Document No. 3

Integrated Resource Plan

Integrated Resource Analysis

PUBLIC VERSION

Corporate Planning Department

December 2005

NP

Forward-Looking Statements

In order to perform the Integrated Resource Analysis, a large amount of data is required. The data required includes the magnitude and timing of resource needs, corporate level financial information, existing and future unit operating characteristics, electric production cost and environmental information, existing and future unit cost information and market prices for a wide variety of commodities. The following brief describes various assumptions used in the analysis and the basis for the sensitivities performed. Certain portions contain forward-looking statements that are based on expectations, estimates, projections and multiple assumptions made by AmerenUE and/or its consultants, which are contemporaneous to the analysis and results outlined herein. Words such as "expects," "anticipates," "plans," "believes," "scheduled," "estimates," "forecasts," "projections," "evaluation," "future," "prospective," "trends," "assumptions," "modeled," and variations of these words and similar expressions are intended to identify forward-looking statements and conditions. These statements and conditions are not intended as guarantees of future results and involve certain risks and uncertainties, which are difficult to predict. Assumptions, conditions, and world states are expected to change and in the future may not reflect what is detailed in this report. Actual future results and trends may differ materially from what is presented in forward-looking statements due to a variety of factors, including, without limitation:

- General U.S. and international political and economic conditions;
- Regional and commodity global supply/demand characteristics;
- Structural and fundamental changes with respect to legislative, economic, or infrastructure elements;
- Errors or omissions discovered in modeling software, data content, historical data, or assumptions utilized or made by third-party suppliers;
- Technology changes and modifications;
- Fundamental structural changes in the physical, financial, or economic elements of the wholesale electricity supply, demand, or delivery sector;

All forward-looking statements speak only as of the date of this report or, in the case of any document incorporated by reference, the date of that document. All subsequent written and oral forward-looking statements attributable to AmerenUE or any person acting on behalf of AmerenUE are qualified by the cautionary statements above. AmerenUE will continue to monitor the appropriate conditions, markets, legislations, and other information sources as they pertain to the assumptions made in the Integrated Resource Analysis.

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Appendices

1 INTRODUCTION

1.1 OVERVIEW

The **Integrated Resource Analysis** (IRA) report provides the details of the analysis process involved in the development of AmerenUE's preferred resource plan. It provides an overview of the sequential steps in the analysis process, analysis assumptions, load forecast methodologies employed, demand response and energy efficiency analysis parameters, supply technologies assessments, capacity expansion plan portfolio considerations, analysis results and the preferred plan selection and implementation.

It is important to note that this report is a snapshot of an ongoing resource planning process at AmerenUE. The plan continuously evolves as new information is received, economic conditions change, new technologies emerge, and legislation changes.

The planning process focuses on identifying future system requirements and developing a flexible resource strategy to meet those requirements. The IRA report provides a discussion of the resource planning process and direction for the 20-year planning horizon through 2025.

The AmerenUE resource planning process for the December 2005 filing has the following objectives:

- Treat demand-side programs and supply-side alternatives on an equivalent basis.
- Use minimization of the present value of revenue requirements as the primary judgment criteria.
- Attempt to work within the confines of the Missouri Chapter 22 Electric Utility Resource Planning rules recognizing that the rules, adopted in 1993 and tabled for all investor-owned electric utilities in Missouri since 1999, are out-of-date and do not reflect electric utility planning practices in 2005.
- Focus on stochastic analysis – analysis including random elements as opposed to a deterministic analysis that has no random element. We use two distinct stochastic analysis tools – simulation analysis and scenario analysis – to achieve a comprehensive assessment of the exposure to risk and uncertainty.
- Analysis of key risks:
    - Natural gas prices
    - Coal commodity prices
    - SO_2 allowance prices
    - Peak and energy load growth
- Analysis of environmental scenarios
    - Carbon legislation in varying degrees of severity

The planning process begins with an assessment of future resource needs and identification of the resource options available to meet those needs. Details of the demand and energy forecasts are found in the *2005 Load Forecast Data and Methodology* report. The *Demand-Side Management Briefing* report provides information on the development of demand-response and energy-efficiency programs.

The **Integrated Resource Analysis** report includes the following:

- A discussion of existing resources, as well as potential supply-side technologies
- Ranges of values for parameters used in the study
- Methodologies used in the screening, optimization, integration and stochastic analyses
- Results of the analysis and plan selection
- Descriptions of models used in the analysis

1.2 BACKGROUND

AmerenUE is the largest of the Ameren operating companies. It is also the largest electric utility in the state of Missouri. Its operations are limited to the state of Missouri. AmerenUE provides service to 1.2 million customers in eastern Missouri. AmerenUE's net integrated peak demand for its native load customers reached a record 8,463 MW on July 25, 2005. AmerenUE also serves a total of six wholesale customers in Missouri, the sum of which have a total contract demand 132 MW. [redacted]

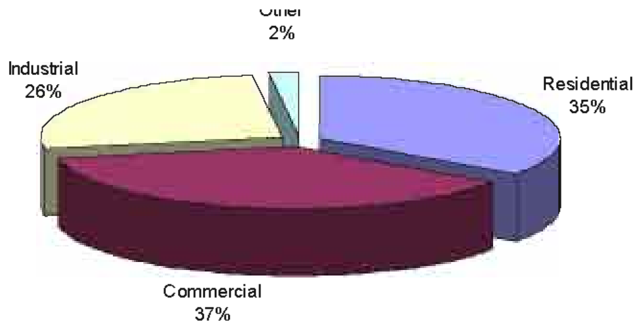
AmerenUE relies upon one nuclear-fueled and five fossil-fueled steam generating plants containing a total of 19 units with a net summer generating capability of approximately 6600 MW to supply the bulk of its energy requirements. In addition, two hydroelectric plants, one pumped storage plant, and 28 combustion turbine units provide net summer generating capability of approximately 2500 MW.

Ameren is a member of the Midwest Independent Transmission System Operator (MISO) regional transmission organization. As such, AmerenUE still has physical ties to neighboring companies, but most of these neighbors to the east and north are with MISO participants. MISO has ties to AECI, TVA, Entergy, EEInc, Big Rivers, Eastern Kentucky, OVEC, PJM, MEC, NPPD, OPPD, and SPP.

The AmerenUE system load factor is approximately 55 percent. A graph of AmerenUE's projected load duration curves for 2006, 2015 and 2025 is provided in the both the Executive Summary and Plan Implementation sections of this filing. The most significant change in the composition of the AmerenUE load is the addition of the Noranda Aluminum Smelting plant, located in New Madrid, Missouri, beginning June 2005. Noranda's load is approximately 500 MW at close to a 98 percent annual load factor. Figure 1.1 is a pie chart showing the projected percentage of 2006 AmerenUE sales by class.

Figure 1.1

AmerenUE Projected 2006 Sales (MWh)



1.3 RESOURCE NEEDS

The magnitude and timing of resource needs were established using AmerenUE's peak demand and energy forecasts prepared in October 2004. New forecasts finalized in October 2005 were not available in time for the preparation of this filing. Table 1.1 shows the 20-year forecast of the AmerenUE capacity position required to maintain a [redacted] percent long-term planning reserve margin.

Table 1.1
Resource Needs
No New Resource Additions; Nominal Forecast Scenario

[redacted]

2 ANALYSIS PROCESS

2.1 OVERVIEW

The integrated resource analysis identifies alternative strategies consisting of both demand-side and supply-side resources which meet future peak demand and energy requirements in a cost effective manner. This analysis develops the preferred resource strategy that provides flexibility to respond to changing conditions.

