ANL-06/16

Evaluating the Potential Impact of Transmission Constraints on the Operation of a Competitive Electricity Market in Illinois

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EXECUTIVE SUMMARY

In Illinois, electricity restructuring is mandated by the Electric Service Customer Choice and Rate Relief Law of 1997. The law provides for a transition period up to January 1, 2007, in which the electric power system is to move toward a competitive market. Despite the current adequacy of the generation and transmission system in Illinois, there is concern that the uncertainties of electricity restructuring warrant a more detailed analysis to determine if there might be pitfalls that have not been identified under current conditions. The problems experienced elsewhere in the country emphasizes the need for an evaluation of how Illinois might fare under a restructured electricity market.

The Illinois Commerce Commission (ICC) commissioned this study to be undertaken as a joint effort by the University of Illinois at Urbana-Champaign and Argonne National Laboratory to evaluate the Illinois situation in the 2007 period when restructuring is scheduled to be fully implemented in the State. The purpose of this study is to make an initial determination if the transmission system in Illinois and the surrounding region would be able to support a competitive electricity market, would allow for effective competition to keep prices in check, and would allow for new market participants to effectively compete for market share. The study seeks to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power in one or more portions of the state and thereby create undue pressure on the prices charged to customers and/or inhibit new market participants from entering the market.

The term "market power" has many different definitions and there is no universal agreement on how to measure it. For the purposes of this study, the term is defined as the ability to raise prices and increase profitability by unilateral action. With this definition, the central question of this analysis becomes:

"Can a company, acting on its own, raise electricity prices and increase its profits?"

It should be noted that the intent of the study is not to predict whether or not such market power would be exercised by any company. Rather, it is designed to determine if a set of reasonably expected conditions could allow any company to do so. It should also be emphasized that this study is not intended to be a comprehensive evaluation of the electric power system in the State. Rather, it is intended to identify some issues that may impact the effective functioning of a competitive market.

Two analytical tools are used in this study: the PowerWorld® model and the Electricity Market Complex Adaptive Systems (EMCAS)© model. PowerWorld Simulator is an interactive power system package designed to simulate high voltage power system operation. EMCAS uses an agent-based modeling structure to simulate the operation of the different entities participating in the electricity market.

The analysis of the power system in Illinois in this study was based on a set of assumptions and input data. These assumptions and inputs were used to provide a straightforward set of conditions that could be used to determine how the power system might

function. They were not intended to represent the predicted, most likely, or optimal set of conditions for the Illinois market. Rather, they were intended to test how the market might behave under a given configuration. The basic assumptions included the following:

- *A single market for electricity will be operating in the State and surrounding study area in the analysis year of 2007. A single independent system operator (ISO) will operate the entire transmission system in the State.*

- *A day-ahead market (DAM) for energy and ancillary services will operate in the State. The DAM will allow suppliers (i.e., generation companies, or GenCos in the terminology of the analytical models used here) and purchasers (i.e., demand companies, or DemCos) to bid for their participation in the market. No bilateral contracts are assumed to be in place. There will be no tariffs or price caps to limit charges to consumers.*

- *The configuration of the power system in Illinois in the analysis year was constructed from the 2003 summer case prepared by the North American Electric Reliability Council (NERC), which includes about 1,900 buses and 2,650 branches in Illinois. In addition to the in-state transmission configuration, the power transfers into and out of the State were accounted for in order to get an accurate picture of how the State's system would perform. PowerWorld used a larger portion of the eastern interconnection. EMCAS used a reduced out-of-state network with transmission capacity that allowed power to move into and out of the State.*

- *Load forecasts were based on data contained in Feferal Energy Regulatory Commission (FERC) Form 714.*

- *Generation capacity additions were taken from FERC, Energy Information Agency (EIA), and Illinois EPA sources. About 6 GW of new capacity represented a growth of about 14% from 2001 levels.*

- *Fuel price projections were based on regional forecasts produced by the EIA National Energy Modeling System (NEMS) model that are reported in its Annual Energy Outlook (AEO).*

The basic assumptions were grouped into two sets. The Case Study Assumptions provided a point of comparison for a single configuration and operating profile of the power system. The Conservative Assumptions were designed to verify that the results and conclusions were not distorted by the details of this single configuration. Under Conservative Assumptions forced outages and company-level unit commitment decisions were eliminated. Also, generation production cost included only fuel and variable operation and maintenance costs under Conservative Assumptions.

Using the basic assumptions and inputs, alternative cases were analyzed to determine how the Illinois market might function in the analysis year. The cases studied included the following:

Production Cost (PC)	*GenCo bids were based on unit production cost*
Physical Withholding (PW)	*GenCos withheld units from the market*
Economic Withholding (EW)	*GenCos increased prices above production cost*

The following observations can be made from what has been studied thus far under the assumptions applied:

Basic System Status

(a) The State has an adequate supply of generation capability to meet its needs and to export power to surrounding areas. It might even be argued that there is an excess of capacity given that the projected statewide generation reserve margin (in excess of 40%) is higher than what is generally used for system reliability planning. Further, some generators would not be dispatched at all under the conditions laid out in the PC case.

(b) The ownership of the generation capacity is concentrated in five companies: Exelon Nuclear, Midwest Generation, Ameren, Dynegy, and Dominion Energy. Together, they account for more than 77% of the generation capacity in the State. If they were to be dispatched under PC case market conditions, they would account for about 98% of the electricity generated in the State. Using any one of a number of measures of market competition, the State's generation capacity can be considered to be concentrated. With this degree of concentration and with much of this capacity in the form of low cost nuclear and coal units, it would be difficult for new generation companies to enter the deregulated market. In fact, many of the existing natural gas units, some of which are only a few years old, would have difficulty competing in this market.

(c) During the high load periods, which occurred about 5% of the time, electricity prices rose, since higher-cost generators had to be brought on-line to meet loads while maintaining the integrity and stability of the power grid. Even without any attempt to manipulate prices on the part of generation companies, prices were as much as 30% higher in high load periods.

(d) The transmission system in the State has areas that show evidence of congestion. Some transmission equipment was operated at its capacity limits for a significant number of hours in a year. The congested regions include the City of Chicago, the areas north and west of Chicago out to the Iowa border, a broad area stretching southwest of Chicago to Peoria and Springfield, and several smaller isolated areas in the southern part of the State. The effects of the transmission congestion were more prevalent during peak load periods, during which prices spread across the State. Price variations across the State due to transmission congestion were as much as 24% during these peak load periods.

(e) Using Conservative Assumptions, in which more generation capacity was assumed to be made available by the elimination of forced outages and company level unit commitment decisions, the results did not materially change. The generation market was still concentrated and transmission congestion was still evident. Price variations, though smaller in absolute magnitude, were equivalent in relative terms.

(f) Under a fully competitive market in the State using the market rules assumed here, some generation companies were pressed to maintain operating profitability. Only 6 out of 24 generation companies in the State were able to operate profitably. The dominance of the low cost nuclear and coal units made it difficult for others to compete. Under Conservative Assumptions, none of the generation companies, except Exelon Nuclear, was profitable. Exelon's operating profit was very small. For both the Case Study Assumptions and the Conservative Assumptions, the analysis period was only one year, and an assessment of long-term profitability that includes factors such as capital outlays was not included.

Market Power Potential

(g) If generation companies seek to raise market prices by physically withholding single units from service, the results here show that, for the most part, they would not likely benefit. Because of the abundance of generation in the State, there was almost always another unit that could be brought into service to replace one that was withheld. This is true even in light of the transmission congestion.

(h) In contrast, physically withholding multiple units that are strategically located in the transmission network, particularly during peak load conditions, can increase profitability. A single company using a strategy based on indicators of system reserve margin to identify times to withhold capacity and indicators of locational prices to identify which capacity to withhold could significantly increase its profitability. This type of strategic physical withholding could even create conditions where some load cannot be met and could result in very steep price increases. Exelon Nuclear, Midwest Generation, and Ameren all had market power (as defined here) when using this strategy. Dynegy and Dominion Energy did not.

(i) If the major generation companies sought to raise market prices by unilaterally increasing the price of their units (i.e., by economic withholding), the results would be mixed. Applying a price increase to all units for all hours increased profits for Exelon Nuclear and Midwest Generation, but at the expense of significant loss in generator dispatch since some of the higher cost units would be selected only sporadically by the market. The resulting dispatch schedule may not be technically practical for the companies' larger units. For Ameren, Dynegy, and Dominion Energy, the higher priced units would not be selected in the market and the price increase gained by other units would not be sufficient to recover the lost revenue. Profitability decreased.

(j) Alternatively, a more limited application of price increases that was restricted to peak hours only allowed Exelon Nuclear and Midwest Generation to significantly increase profits with only a small decrease in generator dispatch. Ameren, Dynegy, and Dominion did not see any profit increase by applying this strategy. The same was true under Conservative Assumptions except that Exelon would need very large price

increases to increase its profitability. When using this strategy, Exelon Nuclear and Midwest Generation had market power according to the definition used here.

(k) By raising their prices, all generation companies could cause consumer costs to rise, some by as much as 250% in some parts of the State on a peak day. However, only Exelon Nuclear and Midwest Generation saw a significant increase in their operating profits by applying this strategy.

Overall, the answer to the basic question of the study, "*Can a company, acting on its own, raise electricity prices and increase its profits?*" is affirmative. There is a concentration in the generation market and evidence of transmission congestion, at least during high load periods. This will give rise to the ability of some companies to unilaterally raise prices and increase their profits. Consumer costs will increase, in some cases substantially. However, the situations under which this can be done are limited to a number of conditions, especially high load periods.

1 INTRODUCTION

1.1 BACKGROUND

In 1978, the Public Utility Regulatory Policies Act (PURPA) passed by Congress began the process of restructuring the electricity system in the U.S. away from regulated monopolies and toward competitive businesses. This process continued with the Energy Policy Act of 1992, which focused on providing opportunities for competition in the wholesale electricity market. Orders 888 and 889, issued by the Federal Energy Regulatory Commission (FERC) in 1996, provided for open access to the bulk power transmission system for all wholesale electricity producers and purchasers. However, the FERC recognized that open access at the retail level would also require legislative and/or regulatory action by the states.

Since the passage of these legislative and regulatory measures, a number of states have taken steps to restructure the electricity system in their jurisdictions and to provide access to retail customers to electricity providers other than their local electric utility. To date, 24 states have implemented some form of electricity restructuring legislation. Of these, 18, including Illinois, are actively engaged in implementing the process, five have delayed implementation, and one, California, has suspended implementation.[1]

While restructuring has proceeded relatively smoothly in some parts of the country, such as with the New York Independent System Operator (NYISO), and the Pennsylvania-New Jersey-Maryland (PJM) area, the serious problems experienced in California in 2000/2001 have demonstrated the need to better understand the operation of a restructured electricity market. The California experience showed how a set of conditions, such as the following, could combine to create a "perfect storm" in the electricity business:

- *Low investment in new generation capacity.* California's load increased by 11% in the 1990s while generation capacity decreased by 2%.

- *Low hydropower conditions.* California depended on 7–11 GW of out-of-state generation capacity, much of which was hydropower-based and much of which experienced low water levels due to an extended period of dry weather.

- *Generation units out of service.* As much as 10 GW of generation capacity were out of operation, some during peak load periods.

- *Transmission limitations.* A major transmission line, Path 15, was significantly congested, thus inhibiting the transfer of power between northern and southern California.

- *Independent power producers' reluctance to sell power.* Because of the precarious financial position of the utilities, independent producers feared not being paid for the power they provided.

[1] Energy Information Administration last update (Feb. 2003).

- *Shortcomings of the wholesale market design.* The California market rules prohibited the use of forward long-term contracts for the purchase of electricity; utilities were required to use the volatile spot market exclusively.

- *High natural gas prices.* The high prices for natural gas added to the cost of electricity.

- *Fixed retail prices.* With high wholesale prices and fixed retail prices, there was no price feedback to consumers. Companies were unable to recover their costs and accumulated significant debts. [2]

In addition to these extreme conditions, experience in other electricity markets in the U.S. and abroad has shown that it is possible for restructuring to function in such a way as to reduce or negate the benefits that should accrue from open competition.

In Illinois, electricity restructuring is mandated by the Electric Service Customer Choice and Rate Relief Law of 1997. [3] The law provides for a transition period up to January 1, 2007, in which the electric power system is to move toward a competitive market.

Under the historical structure of electric utility monopolies, Illinois has had an adequate level of generation and transmission capacity to meet demand. In a reliability assessment, [4] the North American Electric Reliability Council (NERC) indicated that the long-term generation capacity reserve margins for the MidAmerica Interconnected Network (MAIN), which encompasses most of Illinois and parts of Iowa, Minnesota, Missouri, and Wisconsin, is well within requirements. Further, it indicated that the "…bulk electric transmission system generally appears to have no major limitations and is expected to perform adequately over a wide range of system conditions." There were, however, some reported limitations on power transfers into Wisconsin and Iowa and heavy loadings on lines in the southern part of the MAIN area.

1.2 PURPOSE OF THE STUDY

Despite the current adequacy of the generation and transmission system in Illinois, there is concern that the uncertainties of electricity restructuring warrant a more detailed analysis to determine if there might be pitfalls that have not been identified under current conditions. The problems experienced elsewhere in the country emphasize the need for an evaluation of how Illinois might fare under a restructured electricity market.

The Illinois Commerce Commission (ICC) commissioned this study to be undertaken as a joint effort by the University of Illinois at Urbana-Champaign and Argonne National Laboratory to evaluate the Illinois situation in the 2007 period when restructuring is scheduled to be fully

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[2] *Status of the California Electricity Situation*, Energy Information Administration (Aug 2002).
[3] Illinois Compiled Statutes, Utilities, Public Utilities Act, 220 ILCS 5.
[4] North American Electric Reliability Council, "Reliability Assessment 2002-2011, The Reliability of Bulk Electric Systems in North America (October 2002).

implemented in the State. The purpose of this study is to make an initial determination if the transmission system in Illinois and the surrounding region would be able to support a competitive electricity market, would allow for effective competition to keep prices in check, and would allow for new market participants to effectively compete for market share. The study seeks to identify conditions that could reasonably be expected to occur that would enable a company to exercise market power in one or more portions of the State and thereby create undue pressure on the prices charged to customers and/or inhibit new market participants from entering the market.

The term "market power" has many different definitions, and there is no universal agreement on how to measure it. For the purposes of this study, the term is defined as the ability to raise prices and increase profitability by unilateral action. A more complete definition is provided later. With this definition, the central question of this analysis becomes:

"Can a company, acting on its own, raise electricity prices and increase its profits?"

It should be noted that the intent of the study is not to predict whether or not such market power would be exercised by any company. Rather, it is designed to determine if a set of reasonably expected conditions could allow any company to do so. It should also be emphasized that this study is not intended to be a comprehensive evaluation of the electric power system in the State. Rather, it is intended to identify some issues that may impact the effective functioning of a competitive market.

1.3 METHODOLOGY

Two analytical tools are used in this study: the PowerWorld® model and the Electricity Market Complex Adaptive Systems (EMCAS)© model.

1.3.1 PowerWorld Model

PowerWorld® Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 100,000 buses (i.e., transmission network connection points). Powerful visualization techniques are used on an interactive basis, resulting in an intuitive and easy-to-use graphical user interface (GUI). The GUI includes animated one-line diagrams with support for panning, zooming, and conditional display of objects.

One of the add-ons available with Simulator is the Security Constrained Optimal Power Flow (SCOPF). The advantage of having an SCOPF embedded into Simulator is that it is now possible to optimally dispatch the generation in an area or group of areas while *simultaneously* enforcing the transmission line and interface limits both for a baseline case and for a set of contingencies. Simulator SCOPF can then calculate the marginal price to supply electricity to a bus (also known as the locational marginal price), taking into account transmission system congestion. The advantage with Simulator is that these values are not just calculated; they can

also be shown on a one-line diagram, on a contoured map, or exported to a spreadsheet. Simulator SCOPF was used to perform the detailed power flow analyses in this study.

More details on the PowerWorld model are given in Appendix A.

1.3.2 EMCAS Model

EMCAS uses an agent-based modeling structure to simulate the operation of the different entities participating in the electricity market. In this approach, an agent is modeled as an independent entity that makes decisions and takes actions using the limited and/or uncertain information available to it, similar to how organizations and individuals operate in the real world. Figure 1.3.2-1 shows the basic structure of EMCAS. EMCAS agents included in the simulation are:

- Consumers – the end users of electricity including residential, commercial, industrial and other customers.
- Generation Companies (GenCos) – companies that own and operate generators.
- Demand Companies (DemCos) – companies that are financially obligated to provide electricity to consumers. DemCos do not own any physical assets (e.g., distribution lines).
- Distribution Companies (DistCos) – companies that own and operate the distribution system. DistCos and DemCos are frequently under the same corporate parent. In the simulation, they are treated as individual entities.
- Transmission Companies (TransCos) – companies that own the transmission system.
- Independent System Operator (ISO) – the organization that operates the transmission system. This agent can be an Independent System Operator (ISO), a Regional Transmission Organization (RTO), or Independent Transmission Provider (ITP).
- Regulator – the organization that sets the market rules.

An important point in the use of this framework is that some of the agents may belong to the same corporate parent. For example, a company may have subsidiaries that include a GenCo, a DemCo, a DistCo, and a TransCo. In the study, these entities are tracked separately.

