30.0%	512,833	Proposed, 2012
Wind 10	Henry	North	198	31.4%	544,049	Proposed, 2013
Wind 16	McLean	Central	207	30.0%	544,397	Proposed, 2013
Total			2,979		8,025,444	

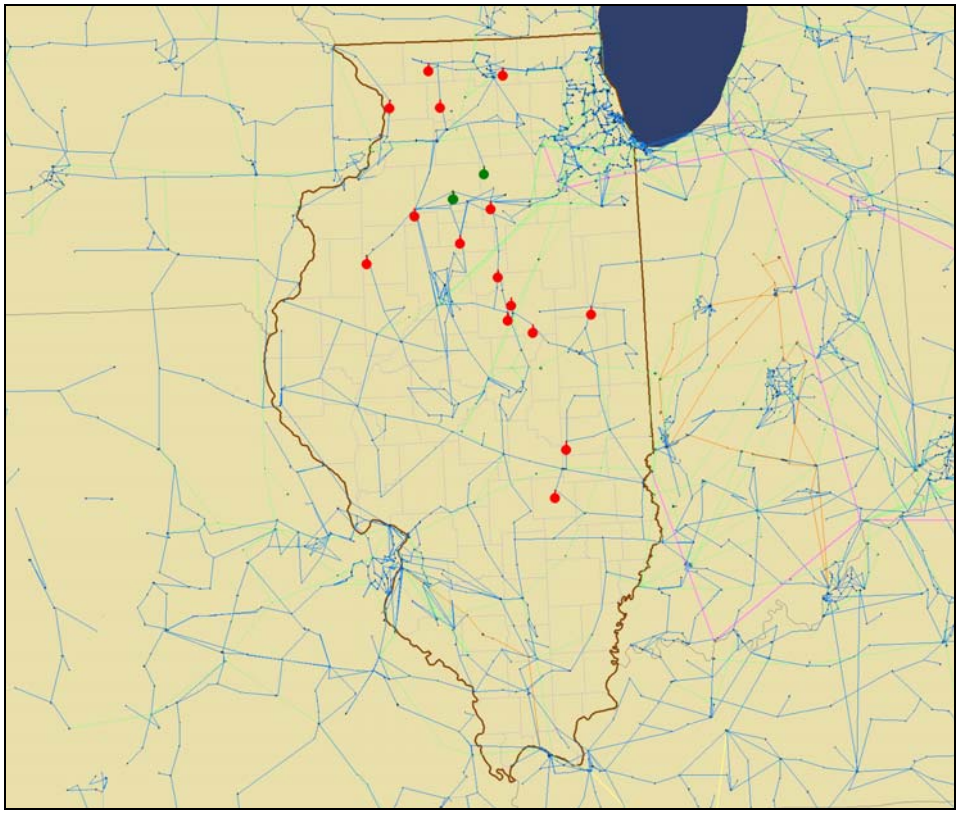


Figure 2 - Location of Wind Generation in Illinois:
Existing (Green, 102 MW) and Proposed (Red, 2877 MW)

Energy Efficiency Portfolio Standard

The Illinois Energy Efficiency Portfolio Standard (EEPS) was also modeled into the RPS case as a reduction in load for control areas with operations in Illinois. The 2007 Illinois load is assumed to be 146,857 GWh[1]. Base case load growth for years that follow is assumed to be 1.3% per year. The EEPS calls for a progressive reduction in the base case growth rate.

It was assumed that wind energy would supply 95% of the RPS requirements, and that the remaining 5% would be satisfied with small distributed renewable generation projects such as biomass. The effects of these projects were incorporated into the modeled load. Table 2 shows the base case and RPS case Illinois energy load.

[1] Source: Mueller, S. and Bournakis, A. D., *Emissions Impact Assessment for the Illinois Sustainable Energy Plan Based on Economic Dispatch Considerations (Draft)*, Energy Resources Center, University of Illinois at Chicago, February 9, 2006.

Table 2 - Illinois Load

Year	Base Case Load (GWh)	EEPS Growth Reduction	EEPS Load (GWh)	EEPS Savings (GWh)	5% RPS (GWh)	Net RPS Load (GWh)
2007	146,857	10%	146,668	189	98	146,571
2008	148,767	10%	148,388	380	149	148,239
2009	150,702	15%	150,032	670	201	149,832
2010	152,662	15%	151,698	965	254	151,444
2011	154,648	15%	153,386	1,262	309	153,077
2012	156,659	20%	154,995	1,665	365	154,630
2013	158,697	20%	156,625	2,071	422	156,203
Total	1,068,992		1,061,792	7,201	1,797	1,059,996

Modeling Results

The simulated seven-year energy production values are summarized in Figure 3 and Table 3 below. The proposed wind production is expected to displace some coal-fired production in Illinois. Natural gas-fired production actually increases with the wind, due to the locational value of the gas-fired generators. The RPS wind production, which is fixed based on wind patterns and cannot be scheduled in the simulation, requires that some natural gas-fired units produce more to avoid overloading transmission facilities at the optimal dispatch. Exports to other states are also expected to increase with the RPS wind production, assuming the portfolio of generation outside of Illinois does not change.

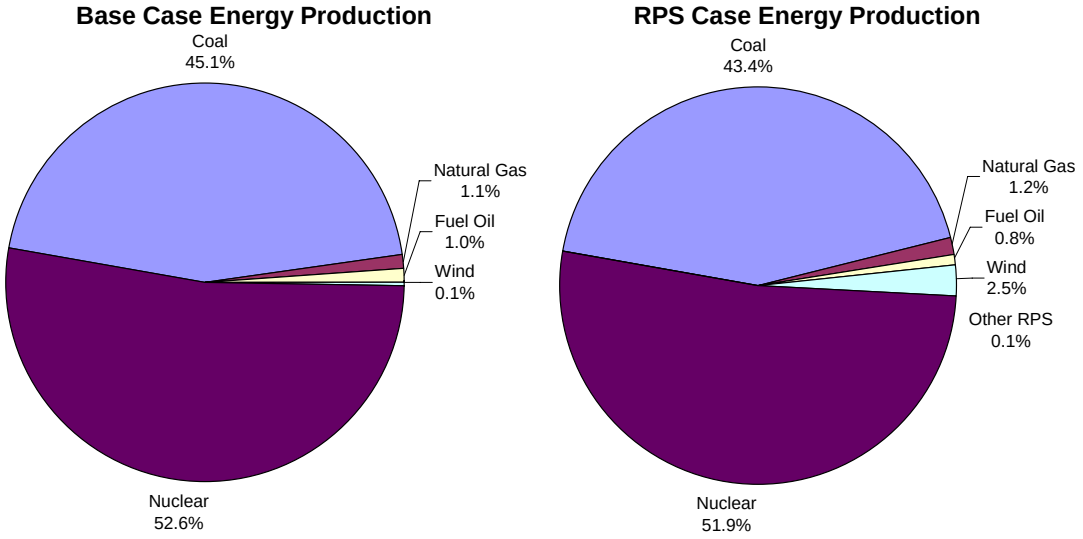


Figure 3 - Simulated Production Summary (2007 – 2013)

Table 3 – Simulated Production Summary (2007 – 2013)

Fuel Type	Energy Production (Base, GWh)			Energy Production (RPS, GWh)			RPS Change	
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	GWh, Total	%, Total
Coal	339,569	260,022	599,591	329,999	255,695	585,694	**(13,897)**	**(2.32%)**
Natural Gas	7,817	7,343	15,160	9,382	7,225	16,607	**1,447**	**9.55%**
Fuel Oil	7,396	6,274	13,670	5,077	5,690	10,767	**(2,903)**	**(21.2%)**
Wind	1,409	551	1,960	25,169	9,032	34,202	**32,242**	**1645%**
Nuclear	406,386	293,288	699,673	406,386	293,288	699,673	**-**	**-**
Other RPS[2]	-	-	-	1,015	782	1,797	**1,797**	**-**
Imports (Exports)	(158,355)	(102,706)	(261,060)	(177,171)	(109,777)	(286,948)	**(25,888)**	**9.92%**
Total Load	604,222	464,772	1,068,994	599,857	461,935	1,061,792	**(7,202)**	**(0.67%)**

[2] Other RPS resources were modeled as load in the RPS case, but are shown separately from load in this table.