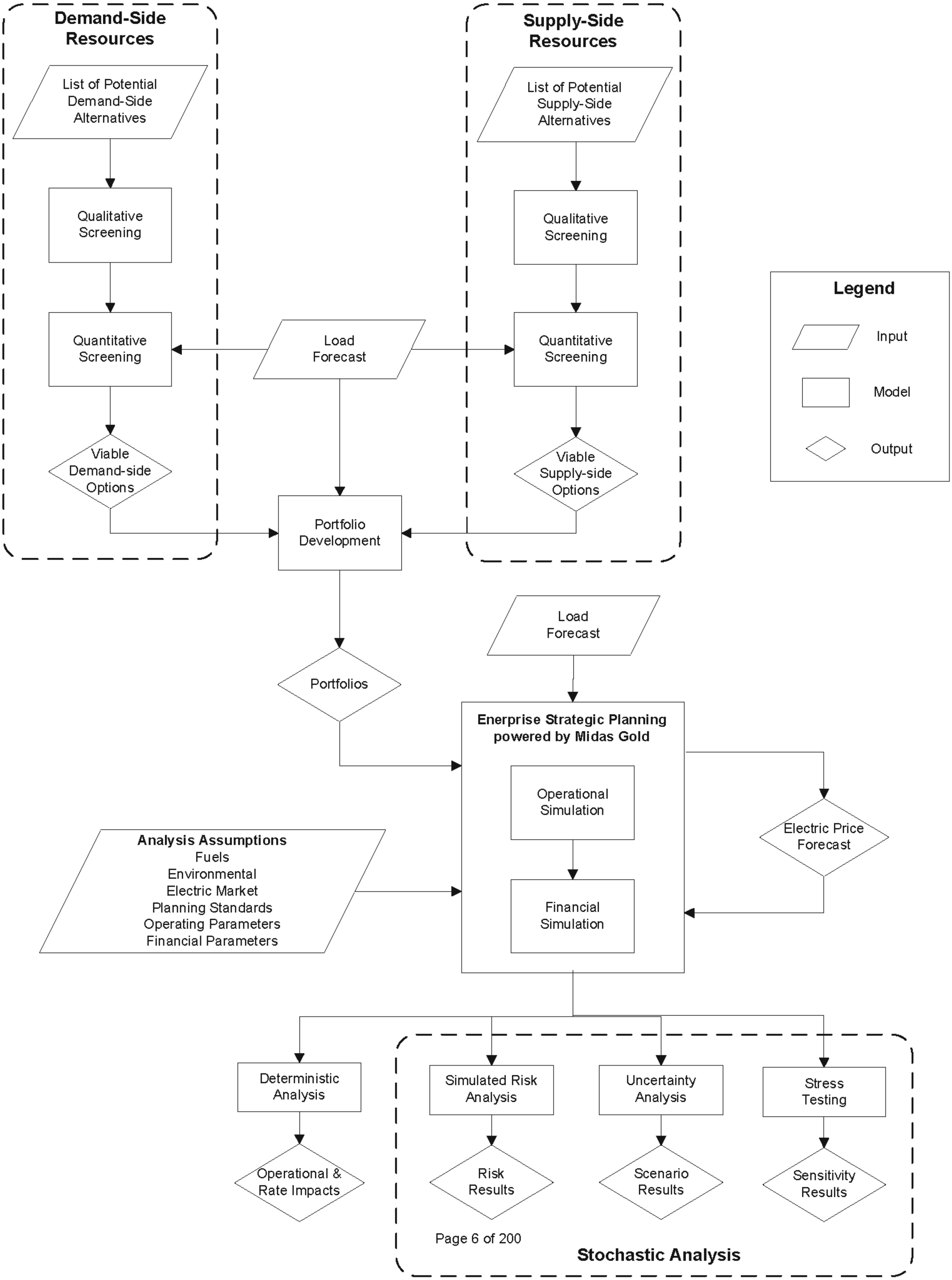
The main analytical objective in integrated resource planning is to compare the cost, measured as Present Value of Revenue Requirements (PVRR), and performance (risk or variability of PVRR) of various resource plans. This section highlights the analytical framework used in performing the integrated resource analysis. The analysis involves a number of distinct steps.

Integrated Resource Planning Analysis Process

- Load forecasting
- Analysis Assumptions
- Demand-Side and Supply-Side Resources
- Portfolios (Integration)
- Simulations

    - Electric Market Price Simulation
    - Operational simulations
    - Cost Analysis
    - Risk Analysis and Stress Testing

Figure 2.1 Integrated Resource Process



2.2 LOAD FORECASTING

The energy and demand forecast used in the 2006-2025 integrated resource plan analysis was prepared in the fall of 2004. The energy and demand forecasts do not include the effects of new programs that AmerenUE may initiate to encourage increased energy efficiency and demand response. These programs are discussed in detail in the *Demand Side Management Briefing* document. However, the 2004 energy and demand forecasts implicitly take into account the impact of the multiple energy-efficiency and demand-response programs in AmerenUE's current portfolio. These programs are also described in detail in the *Demand Side Management Briefing*.

AmerenUE develops a 10-year sales and peak demand forecast. Typically, the uncertainty around the forecasts of the econometric driver variables beyond 10 years is such that there is little value to extend the forecast. However, for purposes of developing the 20-year integrated resource plan, the energy and demand forecasts were extended from 10 to 20 years by extrapolating the economic driver variable forecasts at the 10-year average annual compounded growth rates and using the forecast model coefficients on the extended driver variables.

The methodology underlying the AmerenUE sales forecast process is that monthly forecast models are built based on monthly billed sales data. Monthly calendar sales forecasts are developed by converting monthly billed forecasts using monthly calendar weather data and calendar days. Regional economic data is developed from Economy.com. A Statistically Adjusted End-Use (SAE) modeling approach, which combines the strengths of both end-use and econometric modeling approaches, is used for the residential and commercial classes. End-use saturation and efficiency trends are developed from DOE/EIA regional projections. Econometric models are developed for all other classes. Forecasts are based on predicted future economic conditions and normal weather assumptions.

AmerenUE uses an Itron model called *MetrixLT* to do the peak demand forecast. *MetrixLT* has been developed to construct a "bottom-up" load forecast and to calibrate the bottom-up forecast to actual system load or short-term system hourly load forecasts. The overall forecasting approach is similar to the Hourly Electric Load Model (HELM) approach used at AmerenUE in the 1990s. In addition to *MetrixLT*, AmerenUE uses a variety of regression-based models to do sanity checks on the peak demand forecast. Section 3 and the *Load Forecast Data and Methodology* book contain more information regarding this subject.

2.3 ANALYSIS ASSUMPTIONS

The inputs and assumptions underlying the analysis were developed using sources inside and outside the company. AmerenUE utilized experts from the utility industry and within the company to develop costs, commodity forecasts, resource estimates, operational parameters and risks. Section 4 describes the data development and assumptions in greater detail.

2.4 DEMAND-SIDE RESOURCES AND SUPPLY-SIDE RESOURCES PROCESS

Both the demand-side and supply-side resources analysis starts with a preliminary screening process that consists of developing a list of potential alternatives, a qualitative screening and then a quantitative screening. A list of potential options was developed as a starting point for the screening analysis. Independent reports covering various technologies were requested and received from outside consulting firms as the initial source of potential supply-side options.

The screening analysis used the detailed information concerning different technologies and performed a comparative analysis among the potential resource options. This analysis helped determine which technologies were the low-cost options. The options that were not low-cost options were not given future consideration in the integrated resource analysis. The demand-side screening analysis is described in section 5 of this book and the *Demand-Side Briefing*. Supply-side resource screening is described in section 6 of this book and the *Generation Technology Reports*.