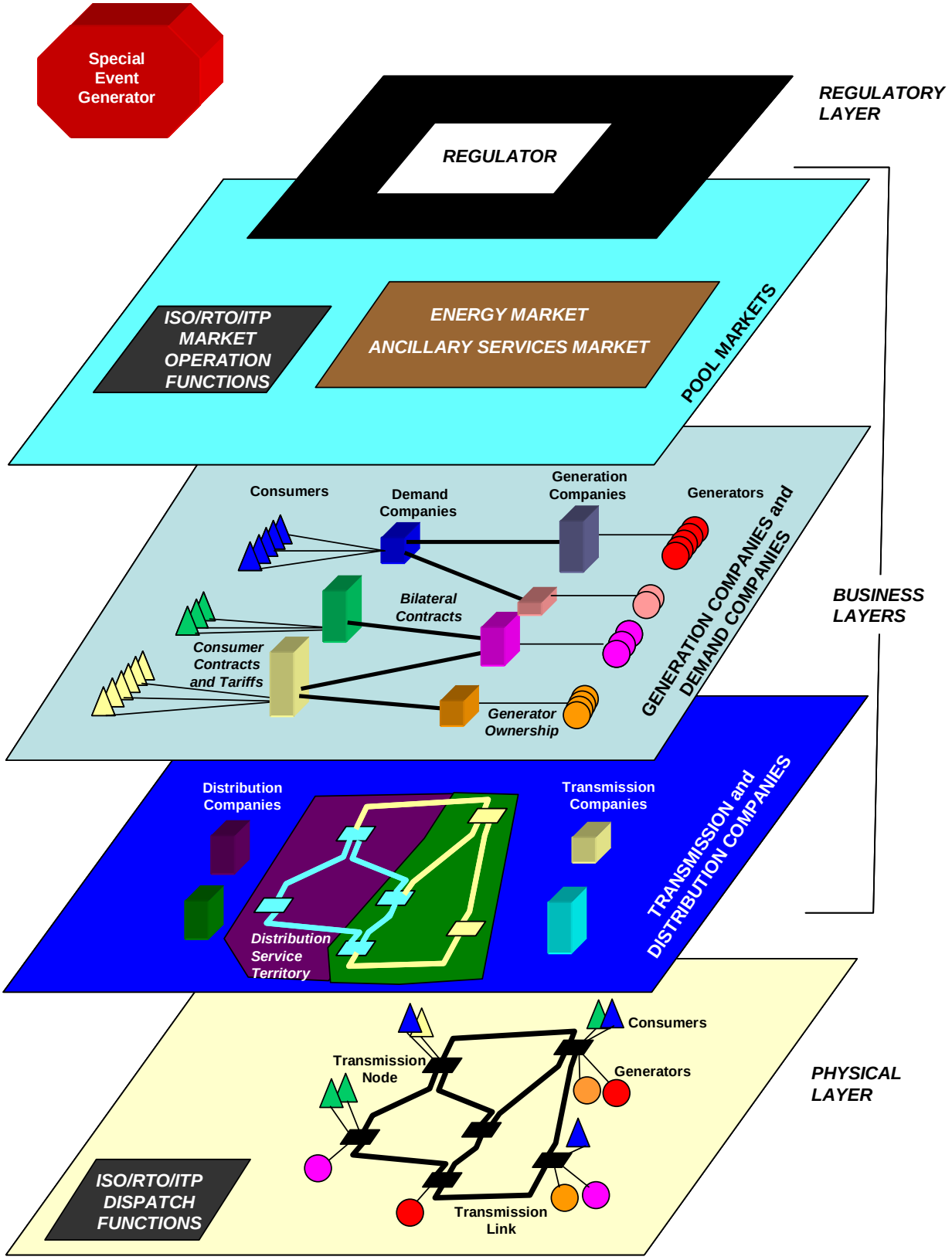

Figure 1.3.2-1 EMCAS Structure

The agents interact on several different layers. In the physical layer, the consumers use electricity, thus putting load on the power system. The ISO dispatches the available generators to meet that load while maintaining the constraints and limitations of the transmission system. In the business layers, pool markets are operated and bilateral contracts are executed to allow companies to buy and sell power under market conditions. Transmission and distribution costs are included as part of the business arrangements.

Figure 1.3.2-2 is a simplified schematic of the flow of the simulation in the EMCAS model. The basic procedure is as follows:

Day-Ahead Market

ISO. The simulation begins with the ISO projecting the system loads for the next day.

GenCo. Each GenCo receives this information and makes a projection of the next day's prices. The basic price projection scheme used here is to average the prices of the previous week for each hour, with corrections made for weekends. (Other price projection schemes were also implemented. These are described later.) This captures the general trend of recent prices and can be considered as a relatively conservative estimate of where prices might be. In addition, each GenCo makes an evaluation of the previous success or failure of bids that have been submitted into the market.

Each GenCo runs the company level unit commitment and resource allocation (CLUCRA) algorithm to determine which units can be expected to be profitable, given the projected prices for the next day. The CLUCRA algorithm considers fuel costs, operating and maintenance costs, and startup/shutdown costs in making this determination. The determination is based on evaluating the prices for each hour and the potential costs and revenue for the whole day. Details of CLUCRA algorithm are in Appendix B. Using the CLUCRA results, a decision is made to commit the unit to the next day's market or to shut it down to avoid expenses that cannot be recovered at the projected prices.

Each GenCo applies its business strategy to determine what price will be applied to the units that are being offered into the market. Bid prices can be for the entire capacity of the unit or can be for blocks or portions of capacity.

The bids (a quantity and a price) are submitted to the ISO.

DemCo. Each DemCo projects the loads that will be coming from the consumers it serves. As described earlier, the loads are assumed to be firm commitments and not on interruptible service. Load bids are submitted to the ISO.

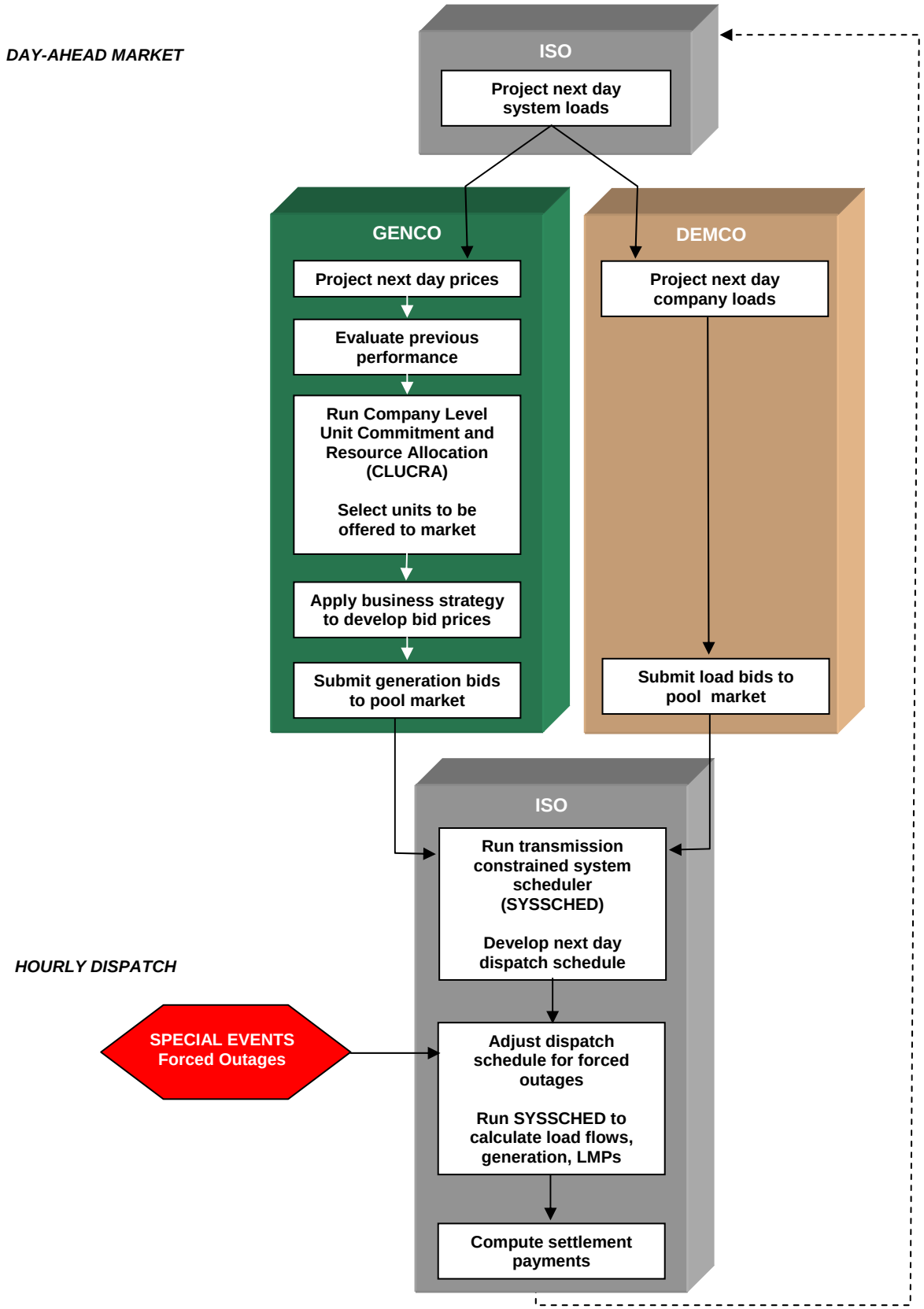

Figure 1.3.2-2 Schematic of EMCAS Simulation Sequence

ISO. With the generation and load bids, the ISO runs the transmission constrained system scheduler (SYSSCHED) algorithm. SYSSCHED is a DC optimal power flow (DCOPF) load flow calculation. It selects the lowest cost combination of units, based on the bid prices received from the GenCos, to meet the load bids received from the DemCos. The flow limits of the transmission system serve as constraints in the algorithm. SYSSCHED is used to develop the schedule of units that will be dispatched the next day.

In addition to determining the generators that will be scheduled to meet the projected load, ancillary service generators that provide spinning, non-spinning, and replacement reserve capacity are also selected.

Hourly Dispatch

Special Events. During the hourly dispatch portion of the simulation, special events are injected to represent conditions that are different than what was projected in the day-ahead market analysis. Generator forced outages are introduced at this point. Although it is possible to inject transmission line outages and load perturbations, these were not implemented here.

ISO. The ISO adjusts the availability of generators to account for the forced outages. The ISO runs the SYSSCHED DCOPF to dispatch the available generators, including those that are on standby to provide reserves, to meet the load. Generation rates, load flow, and locational marginal prices (LMPs) are calculated.

At the completion of the 24 hours of the dispatch day, the ISO calculates the revenues and costs associated with the day's operation.

The process then recycles to begin the simulation for the next day.

This basic sequence is used in all of the cases that are included in the analyses here. More details on the EMCAS model can be found in Appendix B.

1.3.3 Model Application

The PowerWorld and EMCAS models were used in tandem. EMCAS was used to calculate the behavior of the agents participating in the market. It focused on the manner in which the market participants make decisions and on how they adapt their behavior to market changes and to their own success or failure in the marketplace. PowerWorld was used to calculate the detailed operation of the physical power system. It provided a detailed look at generator dispatching, transmission loading, and contingency conditions for the various behavior patterns of the market participants. The use of both models provides the ability to look at the details of the market and the details of the physical power system in an integrated fashion. Appendix C provides a comparison of the EMCAS and PowerWorld load flow results and shows them to be in very good correlation.

1.3.4 Locational Marginal Prices

One of the primary focuses of this study is the locational differences in electricity prices under a fully restructured market. The locational marginal price (LMP), expressed in $/MWh, is defined as the cost of serving one additional MW of load at any point in the network.[5] The LMP has three components: (1) the marginal cost to produce the last MW of power, (2) a transmission congestion charge, and (3) the cost of marginal transmission losses. In situations where there is no transmission congestion, LMPs at all buses are similar, varying only by a relatively small amount to cover marginal transmission losses. An uncongested state only occurs when generating units can be dispatched according to an economic merit order without overloading transmission lines and violating security measures. The economic merit ordering of units or blocks of units is typically based on marginal production costs such that generators that are the least expensive to operate are dispatched first while the most expensive units are utilized only during times of the highest demand. However, the actual dispatch of units must often deviate from the economic merit order to keep the transmission system operating within a stable and secure state. This change in the order of dispatch of units when transmission congestion occurs leads to variations in LMPs across a region. In some cases, the variation in LMPs among network nodes can be significant.

In this study, the LMPs are calculated for each node in the network by the PowerWorld and EMCAS models. The algorithms used in the models, in effect, check each node in the transmission network to determine what the cost would be to provide a small increment of power to that node. Both models seek to dispatch the available generators such that the total cost of operating the system is minimized, subject to the transmission system's constraints and reliability standards.

1.3.5 Market Power

In a Notice of Proposed Rulemaking, the Federal Energy Regulatory Commission (FERC) defined "market power" as the "…ability to raise price above competitive levels." [6] Not included in the FERC definition is what constitutes a "competitive level" in an electricity market.

FERC has, at various times, considered several different measures of market power, including the following:

- *20% Benchmark.* A power supplier was considered to have the potential for market power if it had a 20% or more share of the market.

- *Limited Competing Supplier Test.* An evaluation is made of whether the total transmission capacity (TTC) in an area would allow competitors to provide power.

- *Supply Margin Assessment.* An evaluation is made of whether the power supplied from a specific seller is needed to meet peak day demand.

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[5] See *Power System Economics*, S. Stoft, IEEE Press, New Jersey (2002) for a description of LMPs.
[6] "Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design," paragraph 393, Docket No. RM01-12-000, Federal Energy Regulatory Commission (July 2002).

- *Delivered Price Test.* The ability of a supplier to provide power into a market with a price of no more than 5% of a reference price in the area is determined.

- *Residual Supply Index.* A determination is made of whether a particular demand can be met without any production from a specific seller.

Separate from the FERC approaches, the U.S. Department of Justice uses the Herfindahl-Hirschman Index (HHI) to estimate the level of concentration in a market and the potential for the exercise of market power. The HHI is the sum of the squares of the market shares, in percent, of each company in a market. HHI values between 1,000 and 1,800 are considered to be indicative of "moderately concentrated" markets. HHI values above 1,800 are considered to be indicative of "concentrated" markets. With this definition, concentrated markets can provide the opportunity for a company to exercise market power. While the HHI has been used to some degree in the electric power industry, it is recognized as not being the best measure of market power potential, since it does not capture the unique aspects of the power system. The inability to store the product (i.e., electricity) in anticipation of price changes, the interconnectedness of all the market participants, and the need to maintain overall system reliability are not captured by the HHI. Thus, market power behavior can theoretically be exercised in the electricity system even in markets with HHI values below 1,000.

As stated earlier, to date, there is no universal agreement on what constitutes a definitive measure of market power in the electric power industry. For the purposes of this study, the following are used to indicate the ability of a company to exercise market power:

Baseline price levels are the locational marginal prices (LMPs) when all potential suppliers in the market (i.e., all GenCos) offer their power at production cost.

Market power is the ability of a company to profitably increase prices (i.e., LMPs) above baseline price levels by its own actions, independent of what other companies do.

The application of these relatively simple definitions will be demonstrated in more detail in the sections giving results of the analyses.

1.3.6 Data Sources

Data for the analysis were drawn from several different sources as shown in Table 1.3.6-1. The information is primarily from publicly available sources. Therefore, the information used in this study does not necessarily reflect the actual conditions that currently exist in the electricity market or that will be experienced in the future. Although several companies provided some data modifications, business proprietary information such as fuel purchase contracts, actual generator performance, and corporate debt service were not utilized here. The results presented here must be viewed in the light of these limitations. Comparisons with current information on electricity prices, company profitability, and other such parameters must be made with the awareness of the data restrictions.

Table 1.3.6-1 Data Sources

Data	Primary Sources
Transmission Network Configuration	National Electric Reliability Council (NERC) – Summer 2003 Case
Generator Performance and Cost	• FERC Form 1 data (1994-2000) • EIA Form 860A – Annual Electric Generator Report – Utility • EIA Form 860B – Annual Electric Generator Report – Nonutility • EIA Form 861 – Annual Electric Power Industry Report • Argonne Power Plant Inventory (APPI database) • NERC's Electricity Supply & Demand (ES&D) database • EIA Electric Power Monthly • EIA Form 767 Steam-Electric Plant Operation and Design Report • EIA Form 906 – Power Plant Report • IL EPA – Electric Power Plant Construction Projects Since 1998 (Status as of June 22, 2001) • IL EPA – Electric Power Plant Construction Projects Since 1998 (Status as of June 13, 2002) • NERC Generation Availability Data Set (GADS) – Generating unit outage factors
Load	• FERC Form 714 - Hourly control area loads (aggregated among all power sinks) - Control area load growth projections • EIA's AEO 2003 with projections to 2025 - Default regional load growth rates (when Form 714 is not available) • Based on Power World Case – Bus-load distribution factors
Fuel Prices	• EIA's AEO 2003 with projections to 2025 – Regional electric utility fuel prices

1.3.7 Company and Ownership Convention

Since the passage of the Illinois restructuring law, the ownership of the various components of the electric power system in the State has changed considerably. The traditional vertically integrated electric utilities that owned and operated the generation, transmission, and distribution system as a single corporate entity have given way to a mix of company configurations. Some still own and operate the full spectrum of power system components. Some have subsidiaries under a corporate parent, each of which owns different components. Some are separate companies that own only generation equipment. Some own no physical electric power assets, but operate as intermediaries or brokers in the market.

The company ownership terminology that is employed in the analytical models is used throughout this document. It identifies each organizational unit as a separate agent (e.g., GenCos, DistCos, TransCo, DemCo) even though they may be part of the same corporate parent.

2 CURRENT STATUS OF THE POWER SYSTEM IN ILLINOIS

2.1 REGULATORY AND MARKET STRUCTURE

The Electric Service Customer Choice and Rate Relief Law of 1997 specifies how Illinois will transition to a restructured electricity market. Table 2.1-1 lists the key provisions that are relevant to this study.

In summary, by 2007 the Illinois power market is envisioned to have the following characteristics:

- All customers will have the choice of purchasing their electricity from any of the alternative suppliers willing to serve them.

- Electricity prices to customers, whether supplied by third party retailers or the incumbent utility, will ultimately be based on market conditions, whether those markets are concentrated or not and whether the prices are high or low.

- All electricity suppliers will have equal access to the transmission and distribution system to supply their customers.