Table 4 shows the simulated production summary for 2013, the final year of the RPS planning horizon.

Table 4 - Simulated Production Summary (2013)

Fuel Type	Energy Production (Base, GWh)			Energy Production (RPS, GWh)			RPS Change	
	Non-Ozone	Ozone	Total	Non-Ozone	Ozone	Total	GWh, Total	%, Total
Coal	53,069	39,968	93,038	50,397	38,793	89,190	**(3,848)**	**(4.14%)**
Natural Gas	1,855	1,776	3,631	2,192	1,714	3,907	**276**	**7.60%**
Fuel Oil	1,564	1,257	2,821	1,003	1,094	2,097	**(724)**	**(25.7%)**
Wind	201	79	280	5,913	2,113	8,025	**7,745**	**2766%**
Nuclear	58,055	41,898	99,953	58,055	41,898	99,953	**-**	**-**
Other RPS[3]	-	-	-	239	184	422	**422**	**-**
Imports (Exports)	(25,085)	(15,941)	(41,027)	(29,310)	(17,660)	(46,969)	**(5,942)**	**14.5%**
Total Load	89,659	69,037	158,696	88,489	68,136	156,625	**(2,071)**	**(1.31%)**

[3] Other RPS resources were modeled as load in the RPS case, but are shown separately from load in this table.

A detailed breakdown of how the RPS affects the dispatch of resources in other states is beyond the scope of the study. An estimate of how energy from selected resources in other states would change as a result of the Illinois RPS is shown in table 5, based on representative samples of the simulated energy production.

Table 5 – Estimated Change in Out-of-State Energy Production

Resource	Estimated RPS Change (GWh)
Coal, Iowa	(11,000)
Coal, Indiana	(3,000)
Coal, Kentucky	800
Coal, Michigan	400
Coal, Missouri	(3,300)
Coal, Ohio	(600)
Coal, Wisconsin	(1,000)
Natural Gas for 7 state area	200
Other Out-of-State Resources (all types)	(8,388)
Total	(25,888)

Energy savings from RPS and EEPS measures are illustrated in Figure 4.

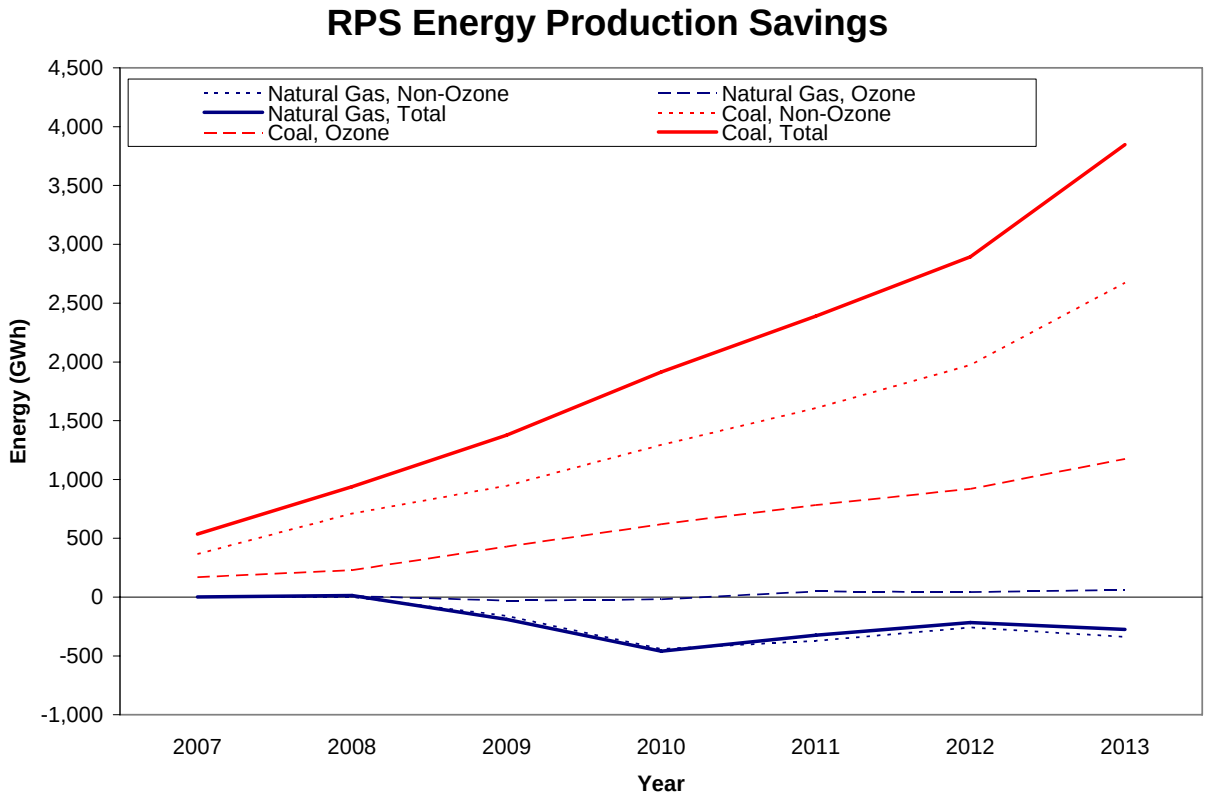


Figure 4 - Forecast Energy Production Savings

Coal-fired energy production trends are illustrated in Figure 5.