Focusing only on alternatives that survive this winnowing allows further analysis to be performed on the most viable resource options. This methodology was applied to both the supply-side and demand-side options. The results of this step are inputs into the portfolio development. The Cost Analysis Models Appendix contains a discussion of the software used for the balance of the analysis that follows the screening step.

2.5 PORTFOLIO DEVELOPMENT

The results of the supply-side and demand-side screening are used to develop "portfolios" of demand-side and supply-side combinations that can be used in filling the gap between AmerenUE's known resources and prospective load obligations. Portfolio development focuses on the candidate options that are known and are considered as realistic, feasible alternatives for balancing resource supply with electricity demand. Formulating the portfolios requires specifying the types and timing of resource additions such that anticipated loads are reliably served. Portfolios are chosen to span a complete range of likely resource strategies.

Constructing portfolios is a process of assembling system and market assumptions, estimating AmerenUE's short position and choosing which portfolio resources are added each year to serve it. The list of viable demand-side and supply-resources are used as the set of building blocks from which candidate portfolio are constructed. Building a portfolio is not merely a process of randomly adding resources. Section 7 of this book details the portfolio development.

2.6 SIMULATIONS

2.6.1 ELECTRIC MARKET MODELING PROCESS

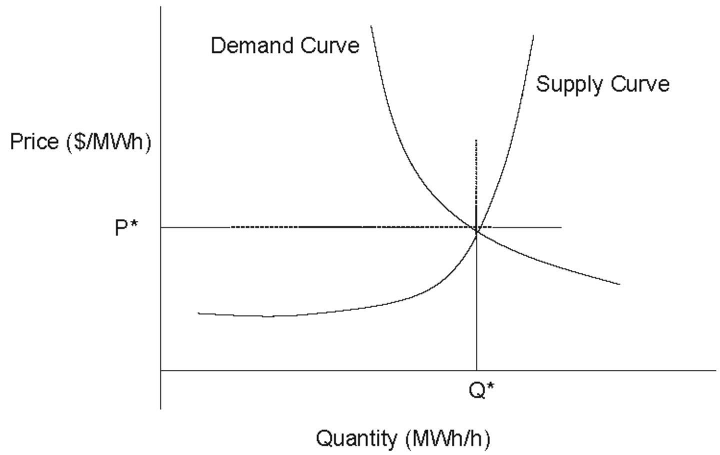
Predicting Plant Dispatch and Energy Clearing Prices

Developing an electricity price forecast through modeling the dispatch and operation of generating assets requires a sophisticated and detailed electric market simulation model. In order to meet hourly electricity demand with the least-cost generation resources, a detailed chronological production-cost model is needed to simulate generation plant dispatch on an hourly basis across multiple interconnected regions and calculate resulting electricity clearing prices. Simulations must be performed with sufficient detail related to the subject market area and neighboring areas to ensure that economic energy transactions are captured in the marginal clearing price calculation. Additionally, multiple assumptions and constraints must be included in the simulation to emulate the impacts of generator performance and operational capabilities, transmission system flows and congestion, etc., on the dispatch of the system and resulting market clearing prices.

The determination of optimal generation resources is significantly influenced by the fundamental development of electricity forecast(s) of wholesale market prices. The commodity nature of a wholesale electric market anticipates that reasonable, well-informed parties will possess different market expectations and will participate in the market based upon these expectations. The challenge in determining the optimal generation supply mix is to determine a pricing path that best achieves the identified objectives, irrespective of achieving an exact match of market prices in the future. The model that AmerenUE utilized to develop its fundamental wholesale electricity price forecast is MIDAS Transact. MIDAS Transact incorporates the characteristics and intricacies of the electricity market with economic fundamentals to serve hourly electricity demand with the least expensive supply resources available.

Translating the supply/demand calculation method described above into fundamental economic theory, the energy-clearing price calculated for any given hour reflects the price at the intersection of the supply and demand curves for energy in that hour, as illustrated in Figure 2.2 below. The marginal energy-clearing price is calculated for each separate power market and constrained transmission area, as dictated by the prevailing transmission constraints for that hour.

Figure 2.2
Illustration of Hourly Energy-Clearing Price Process



In the above figure the hourly clearing price, P*, represents the bid price of the unit of supply needed to meet the last increment of the total system demand, Q*. In effect, the MIDAS model prepares energy market supply and demand curves similar to those illustrated above for every hour of the year, in each case calculating the clearing price at the intersection of the supply and demand curves. Thus, the algorithm used by the MIDAS model is consistent with the fundamental economic theory of supply and demand equilibrium that underlies the anticipated market behavior in the bid-based energy market in various restructured markets.

MIDAS Model Overview

AmerenUE utilized the MIDAS Transact electric market price forecasting model, an hourly, chronological wholesale market clearing price dispatch model that fundamentally develops prices that reflect specific inputs and data. The following represents the major characteristics of the modeling platform and the simulation variables required:

1. The central portion of the Eastern Interconnect (NERC regions including MAIN, MAPP, SPP, SERC, and ECAR) is modeled on an hourly basis for the term of the analysis, including all the loads, thermal unit data, and the interconnected transmission system transfer limits. Loads and resources are grouped according to the bulk system to represent known constraints and limits on electricity transfers.
2. Generation supply cost curves are developed for each load center based on fuel price forecasts, variable dispatch costs (e.g. variable O&M, emissions, etc.), and fuel conversion/efficiency rates. This curve represents a variable cost supply stack of generation resources, stacked from lowest to highest dispatch cost.
3. The model determines an efficient dispatch and import/export of generation, respecting regional transmission limits and any wheeling rates, to minimize the cost

to meet hourly demand on the system. The hourly market clearing price reflects the dispatch cost of the unit on the margin for each load center, given transmission and operational constraints.

4. Additionally, the model simulates the addition of various pre-specified economic new generation resources by technology in response to market prices. A new resource will be automatically added to the supply of resources when market prices are sufficient to recover the costs of that new resource, including capital recovery. If not capable of achieving economic new entry, the model will add resources to meet pre-determined reserve margin specifications.
5. Input variables driving the chronological, marginal cost dispatch within the model include all fuel price forecasts, variable O&M, capital costs and escalation factors.

Global and Regional Market Modeling Processes

AmerenUE utilizes the MIDAS Transact model for two separate tracks of modeling wholesale market clearing prices. A multi-area simulation of the broader market (the central Eastern Interconnect region) is performed, with common commodity and volatility assumptions. All units within the central Eastern Interconnect region are dispatched to meet hourly load on a marginal cost basis, constrained by the transmission system limitations and constraints. The purpose of developing a multi-area wholesale price forecast is to establish an hourly market "interface" price between the AmerenUE system and the interconnected system beyond the AmerenUE border.

The results of the multi-area modeling process, as reflected by an hourly wholesale interface market clearing price, are used as inputs to the single-area simulation of the AmerenUE system. The single-area simulation models the AmerenUE system characteristics and utilizes the interface price developed from the multi-area simulation to emulate economic purchases and sales with the broader market.

2.6.2 System Level Simulations

After assembling the candidate portfolios, the next step is to simulate the combined hourly operation of AmerenUE's system and the additions. For this purpose, AmerenUE uses the **EnerPrise Strategic Planning** *powered by* MIDAS Gold®. Midas provides a very precise analysis of resource interactions and the resulting operating costs (see the Appendix for more detailed information on the Cost Analysis Models). Combined with operating costs, these factors provide valuable information as to how successfully a portfolio meets its intended purposes.