- The transmission system will be operated by one or more Independent System Operators (ISOs), which will run the system in an equitable and efficient manner for all suppliers and customers.

This is, of course, a highly simplified description of the power system specified in the law. There are a number of requirements that must be met before this idealistic structure can be fully realized.

An important note is that the Illinois law does not specify the details of how the competitive market will be set up. Unlike the California law, which mandated certain actions by the electric utilities (e.g., the sale of their generators) and which dictated the structure of the market (e.g., reliance on a bidding market rather than bilateral contracts), the Illinois law leaves much of the market design open to later development.

In addition to the State regulatory requirements, the power system is subject to the federal requirements imposed by the Federal Energy Regulatory Commission (FERC). FERC has issued its proposed structure for the operation of competitive electricity markets. [7] This Standard Market Design (SMD) has undergone a significant amount of review and comment and has not yet been finalized. Because of serious objections raised by affected parties in some areas of the country, it appears unlikely that the SMD will be implemented in the proposed form.

[7] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, Docket No. RM01-12-000, Federal Energy Regulatory Commission (July 2002).

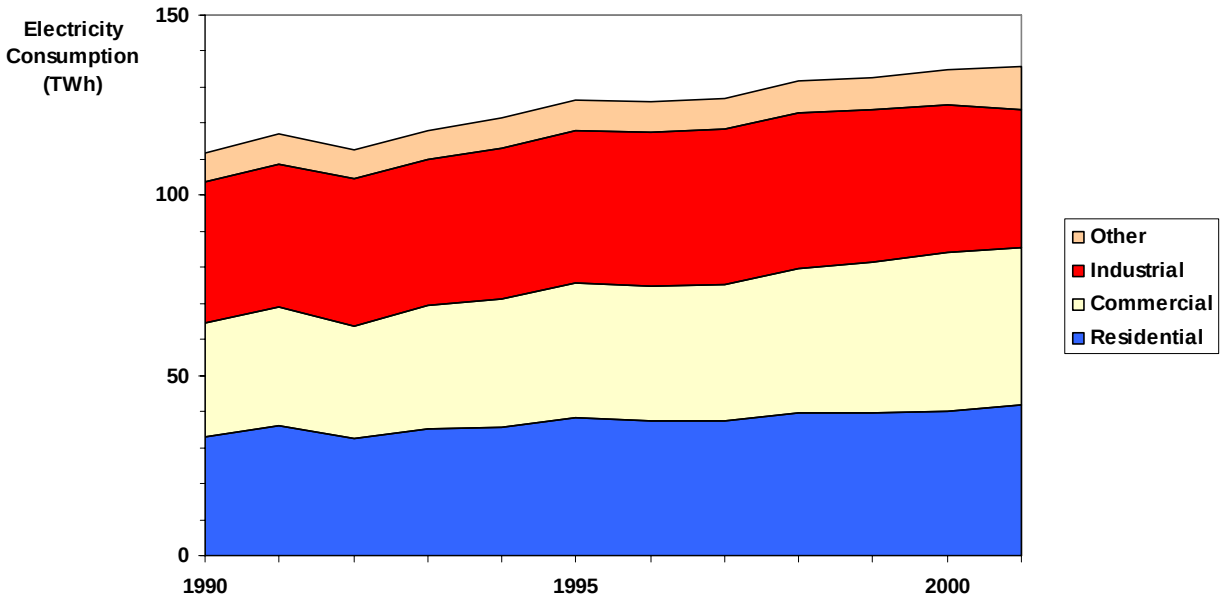
Table 2.1-1 Summary of Related Provisions of Illinois Electricity Restructuring

Electricity Providers – The Law identifies two major types of electricity providers: *Electric utilities* – the public utilities that have franchises to sell electricity to retail customers within a service area. *Alternative retail electric suppliers* – entities other than electric utilities that offer electricity for sale to retail customers. Included are corporations, cooperatives, power marketers, aggregators, resellers, and others.
Electricity Services – Several types of electricity services are identified, including: *Tariffed services* – electricity service that is provided by an electric utility under rates that are regulated by the ICC. *Unbundled services* – portions of a tariffed service that electric utilities offer separately to their customers. *Competitive services* – electricity service that is available to a customer segment or to a geographic area and that can be provided by an entity other than an electric utility or utility affiliate. An electric utility may petition the ICC to declare a tariffed service to be a competitive service. In making its determination, the ICC must consider if there is adequate transmission capacity available to supply the customer segment or geographic area from providers other than the electric utility or its affiliates. When a service is declared to be competitive, the suppliers may charge market-based prices for it. *Contract services* – electricity service that is provided by mutual agreement between an electric utility and a retail customer. *Delivery services* – electricity transmission and distribution services. Delivery services are not expected to be declared competitive services.
Prices – The law identifies several types of pricing mechanisms: *Market based prices* – prices for electricity based on the cost of obtaining the service at wholesale through a competitive bidding or similar process. *Real-time prices* – prices for electricity that vary with time; typically hourly for non-residential customers, periodically during the day for residential customers. *Cost-based prices* – prices that are based on the cost of providing the service.
Customer Choice – The law provides for customer choice of electricity service. The dates when different customer classes were able to choose alternative suppliers are: *Large commercial and industrial customers* – October 1, 1999. *All other non-residential customers* – December 31, 2000. *Residential customers* – May 1, 2002. Transition charges may be imposed by electric utilities through 2006.
Asset Ownership – Electric utilities may sell, lease, or transfer assets (e.g., generators) to an affiliated entity (e.g., a subsidiary of its parent company) or unaffiliated entity (e.g., an entirely separate company). The ICC may adopt rules requiring functional separation between the generation service and delivery service components of an electric utility in order to ensure efficient competition for alternate suppliers.
Access to Transmission and Distribution Facilities – Electric utilities must allow alternative retail electric providers to interconnect to their transmission and distribution systems in order to supply customers.
Independent System Operator (ISO) – Every electric utility that owns transmission facilities must submit to FERC a plan for joining an ISO that will independently manage and control the transmission system. The ISO operating in Illinois may establish a competitive power exchange auction open to all suppliers.
Transition Period – The law sets the transition period in which the move from the traditional electric utilities providing tariffed services to a fully competitive market as 1997 to January 1, 2007. A number of rules and procedures are specified for the operation of the power system and the charges that may be levied during this period.

Note: In addition to these provisions, there are other elements of the law that do not affect this study and are not included in the table. Examples are how the transition period will be managed, consumer protection, protection of labor, nuclear decommissioning, and others.

2.2 ELECTRICITY DEMAND

Figure 2.2-1 shows the electricity demand growth in the State since 1990. Consumption has grown by about 20% over the period, with the largest increase coming in the commercial sector.



Source: Energy Information Administration

Figure 2.2-1 Electricity Demand Growth in Illinois

Figure 2.2-2 shows the service territories of the distribution companies (DistCos) operating in Illinois. Table 2.2-1 shows electricity sales and the number of consumers served for each. The figure and table show the major distribution companies in the State. There are a number of smaller, municipally-owned distribution companies that buy bulk power and operate their own systems. These are not included here.

The distribution companies are regulated monopolies in Illinois and are part of the electric utilities as defined in the restructuring law. They own and operate the distribution lines, substations, and other equipment. For the purposes of this study, they are distinguished from "Demand Companies," which are discussed next. Distribution services are expected to remain tariffed delivery services, even after the completion of restructuring.

Table 2.2-2 lists the Demand Companies (DemCos) certified to sell electricity in Illinois. By convention for this study, DemCos are distinguished from DistCos in that they do not have a monopoly service territory and, in theory, can sell electricity to any consumer anywhere in the State. Some of these are affiliates of the electric utilities; some are registered as alternative retail electric suppliers (ARES). While some have been providing service to customers, some are only certified with the State but have not yet begun actual sales.

Table 2.2-3 shows the electricity sales by Illinois DemCos split between those that are electric utility affiliates and those that are alternative retail electricity suppliers. Table 2.2-4 shows the number of customers eligible to switch from the traditional bundled service from electric utilities to delivery services that are market based, along with statistics on those that have actually switched. To date, only a small number of consumers have switched supply plans. Large consumers, those with greater than 1 MW of load, have been much more active in exercising their supplier choice with about half choosing alternative plans.

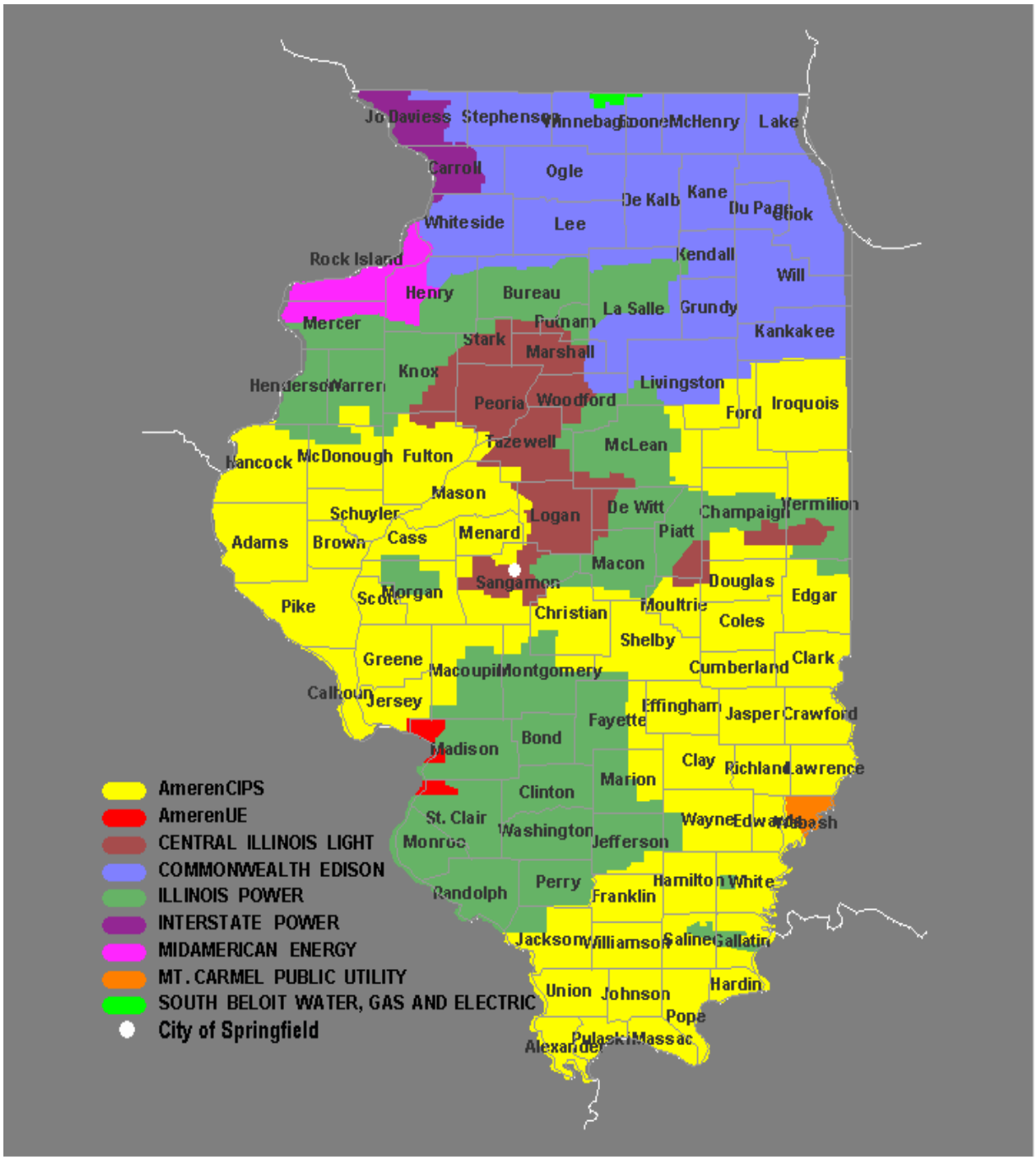


Figure 2.2-2 Distribution Company Service Territories

Table 2.2-1 Distribution Companies in Illinois

Distribution Company Name	Ownership	Total Sales in 2002 (TWh)	Number of Consumers in Service Territory (Thousands)
DistCo Ameren – CILCO	Private	6.1	203
DistCo Ameren – CIPS	Private	9.0	326
DistCo Ameren – UE (Illinois only)	Private	3.5	66
DistCo Ameren – EEI[a]	Private	NA	NA
DistCo Commonwealth Edison Co.	Private	87.1	3,590
DistCo Illinois Power Co.	Private	19.1	573
DistCo Alliant Energy (Interstate Power, South Beloit) [b]	Private	0.6	20
DistCo MidAmerican Energy Co. [c]	Private	1.9	84
DistCo Mt Carmel Public Utility Co.	Private	0.1	6
DistCo Springfield, City of	Municipal	0.2	68

[a] Ameren is a majority owner of Electric Energy, Inc.

[b] Alliant Energy operates primarily in Iowa and Wisconsin with small service territories (Interstate Power and South Beloit Water, Gas, and Electric) in Illinois.

[c] MidAmerican is owned by MidAmerican Energy, which operates primarily in Iowa with a small service territory in Illinois.

Source: Illinois Commerce Commission

Table 2.2-2 Demand Companies in Illinois

Demand Company Name	Ownership
Electric Utility Affiliates	
DemCo – Ameren	Private
Ameren – CILCO	
Ameren – CIPS	
Ameren – UE (Illinois portion)	
Ameren – Electric Energy Inc.	
DemCo – Commonwealth Edison Co.	Private
DemCo – Illinois Power Co.	Private
DemCo – Alliant Energy (Interstate Power Co, South Beloit)	Private
DemCo – MidAmerican Energy Co (Illinois portion)	Private
DemCo – Mt Carmel Public Utility Co.	Private
DemCo – City of Springfield	Municipal
DemCo – IMEA - Illinois Municipal Electric Agency	Municipal
DemCo – Soyland Power Coop Inc.	Cooperative
Alternative Retail Electric Suppliers	
DemCo – Constellation NewEnergy Inc.	Private
DemCo – Ameren Energy Marketing Co.	Private
DemCo – Blackhawk Energy Services, LLC	Private
DemCo – Dynegy Energy Services, Inc.	Private
DemCo – EnerStar Power Corp.	Private
DemCo – Exelon Energy Co.	Private
DemCo – Illinois Power Energy, Inc.	Private
DemCo – Peoples Energy Services Corp.	Private
DemCo – Sempra Energy Solutions	Private
DemCo – Sempra Energy Trading Corp.	Private
DemCo – WPS Energy Services, Inc.	Private

Source: Illinois Commerce Commission

Table 2.2-3 Sales by Electric Utilities and Alternative Retail Electricity Suppliers in 2002

Seller and Category of Service	Portion of Total Electricity Sales (%)
DemCos: Electric Utility Services	
Bundled Service	72.7
Contract Service	5.6
Power Purchase Option	9.3
DemCos: Alternative Retail Electricity Suppliers	
In-state, unregulated, retail utility sales outside utility's own territory.	5.0
Retail electric suppliers (affiliate and unaffiliated sales).	7.4
	100.0

Source: Illinois Commerce Commission

Table 2.2-4 Delivery Service Consumers in 2002

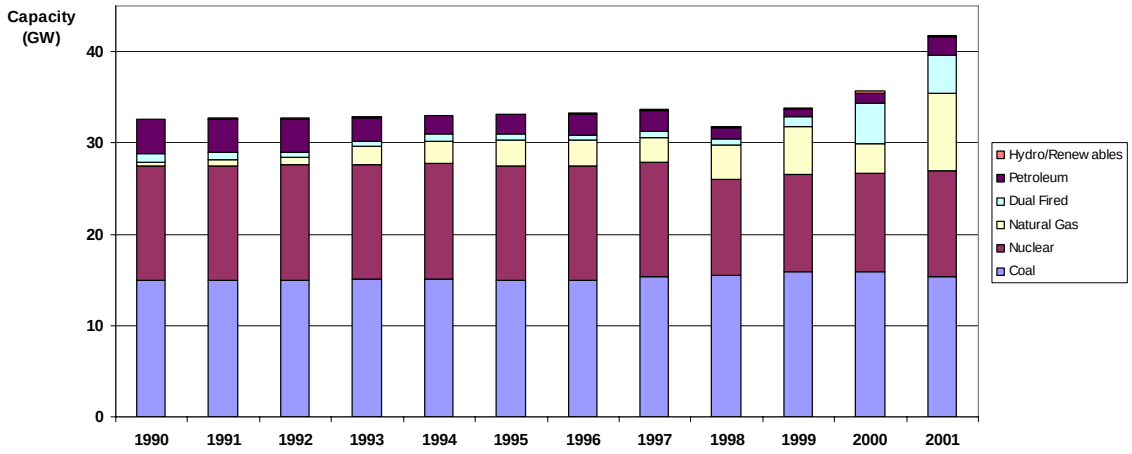
	Total Number of Customers	Number of Customers Eligible for Delivery Services		Number of Customers Switched to Delivery Services		Percentage of Customers Switched to Delivery Services (%)	
DemCo: Electric Utility Affiliates		Less than 1 MW	Greater than 1 MW	Less than 1 MW	Greater than 1 MW	Less than 1 MW	Greater than 1 MW
DemCo: AmerenCILCO	199,878	19,935	71	0	0	0.0	0.0
DemCo: AmerenCIPS	323,563	47,338	119	703	44	0.0	0.0
DemCo: AmerenUE	65,634	7,504	40	0	0	1.5	37.0
DemCo: Commonwealth Edison	3,526,553	328,038	1,846	20,465	1,101	6.2	59.6
DemCo: Illinois Power	567,485	65,986	218	990	61	1.5	28.0
DemCo: MidAmerican	83,087	1,392	28	0	0	0.0	0.0
Total		470,193	2,322	22,158	1,206	4.7	51.9

Source: Illinois Commerce Commission

2.3 GENERATION CAPACITY

Figure 2.3-1 shows the generation capacity located in the State since 1990. Capacity has grown by about 28% over the period. The dip in 1998 reflects the closing of the 2,000 MW Zion nuclear plant in 1998.