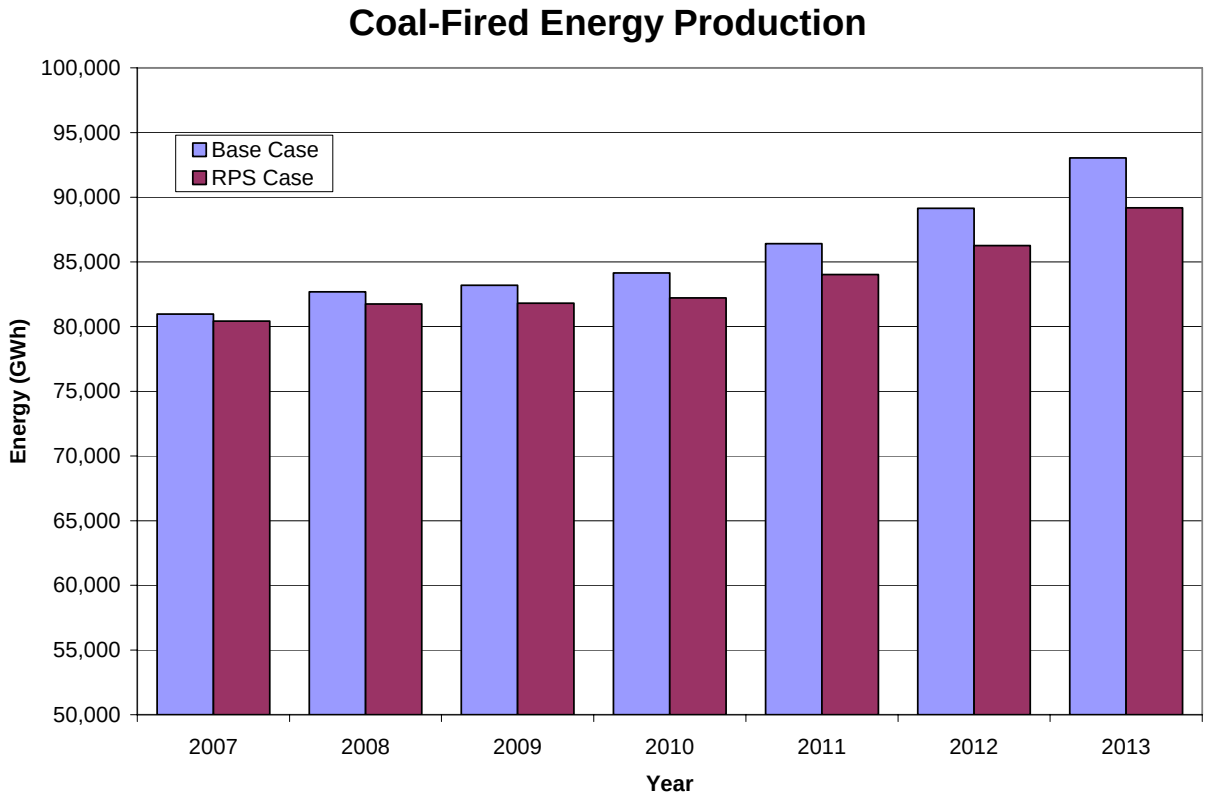


Figure 5 - Forecast Coal-Fired Energy Production

Natural-gas fired energy production trends are illustrated in Figure 6.

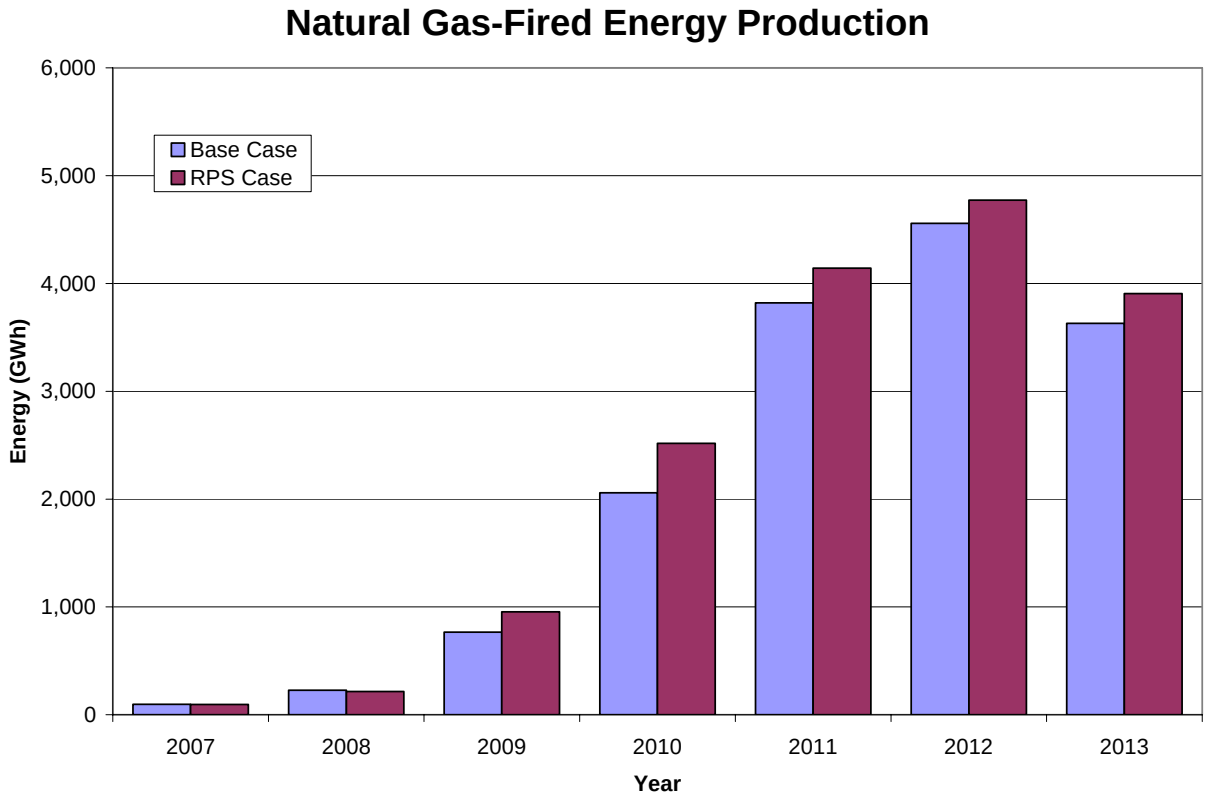


Figure 6 - Forecast Natural Gas-Fired Energy Production

Conclusions

The large-scale electric power simulations performed in this study suggest that the RPS and EEPS measures would reduce the coal-fired power plant emissions in the State of Illinois. Natural gas-fired emissions would increase slightly, based on an optimal dispatch over the Midwestern study system. Exports to other states would also increase.

Appendix A

Table A1 - Coal-Fired Energy Production Detail (GWh)