Operational Simulation

The operational simulation provides a base or reference view of the future. In so doing, this step requires calculating the operating costs of the integrated system (both the portfolio additions and the existing resource system) and other performance characteristics under a representative set of assumptions about the future.

The above inputs are processed and the resulting operating costs are determined. A large set of detailed outputs provide information on the portfolio's performance, such as:

- Unit capacity factors
- Market sales/purchases
- Emissions
- Variable and fixed operating costs

Cost Analysis

Operating costs represent only a portion of a portfolio's cost profile. Capital costs are a function of the kinds of resources in each portfolio and the timing of their addition. Each portfolio's system operating costs are combined with the corresponding capital costs, yielding the PVRR, the main cost metric. PVRR and other measures of a portfolio's performance allow a screening or winnowing of portfolios, while highlighting those with the most promising performance (lowest-cost). Focusing only on portfolios that survive this winnowing allows risk analysis to be performed on the most promising portfolios.

2.6.3 RISK ANALYSIS AND STRESS TESTING

A key component to the *integrated resource analysis* is a comprehensive stochastic analysis. A stochastic analysis is one that assesses the exposure of a decision to the randomness of the variables that drive the decision. The AmerenUE **stochastic analysis** is comprised of three primary components – a risk analysis, a scenario analysis and a sensitivity analysis.

The **risk analysis** assesses the exposure of AmerenUE's candidate portfolios to mathematically describable randomness or volatility. Specifically, the risk analysis assesses the exposure of AmerenUE's candidate portfolios to randomness in commodity prices such as coal, natural gas, emission allowances and electricity, as well as randomness in peak load and energy growth rates. The randomness associated with these variables was assessed using a simulation analysis which models the randomness of the variables in an integrated fashion.

Scenario analysis is appropriate when exposures to randomness cannot be described mathematically through probabilistic or statistical methods. A scenario analysis is different from a sensitivity analysis in that the scenario attempts to consider multiple variables in a correlated fashion without the benefit of statistical analysis. AmerenUE considered one scenario in its resource analysis – the potential for carbon regulation. In this scenario analysis, carbon emission allowance prices, coal plant retirements, natural gas prices and electricity prices were assessed in a correlated way to see how the resource portfolio candidates behaved.
AmerenUE performed a **sensitivity analysis** to "stress test" its candidate portfolios. Sensitivity analysis has little connection with potential real world outcomes like

simulation and scenario analysis do, as variables rarely move in isolation. Sensitivity analysis can, however, be useful to the decision maker. AmerenUE analyzed environmental compliance strategies, market depth, end effects and resource technology parameters in its sensitivity analysis. The *Risk and Uncertainty Analysis Briefing* contains a comprehensive description of the stochastic analysis.

2.7 IRP DOCUMENTATION

Below is an index of documents included in this filing.

Table 2.1
AmerenUE IRP Document Index

Document	Name
1	Executive Summary
2	Filing Requirements
3	Integrated Resource Analysis
4	Integrated Resource Analysis - Appendices
5	Load Forecast Data and Methodology
6	Demand-Side Management Briefing
7	Demand-Side Management Briefing – Appendix 1
8	Demand-Side Management Briefing – Appendix 2
9	Risk & Uncertainty Analysis Briefing
10	Generation Technology Reports – Venice Combined Cycle Study
11	Generation Technology Reports – Strategic Siting Study
12	Generation Technology Reports – Missouri Pumped Storage Project Concept Study
13	Generation Technology Reports – Rush Island Unit 3 Feasibility Study
14	Generation Technology Reports – Rush Island Unit 3 Conceptual Cost & Performance Study
15	Generation Technology Reports – Generation Technology Assessment
16	Generation Technology Reports – Nuclear Industry Overview & IRP Analysis Parameters
17	Generation Technology Reports – IGCC Technology Assessment Report

3 LOAD FORECAST ANALYSIS PROCESS

3.1 STATISTICALLY ADJUSTED END USE MODELS

The models developed for the 2005-2014 monthly sales forecast use the statistically adjusted end use (SAE) approach. The traditional approach to forecasting monthly sales is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. The strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use modeling framework exploits the strengths of both approaches.

The 10-year forecast of annual sales growth at AmerenUE is 1.35 percent or 473 GWh per year. The 10-year forecast of peak demand growth is 1.1 percent or approximately 90 MW/year.

The individual ten-year class sales forecasts are discussed below.

3.2 RESIDENTIAL

The residential sales forecast average annual compounded growth rate is 1.32 percent or 179 GWh per year. Nationally, residential electricity demand growth is projected to average 1.8 percent through 2025 (EIA Annual Energy Outlook 2004). The relatively moderate growth is due to the saturation of appliances, the installation of more efficient equipment and increased energy efficiency standards.

The residential SAE driver variable descriptions are as follows:

SAE Heating Use: A combined effect of monthly HDD, heating equipment share levels and operating efficiencies, billing days, average household size, household income and real energy price.

SAE Cooling Use: A combined effect of monthly CDD, cooling equipment saturations and operating efficiencies, billing days, average household size, household income and real energy prices.

SAE Other Use: A combined effect of appliance and equipment saturation levels, appliance efficiency levels, average household size, real income, real prices and billing days.

Please see the *2005 Load Forecast Data and Methodology* for more details about the model specifications.

3.3 COMMERCIAL

The total commercial sales forecast average annual compounded growth rate is 2.3 percent or 351 GWh per year. Nationally, commercial electricity demand growth is projected to average 2.2 percent through 2025 (EIA Annual Energy Outlook 2004).

Commercial small general service and large general service sales were forecasted using SAE modeling approach:

Heating Use: A combined effect of HDD, heating equipment share levels, heating equipment operating efficiencies, billing days, commercial output and energy price.

Cooling Use: A combined effect of CDD, cooling equipment saturations and operating efficiencies, billing days, commercial output and energy price.

Other Use: A combined effect of equipment saturation levels, efficiency levels, commercial output, prices and billing days.

Commercial primary and dusk-to-dawn sales were forecasted using econometric models with Gross Domestic Product and/or CDD as driver variables.

Please see the *2005 Load Forecast Data and Methodology* for more details about the model specifications.

3.4 INDUSTRIAL

The industrial sales forecast average annual compounded growth rate is 0.1 percent or 4 GWh per year; these figures do not include sales to Noranda Aluminum Inc. Nationally, industrial electricity demand growth is projected to average 1.6 percent through 2025 (EIA Annual Energy Outlook 2004). AmerenUE service territory's heavy exposure to defense-related manufacturing, food manufacturing, automobile manufacturing, and conversely its light exposure to emerging industries, constrains the industrial electric sales growth.

Total industrial sales are forecasted using an econometric model with a Cooling Variable (CDD * Price * Elasticity of Price) as the driver variable.

Please see the *2005 Load Forecast Data and Methodology* for more details about the model specifications.

3.5 OTHER (PRIMARILY WHOLESALE)

The "other" sales forecast average annual compounded growth rate is [redacted] GWh per year. [redacted] The average annual compounded growth rate for the other sales between 2004 and 2008 [redacted] is 1.4 percent or 10 GWh per year.

Currently, AmerenUE has six wholesale customers, and the sales for these customers were modeled separately. Some were modeled using SAE approach like the residential sales, and some were modeled utilizing econometric models that use CDD, HDD and GDP as driver variables. Street lighting sales were also forecasted by regression models that use GDP and monthly binary variables as driver variables.