Table 2.3-1 shows the generation companies (GenCos) that are operating in the State. The GenCos are the corporate entities that own and operate generation equipment. Two companies, Midwest Generation and Exelon Nuclear, own more than half of the generation capacity in the State. Adding the next two largest companies, Dynergy Midwest Generation and Ameren, brings the total to about 77% of the State's generation capacity owned by four companies.



Sources: Energy Information Administration (1990-2000),
State of Illinois data (2001)

Figure 2.3-1 Historical Generation Capacity in Illinois

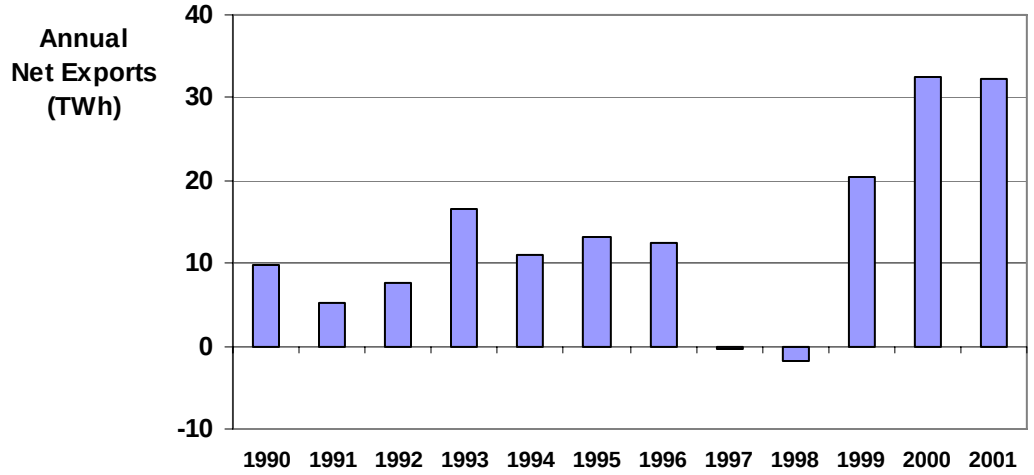
Table 2.3-1 Generation Capacity by Company in 2001

Generation Company	Coal	Oil	Natural Gas	Nuclear	Total Capacity (MW)	Portion of State Total (%)
GenCo – Allegheny Power	0	0	664	0	664	1.6%
GenCo – Ameren						
Ameren-CILCO	1,221	26	46	0	1,293	3.1%
Ameren-CIPS	2,944	213	300	0	3,457	8.3%
Ameren-EEI	1,100	193	0	0	1,293	3.1%
Ameren-UE	0	511	926	0	1,437	3.4%
GenCo – Aquila Energy	0	0	0	0	0	0.0%
GenCo – Calpine	0	0	174	0	174	0.4%
GenCo – Calumet Energy LLC	0	0	0	0	0	0.0%
City of Springfield	463	44	139	0	646	1.5%
GenCo – Constellation Power	0	0	125	0	125	0.3%
GenCo – Dominion Energy	1,933	0	852	0	2,785	6.7%
GenCo – Duke Energy	0	0	664	0	664	1.6%
GenCo – Dynegy Midwest Generation Inc.	3,369	245	491	0	4,105	9.8%
GenCo – Dynegy/NRG Energy	0	0	398	0	398	1.0%
GenCo – Exelon Generation	0	0	0	9,882	9,882	23.7%
GenCo – Exelon Nuclear/MidAmerican Energy	0	0	0	1,657	1,657	4.0%
GenCo – MidAmerican Energy Co	0	0	572	0	572	1.4%
GenCo – Midwest Generation LLC	6,509	770	3,476	0	10,755	25.8%
GenCo – NRG Energy	0	0	300	0	300	0.7%
GenCo – Power Energy Partners	0	0	0	0	0	0.0%
GenCo – PPL	0	0	0	0	0	0.0%
GenCo – Reliant Energy	0	0	1,108	0	1,108	2.7%
GenCo – Southern Illinois Power Coop.	272	0	0	0	272	0.7%
GenCo - Southwestern Electric Coop.	0	0	0	0	0	0.0%
GenCo – Soyland Power Coop Inc.	22	24	125	0	171	0.4%
Total Capacity In Illinois	**17,833**	**2,026**	**10,360**	**11,539**	**41,758**	**100.0%**
HHI – based on company capacity						**1,498**
HHI – based on coal capacity						**2,173**
HHI – based on natural gas capacity						**1,562**

As shown on the table, calculating the Herfindahl-Hirschman Index (HHI) for this situation gives a value of 1,498, which implies a moderately concentrated market for generation capacity in the State. As discussed earlier, the HHI applied to generation ownership is not the best way to gauge the competitiveness of an electricity market, but it does provide a rough indicator of the degree of concentration in the market.

Another way to look at the HHI is to consider how the various types of generation capacity are distributed among the companies. Table 2.3-1 shows an HHI of 2,173 for the coal capacity and 1,562 for the natural gas capacity. These reflect concentration in the coal capacity and a moderate degree of concentration in the natural gas capacity, based on this index. The nuclear capacity is owned totally by Exelon Nuclear and its joint ownership with MidAmerican Energy.

With the exception of two years, 1997 and 1998, Illinois has been a net exporter of electricity, as shown on Figure 2.3-1. In the latest year of data reported, annual net exports have amounted to about 19% of the electricity generated in the State.



Source: Energy Information Administration

Figure 2.3-2 Annual Net Exports of Electricity

2.4 TRANSMISSION CAPACITY

Figure 2.4-1 shows the configuration of the major lines of the transmission system in Illinois and surrounding states. Transmission capacity is concentrated to provide service to the Chicago area in the northeastern part of the State and in the southwest, near St. Louis. There are several interties with transmission systems in surrounding states, the most significant with northwestern Indiana.

Table 2.4-1 shows the transmission companies in the State. Currently, transmission line ownership is in the hands of the electric utilities. There have been many discussions about selling the transmission facilities to an independent transmission provider or to other companies. This situation will likely not stabilize until the restructuring is complete.

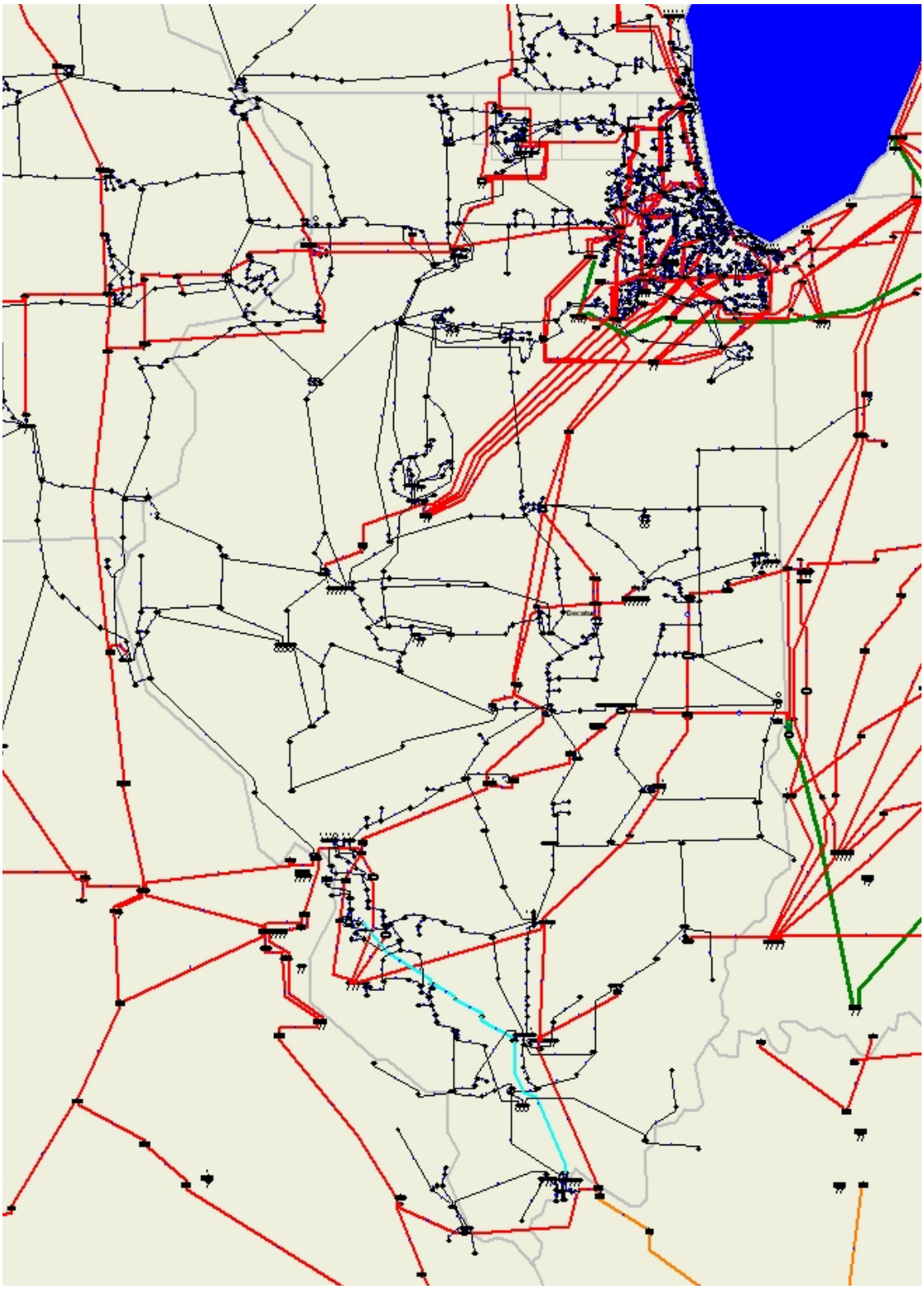


Figure 2.4-1 Detailed PowerWorld Simulator One-line Diagram of Illinois Transmission, along with High Voltage Transmission in Other States

Table 2.4-1 Transmission Companies in Illinois

Transmission Company Name	Ownership
TransCo – Ameren	Private
TransCo – Commonwealth Edison Co.	Private
TransCo – Illinois Power Co.	Private
TransCo – Alliant Energy	Private
TransCo – MidAmerican Energy Co.	Private
TransCo – Mt Carmel Public Utility Co.	Private
TransCo – Springfield, City of	Municipal

3 BASIC ASSUMPTIONS AND DATA INPUTS

The analysis of the power system in Illinois in this study is based on a set of assumptions and input data. These assumptions and inputs provide a set of conditions that can be used to determine how the power system might function. They are not intended to represent the predicted, most likely, or optimal set of conditions for the Illinois market. Rather, they are intended to test how the market might behave under a given configuration.

The basic assumptions are grouped into two sets as shown in Table 3-1. The details of each of the assumptions are provided in the following sections. The Case Study Assumptions provide a point of comparison for a single configuration and operating profile of the power system. The set of Conservative Assumptions is designed to verify that the results and conclusions are not distorted by the features of this single configuration. This will be explained in more detail later.

Table 3-1 Basic Assumptions

Item	Case Study Assumptions	Conservative Assumptions
Illinois Market Configuration	Single independent system operator	Same
	Day-ahead energy market using pay-locational-marginal-price settlement rule	Same
	Day-ahead ancillary services market	Same
	No bilateral contracts	Same
	No consumer tariffs	Same
Agent Profiles	GenCos: apply company-level unit commitment and add prorated fixed operating and maintenance costs into bid price	No company-level unit commitment No fixed operating and maintenance cost added
	Consumers: no price response	Same
	DemCos: apply flat markup to costs	Same
	DistCos: apply fixed distribution use charge	Same
	TransCos: apply fixed transmission use charge and also receive transmission congestion payment	Same
Transmission Network	Detailed representation in-state	Same
	Simplified representation out-of-state	Same
Load	Projections based on FERC information	Same
Generation	Capacity expansion based on announced construction plans	Same
Outages	Planned, maintenance, and forced outages included	No maintenance or forced outages
Fuel Prices	Developed from EIA forecasts	Same

The analyses were carried out for various time periods in a single year. The year 2007 was chosen as the analysis year, as it represented the time when all of the transition activities specified in the Illinois restructuring law are to be completed. It should be emphasized that the results are not intended to be a prediction of what will happen in Illinois in 2007. For this reason, the results are referred to as "analysis year results." In fact, any other year after restructuring is completed could have been used as the analysis year. All of the cost results are presented in 2002 dollars.

A point needs to be emphasized with respect to the comparison of these results to current experience. As was discussed in the earlier section on data sources, there were limits on the information available for the study, the most significant being the need to avoid business proprietary information. In addition to this limitation, the simplifying assumptions used to create the simulation model that approximates the operation of the Illinois market, which are discussed below, will limit how closely the results can match historical experience. While it is appropriate to see how well the model results match actual experience, it should not be expected that there will be a complete correlation. The data limitations and the modeling simplifications prohibit this. For this reason, these results must be viewed as an initial point of comparison against for other studies and analyses. In traditional modeling terms, these results should be viewed as "descriptive" and not as "predictive."

3.1 ILLINOIS MARKET CONFIGURATION

The configuration of the electricity market in Illinois was not explicitly specified as part of the restructuring law. Companies have had a great deal of freedom in how they structure themselves during the transition period. The Federal Energy Regulatory Commission (FERC) issued several versions of a proposed rulemaking to establish a standard market design (SMD), which was recommended for electricity markets across the country. These designs have received numerous positive and negative comments and are still undergoing review and revision. Lacking a State-imposed design or a federal design, there is a great deal of uncertainty regarding how the Illinois electricity market will take form. For the purposes of this study, the following assumptions were used as the market rules in operation in Illinois in the analysis year.

Single Independent System Operator

It is assumed that a single market for electricity will be operating in the State in the analysis year. That is, all of the companies in Illinois that buy or sell electricity will do so in the same marketplace. This is a significant simplifying assumption that avoids consideration of how multiple markets operating in the State might deal with their interfaces, the "seams" issue in the terminology of the FERC SMD. Given that the actual structure of the Illinois market is not yet established, the single market assumption is a reasonable approach to use here.

The single ISO assumption has the effect of simplifying the operation of the State's electricity market in the model simulation. The market operating and settlement rules are the same across the State; there are no cross-ISO charges imposed for moving power across jurisdictional lines; the system reliability standards are uniform across the State, and all market

participants operate under uniform procedures. Clearly, if more than one ISO were to function in the State, the market operation could be much more complex. Companies could participate in multiple markets if they chose, market rules might be different, and the payment procedures for power flows across ISO lines could be complex. While the modeling framework could be set up to simulate multiple ISOs, the current uncertainty in the Illinois market does not warrant adding this complexity at this time.

Another consideration in the assumption of a single ISO in the State is the effect on out-of-state market participants. In this study, companies outside Illinois can participate in the same marketplace as Illinois companies and can be either buyers or sellers of electricity. In the simulation, the Illinois ISO administers the single market in which both in-state and out-of-state companies participate. There are no charges for power flows across State borders or for the wheeling of power from one out-of-state point to another out-of-state point on lines that run through the State. In essence, the simulation considers a market that is larger than just the State borders. However, for this study, out-of-state companies are represented in a simplified fashion, which will be described in more detail later. They do, however, play a role in the Illinois electricity market in that they can purchase electricity from Illinois producers or can sell electricity to Illinois users. The physical limits of the transmission tie lines between Illinois and surrounding states are explicitly included in the analysis.

Consistent with the assumption of a single market, it is assumed that the single independent system operator (ISO) operates the entire transmission system in the State. This ISO has the responsibility for scheduling, dispatching, and reliability of the transmission system.

The Illinois restructuring law does not mandate that there be only one ISO operating in the State, but it does require all electric utilities to join an ISO or RTO. Again, given the uncertainties as to how this will develop, it is assumed here that only one ISO will operate the transmission system in the State.

Day-Ahead Market

It is assumed that a day-ahead market (DAM) for energy and ancillary services will operate in the State. The DAM will allow suppliers (i.e., GenCos in the terminology of the analytical models used here) and purchasers (i.e., DemCos) to bid for their participation in the market. The bidding will be administered by the ISO and will allow market participants to offer to buy and sell electricity at unregulated prices.

There are several different approaches that have been used in pool markets in the U.S. and abroad to pay for electricity that is bought and sold. One of the approaches used in the earliest electricity markets is the pay-market-clearing-price (PMCP) rule. In this approach, generation and demand bids are accepted in the DAM by the ISO based on bid price and on the physical limitations of the transmission system. All pool market purchases and sales in a given hour are settled at the price of the most expensive generator accepted by the market in that hour. This single price is referred to as the market clearing price (MCP). In effect, it is the marginal cost of providing power to the market. All GenCos whose bids are accepted are paid the MCP

independently of what their actual bid was. All DemCos pay the MCP for the electricity they buy.

One shortcoming of the PMCP rule is that it does not have any explicit locational effects. That is, all GenCos (and DemCos) participating in the market are paid (or pay) the same MCP, independent of where they are in the transmission network. A modification to the PMCP rule has been introduced in virtually all operating markets in the U.S. and abroad and is included here. Since transmission system congestion can preclude the use of the lowest-cost generators and since this congestion may be experienced in parts of the power system but not everywhere, the marginal cost of providing power may be different at different points in the system. The pay-locational-marginal-price (PLMP) rule focuses on determining the marginal cost of providing power at each individual point of the power network and includes the effects of transmission congestion explicitly.[8] There is not a single MCP but rather a separate price at each node of the transmission network. In the PowerWorld and EMCAS models used for this study, the LMP is calculated using an optimization routine that, in effect, tests each node of the network to determine what the cost would be to provide an additional unit of power at that point. It determines the shadow price at each network node. When there is no congestion in the transmission network, the LMPs are identical at each node. When there is congestion, the marginal cost of providing power at one node is different than at another node, and the LMPs vary across the network.