		2007				2008				2009				2010				2011				2012				2013			
Plant Name	County	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O
Baldwin	Randolph	8,746	8,634	6,160	6,112	8,812	8,648	6,158	6,098	8,849	8,432	6,197	6,065	8,917	8,414	6,234	6,089	8,900	8,336	6,257	6,074	8,954	8,274	6,314	6,105	9,053	8,002	6,377	6,129
Coffeen	Montgomery	3,296	3,297	2,485	2,491	3,471	3,481	2,580	2,590	3,619	3,499	2,686	2,678	3,676	3,554	2,720	2,699	3,841	3,671	2,850	2,819	3,974	3,784	2,913	2,881	4,086	3,783	2,962	2,897
Crawford	Cook	1,191	1,184	974	969	1,254	1,251	1,010	1,008	1,310	1,387	1,057	1,060	1,357	1,412	1,102	1,096	1,431	1,479	1,135	1,125	1,534	1,581	1,194	1,180	1,772	1,858	1,303	1,291
Dallman	Sangamon	1,329	1,275	985	979	1,377	1,257	1,015	1,002	1,434	1,128	1,039	990	1,457	1,105	1,057	1,001	1,477	1,145	1,070	1,009	1,507	1,165	1,086	1,022	1,542	1,128	1,105	1,024
Duck Creek	Fulton	1,375	1,375	1,004	1,003	1,374	1,374	1,006	1,006	1,374	1,374	1,009	1,007	1,374	1,374	1,011	1,010	1,376	1,374	1,022	1,017	1,379	1,375	1,030	1,026	1,382	1,380	1,041	1,034
Edwards	Peoria	3,780	3,776	2,725	2,716	3,785	3,769	2,727	2,719	3,788	3,661	2,733	2,718	3,790	3,636	2,735	2,716	3,790	3,653	2,736	2,724	3,791	3,649	2,736	2,720	3,791	3,560	2,736	2,712
Fisk Street	Cook	426	421	404	402	478	478	437	437	528	596	480	485	560	618	509	510	629	688	537	530	717	779	587	568	905	996	668	659
Havana	Mason	1,759	1,703	1,303	1,292	1,826	1,608	1,334	1,299	1,022	683	788	688	1,020	646	783	663	1,188	759	892	761	1,288	823	952	816	1,377	791	1,009	826
Hennepin	Putnam	6	5	67	57	6	4	81	75	5	162	87	96	9	143	109	109	17	149	125	126	30	147	157	151	57	188	183	166
Hutsonville	Crawford	377	369	320	318	377	368	325	321	392	374	338	330	384	370	340	327	402	379	347	336	410	383	355	341	424	388	363	345
John Deere	Rock Island	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	1	0	0	1	1
Joliet 29	Will	1,243	1,226	1,170	1,154	1,416	1,411	1,270	1,261	1,594	1,733	1,359	1,391	1,766	1,842	1,500	1,491	1,985	2,060	1,613	1,589	2,338	2,355	1,823	1,768	2,953	3,085	2,123	2,086
Joliet 9	Will	462	462	372	371	465	463	384	383	464	465	392	391	466	468	404	404	477	478	424	423	502	500	447	441	530	588	476	474
Joppa Steam	Massac	5,526	5,526	3,981	3,981	5,526	5,526	3,978	3,977	5,526	5,526	3,972	3,975	5,526	5,526	3,970	3,972	5,526	5,526	3,973	3,973	5,526	5,526	3,974	3,973	5,525	5,520	3,977	3,971
Kincaid	Christian	2,300	2,283	2,097	2,087	2,280	2,233	2,140	2,116	2,342	2,233	2,198	2,121	2,280	2,200	2,148	2,068	2,298	2,200	2,163	2,076	2,294	2,204	2,156	2,064	2,379	2,259	2,209	2,084
Lakeside	Sangamon	215	191	162	159	225	187	171	166	227	156	175	163	238	158	179	164	218	145	181	164	214	142	182	166	235	141	191	163
Marion	Williamson	662	662	522	520	663	662	526	524	664	662	528	524	665	664	530	524	669	666	538	530	675	668	544	536	688	672	553	543
Meredosia	Morgan	789	779	696	690	805	775	719	704	823	776	726	696	736	724	690	663	760	737	708	678	783	755	727	697	812	774	748	705
Newton	Jasper	5,254	5,215	3,818	3,804	5,335	5,267	3,867	3,851	5,402	5,207	3,919	3,886	5,438	5,251	3,940	3,902	5,516	5,295	3,959	3,916	5,585	5,360	4,005	3,952	5,679	5,357	4,059	3,979

		2007				2008				2009				2010				2011				2012				2013			
Plant Name	County	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O	Base NO	RPS NO	Base O	RPS O
Pearl Station	Pike	0	0	2	3	0	0	3	3	0	0	4	3	0	0	5	5	0	0	7	6	0	0	8	8	0	0	10	9
Powerton	Tazewell	3,572	3,570	2,748	2,743	3,575	3,571	2,802	2,790	3,569	3,567	2,815	2,800	3,580	3,570	2,862	2,841	3,609	3,584	2,917	2,886	3,654	3,602	2,990	2,951	3,750	3,658	3,080	3,030
U of I Abbott	Champaign	71	71	51	51	71	71	51	51	71	71	51	51	71	71	51	51	71	71	51	51	71	71	51	51	71	71	51	51
Vermilion	Vermilion	0	0	21	20	0	0	28	28	0	0	40	37	0	0	48	44	2	0	58	54	7	5	67	59	11	15	79	69
Waukegan	Lake	1,949	1,954	1,486	1,485	2,022	2,016	1,519	1,517	2,046	2,030	1,549	1,552	2,057	2,036	1,561	1,561	2,135	2,117	1,629	1,622	2,203	2,173	1,704	1,686	2,318	2,254	1,790	1,756
Will County	Will	1,370	1,366	1,327	1,318	1,543	1,561	1,435	1,423	1,772	2,198	1,572	1,599	1,979	2,314	1,692	1,695	2,254	2,548	1,807	1,782	2,748	3,009	2,003	1,994	3,342	3,687	2,253	2,257
Wood River	Madison	81	69	311	294	96	93	339	328	202	156	462	437	175	127	438	394	291	194	553	495	354	234	604	535	386	241	622	531
Total		45,779	45,412	35,190	35,020	46,783	46,073	35,907	35,678	47,021	46,074	36,174	35,745	47,520	46,225	36,619	36,000	48,860	47,253	37,551	36,768	50,537	48,565	38,612	37,691	53,069	50,397	39,968	38,793

Notes: NO = Non-Ozone Season, O = Ozone Season

APPENDIX B

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Commerce Commission On Its Own Motion	: : :	
Response to Governor's Sustainable Energy Plan for the State of Illinois	: : :	05-0437

RESOLUTION

By the Commission:

WHEREAS, the inflation-adjusted prices of fossil fuels have risen steadily in the last five years; and

WHEREAS, the prices of fossil fuels have a significant effect on the future price of electricity; and

WHEREAS, the price of fossil fuels are decided in national and international markets that are beyond the control of state jurisdiction; and

WHEREAS, on February 11, 2005, the Governor of the State of Illinois sent to the Illinois Commerce Commission a proposal for a Sustainable Energy Plan for Illinois; and

WHEREAS, the Governor's proposed Sustainable Energy Plan included a Renewable Portfolio Standard and an Energy Efficiency Portfolio Standard; and

WHEREAS, the Governor's proposed Sustainable Energy Plan included a recommendation that the Illinois Commerce Commission establish an Illinois Sustainable Energy Advisory Council, with members appointed by the Chairman; and

WHEREAS, the Illinois Commerce Commission commenced the Sustainable Energy Initiative, issuing a "Request for Public Comment Concerning the Implementation of Governor Blagojevich's Proposal for a Sustainable Energy Plan for Illinois" on March 2, 2005; and

WHEREAS, the Illinois Commerce Commission organized workshops to discuss potential issues and invited Illinois utilities to present proposed implementation plans consistent with the Governor's proposed Sustainable Energy Plan; and

WHEREAS, during the course of the workshops, the Illinois Commerce Commission learned that the use of renewable energy sources will lead to rural economic development and improve environmental quality; and

WHEREAS, the Staff of the Energy Division of the Illinois Commerce Commission produced a Staff report dated July 7, 2005 addressing the various issues surrounding the implementation of renewable energy, demand response and energy efficiency programs; and

WHEREAS, the Illinois Commerce Commission adopted a resolution accepting Staff's report on July 13, 2005.

IT IS THEREFORE RESOLVED by the Illinois Commerce Commission that the Commission hereby adopts the Governor's proposed Sustainable Energy Plan with modifications based on information gathered through the Sustainable Energy Initiative and Staff's Report.

IT IS FURTHER RESOLVED that the Renewable Portfolio Standard should be set as follows: 2% of the bundled retail load should be obtained from renewable energy resources as defined below in 2007, 3% in 2008, 4% in 2009, 5% in 2010, 6% in 2011, 7% in 2012 and 8% in 2013.

IT IS FURTHER RESOLVED that sources of renewable energy shall include wind, solar thermal energy, photovoltaic cells and panels, dedicated crops grown for energy production and organic waste biomass, methane recovered from landfills, hydropower that does not involved the construction of new dams or significant expansion of existing dams, and other such alternative sources of environmentally preferable energy.

IT IS FURTHER RESOLVED that the Illinois Commerce Commission recognizes the benefits to Illinois by implementing the Sustainable Energy Plan, including using renewable energy and energy efficiency as a hedge against rising fossil fuel costs, and demand response as a mechanism to maintain system reliability and lower prices for all customers. Additionally, the Sustainable Energy Plan will create economic benefits in rural areas, create jobs and reduce air pollutants.