Please see the *2005 Load Forecast Data and Methodology* for more details about the model specifications.

3.6 HIGH-CASE AND LOW-CASE LOAD FORECASTS

AmerenUE has conducted an in depth study regarding peak and energy variability. Please see the 2005 Risk and Uncertainty Analysis Briefing section of the Integrated Resource Plan.

4 ANALYSIS ASSUMPTIONS

In order to perform the Integrated Resource Analysis, a large amount of data is required. The data required includes the magnitude and timing of resource needs, corporate level financial information, existing and future unit operating characteristics, electric production cost and environmental information, existing and future unit cost information and market prices for a wide variety of commodities. The following sections describe the various assumptions used in the analysis and the basis for the sensitivities performed. Certain portions of this section contain forward-looking statements that are based on expectations, estimates, projections and multiple assumptions made by AmerenUE and/or its consultants, which are contemporaneous to the analysis and results. These statements and conditions are not intended as guarantees of future results and involve certain risks and uncertainties, which are difficult to predict. Assumptions, conditions, and world states are expected to change and and in the future may not reflect the what is detailed in this report.

4.1 FUELS CONSIDERED IN THE ANALYSIS

Commodities play a very important role in resource planning analysis. Price drivers, risk profiles, and interrelationships across various commodities must be rigorously assessed to provide the foundation for sound resource decision making. Several commodities underlie the integrated resource analysis and will be discussed in this section; coal, natural gas, oil, and nuclear fuel. This section contains the following:

- A general discussion of the characteristics of commodities and how their prices are represented in the market as well as the most appropriate way to be represented for integrated resource analysis
- For each commodity, a detailed discussion of the current market situation, the key drivers and interrelationships inherent to the market, and finally, the development of the price forecasts used in the integrated resource analysis

These discussions will provide the foundation upon which the electric price forecast is developed, and upon which the risk analysis is developed.

4.1.1 GENERAL CHARACTERISTICS OF COMMODITY MARKETS AND PRICES

Overview of Commodity Markets and Characteristics

The markets for oil products, natural gas and many other commodities are characterized by high levels of volatility. Prices and inventory levels fluctuate considerably in the short-term, in part predictably and in part unpredictably. Additionally, levels of volatility themselves vary over time. Because commodity markets are volatile, producers and consumers frequently seek ways of hedging and trading risk. In response to this activity, markets for commodity risk trading emerged, and their use has become increasingly widespread. Instruments traded in these markets include futures and forward contracts, options, swaps, and other derivatives. Understanding the relationship among spot prices, futures prices, and inventory behavior in these markets is critical to developing a forward view of price movement and applying fundamental modeling techniques to forecast prospective commodity prices.

Understanding the behavior and role of volatility in commodity pricing is important in its own right. Price volatility drives demand for hedging, whether it is done through financial or physical instruments, and it can be observed that increases in price volatility correspond to increased hedging activity. Volatility is a key determinant of the values of commodity-based contingent claims (claims that are contingent upon specified outcomes), such as futures contracts, options on futures and commodity production facilities such as oil and gas production facilities, refineries and pipelines. (In fact, these production facilities can theoretically be viewed as call options on the underlying commodities.) Furthermore, volatility plays an important role in driving short-run commodity cash and storage market dynamics.

In markets for storable commodities, inventories play a crucial role in price formation. As in manufacturing industries, inventories are used to reduce costs of changing production in response to fluctuations in demand and to reduce production costs by helping to ensure timely deliveries and avoid production interruption. Commodity producers must determine their optimal production levels jointly with expected inventory drawdowns or buildups. These decisions are made in light of two prices: the spot price for sale of the commodity itself and the price of storage. Although the price of storage is not directly observable, it can be determined from the spread between futures and spot prices and is equal to the marginal value of storage, i.e., the flow of benefits to inventory holders from a marginal unit of inventory. The benefit of holding inventory or having immediate access to it is called the marginal convenience yield. Thus there are two interrelated markets for commodities: the cash market for spot purchase and sale and the storage market for inventories held by both producers and consumers of the commodity.

In a competitive commodity market subject to uncertain fluctuations in production and/or consumption, producers, consumers, and possibly third parties will hold inventories. These inventories serve a number of functions. Producers hold them to reduce costs of adjusting production over time, and also to reduce costs by facilitating production and delivery scheduling and avoiding production interruptions. If marginal production costs are increasing with the rate of output, and if demand is fluctuating, producers can reduce their costs over time by selling out of inventory during high-demand periods, and replenishing inventories during low-demand periods. Even if marginal production cost is constant with respect to output, there may be adjustment costs, i.e., costs of changing the rate of production, and selling out of inventory during high-demand periods can avoid these adjustment costs. In addition, inventories are needed to facilitate scheduling and reduce marketing costs. Industrial consumers also hold inventories, and for the same reasons – to reduce adjustment costs and facilitate production.

To the extent that inventories can be used to reduce production and marketing costs in the face of fluctuating demand conditions, they will have the effect of reducing the magnitude of short-run market price fluctuations. Also, because it is costly for firms to reduce inventory holdings beyond some minimal level, and because inventories can never become negative, price volatility is greater during periods when inventories are low.

When inventory holdings can change, production in any period need not equal consumption. As a result, the market-clearing price is determined not only by current production and consumption, but also by changes in inventory holdings. Therefore, equilibrium in both the cash and storage markets will ultimately determine commodity prices.

In the cash market, purchases and sales of the commodity for immediate delivery occur at the spot price. The spot price equates to production and consumption and can be characterized as a relationship between supply and net demand. Net demand is the demand for production in excess of consumption. Thus, the cash market is in equilibrium when net demand equals net supply, therefore market clearing in the cash market implies a relationship between the spot price and the change in inventories.

Looking at commodity price volatility, one of the main causes is fluctuations in net demand, which in turn results from fluctuations in consumption demand and/or production. Furthermore, price fluctuations themselves (whether caused by fluctuations in demand, speculation, etc.) will cause consumption and production to fluctuate, adding to price volatility as well as the volatility of production and consumption. This increase in volatility implies an increase in the demand for storage.

This increase in volatility will also result in an upward shift in the demand curve. The reason is that increased volatility increases the value of commodity producers' operating options, i.e., options to produce now rather than waiting for possible increases or decreases in price. These options add opportunity cost to current production; i.e., the cost of exercising the options rather than holding them. Thus an increase in volatility increases the opportunity cost of current production, which shifts the demand curve up. These occurrences can be readily observed in the cash markets.

Forward and Futures Contracts

A forward contract is an agreement to deliver a specified quantity of a commodity at a specified future date, at a price to be paid at the time of delivery. The commodity specifications, quantity, price, date and delivery point are spelled out in the contract. There are two parties to a forward contract: the buyer (or long position), who will receive the commodity and pay the forward price, and the seller (or short position), who will deliver the commodity.

A futures contract is also an agreement to deliver a specified quantity of a commodity at a specified future date, at a price (the futures price) to be paid at the time of delivery. Futures contracts are usually traded on organized exchanges, such as the New York Mercantile Exchange, and as a result, tend to be more liquid than forward contracts. Other than this, a futures contract differs from a forward contract only in that the futures contract is "marked to market," which means that there is a settlement and corresponding transfer of funds at the end of each trading day relative to the net change in the underlying value of the contract. Settling reduces the risk that one of the parties will default on the contract.

Although futures and forward contracts specify prices to be paid at the time of delivery, it is not necessary to actually take delivery. In fact, the vast majority of futures contracts are "closed out" or "rolled over" before the delivery date, so the commodity does not change hands. Recent data from the NYMEX natural gas market indicates that nearly 98 percent of all futures contracts are closed out prior to expiration, with no physical delivery of the commodity. The reason is that these contracts are usually held for hedging or speculation purposes, so that delivery of the commodity is not needed or desired.