There are several different ways the PLMP rule can be applied when calculating settlement payments to market participants. The rules most commonly used in currently functioning markets are used here. GenCos whose units are dispatched are paid the LMP at the network node (i.e., bus) where each unit is connected. DemCos pay a load-weighted average price for the zone in which their consumers are located, where a zone is a collection of nodes (i.e., buses) in a geographical area. (The zones used in this study are described later.) Zonal pricing for demand, instead of bus-level pricing, is used in current electricity markets as a way of reducing the administrative burden of maintaining prices for thousands of buses on an hourly basis. There is some debate as to whether zonal or bus-level pricing for demand is the best way to operate a market. Since zonal pricing is used in most markets, it has been selected for use here.

One aspect of the PLMP rule is not immediately obvious. When the payments to GenCos and the payments by DemCos are netted out, the sum is generally not zero when there is transmission congestion. This is true whether zonal or bus-level pricing is used. This is a result of the fact that congestion creates LMPs that can vary widely throughout the network in a nonlinear way. In the EMCAS simulation, the difference in payment to GenCos and payment from DemCos is distributed to the transmission company as a congestion payment, as discussed later.

[8] For a more detailed description of locational effects, see *Power System Economics*, S. Stoft, IEEE Press, New Jersey (2002) for a description of LMPs. Good introductory material on locational pricing can also be found at the Web sites of currently operating markets including: www.nyiso.com, www.iso-ne.com, and www.pjm.com.

One alternative to the PMCP rule or the PLMP rule is the pay-as-bid (PAB) rule. In this approach, all GenCos are paid only their bid price if they are selected. There are few electricity markets worldwide that are employing this method.

Ancillary Services

As part of the day-ahead market, the need for reserve capacity to deal with generator outages is included. These ancillary services include regulation reserve, spinning and non-spinning reserve, and replacement capacity. A simplified approach is used here. In the simulation, after the day-ahead market procedure is completed and the dispatch schedule is established, additional capacity is selected to provide for ancillary services. This capacity is taken from the units that have been bid into the day-ahead market but not selected. The amount of additional ancillary service capacity that is needed is determined as the fraction above the projected load, which is determined by the ISO from the demand bids that have been received. In these analyses, the ancillary services requirement is assumed to be 5% above projected load. The units that are selected to provide ancillary services are paid their bid price, regardless of whether or not they are actually dispatched. This is referred to as a capacity payment.

One limitation of this simplified approach is that the capacity selected to provide ancillary services in the day-ahead market may or may not be in the appropriate position in the transmission network to actually deliver the needed service during actual dispatch. Since the location of forced outages during the next day that would require the use of ancillary services is unknown, it could be that the selected units are not able to deliver the service due to transmission congestion. To account for this condition, an additional step is applied in the simulation during the hourly dispatch. Should ancillary services be required (e.g., due to a forced outage of a generator), the available units that were not selected in the day-ahead market (including those that were selected for only a portion of their available capacity) are evaluated to determine their ability to provide the service at lowest cost to the system. Any unit that is dispatched to provide ancillary services is paid for its generation in the in the same fashion as any other generator that was scheduled for dispatch. This is in addition to any capacity payment that is received.

The costs of ancillary services capacity payments are charged to the demand companies purchasing electricity from the market and are prorated based on their load. The costs of generation payments show up in the price that demand companies pay for energy, that is, in the LMP.

It is recognized that this is a simplification of the ancillary services market, but it does provide the ability to account for these costs in an approximate way.

Bilateral Contracts

Bilateral contracts between suppliers (GenCos) and purchasers (DemCos) establish a price for the injection of power at a point in the transmission system and its withdrawal at another point. These bilateral contracts can be short-term (e.g., day-ahead) or longer-term (e.g., week-, month-, or year-ahead). In these analyses, no bilateral contracts are assumed to be in place.

Consumer Tariffs

It is assumed here that all consumers (residential, commercial, industrial) pay the market-based price for electricity, which is based on the LMP. There are no tariffs or price caps to limit charges to consumers.

3.2 AGENT PROFILES

In the analysis, each of the market participants is characterized by its preferences and business strategies. The following assumptions are used here:

Consumers

Consumers are assumed to have no response to electricity prices. That is, they will neither increase nor decrease demand based on prices. It should be noted that the lack of consumer price response is a significant assumption. These conditions can have the effect of allowing electricity prices to rise indefinitely under several circumstances. If there are no competing suppliers that offer lower prices and/or if all suppliers raise prices in unison and/or there are no price caps, consumer prices can rise without limit. There is considerable research that has been done to determine consumer response to electricity prices. In general, it has been determined that residential customers have a much smaller response to electricity prices than do large industrial or commercial customers. A recent study of the California electricity crisis [9] estimated that consumers in San Diego, where retail prices were allowed to fluctuate along with wholesale prices, showed a 5% reduction in demand when prices increased by 100%. It also showed that consumer response to price reflected reaction to their most recent electricity bill (usually monthly) rather than to prevailing daily prices.

The assumption of no consumer response to prices is used here to determine the effect of competition among suppliers in the absence of any consumer reaction.

Generation Companies

Generation companies (GenCos) participate in the market by offering to supply electricity at given location (i.e., injection bus) at a given price. All GenCos are treated as unregulated entities that can offer their capacity to the market at any price they chose. They are not guaranteed any rate of return, nor is there any guarantee that their units will be dispatched. The single ISO operating the market makes decisions on which units will be scheduled for dispatch based on the need to meet load and the limitations of the transmission system.

In the simulations that use the Case Study Assumptions, GenCos utilize a company-level unit commitment algorithm (i.e., the CLUCRA algorithm mentioned earlier) to make an initial decision on the hours (if any) that a unit is offered into the day-ahead market. The CLUCRA algorithm also projects the most profitable operating level for each unit and determines if a unit

[9] Bushnell, James B., and Erin T. Mansur, *Consumption Under Noisy Price Signals: A Study of Electricity Retail Rate Deregulation in San Diego*, University of California Energy Institute, Berkeley, CA (July 2003).

will be able to recover its costs if it is scheduled for dispatch. These costs include expenditures for fuel, variable operating and maintenance, and unit startup/shutdown. It also takes into account minimum downtime between unit startups. If the market prices are expected to be too low and the unit will lose money if it is operated, the GenCo will not offer it for service. Unit commitment decisions are currently made in virtually all power systems, including those that are not deregulated. It provides the GenCo the opportunity to take units out of service that cannot recover their costs. A more detailed description of how the company-level unit commitment analysis (the CLUCRA algorithm) operates in EMCAS is given in Appendix B. To test the effect of the unit commitment analysis on the results, simulations using the Conservative Assumptions bypass this step for each GenCo, and each offers all of its capacity into the market, whether or not it is expected to recover costs. This has the effect of making more generation capacity available to the market. It does, however, imply that a GenCo is willing to accept economic losses on the operation of some of its capacity.

Beyond the unit commitment analysis, GenCos are free to use any one of a number of strategies to determine how much capacity they will offer in the market and what price will be asked. A number of different strategies are tested here.

Demand Companies

In this analysis, all of the demand served by DemCos is assumed to be firm load and is not interruptible based on market price. There is no strategic behavior on the part of DemCos. Any unserved energy (i.e., load not met) is due only to the unavailability of generation and/or transmission capacity (e.g., a forced outage of a generator in a critical location) and not to any market considerations. Since there is no strategic behavior, it is assumed that all DemCos will charge consumers a flat markup of their costs to purchase electricity. This is assumed to be 10% and is applied only to the cost of energy, not to the cost of transmission or distribution services.

As with the assumption of no consumer price response, this assumption has implications for the results, although less so. Recall that there are no bilateral contracts and all DemCos (and GenCos) participate in the market only through the pool. Under these conditions, the only manner in which DemCos could respond to high prices would be to shed load using, for example, interruptible service contracts or incentive payments to consumers that reduce load. These options are generally limited to large customers and are not included here.

Distribution Companies

In the simulation, DistCos are assumed to be simply collectors of revenue for the use of their distribution lines. A distribution use charge (DUC), which is a flat fee measured in $/MWh, is levied on all consumers. There is no strategic business behavior associated with DistCo operation.

The DUC is assumed to be 18 $/MWh,[10] which is an approximation of the rates currently posted by companies in Illinois offering unbundled service for different classes of service.

Transmission Company

It is assumed here that there is a single TransCo that owns the system. It does not employ any strategic business behavior. Instead, it is a collector of revenue for the use of its lines. This assumption is made here because of the uncertainty in who will own various parts of the transmission system in the analysis year. Since the TransCo does not engage in any strategic behavior, this assumption does not affect results in any significant way.

TransCo revenue comes in two forms: a transmission use charge (TUC) and a Transmission Congestion Payment (TCP). The TUC is a flat fee, measured in $/MWh, that is based on the energy withdrawn, and is charged, by convention here, to the DemCos withdrawing the energy. (The DemCos will pass this charge on to their consumers without any markup.) The TUC is assumed to be 3 $/MWh, which is an approximation of the rates currently used by different transmission owners when pricing their services in the wholesale market.[11]

The TCP is based on the differences in LMPs in the network and is calculated for every line in the network. In an uncongested situation without transmission losses, the LMPs are the same throughout the system and there is no TCP. With congestion, the LMP is different at different nodes in the network. As discussed earlier, the market configuration employed here uses the PLMP rule to settle payments to market participants. GenCos are paid the LMP at the buses that their generators are attached to. DemCos pay the load-weighted average LMP of the zones that their consumers are located in. When transmission congestion is present, with resulting variations in LMPs, the net of payments by DemCos and payments to GenCos is generally non-zero. In the simulation, this difference is the TCP that is paid to the TransCo.

The calculation of the TCP, as the difference in LMPs when there is congestion, is done with consideration of the direction of the power flow at any hour. By convention, the TCP on each line is calculated as the LMP at the receiving point minus the LMP at the originating point multiplied by the flow. This convention can sometimes lead to a negative value of the TCP for a line or set of lines.

In some operating electricity markets, there is a transmission rights market in which GenCos and DemCos can purchase transmission options, called firm transmission rights (FTRs), as a hedge. In these types of markets, the TCP would be allocated among the holders of these rights and the TransCo(s). Should the TCP have a negative value, the holders of the FTRs would be required to reimburse the TransCo for this amount. In the current simulation, there is no

[10] The distribution use charges for the companies operating in Illinois are posted on their individual Web sites and are on file with the Illinois Commerce Commission. The rates vary from 10 $/MWh to 21 $/MWh and depend on customer service class. The value of 18 $/MWh is used here as an average value and represents what is charged to the largest number of customers.

[11] The value used for TUC is estimated from rates posted by the Midwest System Operator (MISO). The MISO rate is calculated annually base on filings with FERC and EIA. Converted to a $/MWh basis, the rates range from 2.4 $/MWh to 5.5 $/MWh, with an average of 3 $/MWh.

transmission rights market and the TCP (either positive or negative) is assumed to be allocated solely to the TransCo.

Independent System Operator

The single ISO handles the scheduling and dispatching of the entire system operating in the State. It also handles the settlement of charges and payments in the pool market, including both energy and ancillary services. In operating the transmission system, the ISO uses a transmission-constrained dispatch procedure (the SYSSCHED DCOPF described earlier). This procedure seeks to dispatch the lowest-cost generators at each hour subject to maintaining the physical limits of transmission lines. In some cases, lower-cost generators cannot be utilized, as they would result in unacceptable overloads on transmission lines. Higher-cost generators must be dispatched to avoid these conditions. It is this situation that results in LMPs being different in different locations.

In selecting the lowest-cost generators, the ISO relies on the bid prices supplied by the GenCos. The "lowest cost" generator is, in actuality, the "lowest priced" generator. In the simulation, the ISO does not attempt to adjust bid prices submitted by GenCos.

3.3 TRANSMISSION NETWORK CONFIGURATION

The configuration of the power system in Illinois in the analysis year was constructed from the 2003 summer case prepared by the North American Electric Reliability Council (NERC). Data on load growth, generator additions and retirements, and transmission system changes were added to bring the system up to what might be expected in the analysis year of 2007. The NERC case, which covers the entire eastern interconnection of the U.S., includes about 1,900 buses and 2,650 branches in Illinois. All of the analyses with both PowerWorld and EMCAS were done using this detailed transmission configuration for the State.

For the EMCAS analysis, the buses in Illinois were grouped into zones. These zones serve several purposes. First, they are used to divide larger regions of the State, that are based on traditional utility control areas, into smaller areas that may see different price effects due to different levels of transmission congestion. The selection of the buses that are included in each zone was done using a preliminary analysis of load flows using PowerWorld. Buses that were geographically close and had similar LMPs, thus indicating minimal congestion among them, were included in the same zone.

Second, the zones provide the market areas that are used in determining prices to be charged to DemCos. As discussed previously, DemCos participating in the market pay the load-weighted average of the bus LMPs for the zones that their consumers are located in. This zonal pricing is used in most of the currently operating electricity markets in the U.S., which is why it is used here as well.

In addition to the in-state transmission configuration, the power transfers into and out of the State must be accounted for in order to get an accurate picture of how the State's system

performs. PowerWorld uses a larger portion of the eastern interconnection. EMCAS uses a reduced out-of-state network with transmission capacity that allows power to move into and out of the State. All of the tie lines between Illinois and surrounding States were identified and aggregated into a small set of interconnection points. The interconnection points covered an area including Indiana, Michigan, and parts of Ohio in the east, Tennessee in the south, parts of Missouri served by Ameren and AECI utilities in the southwest, Iowa and parts of Minnesota in the west, and Wisconsin in the north. The in-state zones and the out-of-state interconnection points are shown on Table 3.3-1 and Figure 3.3-1. The zone and interconnection point names reflect the current owners of the primary lines. Figure 3.3-2 shows the zones that have major transmission links between them. The links on this figure represent the ability to move power between zones at 138 kV or higher voltages and, in most cases, represent the availability of multiple transmission lines operating between the zones. Table 3.3-2 shows the capacities of the tie lines between Illinois and out-of-state zones.

The use of this simplified representation of the out-of-state network in EMCAS has implications for the results. In terms of the ability to transfer power into or out of the State, the representation is a good approximation, since the individual tie lines and their capacities are represented explicitly. This allows the physical limits of power flows between in-state and out-of-state nodes to be represented. In terms of which out-of-state suppliers will contribute to meeting the State's load and which out-of-state loads will be met by in-state suppliers, the representation used here does not address these details. Further, the representation used here is not intended to capture power transfers among out-of-state suppliers with any high degree of accuracy. Nor is it intended to provide details of power wheeling that crosses the State from one out-of-state supplier to an out-of-state load. Despite these limitations, this simplified representation can be expected to give reasonable results for the in-state market participants.

Table 3.3-1 In-State Zones and Out-of-State Connection Points

In-State Zones	Current Ownership of Buses in Zone
AMRN – A, B, C, D, E	Ameren [a]
CILC	Ameren
EEI	Ameren
CWLP	City Water and Light (Springfield)
IP – A, B, C, D	Illinois Power
NI – A, B, C, D, E, F, G	Commonwealth Edison [b]
SIPC	Southern Illinois Power Cooperative
Out-Of-State Connection Points	**Current Ownership of Principal Tie Lines**
AEP	American Electric Power
AMRN-OUT	Ameren – outside Illinois
ALTE	Alliant Energy – East
ALTW	Alliant Energy – West
BREC	Big Rivers Electric Corp.
CIN	Cinergy Corporation
DOE	Department of Energy
MEC	MidAmerican Energy Company
NIPS	Northern Indiana Public Service
TVA	Tennessee Valley Authority
WEC	Wisconsin Energy Corporation

[a] Buses owned by Mt Carmel Public Utility are included in the AMRN-B zone. Buses in Illinois owned by MidAmerican Energy are included in the NI-A zone.
[b] Buses in Illinois owned by Alliant Energy (Interstate Power and South Beloit) are treated as part of the out-of-state zone.