IT IS FURTHER RESOLVED that 75% of the renewable energy used to meet the renewable portfolio standard should come from wind power, 25% should come from other sources as defined above.

IT IS FURTHER RESOLVED that the Illinois Commerce Commission will review the Renewable Portfolio Standard every year after its implementation to assess the progress toward meeting the Standard.

IT IS FURTHER RESOLVED that the Energy Efficiency Portfolio Standard should be set as follows: years 2007-2008 at 10% reduction in load growth, years 2009-2011 at 15% reduction in load growth, years 2012-2014 at 20% reduction in load growth and years 2015-2017 at 25% reduction in load growth.

IT IS FURTHER RESOLVED that the Illinois Commerce Commission encourages creativity and innovation with respect to energy efficiency programs and urges participants to explore all possible options.

IT IS FURTHER RESOLVED that any entity participating in the Sustainable Energy Plan shall procure renewable energy and energy efficiency services through arms-length transactions.

IT IS FURTHER RESOLVED that the Chairman of the Illinois Commerce Commission shall appoint members to the Illinois Sustainable Energy Advisory Council within thirty (30) days of the adoption of this resolution.

IT IS FURTHER RESOLVED that the Illinois Commerce Commission expects electric public utilities and alternative retail electric suppliers to participate in the Sustainable Energy Plan by filing appropriate documentation to implement the Plan within thirty (30) days of the adoption of this resolution.

Adopted by the Commission this 19th day of July, 2005

(SIGNED) Edward C. Hurley

Chairman

APPENDIX C

ILLINOIS POWER PLANTS

PlantName	Plant ID	Fuel Class	Fuel Code	Fuel Description	Energy Input (MMBTU)	Energy Output (MWH)	Average Heat Rate (MMBTU per MWH)	Energy Content MMBTU per: ton (coal) mcf (gas) bbl (oil)	Efficiency (Joules OUT versus Joules IN)
1515 S Caron Road	7770	Natural Gas	NG	Natural Gas	5,489	387	14.184	1.026	24.1%
A E Staley Decatur Plant Cogen	10867	Coal	BIT	Bituminous Coal	1,761,848	352,370	4.973	21.020	68.6%
Alliant SBD 9805 Rockford Products	55316	Natural Gas	NG	Natural Gas	120,112	6,998	17.164	1.000	19.9%
Alsey	7818	Natural Gas	NG	Natural Gas	13,061	616	21.204	1.017	16.1%
Alsey	7818	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	9,485	515	18.418	5.877	18.5%
Alsip Paper Condominium Association	10406	Natural Gas	NG	Natural Gas	323,077	41,156	7.850	1.020	43.5%
Altamont	7990	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,265	120	10.554	5.750	32.3%
Archer Daniels Midland Decatur	10865	Coal	BIT	Bituminous Coal	9,688,007	613,380	15.622	21.200	21.8%
Archer Daniels Midland Decatur	10865	Coal	SC	Coal-based Synfuel and include briquettes, pellets, or extrusions, which ar	2,539,006	300,878	7.526	21.200	45.3%
Archer Daniels Midland Decatur	10865	Coal	SUB	Subbituminous Coal	3,727,204	405,742	8.755	17.500	39.0%
Archer Daniels Midland Decatur	10865	Other	TDF	Tires	329,868	11,521	28.628	28.000	11.9%
Aurora	55279	Natural Gas	NG	Natural Gas	551,250	53,134	10.432	1.025	32.7%
Aventis Behring LLC	54790	Natural Gas	NG	Natural Gas	548,700	35,914	15.278	1.100	22.3%
Avenue A Generator Sets	7854	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	366	49	7.480	5.809	45.6%
Avon Energy Partners LLC	55768	Natural Gas	LFG	Landfill Gas	138,480	12,699	10.905	0.500	31.3%
Baldwin Energy Complex	889	Coal	SUB	Subbituminous Coal	132,792,220	13,037,830	10.197	17.345	33.5%
Baldwin Energy Complex	889	Other	OTH	Other (Batteries, Chemicals, Hydrogen, Pitch, Sulfur, misc technologies)	2,442	241	10.133	33.000	33.7%
Baldwin Energy Complex	889	Other	TDF	Tires	1,236,686	119,513	10.245	32.157	33.3%
Baldwin Energy Complex	889	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	107,839	10,508	10.226	5.886	33.4%
Braidwood Generation Station	6022	Nuclear	NUC	Nuclear (Uranium, Plutonium, Thorium)	208,863,636	20,008,012	10.439		32.7%
Breese	934	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	4,363	366	11.922	5.802	28.6%
Brickyard Energy Partners LLC	55762	Natural Gas	LFG	Landfill Gas	274,764	20,236	13.578	0.500	25.1%
Bunge Milling Cogen	51000	Coal	BIT	Bituminous Coal	376,264	75,253	4.973	19.680	68.6%
Bunge Oil	52034	Natural Gas	NG	Natural Gas	196,363	13,739	14.293	1.010	23.9%
Bushnell	935	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,709	167	10.242	5.755	33.3%
Byron Generating Station	6023	Nuclear	NUC	Nuclear (Uranium, Plutonium, Thorium)	208,827,643	20,004,564	10.439		32.7%
Cadbury Adams - Rockford	54933	Natural Gas	NG	Natural Gas	269,872	20,891	12.918	1.010	26.4%
Calumet Energy Team LLC	55296	Natural Gas	NG	Natural Gas	121,322	11,546	10.624	1.013	32.1%
Carmi	937	Natural Gas	NG	Natural Gas	2,933	240	12.224	1.000	27.9%
Carmi	937	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	3,586	305	11.758	5.500	29.0%
CID Gas Recovery	50573	Natural Gas	LFG	Landfill Gas	700,140	34,033	20.572	0.570	16.6%
City of Casey	56053	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,295	145	8.944	5.756	38.2%
Clinton Power Station	204	Nuclear	NUC	Nuclear (Uranium, Plutonium, Thorium)	83,657,823	8,013,969	10.439		32.7%
Coffeen	861	Coal	BIT	Bituminous Coal	48,312,310	4,836,544	9.987	20.521	34.2%
Coffeen	861	Coal	SUB	Subbituminous Coal	9,596,383	965,391	9.776	17.801	34.9%
Coffeen	861	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	65,951	6,580	9.912	5.755	34.4%
Collins	6025	Natural Gas	NG	Natural Gas	1,410,783	103,946	14.454	1.000	23.6%
Collins	6025	Petroleum	RFO	Residual Fuel Oil (No 5 Fuel Oil, No 6 Fuel Oil)	6,875,074	529,555	13.648	6.224	25.0%
Cordova Energy	55188	Natural Gas	NG	Natural Gas	3,026,956	405,053	7.437	1.006	45.9%
Corn Products Illinois	54556	Coal	BIT	Bituminous Coal	1,979,876	260,705	7.553	24.000	45.2%
Corn Products Illinois	54556	Natural Gas	NG	Natural Gas	373,940	45,323	8.865	1.010	38.5%
Countyside Genco LLC	55773	Natural Gas	LFG	Landfill Gas	579,264	52,954	10.939	0.500	31.2%
Crawford	867	Coal	SUB	Subbituminous Coal	29,852,768	2,969,861	10.077	17.200	33.9%
Crawford	867	Natural Gas	NG	Natural Gas	130,230	12,736	10.279	1.002	33.2%
Crete Energy Park	55253	Natural Gas	NG	Natural Gas	21,908	328	12.529	1.021	27.2%
Dallman	963	Coal	BIT	Bituminous Coal	21,883,487	1,926,892	11.361	20.966	30.0%
Dallman	963	Other	AB	Agriculture Byproducts, Bagasse,Straw,Energy Crops	157,122	6,333	24.692	14.077	13.8%
Dallman	963	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	19,018	1,412	13.327	5.819	25.6%
Devonshire Power Partners LLC	55761	Natural Gas	LFG	Landfill Gas	326,052	28,568	11.413	0.500	29.9%
Dixon/Lee Energy Partners LLC	55763	Natural Gas	LFG	Landfill Gas	148,332	20,284	7.313	0.500	46.7%
Dresden Generating Station	869	Nuclear	NUC	Nuclear (Uranium, Plutonium, Thorium)	128,887,380	12,346,717	10.439		32.7%