Convenience Yield

Marginal convenience yield can be thought of as the premium that someone is willing to pay in order to ensure physical delivery of a commodity. The price of storage is the “payment” for the privilege of holding physical inventory. Even if no change in the spot price is expected, there is an opportunity cost of capital equal to forgone interest in addition to the potential for the spot price to fall during the holding period, which is also an additional component of the opportunity cost of capital. In the case of commodity storage, this marginal value is the value of the flow of services accruing from holding the marginal unit of inventory; this value is the marginal convenience yield.

For commodities with actively traded futures contracts, the futures price can be used to measure the marginal convenience yield (the return from holding a commodity over a period of time). The convenience yield obtained from holding a commodity can be compared with the dividend obtained from holding a company's stock. The ratio of the net convenience yield to the spot price is referred to as the percentage net basis, and is equivalent to the dividend yield on a stock. In fact, if storage is always positive, one can view the spot price of a commodity as the present value of the expected future flow of the convenience yield, just as the price of a stock can be viewed as the present value of the expected future flow of dividends.

The real option characteristic of extractive resources (resources that are extracted from the earth) creates a direct impact for the convenience yield to respond positively with the level of volatility. Since holding unproduced reserves is comparable to holding a call option on those reserves, the convenience yield will increase when volatility increases because greater volatility increases the demand for storage, and greater volatility raises the option value of keeping the commodity in the ground, thereby raising the spot price relative to the futures price.

The Behavior of Convenience Yield

Given a spot price and futures price, the net marginal convenience yield (net of storage costs) can be determined and with transparent information on storage costs, the marginal convenience yield can be determined. As a practical matter, however, there are issues with respect to measuring the spot price. Although data for futures prices are readily available, that is not the case for spot prices. Data does exist for cash prices, which are actual transaction prices, however cash prices often do not pertain to the same specification for the commodity (i.e. quantity, delivery point, etc.) as the futures price. Also, while cash price data reflect actual transactions, they usually represent only average transaction prices making it impossible to be matched with futures prices for specific days. In addition, cash prices will typically contain discounts and premiums resulting from relationships between buyers and sellers, and therefore are not directly comparable to futures prices.

When possible, the price on the spot futures contract (the contract for delivery in the current month) can be used as a proxy for the spot price. However, for most commodities, a spot contract is not available in every month. To estimate convenience yields, often a spot price must be inferred from the nearest and next-to-nearest active futures contract, usually done by extrapolating the spread between these contracts backward to the prompt month.

Analysis of historical pricing data suggests that the marginal convenience yield fluctuates considerably over time. Some of these fluctuations are predictable in that they correspond to seasonal variations in the demand for storage. However much of the variation in convenience yield is unpredictable, corresponding to temporary fluctuations in demand or supply that are unpredictable.

Convenience yield and the spot price are positively correlated. The convenience yield tends to be high during periods when the spot price is unusually high. This does not simply follow from the fact that convenience yield is calculated from the spread between the spot price and the futures price, because the spot and futures prices also tend to move together. But rather it follows from the fact that in a competitive commodity market, the spot price is expected to track or revert to the long-run marginal cost. Thus when the spot price is unusually high, it is often the result of temporary shifts in demand or supply that make short-run marginal cost higher than long-run marginal cost. In this situation, inventories will be in high demand because they can be used to reallocate production across time and thereby reduce production costs.

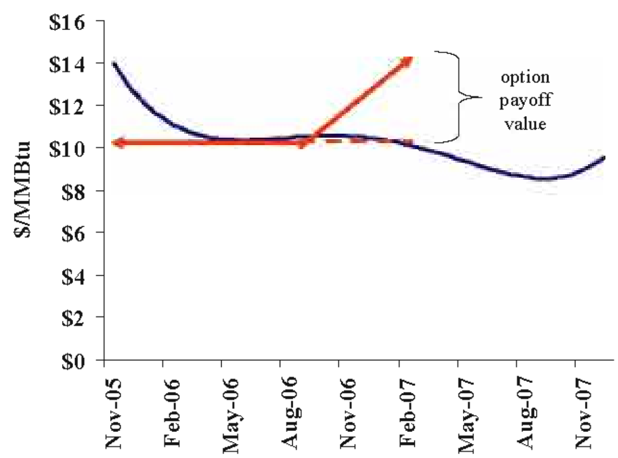
Although convenience yield and the spot price are positively correlated, they are not perfectly correlated. There are periods when the spot price is unusually high and convenience yield is low, and vice versa. This simply reflects the fact that the demand for storage curve can shift, irrespective of shifts of demand and supply in the spot market.

Price Backwardation

The futures price can be greater or less than the spot price, depending on the magnitude of the marginal convenience yield. If the marginal convenience yield is large, the spot price will exceed the futures price; in this case the futures market is said to exhibit strong backwardation. If the marginal convenience yield is precisely zero, the spot price will equal the discounted future price. If the marginal convenience yield is positive but not large, the spot price will be less than the futures price, but greater than the discounted future price, in which case the futures market exhibits weak backwardation. Thus contango price curves (curves in which price escalates from the current period) includes weak backwardation and zero backwardation.

For an extractive commodity like crude oil or natural gas, the futures market should exhibit strong backwardation most of the time, which is actually observable. The reason is that owning unproduced reserves is equivalent to owning a call option with an exercise price equal to the extraction cost, and a payoff equal to the current spot price. Figure 4.1 depicts the payoff profile of a call option on NYMEX Henry Hub futures. Note that for a backwardated price profile, the highest payoff value is in the earliest time interval, thus providing the economic impetus for an early exercise.

Figure 4.1
Payoff Curve in Backwardated Markets



Source: Bloomberg Financial Henry Hub Futures

If there were no backwardation, producers would have no incentive to exercise this option early and in fact would be rewarded for holding the option for future exercise (under a contango profile). If spot price volatility is high, the option to extract and sell the commodity becomes even more valuable, so that production is likely to require strong backwardation in the futures market. This is what is clearly observed in the market during periods of high volatility: convenience yields are high and therefore the spot price exceeds the futures price.

Figures 4.2 and 4.3 below demonstrate price backwardation in the natural gas and oil futures markets.

Figure 4.2
NYMEX West Texas Intermediate Crude Oil Index

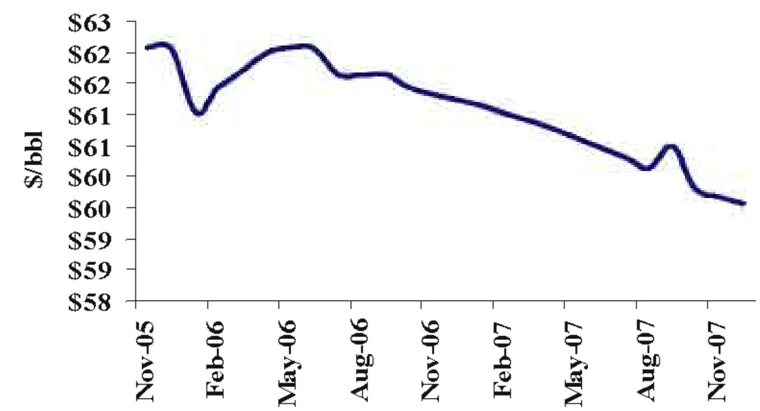
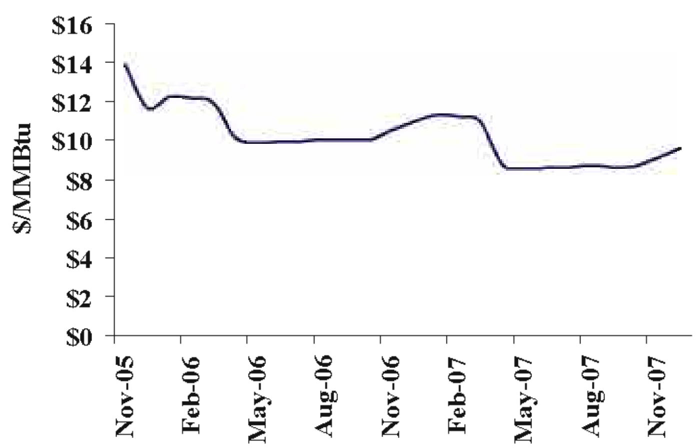