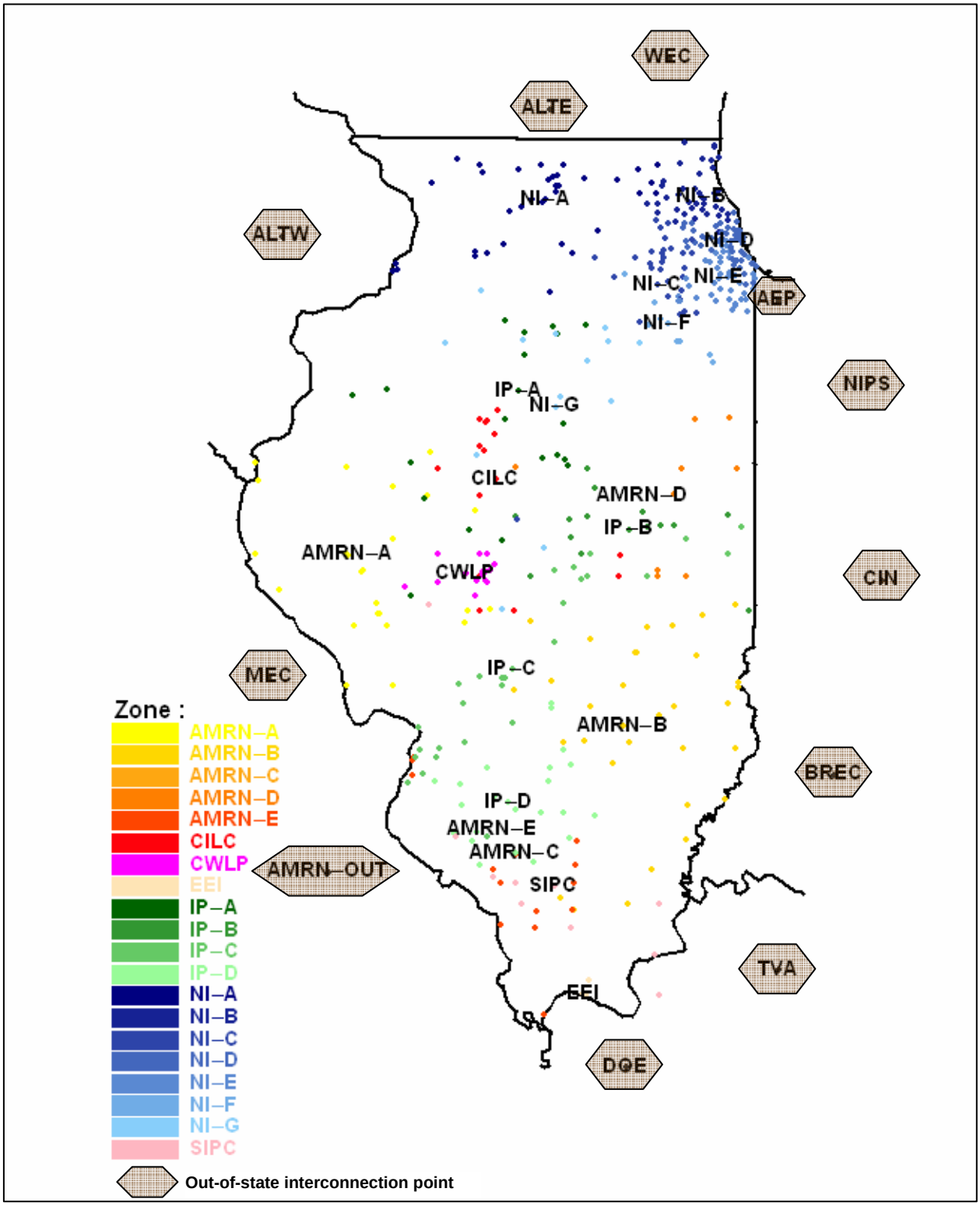


Figure 3.3-1 In-State Zones and Out-of-State Interconnection Points

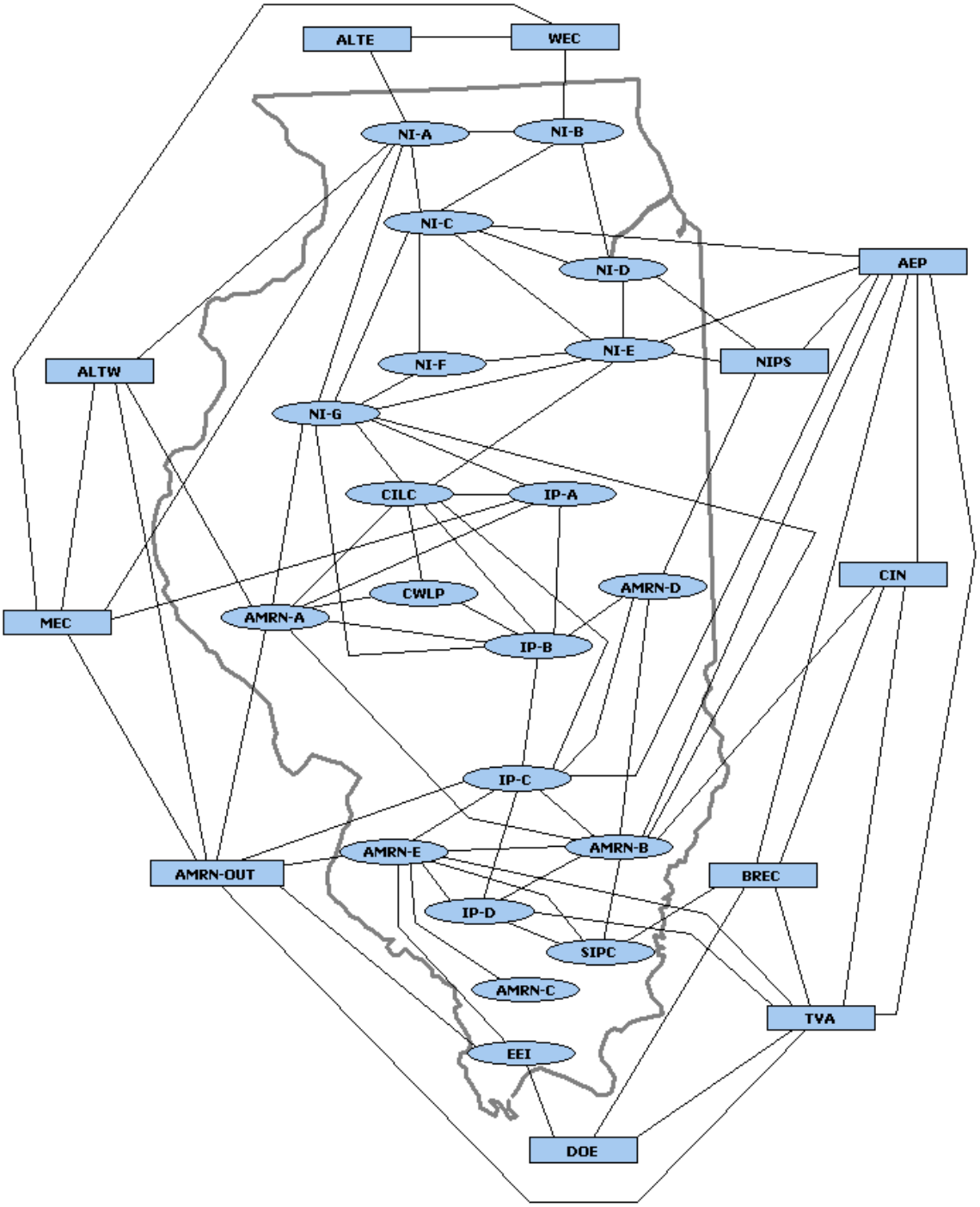


Figure 3.3-2 Zone Power Transfer Links

Table 3.3-2 Transmission Line Limits between In-State and Out-of-State Zones

In-State Zone	Out-of-State Connection Point	Transmission Capacity Based on Thermal Line Limits (MW)
AMRN-A	ALTW	295
AMRN-A	AMRN-OUT	460
AMRN-B	AEP	1,332
AMRN-B	CIN	1,505
AMRN-D	NIPS	227
AMRN-E	AMRN-OUT	4,187
AMRN-E	AMRN-OUT	495
AMRN-E	TVA	949
EEI	AMRN-OUT	221
EEI	DOE	1,752
IP-A	MEC	200
IP-C	AEP	937
IP-C	AMRN-OUT	372
IP-D	TVA	1,195
NI-A	ALTE	1,325
NI-A	ALTW	1,157
NI-A	MEC	6,195
NI-B	WEC	2,505
NI-C	AEP	3,975
NI-D	NIPS	1,755
NI-E	AEP	1,957
NI-E	NIPS	4,671
SIPC	BREC	259

Note: The sum of the thermal line limits does not reflect the transmission capacity into and out of the State, which is significantly less. The actual capacity is a function of the power flows in the whole system at any point in time and is considered in both the EMCAS and PowerWorld simulations.

In order to provide a more accurate representation of the power flows outside of the State, PowerWorld used a significantly larger network configuration than was used in EMCAS. Since the focus area of this study was the U.S. Midwest in general and Illinois in particular, the original 42,700 bus, 6800 generator, 57,000 line/transformer NERC case modeled was equivalenced to one with 12,925 buses, 1790 generators, and 17,647 lines and transformers. The explicitly retained portion of the system roughly covers the region bounded by Minnesota, Missouri, Tennessee, Ohio, and Michigan. The total generation capacity was reduced from about 780 GW in the original NERC case to about 216 GW. While the reduced case had only about one quarter the generation capacity of the original case, it still contained four times the total Illinois generation capacity (171 GW out-of-state and 45 GW in-state). Hence, the reduced case provided a sufficiently large generation and load market. The breakdown of the 12,925 buses by NERC region was 2,207 in SERC, 4,052 in ECAR, 1,929 in MAPP, and 4,737 in MAIN (1,847 in-state and 2,919 out-of-state). During the study, the limits on all in-state transmission lines were enforced. Limits were only enforced for out-of-state lines for voltages above 200 kV.

The PowerWorld representation provides much more detail on the out-of-state network, but it too is limited in representing the full extent of the power grid. It represents the system in the states immediately adjacent to Illinois but does not include the parts of the eastern

interconnection beyond these areas. The large eastern markets (e.g., PJM, NYISO) and southeastern markets, which could have an impact on the behavior of the Illinois market, are not represented here.

3.4 LOAD

Table 3.4-1 shows projected seasonal peaks and total load that were used for this analysis. This load profile is based on data contained in FERC Form 714 that contains total control area loads for all hours of an historical year. This form also contains 10-year forecasts of seasonal peak loads and total annual loads. To project hourly loads for a control area, historic hourly loads are scaled such that the total annual load and both summer and winter peaks match the Form 714 projection. This method produces results that exactly match the annual load factor predicted by the reporting control areas.

Hourly loads at a bus are based on a bus distribution factor (BDF) that indicates the portion of the total control area load that is assigned to that specific bus. The BDFs remain constant throughout the simulation year and are based on PowerWorld input data for a peak load day. A BDF is multiplied by the hourly control area load to obtain the hourly bus load; that is, the FERC Form 714 data that were scaled to the projection year. This methodology assumed that the relative load contribution that a bus makes to the control area total is constant throughout the year.

The load forecasting method used here addresses the need to develop projections of hourly load patterns in order to run the PowerWorld and EMCAS simulations. Clearly, it is not possible to develop an accurate representation of how loads will vary by hour at each bus in the network for a period several years in the future. The method used here provides a load profile that is tied to a number of key reference points that make it reasonable for use in this analysis. First, the peak, seasonal, and annual loads are tied to the FERC Form 714 projections. These may or may not be accurate in forecasting years into the future, but they represent a common point that is used by many organizations studying load growth. Second, the BDFs used to distribute load to individual buses are taken from historical data. Using them with the assumption that they are constant throughout the year cannot be expected to be entirely accurate, but lacking detailed bus-by-bus load data for an entire year, it is a reasonable assumption. The use of actual load profile data for the analysis year would change the results to the extent that the data deviated from the profiles used here.

Figure 3.4-1 shows the assumed load for the State for the 8,760 hours of the analysis year. The load shows the typical seasonal variation for a northern U.S. State. Peak loads are seen in the summer months – June, July, August – as air conditioning use increases. Some unusually warm days in the spring and fall also show up on this data. During the rest of the year, the load follows a pattern that varies within a smaller range. April and October are the months with the lowest loads. Daily and weekly variations in load are evident from the data.

Figure 3.4-2 shows the peak load by zone for the analysis year. The load data also shows the wide variation between the northern part of the State and downstate. Northern Illinois

accounts for more than 70% of the statewide peak load. It also shows a much larger seasonal variation due to the more extensive use of air conditioning in the summer along with the higher population density. The downstate areas show much less variability in load with a flatter load profile.

Table 3.4-1 Load Forecasts for 2007

Control Area	Summer Peak (MW)	Summer Loads (MWh)	Winter Peak (MW)	Winter Loads (MWh)	Annual Load (MWh)	Annual Load Factor (Frac.)
Central Illinois Light Company (CILCO)	1,272	3,585,804	956	3,248,826	6,834,629	0.6134
Commonwealth Edison (ComEd)	24,200	54,652,572	16,300	50,597,428	105,250,000	0.4965
Electric Energy Inc. (EEI)	900	603,800	1,194	2,538,119	3,141,919	0.3004
Illinois Power Company (IP)	3,333	9,009,642	2,446	8,165,738	17,175,379	0.5883
Southern Illinois Power Co-operative (SIPC)	270	663,146	272	704,341	1,367,487	0.5739
Springfield Il. City Water Light & Power (CWLP)	502	1,132,894	346	1,001,106	2,134,000	0.4853
Associated Electric Power Coop.	4,066	9,427,934	3,646	9,638,734	19,066,668	0.5353
Madison Gas and Electric Company	829	1,918,063	548	1,738,919	3,656,982	0.5036
Dairyland Power Cooperative	877	2,429,482	804	2,356,518	4,786,000	0.6230
Indianapolis Power & Light Co.	3,390	8,351,066	2,741	7,960,934	16,312,000	0.5493
AEP-East System	21,217	63,701,767	21,062	65,091,997	128,793,763	0.6929
Hoosier Energy	1,246	2,943,619	1,254	3,086,454	6,030,073	0.5525
Tennessee Valley Authority	34,110	94,016,640	33,509	89,074,360	183,091,000	0.6127
Mid-American Energy	4,345	10,558,673	3,005	9,753,545	20,312,218	0.5337
Alliant West	3,555	10,761,793	2,695	10,364,724	21,126,517	0.6784
Alliant East	2,908	7,228,927	2,547	6,900,751	14,129,678	0.5547
AMEREN	10,967	27,280,332	8,592	24,987,668	52,268,000	0.5441
Cinergy	11,740	32,148,313	9,687	30,434,975	62,583,288	0.6085
Consumers Power	9,501	24,471,445	7,264	23,039,555	47,511,000	0.5708
Northern Indiana Public Service Corp.	3,172	9,331,131	2,571	8,697,869	18,029,000	0.6488
Wisconsin Electric Power Company	6,800	17,821,877	5,096	17,107,123	34,929,000	0.5864
Wisconsin Public Service Corp.	2,429	6,972,091	2,036	6,780,663	13,752,755	0.6463
Big Rivers Electric Corp.	1,502	4,146,879	1,433	4,459,158	8,606,037	0.6539
Northern States Power	8,587	23,495,460	7,329	22,411,956	45,907,416	0.6103
Louisville Gas and Kentucky Utilities	7,587	18,243,760	6,325	16,702,240	34,946,000	0.5258
Dayton Power and Light	3,285	9,136,039	2,855	8,560,954	17,696,993	0.6150
Southern Indiana Gas and Electric	1,376	3,536,046	1,001	3,134,954	6,671,000	0.5534
Total	**173,967**	**457,569,194**	**147,513**	**438,539,609**	**896,108,802**	**0.5880**

Source: NERC, Energy Information Administration

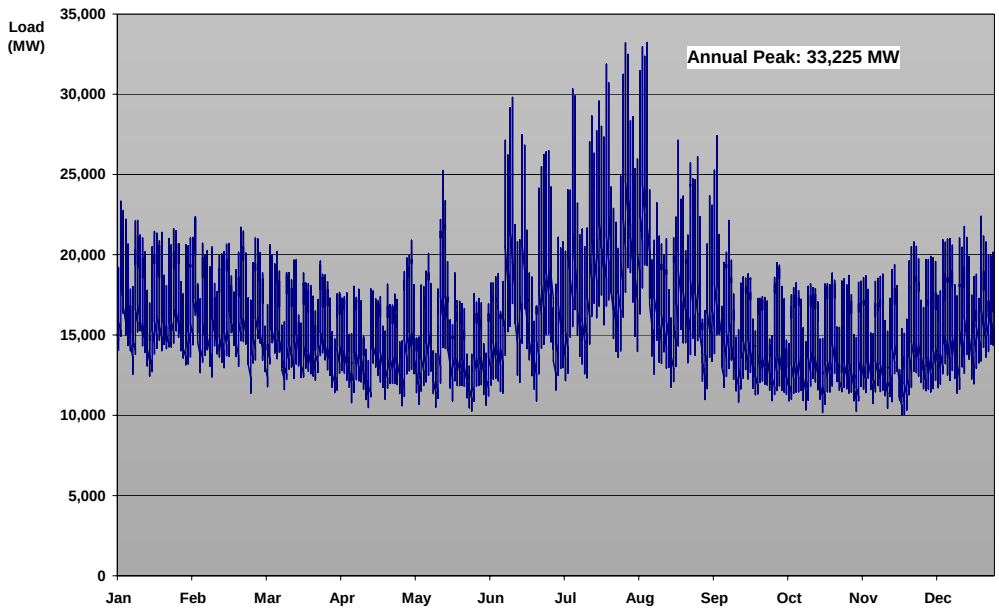


Figure 3.4-1 Statewide Hourly Load for the Analysis Year

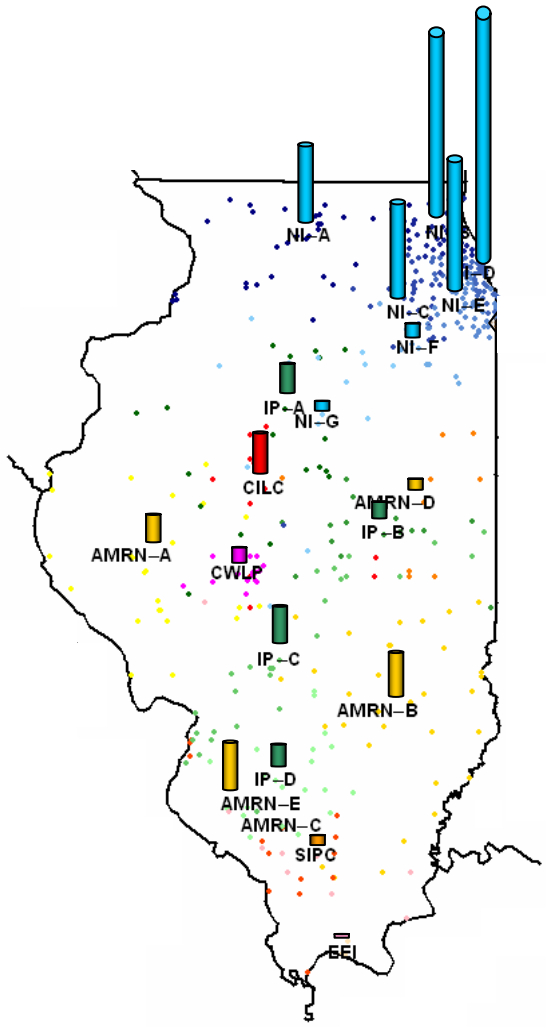


Figure 3.4-2 Peak Load by Zone for the Analysis Year

3.5 GENERATION CAPACITY

Table 3.5-1 summarizes the generation capacity assumed to be operating in the State in the analysis year. Detailed unit-by-unit information was taken from FERC, EIA, and Illinois EPA sources, as discussed earlier. The total increase of about 6 GW from capacity in 2001 represents a growth of about 14%. Since the load growth in this period is projected to be much smaller, the statewide generation reserve margin will grow to be about 43%. Whether this large reserve margin will actually be realized is open to question.