ILLINOIS POWER PLANTS

PlantName	Plant ID	Fuel Class	Fuel Code	Fuel Description	Energy Input (MMBTU)	Energy Output (MWH)	Average Heat Rate (MMBTU per MWH)	Energy Content MMBTU per: ton (coal) mcf (gas) bbl (oil)	Efficiency (Joules OUT versus Joules IN)
Duck Creek	6016	Coal	BIT	Bituminous Coal	23,362,872	2,187,720	10.670	21.298	32.0%
Duck Creek	6016	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	38,449	3,139	12.060	5.761	28.3%
Duraco Products	54798	Natural Gas	NG	Natural Gas	39,485	3,122	12.648	1.010	27.0%
E D Edwards	856	Coal	BIT	Bituminous Coal	32,675,282	3,211,629	10.109	21.234	33.8%
E D Edwards	856	Coal	SUB	Subbituminous Coal	11,979,474	1,034,926	11.549	17.694	29.5%
E D Edwards	856	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	86,439	7,367	11.686	5.768	29.2%
Electric Junction	870	Natural Gas	NG	Natural Gas	357,440	17,462	19.754	1.000	17.3%
Elgin Energy Center	55438	Natural Gas	NG	Natural Gas	220,631	19,258	11.521	1.015	29.6%
Elwood Energy LLC	55199	Natural Gas	NG	Natural Gas	2,284,712	199,018	11.216	1.000	30.4%
Energy Shelby County	55237	Natural Gas	NG	Natural Gas	85,480	9,685	9.176	1.033	37.2%
Entenmanns Cogeneration Facility	10376	Natural Gas	NG	Natural Gas	34,003	2,806	12.119	1.030	28.2%
Evanston Township High School	54788	Natural Gas	NG	Natural Gas	20,092	2,916	6.890	1.030	49.5%
ExxonMobil Oil Joliet Refinery	50627	Natural Gas	OG	Other Gas	2,182,315	176,920	12.658	1.126	27.0%
Factory	8016	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	546	43	12.696	5.809	26.9%
Fairfield	940	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	3,051	292	10.450	5.800	32.7%
Farmer City	941	Natural Gas	NG	Natural Gas	479	43	11.164	1.023	30.6%
Farmer City	941	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	172	15	11.492	5.731	29.7%
Fisk Street	886	Coal	SUB	Subbituminous Coal	17,877,561	1,783,908	10.041	17.200	34.0%
Fisk Street	886	Natural Gas	NG	Natural Gas	35,980	3,552	9.982	1.001	34.2%
Fisk Street	886	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	49,630	3,083	15.830	5.863	21.6%
Fox Metro Water Reclamation District	50904	Natural Gas	NG	Natural Gas	630	57	10.974	1.082	31.1%
Fox Metro Water Reclamation District	50904	Other	OBG	Other BioMass Gases (Digester Gas, Methane, other gases)	468	42	11.017	0.642	31.0%
Freeburg	943	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	2,207	212	10.410	5.747	32.8%
Freedom Power Project	7842	Natural Gas	NG	Natural Gas	3,358	324	10.366	1.100	32.9%
Geneseo	944	Natural Gas	NG	Natural Gas	5,121	572	8.954	1.020	38.1%
Geneseo	944	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,420	142	10.004	5.796	34.1%
Gibson City	55201	Natural Gas	NG	Natural Gas	42,927	1,116	18.477	1.017	18.5%
Goose Creek Energy Center	55496	Natural Gas	NG	Natural Gas	9,505	768	12.573	1.027	27.1%
Grand Tower	862	Natural Gas	NG	Natural Gas	1,933,498	216,528	9.256	1.029	36.9%
Greene Valley Gas Recovery	55014	Natural Gas	LFG	Landfill Gas	985,020	49,893	19.743	0.540	17.3%
Hallock	7895	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	5,451	562	9.700	5.750	35.2%
Havana	891	Coal	BIT	Bituminous Coal	22,769,581	2,033,708	11.235	23.938	30.4%
Havana	891	Natural Gas	NG	Natural Gas	38,416	3,361	11.366	1.000	30.0%
Havana	891	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	86,611	7,608	11.287	5.778	30.2%
Havana	891	Petroleum	RFO	Residual Fuel Oil (No 5 Fuel Oil, No 6 Fuel Oil)	19,147	1,724	11.274	6.290	30.3%
Hennepin Power Station	892	Coal	SUB	Subbituminous Coal	20,959,123	2,009,828	10.413	17.536	32.8%
Hennepin Power Station	892	Natural Gas	NG	Natural Gas	34,682	3,335	10.426	1.012	32.7%
Highland	946	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	2,999	295	10.168	5.801	33.6%
Hoffer Plastics	54523	Natural Gas	NG	Natural Gas	117	12	9.942	1.011	34.3%
Holland Energy Facility	55334	Natural Gas	NG	Natural Gas	1,057,980	137,582	11.664	1.030	29.3%
Hutsonville	863	Coal	BIT	Bituminous Coal	7,917,745	768,665	10.301	20.960	33.1%
Hutsonville	863	Coal	SUB	Subbituminous Coal	32,472	3,152	10.302	17.600	33.1%
Hutsonville	863	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	21,754	2,112	10.300	5.760	33.1%
Illinois Institute of Tech Cogen Fac	52021	Natural Gas	NG	Natural Gas	919	64	14.465	1.000	23.6%
IMEA Flora	56116	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	396	40	9.888	5.824	34.5%
IMEA Highland	56114	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,056	100	10.568	5.803	32.3%
IMEA Waterloo	56115	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,437	132	10.897	5.794	31.3%
Indian Trails Cogen 1	7384	Natural Gas	NG	Natural Gas	322,186	29,832	10.800	1.000	31.6%
Industrial Park	7934	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	933	118	7.905	5.795	43.2%
Interstate	7425	Natural Gas	NG	Natural Gas	31,452	2,380	13.215	1.030	25.8%
Interstate	7425	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	19,783	1,520	13.015	5.800	26.2%