Figure 4.3
NYMEX Henry Hub Natural Gas Index



Source: Bloomberg Financial

The Expected Future Spot Price

In general, the futures price and the expected future spot price need not be equal. Consider an investment in one unit of the commodity to be held for a period of time and then sold. Because the price realized at the point of sale is not known at the time of purchase, the return is risky and must yield an appropriate risk-adjusted return on investment.

Viewed differently, the purchase price must reflect an appropriate risk-adjusted discount rate for the commodity relative to the sales price. Therefore the relationship between the futures price and the expected future spot price should reflect that the futures price will equal the expected future spot price only if the risk-adjusted discount rate is equal to the risk-free rate, i.e., there is no risk premium. For most commodities the expectation is that the spot price will co-vary positively with the overall economy, because strong economic growth creates greater demand, and therefore higher prices.

Said differently, within the context of the Capital Asset Pricing Model which is central to equity valuation theory, the betas (correlation to overall market movement) for these commodities are positive, therefore the expectation is to see a positive risk premium since the risk-adjusted discount rate should exceed the risk-free rate. This implies that the futures price should be less than the expected future spot price. Intuitively, holding a commodity entails risk, and as a reward for that risk an investor expects, on average, that the spot price will rise above the current futures price during the holding period.

The difference between the futures price and the expected future spot price can be significant. For example, crude oil estimates of beta have been in the range of 0.5 to 1. Given an average annual excess return for the stock market of 9 percent, this would put the annual risk premium at 4.5 to 9.0 percent. Accordingly, a six-month crude oil futures contract should "under-predict" the spot price six months out by around 3 to 4.5 percent.

Hedging Risk with Futures Contracts

Futures markets provide a convenient way for producers and consumers of commodities to reduce risk. The futures contract need not cover the entire exposure period because the futures position can be repeatedly rolled forward. It is not always possible to hedge all risk with futures contracts. The most common reason is that the commodity specified in the futures contract is not exactly the same as the commodity or asset being hedged, therefore futures can provide only an imperfect hedge on commodities produced or delivered to a different location or is of a different characteristic. For example, while there is no futures market for jet fuel, airlines hedge their exposure to the price of jet fuel through the use of a combination of heating oil and gasoline futures. Since heating oil and gasoline prices are not perfectly correlated with jet fuel prices, much of the risk will be hedged, but not all of it.

The remaining (unhedged) risk is considered basis risk. In a hedging situation, the basis is defined as the difference between the spot price of the asset to be hedged and the futures price of the contract used to hedge. If the asset being hedged exactly matches that specified in the futures contract, the basis will be zero when the futures contract expires. However if the commodity being hedged does not exactly match the futures contract, the basis will not go to zero when the futures contract expires, and a portion of the risk will remain unhedged.

Price Volatility and the Behavior of Volatility

Commodity price volatility changes considerably over time. As observed, changes in volatility can affect market variables such as production, inventories, and prices. In addition, volatility is a key determinant of the value of commodity-based contingent claims, including financial derivatives (such as futures contracts and options on futures), and real options (such as undeveloped oil and gas reserves).

Fluctuations in volatility are for the most part very ephemeral and follow a rapidly mean-reverting stochastic process. With only a few exceptions, sharp increases in volatility do not persist for extended periods of time. Thus fluctuations in volatility are likely to be important in the short run, but may be less important for longer-run market dynamics.

Sometimes there are easily identifiable factors that can explain most of the increases in volatility. At other times, however, the causes of increased volatility are much less clear, as are the movements in prices themselves. Whether or not changes in volatility can be explained after the fact, it is clear that these changes are partly unpredictable.

Conclusions

Short-run commodity price movements are based on rational shifts in supply and demand. We might expect that some portion of commodity price variation is not based on fundamentals, but is instead the result of speculative "noise trading" or herd mentality, and there is empirical evidence that this is the case. For example, only a small fraction of price variation for frozen orange juice can be explained by fundamental variables such as the weather, which in principle should explain a good deal of the variation. And high levels of unexplained price correlation across commodities that are inconsistent with prices that are driven solely by fundamentals can also be observed.

Such findings do not invalidate the fundamental relationship between futures, spot prices, and storage since these fundamentals do explain a large part the short-run dynamics of prices and other variables. These fundamentals can also demonstrate how commodity markets respond to changes in various exogenous variables and provide a foundation upon which to forecast expected spot prices.

4.1.2 Implications for Electric Price Forecasting

In light of the distinction between futures/forwards and expected spot prices, AmerenUE has adopted the use of expected future spot prices for all commodity inputs to the electric market price simulation process. The underlying premise for exclusively utilizing expected spot forecasts rather than incorporating observable market data (as far into the future as available) is predicated upon capturing the entire spectrum of risk and uncertainty in the electric price forecasting process.

The expected future spot price of power, resulting from the fundamental production cost simulation process, represents the price of delivered power at the time it is delivered. Futures and forward prices are prices established today for the future delivery of a commodity. The difference between the two reflects the risk of price movement over time, and this distinction is critical toward understanding the basis of price forecasting. Futures represent today's price for a future commodity delivery while spot prices represent the price of the commodity at the time it is delivered.

Futures/forwards reflect a financial or contingent claim in which the price has been predetermined for a specified quantity of power at a specified delivery date. Since the majority of futures contracts are entered into for hedging purposes, market participants (other than speculators) are not concerned with the price at the time of delivery, but rather the current price at which they are committing to future delivery. Spot prices, on the other hand, represent the price of a commodity at the time it is delivered, reflecting no volumetric guarantees or financial contingencies. Without these guarantees or contingencies, the price is uncertain and reflects a myriad of potential outcomes.

If a market participant is relatively certain about the price of a product in the future, there is little incentive to buy forward to eliminate price level risk. A market participant is indifferent between committing to purchase the commodity today and waiting to buy it on the spot market if the expectation holds that there is little difference between the spot price at future delivery and the price one is willing to contract on a forward basis today.

On the other hand, if significant price risk is present over time, then the difference between the spot and forward price must reflect this potential disconnect. The more uncertainty there is about what the price will be at some future time, the greater the difference between spot and forward prices. Therefore, the difference between spot and forward prices reflects this uncertainty and to the amount of time until contractual delivery.

A good example of how this difference impacts market prices is to look to the capitalization of a merchant power plant. If the investor seeks bank financing, typically the project must have a Purchase Power Agreement. If such an agreement is in place to sell power to a creditworthy company, the investor can expect a lower cost of capital (both debt and equity). Therefore, since capital costs are less expensive, the project is able (and has the incentive) to charge a lower price for the power in order to gain certainty of return. If no such agreement is in place and the investor seeks to market the plant output in the spot market, debt and equity participants will require a higher cost of capital. As such, market participants can employ cost of capital assumptions to determine the difference in expected revenues and expectations regarding risk to estimate the expected differences between a forward and spot price, all things else being equal. Said differently, the futures/forward price should reflect the expected future spot price discounted by an appropriate risk premium. The risk premium is a function of future volatility of the market, as well as potential price drift.