Table 3.5-1 also shows the generation ownership in the analysis year. The HHI based on installed capacity drops somewhat from its current value of 1,498 to 1,123, which still indicates a moderately concentrated market based on the Department of Justice guidelines. The HHI for coal capacity is essentially the same as in 2001. For natural gas capacity, the HHI drops from 1,562 in 2001 to 783 in the analysis year. The natural gas capacity additions by a number of different companies have moved this into the range that indicates a market that is not considered as concentrated by this index.

In the simulations using the Case Study Assumptions, it was assumed that for each hour of the year, some capacity would not be available, due to scheduled outages and forced outages. Scheduled outages include what are termed "planned outages" that involve the removal of a unit from service to perform work during a prearranged time period. This period is determined well in advance, and tasks such as annual overhauls, testing, and component inspections are conducted. Scheduled outages also include "maintenance outages." A maintenance outage is the removal of a unit from service to perform work on a specific problematic component. This work need not be done immediately and can be deferred to a more convenient time, usually within about a week. Both planned and maintenance outages may be extended in time if the work takes longer to complete than originally scheduled. A "forced outage" is the result of a component failure. It must be fixed within a short period of time (usually within less than a week, if not immediately). All outages used in this study are based on information contained in the Generation Availability Data System (GADS). [12]

The analysis assigns planned outage lengths to individual units based on the type of fuel that the unit burns and the prime mover (i.e., steam, gas turbine, combined cycle, etc.). Planned outages are scheduled at the beginning of the year and are coordinated among all generation companies such that the highest hourly reserve margin (not including unplanned outages) during the year is at the lowest possible level. Planned outages are therefore scheduled to occur during low-load periods when reserve margins are at a peak. The simulation schedules planned outages sequentially, one unit at a time, in a pre-specified order. For this analysis, units are ordered according to average production costs in terms of $/MWh such that less expensive units are scheduled first and those with the highest costs are scheduled last.

[12] *Generating Availability Report*, North American Reliability Council, New Jersey (2002).

Table 3.5-1 Analysis Year Generation Capacity by Company

		Capacity Additions/ Retirements		Analysis Year Capacity					
Generation Company	**2001 Capacity (MW)**	**(MW)**	**Type**	**Coal**	**Oil**	**Natural Gas**	**Nuclear**	**Total Capacity (MW)**	**Portion of State Total (%)**
GenCo – Allegheny Power	664	0		0	0	664	0	664	1.4%
GenCo – Ameren									
Ameren-CILCO	1,293	0		1,221	26	46	0	1,293	2.7%
Ameren-CIPS	3,457	-304 -3 200	Coal Oil Gas	2,640	210	500	0	3,350	7.1%
Ameren-EEI	1,293	-193 318	Oil Gas	1,100	0	318	0	1,418	3.0%
Ameren-UE	1,437	-474 600	Oil Gas	0	37	1,526	0	1,563	3.3%
GenCo – Aquila Energy	0	770	Gas	0	0	770	0	770	1.6%
GenCo – Calpine	174	480	Gas	0	0	654	0	654	1.4%
GenCo – Calumet Energy LLC	0	305	Gas	0	0	305	0	305	0.6%
GenCo – City of Springfield	646	0		463	44	139	0	646	1.4%
GenCo – Constellation Power	125	871	Gas	0	0	996	0	996	2.1%
GenCo – Dominion Energy	2,785	688	Gas	1,933	0	1,540	0	3,473	7.3%
GenCo – Duke Energy	664	0		0	0	664	0	664	1.4%
GenCo – Dynegy Midwest Gener.	4,105	0		3,369	245	491	0	4,105	8.6%
GenCo – Dynegy/NRG Energy	398	0		0	0	398	0	398	0.8%
GenCo – Exelon Generation	9,882	328	Gas	0	0	328	9,882	10,210	21.5%
GenCo – Exelon Nucl/MidAmer	1,657	0		0	0	0	1,657	1,657	3.5%
GenCo – MidAmerican Energy Co.	572	0		0	0	572	0	572	1.2%
GenCo – Midwest Generation LLC	10,755	-371 -1,061	Coal Gas	6,138	770	2,415	0	9,323	19.6%
GenCo – NRG Energy	300	2,357	Gas	0	0	2,657	0	2,657	5.6%
GenCo – Power Energy Partners	0	356	Gas	0	0	356	0	356	0.7%
GenCo – PPL	0	450	Gas	0	0	450	0	450	0.9%
GenCo – Reliant Energy	1,108	194	Gas	0	0	1,302	0	1,302	2.7%
GenCo – Southern Ill Power Coop.	272	166	Gas	272	0	166	0	438	0.9%
GenCo – Southwestern Elec. Coop.	0	71	Gas	0	0	71	0	71	0.1%
GenCo – Soyland Power Coop. Inc.	171	0		22	24	125	0	171	0.4%
TOTAL CAPACITY IN ILLINOIS	**41,758**	**5,748**		**17,158**	**1,356**	**17,453**	**11,539**	**47,506**	**100.0%**
HHI – based on total company capacity									**1,123**
HHI – based on coal capacity									**2,130**
HHI – based on natural gas capacity									**783**

The planned outage algorithm first computes reserve margins for each hour of the year under the assumption that all units are always available for service. The unit with the lowest average production cost is then taken off-line for a continuous planned outage length that is consistent with the average downtime for units of that specific type. The planned outage period is selected such that it maintains the minimum reserve margin. After recomputing hourly reserve margins, the planned outage period for the unit with the next lowest production cost is determined. All units are scheduled for maintenance sequentially using the same rule. The end result is to "valley fill" the low-load period with maintenance, thus reducing variability in hourly reserve margins among seasons of the year.

Maintenance outages typically range in length from a few hours to a few days. The work can be deferred beyond the end of the next weekend, but must be scheduled before the next planned outage period. In the simulation, component problems that result in this type of outage occur at random. The maintenance outage algorithm schedules the down period within one month of a randomly drawn problem event. The duration of the maintenance period is consistent with the work that must be performed on the failing component as indicated by GADS statistics.

Forced outages occur at random as the result of component failures. Outage durations range from a few hours to several days as a function of the cause of the failure. Consistent with GADS statistics, the forced outage algorithm determines the number of outages, by cause, that the entire fleet of units will encounter. The algorithm also determines the approximate number of hours that each unit is forced out of service based on GADS cumulative frequency distributions. This methodology results in a pattern of outages in which there is diversity among units in terms of the number of hours that each are out of service during a given year. A Monte Carlo simulation approach was used to generate a set of forced outage patterns from which the one used here was selected.

Using a specific forced outage scenario, as employed here, implies that a strict interpretation of results should be confined to the outage scenario chosen. However, it is felt that this approach will deliver results that are more representative of actual system performance than the alternative approach of using derated capacity, even when the results are extrapolated to conditions other than the specific outage scenario chosen.

To verify that the results and conclusions are not skewed by the specific maintenance and forced outage scenario selected, simulations were run using the Conservative Assumptions in which the planned outages were included but maintenance and forced outages were not. This removes the outages that are random in nature while including those that can be reasonably predicted. This assumption results in more generation capacity being available than would ordinarily be expected at any given time, but it does provide a point of comparison under conservative conditions.

Figure 3.5-1 shows the capacity that is assumed to be on-line in the analysis under Case Study Assumptions. Planned maintenance outages are greatest in the spring and fall periods and are minimal during peak load periods. Forced outages are random throughout the year. It can be seen from the figure that, on a statewide basis, there is always adequate generation capacity to

meet the load. Statewide, the hourly generation reserve margin never falls below 22%, even with scheduled and forced outages.

Figure 3.5-2 shows the capacity available under Conservative Assumptions in which the maintenance and forced outages are eliminated. Note that during the high-load summer months, all of the capacity in the State is assumed to be available for operation. Although the probability that these conditions will be seen in practice is very small, they are used in this analysis to test the ability of a company to exercise market power under a very optimistic state of the power system. If the exercise of market power can be seen under these conditions, the loss of available capacity due to outages would only exacerbate the situation. An alternative way to study this issue would have been to investigate a range of outage scenarios; however, the large number of possible combinations makes this impractical.

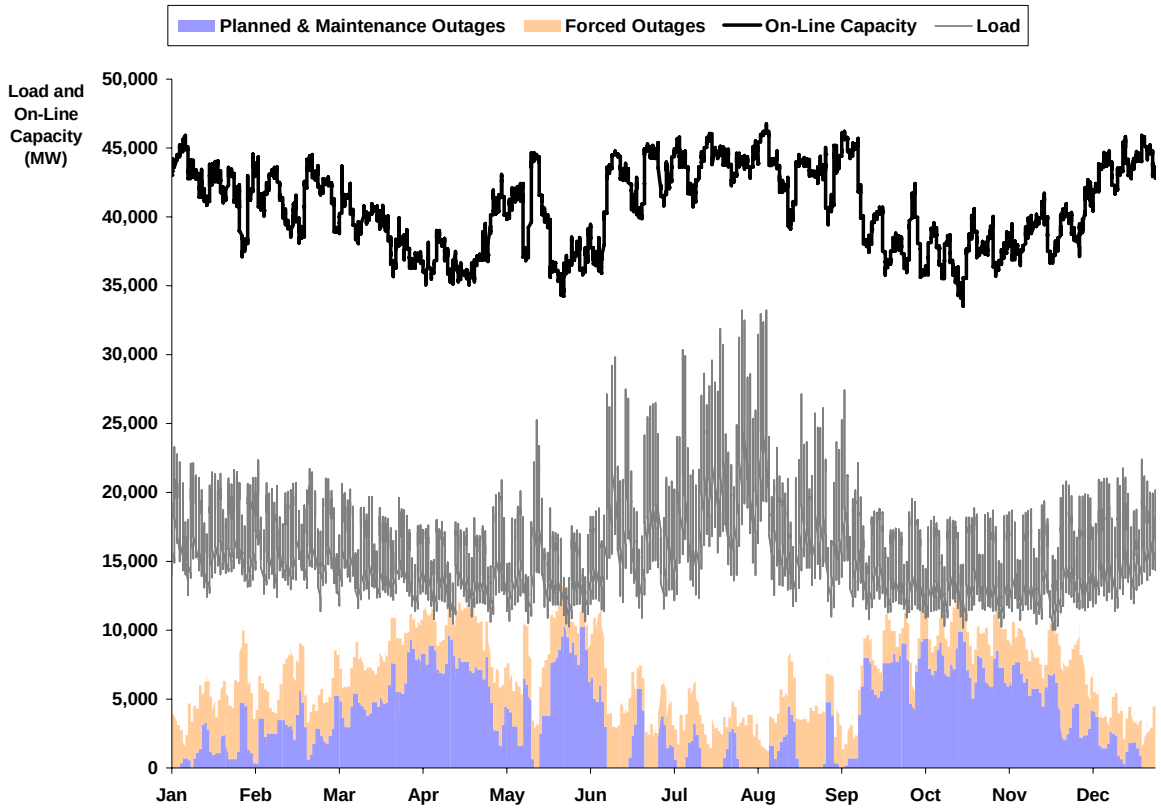


Figure 3.5-1 Analysis Year Available Generation Capacity (Case Study Assumptions)

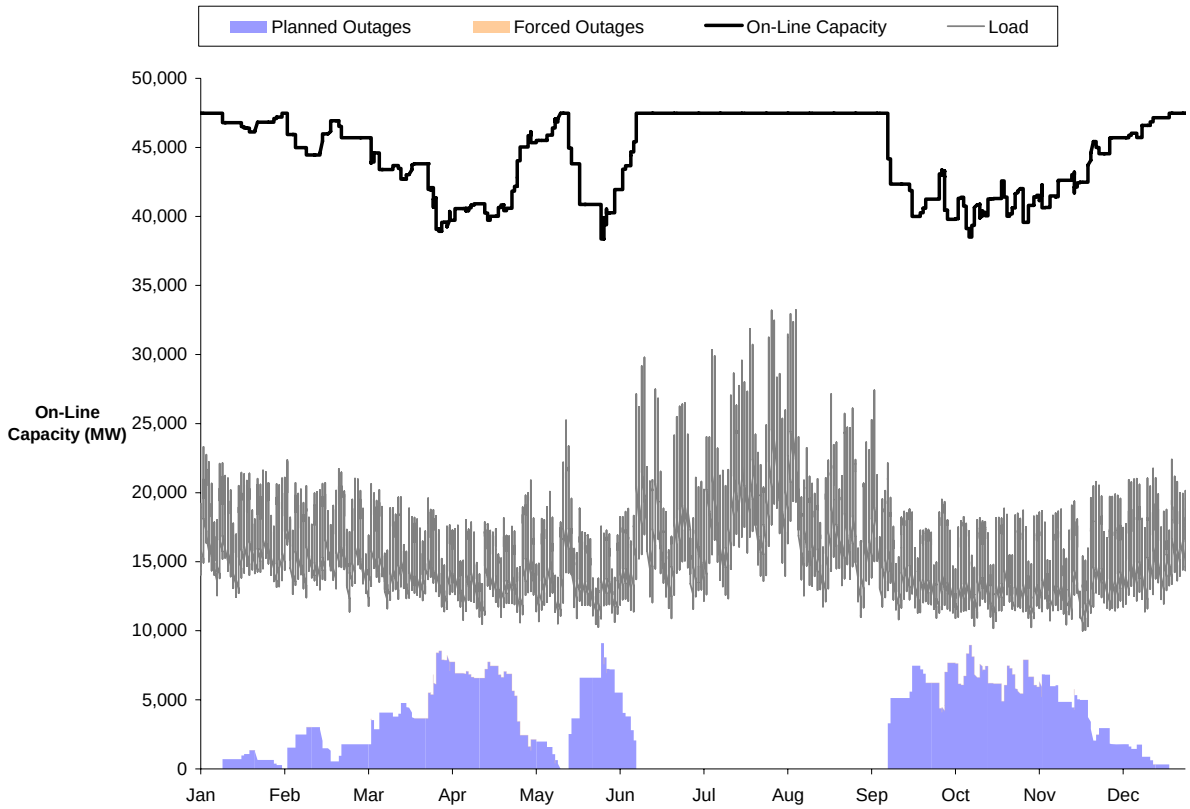


Figure 3.5-2 Analysis Year Available Generation Capacity (Conservative Assumptions)

3.6 FUEL PRICES

Fuel price projections are based on regional forecasts produced by the Energy Information Agency's (EIA) National Energy Modeling System (NEMS) model that are reported in its Annual Energy Outlook (AEO).[13] NEMS prices are based on supply and energy demand simulations. The model accounts for numerous factors that impact domestic fuel prices. These include macroeconomic growth, energy intensity, domestic and international energy production, sectoral energy demands, and environmental considerations.

Fuel prices delivered to the electric sector are projected regionally in the AEO. The East North Central Region, which includes Illinois, also includes Wisconsin, Michigan, Indiana, and Ohio. Load control areas in Iowa and Missouri are in the West North Central Region, and TVA is in the South Atlantic Region. AEO utility fuel price forecasts for the three regions developed in late 2002 by EIA are shown in Tables 3.6-1 through 3.6-3. Prices are projected for distillate fuel oil, residual fuel oil, natural gas, and steam coal. Each unit in the power plant inventory is assigned a fuel price in the forecast year based on its location and primary fuel type. Note that fuel prices increase slightly in 2003 but return to lower levels in 2004. After 2004, prices are nearly constant through 2007.

[13] *Annual Energy Outlook with Projections*, AEO, 2003, National Energy Modeling System Run aeo2003.d110502c, Energy Information Administration, Washington, DC.

Table 3.6-1 Electric Generator Fuel Prices for the East North Central Census Division

Fuel Type	Fuel Price ($ / million Btu)							
Year	2000	2001	2002	2003	2004	2005	2006	2007
Jet Fuel	7.07	6.14	5.74	6.16	5.82	5.58	5.36	5.36
Distillate Fuel	6.56	5.94	5.53	5.95	5.14	4.95	4.86	4.87
Residual Fuel	3.50	4.41	4.15	4.46	4.04	3.91	3.95	3.97
Natural Gas	3.54	4.20	2.78	3.12	2.96	2.90	2.83	2.89
Steam Coal	1.21	1.24	1.20	1.20	1.19	1.21	1.19	1.18
Petroleum Products	3.93	4.71	5.34	5.84	5.13	4.94	4.85	4.85
Fossil Fuel Average	1.33	1.41	1.36	1.39	1.38	1.39	1.37	1.36

Table 3.6-2 Electric Generator Fuel Prices for the West North Central Census Division

Fuel Type	Fuel Price ($ / million Btu)							
Year	2000	2001	2002	2003	2004	2005	2006	2007
Jet Fuel	7.28	6.39	6.07	6.49	6.22	5.98	5.77	5.76
Distillate Fuel	6.67	6.18	5.57	5.99	5.22	5.03	4.94	4.95
Residual Fuel	4.50	4.13	3.34	3.63	3.06	2.93	2.96	2.98
Natural Gas	4.37	4.26	3.25	3.45	3.31	3.25	3.21	3.22
Steam Coal	0.86	0.92	0.87	0.88	0.88	0.90	0.89	0.89
Petroleum Products	6.00	5.22	5.47	5.98	5.18	4.99	4.91	4.89
Fossil Fuel Average	1.02	1.05	0.97	0.99	0.97	0.96	0.96	0.94

Table 3.6-3 Electric Generator Fuel Prices for the South Atlantic Census Division

Fuel Type	Fuel Price ($ / million Btu)							
Year	2000	2001	2002	2003	2004	2005	2006	2007
Jet Fuel	7.32	6.40	5.98	6.40	6.10	5.88	5.66	5.65
Distillate Fuel	6.70	6.07	5.37	5.80	4.98	4.80	4.72	4.72
Residual Fuel	4.43	5.33	3.85	4.13	3.89	3.77	3.79	3.81
Natural Gas	4.54	4.64	3.40	3.85	3.63	3.54	3.48	3.56
Steam Coal	1.45	1.47	1.47	1.47	1.46	1.45	1.44	1.43
Petroleum Products	4.58	5.41	4.06	4.50	4.24	4.15	4.15	4.16
Fossil Fuel Average	2.02	2.18	1.74	1.78	1.76	1.73	1.72	1.71

Note for Tables 3.2.6-1,2,3: Includes combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Jet fuel price is for units using a kerosene-type jet fuel. Price includes federal and State taxes while excluding county and local taxes.
Source: www.eia.doe.gov/oiaf/aeo/supplement/sup_t2t3.pdf (Model run November 2002)

3.7 OUT-OF-STATE LOAD AND GENERATION

For the simplified representation of the out-of-state power system described earlier, the loads and generation were represented by simple supply and demand curves. The total generation capacity of the reduced network was 216 GW serving the total system peak load of about 172 GW. While generating units within Illinois were represented in the EMCAS model with their individual characteristics, the out-of-state generation capacity was aggregated by interconnection point and modeled with their respective cumulative supply curves. The supply curves for out-of-state generators were constructed on the basis of their variable production costs. Under Case Study Assumptions, the effects of outages are accounted for by derating the units (i.e., reducing their available capacity by their average outage rates) and adjusting the out-of-state supply curves accordingly. This simplified approach is required, since there was insufficient information to allow for a unit-specific outage scenario, such as was developed for the in-state units. It allows for an approximation of how outages can affect available capacity. For simulations using the Conservative Assumptions, the derating of out-of-state units is maintained using only planned and maintenance outage rates. Forced outages were eliminated for consistency with the in-state representation.