ILLINOIS POWER PLANTS

PlantName	Plant ID	Fuel Class	Fuel Code	Fuel Description	Energy Input (MMBTU)	Energy Output (MWH)	Average Heat Rate (MMBTU per MWH)	Energy Content MMBTU per: ton (coal) mcf (gas) bbl (oil)	Efficiency (Joules OUT versus Joules IN)
IVEX Packaging	52032	Natural Gas	NG	Natural Gas	283,309	27,775	10.200	1.000	33.5%
Joliet 29	384	Coal	SUB	Subbituminous Coal	60,075,971	5,946,956	10.110	17.200	33.8%
Joliet 29	384	Natural Gas	NG	Natural Gas	280,447	26,924	10.094	1.002	33.8%
Joliet 9	874	Coal	SUB	Subbituminous Coal	17,566,327	1,588,158	11.064	17.200	30.8%
Joliet 9	874	Natural Gas	NG	Natural Gas	54,212	4,883	11.024	1.002	31.0%
Joppa Steam	887	Coal	SUB	Subbituminous Coal	87,743,350	8,426,231	10.404	16.949	32.8%
Joppa Steam	887	Natural Gas	NG	Natural Gas	195,380	17,685	11.140	1.030	30.6%
Kankakee Gas Recovery	54659	Natural Gas	LFG	Landfill Gas	145,740	11,763	12.390	0.570	27.5%
Kendall County Generation Facility	55131	Natural Gas	NG	Natural Gas	593,188	204,227	10.419	1.020	32.7%
Kickapoo	7896	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	3,445	346	9.957	5.751	34.3%
Kincaid Generation LLC	876	Coal	SUB	Subbituminous Coal	75,188,218	7,506,798	10.032	17.352	34.0%
Kincaid Generation LLC	876	Natural Gas	NG	Natural Gas	18,889	1,867	10.099	1.003	33.8%
Kinmundy	55204	Natural Gas	NG	Natural Gas	51,851	2,148	15.271	1.026	22.3%
KMS Joliet Power Partners LP	5756	Natural Gas	LFG	Landfill Gas	56,652	5,554	10.200		33.5%
Lake Gas Recovery	50575	Natural Gas	LFG	Landfill Gas	804,660	42,541	18.915	0.580	18.0%
Lakeside	964	Coal	BIT	Bituminous Coal	2,255,565	172,915	13.044	20.990	26.2%
Lakeside	964	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	7,784	507	15.355	5.800	22.2%
LaSalle Generating Station	6026	Nuclear	NUC	Nuclear (Uranium, Plutonium, Thorium)	198,257,068	18,991,960	10.439		32.7%
Lee Energy Facility	55236	Natural Gas	NG	Natural Gas	134,301	10,577	12.204	1.013	28.0%
Lincoln Generating Facility	55222	Natural Gas	NG	Natural Gas	86,442	5,557	12.869	1.005	26.5%
Little Company of Mary Hospital	10400	Natural Gas	NG	Natural Gas	295,788	14,896	19.857	1.000	17.2%
Lombard	877	Natural Gas	NG	Natural Gas	25,500	1,610	15.839	1.000	21.5%
M&M Mars Chicago	54855	Natural Gas	NG	Natural Gas	499,377	28,793	17.344	1.020	19.7%
Mallard Lake Electric	55592	Natural Gas	LFG	Landfill Gas	1,191,912	95,951	12.422	0.550	27.5%
Mallard Lake Electric	55592	Natural Gas	NG	Natural Gas	466,329	45,714	10.201		33.4%
Mallard Lake Electric	55592	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	2,160	174	12.414	5.510	27.5%
Marion	976	Coal	BIT	Bituminous Coal	11,433,033	971,798	11.766	21.981	29.0%
Marion	976	Coal	WC	Waste/Other Coal (Anthracite Culm, Bituminous Gob, Fine Coal, Lignite W	10,415,677	843,601	12.350	16.630	27.6%
Marion	976	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	78,957	8,401	9.396	5.692	36.3%
Marion	976	Petroleum	PC	Petroleum Coke	1,105,266	89,834	12.436	28.075	27.4%
Marshall	949	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	3,651	377	9.685	5.750	35.2%
Mascoutah	950	Natural Gas	NG	Natural Gas	636	66	9.648	1.021	35.4%
Mascoutah	950	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	984	147	6.692	5.892	51.0%
McLeansboro	948	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,266	134	9.454	5.754	36.1%
Meredosia	864	Coal	BIT	Bituminous Coal	3,305,807	283,299	11.391	21.186	30.0%
Meredosia	864	Coal	SUB	Subbituminous Coal	12,935,607	1,123,100	11.548	17.621	29.5%
Meredosia	864	Natural Gas	NG	Natural Gas	1,103	98	11.183	1.011	30.5%
Meredosia	864	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	54,328	4,433	11.495	5.776	29.7%
Meredosia	864	Petroleum	RFO	Residual Fuel Oil (No 5 Fuel Oil, No 6 Fuel Oil)	25,065	2,195	11.179	6.050	30.5%
Milam Gas Recovery	50566	Natural Gas	LFG	Landfill Gas	222,924	19,046	11.705	0.600	29.2%
Morris Genco LLC	55774	Natural Gas	LFG	Landfill Gas	284,988	23,947	11.901	0.500	28.7%
Morris Power Plant	55216	Natural Gas	NG	Natural Gas	2,682,988	434,395	6.176	1.040	55.2%
Morris Power Plant	55216	Natural Gas	OG	Other Gas	694,068	113,602	6.110	0.930	55.8%
Nalco	50326	Natural Gas	NG	Natural Gas	189,492	18,963	10.488	1.050	32.5%
New Heights Recovery and Power LLC	55174	Other	TDF	Tires	5,195	365	14.236	28.241	24.0%
Newton	6017	Coal	SUB	Subbituminous Coal	74,941,210	7,017,107	10.691	17.570	31.9%
Newton	6017	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	80,279	7,538	10.687	5.765	31.9%
Nicor Gas	50040	Natural Gas	NG	Natural Gas	70,201	5,880	11.939	0.900	28.6%
North Ninth Street	960	Natural Gas	NG	Natural Gas	3,980	206	19.320	1.026	17.7%
North Ninth Street	960	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,684	88	19.155	5.807	17.8%
NRG Rockford I	55238	Natural Gas	NG	Natural Gas	278,750	27,592	10.119	1.001	33.7%