A similar simplified approach has been applied for the modeling of out-of-state loads that were also aggregated by interconnection point. The details of these out-of-state supply and demand curves are given in Appendix D.

This simplified representation of out-of-state load and generation in EMCAS can be expected to have some impacts on the results. The spatial distribution of loads and generation at the out-of-state nodes does not capture the details of how power might be distributed in the out-of-state areas. As a result, the ability of in-state generation to meet out-of-state loads may be overestimated, since transmission limitations in the out-of-state areas are not considered. All load is assumed to be at the few out-of-state nodes that are included, and the only limitations on their being met by in-state suppliers are the capacity limits on the interties. Capacity limits on any strictly out-of-state lines are not considered. In an analogous fashion, the ability of out-of-state generation to meet in-state loads may also be overestimated, since some of that generation may experience local transmission congestion that is not represented in the simplified structure.

The use of the PowerWorld model overcomes some of these issues, since it is configured to represent much more of the eastern interconnection in detail. By including transmission details in a wider area surrounding the State, the effects of the simplification are reduced. In the PowerWorld model, all out-of-state generation and loads in the retained portion of the system were represented in detail. Table 3.7-1 contains a breakdown of the out-of-state generation capacity and peak load by control area and fuel type. Although this addresses some of the problems of representing out-of-state conditions, it too is a simplification in that areas beyond those shown here are not represented.

Table 3.7-1 Out-of-State Generation and Load Modeled in PowerWorld

Control Area	Load (MW)	Generation Capacity by Fuel Type (MW)				
		Coal	Nuclear	Gas	Hydro/ Pumped.	Other or Unknown
AECI (SERC)	4415	2412	0	1614	58	249
TVA (SERC)	30435	16256	5902	7363	6581	560
DOE (SERC0	500	0	0	0	0	0
AEP (ECAR)	23094	21300	2060	6455	731	292
OVEC (ECAR)	2251	2251	0	0	0	0
HE (ECAR)	1250	1250	0	240	0	50
CIN (ECAR)	11775	10171	0	1831	75	1220
DPL (ECAR)	3437	3305	0	1410	0	0
SIGE (ECAR)	1647	1647	0	309	0	135
LGEE (ECAR)	7314	5928	0	796	71	1259
BREC (ECAR)	1558	1709	0	0	0	65
IPL (ECAR)	2971	2664	0	742	0	100
NIPS (ECAR)	3244	2684	0	890	0	375
CONS (ECAR)	9407	3372	774	5887	1872	1999
Other (ECAR)	0	0	0	1776	0	0
ALTW (MAIN)	3454	2100	590	499	0	1049
AMRN-NonIL	7639	5672	1194	1050	808	371
ALTE (MAIN)	2505	2034	0	1136	26	264
WEC (MAIN)	6792	3640	1012	1032	143	868
WPS (MAIN)	2486	1019	500	432	131	414
Other (MAIN)	1157	251	0	244	30	348
NSP (MAPP)	9367	4110	1716	1059	254	1883
MEC (MAPP)	4802	3799	0	1700	0	450
Other (MAPP)	939	1257	0	84	21	60
Total	**142,439**	**98,831**	**13,748**	**36,549**	**10,801**	**12,011**

3.8 SYSTEM CONTINGENCIES

Secure power system operation requires that the system be operated with no limit violations and also with no violations under a specified set of contingent conditions. In this study, the impacts of 1,360 different contingencies were considered. This was done using PowerWorld Simulator's security constrained optimal power flow (SCOPF). While many of the contingencies consisted of single line or transformers outages, others considered multiple device outages (with the most complex having 18 different actions). Table 3.8-1 shows a breakdown of the contingencies by company. During the study, contingent line flows were enforced using the power flow case "B" limit set (as indicated by the Illinois utilities).

Table 3.8-1 Contingencies by Company

Company	Number of Contingencies
Ameren	266
Central Illinois Light Company (CILCO)	38
Commonwealth Edison (ComEd)	450
ECAR (Total)	196
Electric Energy Inc. (EEI)	35
Illinois Power	120
MAIN (other)	129
MAPP (Total)	86
SERC (Total)	10
Southern Illinois Power Co-operative (SIPC)	12
Springfield City Water Light & Power (CWLP)	18

4. ANALYSIS OF ALTERNATIVE CASES

Using the basic assumptions and inputs described in the previous section, alternative cases were analyzed to determine how the Illinois market might function in the analysis year. Table 4-1 lists the cases that have been studied here.

Table 4-1 Alternative Cases Analyzed

Section Number – Case	Description
4.1 Production Cost (PC)	**GenCo bids are based on unit production cost.**
4.2 Physical Withholding (PW)	**GenCos withhold units from the market.**
4.2.1 Single Unit (PW-SU)	Individual units are withheld.
4.2.2 Multiple Unit (PW-MU)	Multiple units are withheld.
4.2.3 Profitability Criteria (PW-PR)	Units withheld based on profitability.
4.2.4 System Reserve Criteria (PW-SR)	Units withheld based on system reserve.
4.2.5 Companywide (PW-CW)	All of a company's units are withheld.
4.3 Economic Withholding (EW)	**GenCos increase prices above production cost.**
4.3.1 Single Unit (EW-SU)	Prices are increased on individual units.
4.3.2 Companywide (EW-CW)	Prices are increased for all of a company's units.

In evaluating each of these cases, the focus is on addressing the primary question of the study: "*Can a company, acting on its own, raise electricity prices and increase its profits?*" The production cost case represents the simplest of the strategies in that all generation companies base their market participation on the production cost of their units. This case is used as the benchmark against which the other cases are compared.

The selection of the other cases was based on developing insight into how the market would respond to the application of various company strategies. The intent here is not to identify any particular strategy as being more or less likely to be employed or more or less desirable than any other. Rather, the case selection was designed to test a number of strategies that have been seen in various forms in other operating electricity markets. These can be viewed as a series of "electronic experiments" designed to improve the understanding of the market.

In testing the various strategies, some were applied in a very simple fashion in order to develop perspective on how they might influence the market. These simple cases were used to identify the effect of one specific element of a business strategy. By using this approach, the understanding of the market behavior is built up in a step-by-step manner in order to better understand the complex and highly nonlinear nature of the electricity market.

Some of the cases were run under both the Case Study Assumptions and under the Conservative Assumptions. This was designed to verify that the use of company-level unit commitment, the inclusion of fixed operating and maintenance costs in bid prices, and the consideration of outages were not skewing the results.

None of the business strategies tested can be said to represent the full complexity of how decisions are made in an electricity market. Rather, the cases tested here should be viewed as indicators of how a specific business decision might affect the market and consumers.

4.1 PRODUCTION COST CASE

The production cost (PC) case assumed that all GenCos participated in the market using production cost-based pricing. In this analysis, the term "production cost" is defined to include the following:

- Fuel cost – the cost of fuel required to generate electricity – depends on the price of the fuel itself (measured in $/Btu) and on the efficiency of the generator, which is referred to as the unit's heat rate and which is measured in Btu/kWh. The fuel cost is the fuel price divided by the heat rate.

- Variable Operation and Maintenance (VOM) – these costs relate to consumables that are needed to generate electricity and include water, chemicals, and other materials that are consumed in proportion to the amount of electricity generated.

Under the Case Study Assumptions, the following was also added to production cost:

- Fixed Operation and Maintenance (FOM) – these costs are independent of the actual number of hours of operation or the amount of electricity generated. They include items such as operating labor and annual maintenance charges. The FOM costs are expressed in units of $/kW-month. These costs are converted to a per-kWh basis by using an average unit capacity factor.

Under the Conservative Assumptions, FOM was not included in production cost.

All of these cost elements vary with the type and efficiency of the unit. The analysis uses specific values for each individual unit included in the simulation. These values were taken from the data sources identified in Section 2. Table 4.1-1 shows the range of values for each unit type included in the analysis.

There are ways to define production cost other than what is used here. In some analyses, the production cost is defined only as the fuel and VOM cost (i.e, as in the Conservative Assumptions), which represents the short-term marginal cost of production. While this method is widely used, it is not a sustainable approach to market bidding over any extended period (i.e., months). A company that receives reimbursement of only the fuel and VOM costs of a unit will not be able to cover the FOM costs. This lack of adequate return will eventually force the company to cease operating the unit. As this analysis is done over a longer time period, it was decided to include the FOM as part of what is termed the production cost when applying the Case Study Assumptions. Deleting it under the Conservative Assumptions provides an indication of the magnitude of its impact.

The amortization of capital costs was not included here as part of what is termed production cost. These costs are generally considered in analyses that span longer time periods (i.e., several years) than what is addressed here. It can be argued that the amortization of capital should be included in market bidding in the same manner as the FOM costs. A company that does not receive enough return to cover its capital amortization costs will likewise be forced to

cease operation after some period of time. In addition to the analysis being limited to one year, there was insufficient data available on capital amortization to allow it to be used in this study. Hence it was not considered here.

Table 4.1-1 PC Case – Range of Generator Cost Parameters

Generating Unit Type	Unit Sizes (MW)	Fuel Cost ($/MMBtu)	Variable Operating and Maintenance Cost ($/MWh)	Total Variable Operating Cost [a] ($/MWh)	Fixed Operating and Maintenance Cost ($/kW-m)	Shutdown & Startup Cost [b] ($1,000 per cycle)
Nuclear	828–1,225	0.43–0.47	3.0–8.0	8.3–13.1	1.3–4.0	56.9–87.2
Bituminous Coal (<100 MW)	22–81	1.18	2.0–6.4	16.2–24.1	0.5–4.0	1.6–5.9
Bituminous Coal (>100 MW)	109–635	1.18	0.9–4.5	13.0–18.6	0.5–1.9	7.0–45.6
Sub-bituminous Coal	120–893	1.18	0.9–4.5	12.8–16.9	1.0–2.0	7.2–47.6
Oil-Fired Steam Units	46–210	3.97	1.6–3.0	47.5–48.5	0.5–0.7	2.2–10.2
Natural Gas-Fired Steam Units	50–545	2.89	0.6–0.9	41.1–50.0	0.4–0.8	7.5–67.2
Natural Gas-Fired Combined Cycle	250–300	2.89	0.5	20.8–24.6	1.2	17.8–21.1
Natural Gas-Fired Gas Turbines	10–172	2.89	0.0-4.4	25.8–71.2	0.0–4.8	0.0–0.4
Gas Turbines (Diesel-Fired)	13–57	4.87	0.0–3.0	45.0–93.0	0.0–0.5	0.0–0.2
Jet Engines	22–38	5.36	0.0–1.6	80.7–129.3	0.0–0.4	0.0–0.3

[a] Includes fuel cost calculated from unit heat rate and variable operating and maintenance cost.
[b] For cold start.

In the PC case, the bids that GenCos offer for the sale of electricity were based entirely on the production costs of the generators (with and without FOM under Case Study and Conservative Assumptions, respectively). No strategic bidding, designed to take advantage of market conditions, was employed by any company. Results of the PC case were used as a point of comparison for the other cases.

4.1.1 Day-Ahead Market Results

In the day-ahead market, DemCos and GenCos submitted bids to buy and sell electricity for each hour of the next day. The bids were used by the ISO to construct supply and demand curves. In the PC case, the demand bids from the DemCos were assumed to represent firm loads (i.e., not interruptible) and were, therefore, not price-sensitive. In contrast, the supply bids from the GenCos had price variations (i.e., as a result of variations in the production cost of different units) and were ranked accordingly. The supply and demand bids were then run through the transmission-constrained dispatch analysis (i.e., the SYSSCHED algorithm) that selected the least cost dispatching schedule subject to the physical constraints of the transmission system.

Figure 4.1.1-1 shows the results of the day-ahead market bidding for typical hours that represent low load, intermediate load, and peak load. Included in the figure are all of the in-state and out-of-state companies, so that the figure is illustrative of the entire market. In all three conditions, the demand is shown as a vertical line representing the non-price-responsive nature of the demand. The supply curve shows two lines: one that represents the bids that were submitted, and one that represents the bids that were selected after the transmission constrained dispatch analysis was applied. The difference between the two lines represents the need to utilize higher cost generators due to congestion in the transmission network.

In the low-load hour, the two supply curves are virtually identical, indicating that it was possible to use the least cost generation, since transmission congestion did not occur. In the intermediate-load hour, there were signs of transmission congestion. Some of the lower-cost units had to be bypassed, and more expensive units were scheduled for dispatch. In peak-load hours, transmission congestion often developed, and it was necessary to dispatch some units out of the economic merit order. When this occurs, generators with relatively low bids remain idle while generators with more expensive bids are put into operation. These high-priced bids were accepted, since power injection into the grid at the unit's specific interconnection point (i.e., bus) served loads, often locally, without overloading transmission lines. On the other hand, accepting the lower-cost bid would have resulted in the violation of transmission system line limitations and/or security safeguards. This dispatch of units out of bid merit order led to LMP differences across the system.

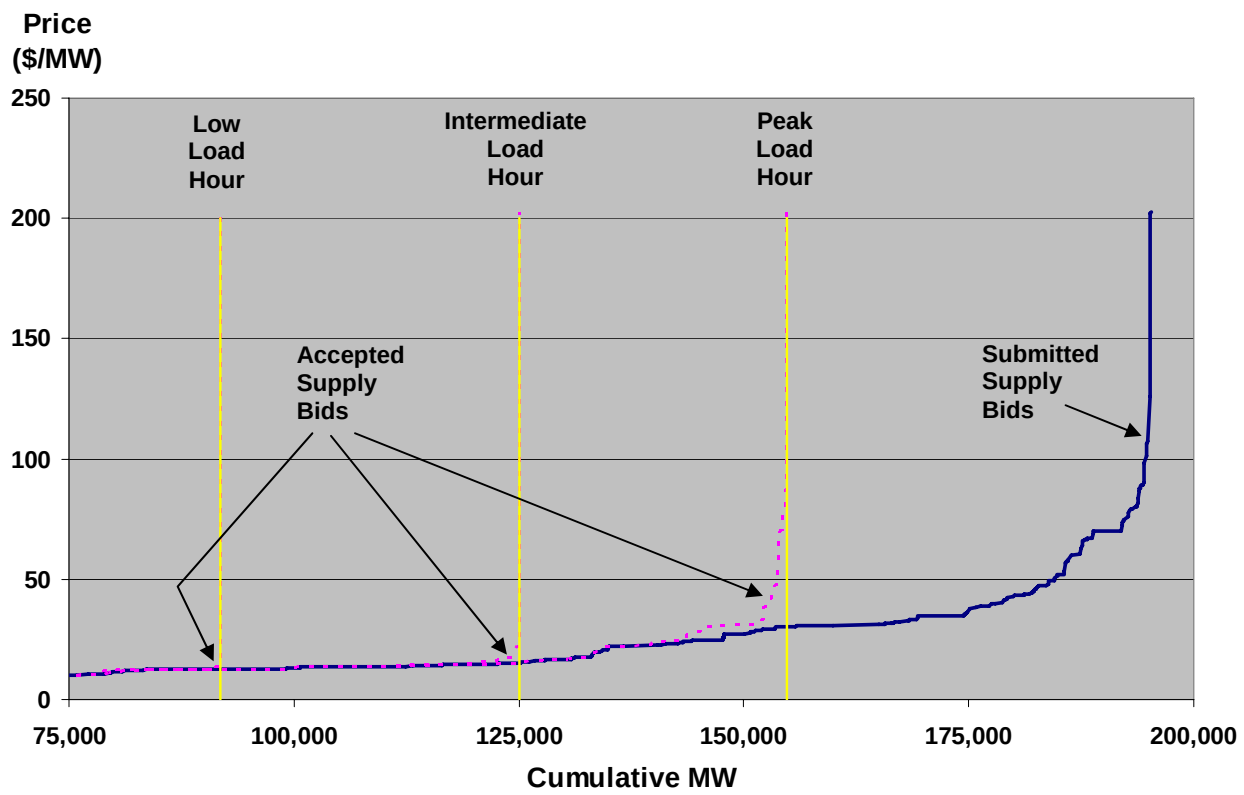


Figure 4.1.1-1 Typical Day-Ahead Market Supply/Demand Curves