ILLINOIS POWER PLANTS

PlantName	Plant ID	Fuel Class	Fuel Code	Fuel Description	Energy Input (MMBTU)	Energy Output (MWH)	Average Heat Rate (MMBTU per MWH)	Energy Content MMBTU per: ton (coal) mcf (gas) bbl (oil)	Efficiency (Joules OUT versus Joules IN)
NRG Rockford II Energy Center	55936	Natural Gas	NG	Natural Gas	63,231	6,333	9.984	1.002	34.2%
Oglesby	894	Natural Gas	NG	Natural Gas	10,025	568	17.651	1.010	19.3%
Pearl Station	6238	Coal	BIT	Bituminous Coal	1,986,842	147,576	13.463	20.670	25.3%
Pearl Station	6238	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	879	30	29.376	5.860	11.6%
Pekin Paperboard	54664	Natural Gas	NG	Natural Gas	363,471	9,792	37.119	1.000	9.2%
Pinckneyville	55202	Natural Gas	NG	Natural Gas	591,331	51,714	11.521	1.025	29.6%
Pittsfield	6237	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	140	13	10.722	5.831	31.8%
Powerton	879	Coal	SUB	Subbituminous Coal	97,973,040	8,894,333	10.966	17.200	31.1%
Powerton	879	Natural Gas	NG	Natural Gas	42,932	3,898	10.938	1.002	31.2%
PPL University Park Power Project	55640	Natural Gas	NG	Natural Gas	1,206,381	116,443	10.381	1.030	32.9%
Princeton	957	Natural Gas	NG	Natural Gas	3,884	449	8.649	1.050	39.5%
Princeton	957	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	2,328	157	14.829	5.748	23.0%
Quad Cities	55593	Natural Gas	LFG	Landfill Gas	75,504	4,550	16.595	0.500	20.6%
Quad Cities Generating Station	880	Nuclear	NUC	Nuclear (Uranium, Plutonium, Thorium)	132,388,450	12,682,101	10.439		32.7%
Rantoul	958	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	4,989	501	9.959	5.801	34.3%
Red Bud	959	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	3,053	294	10.387	5.860	32.9%
Reynolds	965	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	509	34	14.985	5.785	22.8%
Riveside Resource Recovery LLC	55767	Natural Gas	LFG	Landfill Gas	85,836	7,458	11.509	0.500	29.6%
Rockford Electric	55591	Natural Gas	LFG	Landfill Gas	79,284	6,495	12.207	0.510	28.0%
Rocky Road Power LLC	55109	Natural Gas	NG	Natural Gas	306,783	22,978	12.988	1.036	26.3%
Roxana Resource Recovery	55759	Natural Gas	LFG	Landfill Gas	249,708	23,782	10.500	0.500	32.5%
Sabrooke	882	Natural Gas	NG	Natural Gas	5,760	360	16.002	1.000	21.3%
Saint Mary of Nazareth Hospital	54886	Natural Gas	NG	Natural Gas	553	50	11.058	1.002	30.9%
Settlers Hill Gas Recovery	50563	Natural Gas	LFG	Landfill Gas	711,732	38,539	18.468	0.564	18.5%
Sherman Hospital	50909	Natural Gas	NG	Natural Gas	751	75	10.028	1.003	34.0%
South Barrington Electric	55594	Natural Gas	LFG	Landfill Gas	157,560	11,944	13.192	0.510	25.9%
Southeast Chicago Energy Project	55281	Natural Gas	NG	Natural Gas	226,906	17,816	12.731	1.024	26.8%
State Farm	7556	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	13,067	1,210	10.800	5.754	31.6%
Sterling Avenue	860	Natural Gas	NG	Natural Gas	7,725	435	17.760	1.000	19.2%
Streator Energy Partners LLC	55760	Natural Gas	LFG	Landfill Gas	82,320	7,340	11.215	0.500	30.4%
Tazewell Gas Recovery	50721	Natural Gas	LFG	Landfill Gas	214,632	18,073	11.876	0.570	28.7%
Thornridge High School	55005	Natural Gas	NG	Natural Gas	23,281	1,437	16.201	1.010	21.1%
Thornwood High School	55004	Natural Gas	NG	Natural Gas	31,348	2,188	14.328	1.010	23.8%
Tilton	7760	Natural Gas	NG	Natural Gas	725,170	61,884	11.718	1.020	29.1%
University of Illinois Abbott Power Plt	54780	Coal	BIT	Bituminous Coal	336,220	60,755	5.575	21.967	61.2%
University of Illinois Abbott Power Plt	54780	Natural Gas	NG	Natural Gas	2,433,512	243,025	10.472	1.022	32.6%
University of Illinois Abbott Power Plt	54780	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	5,092	954	5.953	5.817	57.3%
University of Illinois Cogen Facility	54044	Natural Gas	NG	Natural Gas	2,379,509	224,895	10.551	1.012	32.3%
University of Illinois Cogen Facility	54044	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	8,451	820	10.390	5.964	32.8%
University Park Energy LLC	55250	Natural Gas	NG	Natural Gas	648,702	59,440	11.300	1.023	30.2%
Upper Rock Energy Partners LLC	55764	Natural Gas	LFG	Landfill Gas	328,584	24,976	13.156	0.500	25.9%
Venice	913	Natural Gas	NG	Natural Gas	50,007	2,365	21.145	1.030	16.1%
Vermilion	897	Coal	BIT	Bituminous Coal	11,210,748	994,623	11.271	21.410	30.3%
Vermilion	897	Natural Gas	NG	Natural Gas	35,765	3,173	11.272	1.020	30.3%
Waterloo	971	Natural Gas	NG	Natural Gas	2,773	343	8.038	1.051	42.5%
Waterloo	971	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,545	144	10.736	5.765	31.8%
Waukegan	883	Coal	SUB	Subbituminous Coal	47,633,199	4,207,471	11.628	17.200	29.3%
Waukegan	883	Natural Gas	NG	Natural Gas	107,593	9,386	11.516	1.001	29.6%
Waukegan	883	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	30,411	2,633	13.024	5.833	26.2%
Wells Manufacturing Dura Bar Division	54540	Natural Gas	NG	Natural Gas	1,574	180	8.748	1.001	39.0%
Will County	884	Coal	SUB	Subbituminous Coal	49,117,439	4,904,110	10.036	17.200	34.0%

ILLINOIS POWER PLANTS

PlantName	Plant ID	Fuel Class	Fuel Code	Fuel Description	Energy Input (MMBTU)	Energy Output (MWH)	Average Heat Rate (MMBTU per MWH)	Energy Content MMBTU per: ton (coal) mcf (gas) bbl (oil)	Efficiency (Joules OUT versus Joules IN)
Will County	884	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	357,171	35,703	10.046	5.844	34.0%
Winnetka	972	Natural Gas	NG	Natural Gas	44,190	2,553	17.309	1.009	19.7%
Winnetka	972	Petroleum	DFO	Distillate Fuel Oil (Diesel, No 1 Fuel Oil, No. 2 Fuel Oil, No. 4 Fuel Oil)	1,652	148	11.160	5.900	30.6%
Wood River	898	Coal	SUB	Subbituminous Coal	26,384,675	2,422,343	10.995	17.629	31.0%
Wood River	898	Natural Gas	NG	Natural Gas	76,576	6,877	11.158	1.028	30.6%
Woodland Landfill Gas Recovery	54662	Natural Gas	LFG	Landfill Gas	157,296	12,115	12.984	0.570	26.3%
Zion Energy Center	55392	Natural Gas	NG	Natural Gas	324,990	29,916	10.898	1.010	31.3%

APPENDIX D

For a copy of the emissions calculations, please contact Erin Daughton, Shaw Environmental, at erin.daughton@shawgrp.com

APPENDIX E

Status of CAIR Set-asides for Renewable Energy Projects

As of December 2006, seven of 28 eastern states have reserved a portion of the NOx emission allowances under the Clean Air Interstate Rule (CAIR) for renewable energy projects in their State Implementation Plans (SIPs). These states are Indiana, Massachusetts, Maryland, Missouri, New Jersey, New York and Ohio. The size of the annual set-asides for renewables varies from 1% in Ohio to 5% in New Jersey. In total, 647,585 tons of NOx allowances are to be set aside.

The basis of allocation is usually 1.5 lbs/MWh in these states, although the basis of allocation for Maryland has not yet been determined. At this basis rate, this represents 431,723 MWh of power. The length of allocation varies from five years to no limit. Aggregation of small projects is allowed in most cases for applying for the required minimum allowance of 1 ton.

Three other states—Pennsylvania, Minnesota and Virginia—are in advanced stages of incorporating NOx allowance set-asides in their SIPs. Virginia is considering approximately 36 tons (0.2% of total allowances), Pennsylvania is considering 5% and Minnesota is considering 15% as set-asides. Georgia has decided that this is a good option for promoting renewable energy projects and will consider it after the State Energy Strategy for Georgia is finalized.

Illinois has a plan for 5% NOx allowance set-aside for EERE projects. The set-aside will be used as an incentive package for those entities that undertake projects resulting in lowering their electricity usage rates (i.e., demand-side management) as well as replacing generation with renewable energy emissions units (REEU—e.g., wind, solar).

An overview of the set-aside program for renewable energy as part of CAIR implementation for the seven states is shown in the following pages of this appendix. The details have been compiled by the American Wind Energy Association.