Volatility that underlies the market risk is a function of several variables that are correlated, interdependent, independent, and isolated. Such variables include uncertainty around demand (as reflected by weather, economic growth, load shape, etc.), supply (unit availability, transmission limitations, technology, etc.), and production costs (fuels, labor, capital, operations, maintenance, disposal, etc.). Changes in these variables can be either ephemeral or substantive. Ephemeral changes have the effect of driving volatility, while substantive changes impact price drift (upward or downward trending within a volatile framework). Any individual changes in these variables, combined uncorrelated changes, or combined changes in correlated variables, will impact expected future spot prices and therefore result in uncertainty regarding expected future spot prices. (Events are another driver of price volatility, although such occurrences are usually represented as scenarios.)

While some of these variables can be fixed, or pre-established, for a period of time (i.e., forward purchase of fuel, operations expenses, etc.) most are not capable of being fixed or known for any extended period of time. Therefore, in light of the multiple factors that influence and determine future electric power prices, the risk profile of each commodity that drives or comprises electricity prices should be consistent and maintain the same uncertainty profile. If some input variables reflect a riskless profile (i.e. futures fuels) while others reflect complete uncertainty, the resulting simulated power price results will represent a hybrid of risks that cannot be clearly identified or segmented for investment purposes.

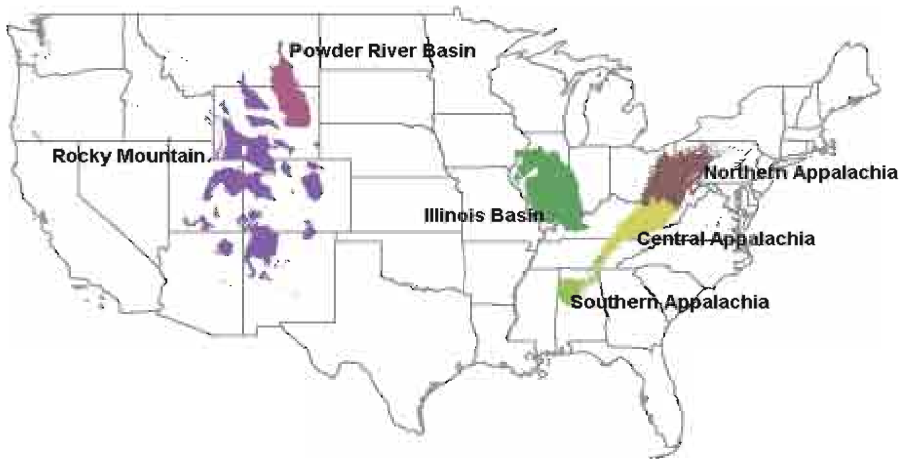
Since the simulation process is designed to forecast expected future spot prices for a commodity (electricity) that reflects no guaranteed volumetric component, or carries no financial contingencies, the results should reflect the inherent risks and uncertainties associated with future delivery and costs. In the absence of guarantees or contingencies, the future price is uncertain, reflecting a myriad of potential outcomes. To maintain a consistent risk profile that reflects the uncertainty of the input variables in aggregate, all input variables to the electric power price simulation process must represent expected future spot prices. Specifically, the natural gas, coal, and SO_2 prices that are used as inputs for the market simulation process must reflect expected future spot prices.

4.1.3 COAL FORECAST DISCUSSION

Current State of the Coal Markets

Coal is one of the most abundant fossil fuels in the world. In the United States alone, there are an estimated four trillion tons of coal resources. Reserves that can be mined using existing technologies are estimated to be about 500 billion tons. Economically recoverable reserves are estimated to be approximately 275 billion tons. At the current rate of consumption, U.S. economic coal reserves will last more than 250 years. There are three primary producing regions in the United States, the Western, Interior, and Eastern regions; Figure 4.4 shows the major producing regions in the US (Lignite producing regions and the Central Interior regions are not shown as they bear little relevance to AmerenUE's resource planning decisions).

Figure 4.4
Major Coal Producing Regions in the US



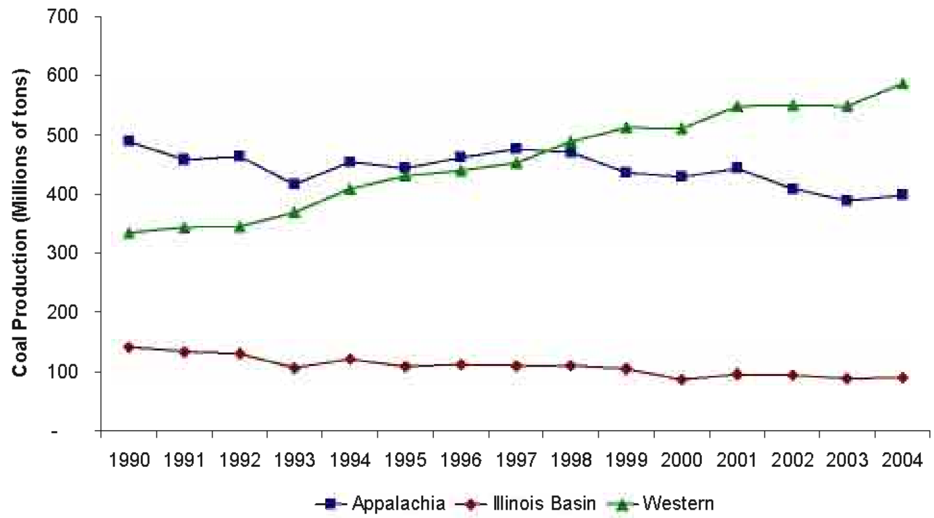
Source: Energy Velocity

Different coal types come from these various regions:

- Lignite is the lowest ranking coal (producing regions not shown in Figure 4.4). Lignite contains up to 45 percent moisture and has heating values that generally range between 6,000 and 7,000 Btu/lb. Lignite is an important form of energy for generating electricity, particularly in the Southwest (most lignite is mined in Texas). Abundant lignite reserves also exist in Montana and North Dakota.
- Sub-bituminous coal is next in heat content with heating values typically ranging from 8,000 to 9,500 Btu/lb and moisture content between 20 percent and 30 percent. Sub-bituminous coal is formed when lignite is placed under greater pressure and is typically mined in Montana, Wyoming, New Mexico, and Colorado.
- Bituminous coal is formed when sub-bituminous coal is placed under even greater subterranean pressure. Bituminous coal typically has heating values ranging from 10,000 to 12,500 Btu/lb and moisture content of less than 20 percent. Bituminous coal is predominantly found in Appalachia and the Midwest (Illinois Basin).
- Anthracite is the highest ranking coal with moisture content generally less than 15 percent and heat content up to 14,000 Btu/lb. Anthracite is sometimes referred to as "hard coal" and was formed from bituminous coal when great pressures developed in folded rock strata during the creation of mountain ranges. In the United States, this occurred in limited areas, principally in the Appalachian region of Pennsylvania.

Historically, the greatest coal production came from the Appalachian Basin in the form of bituminous coal. Western sub-bituminous coal, however, has over taken Appalachian Basin coal in terms of production (see Figure 4.5).

Figure 4.5
Historical US Coal Production by Basin (1990-2004)

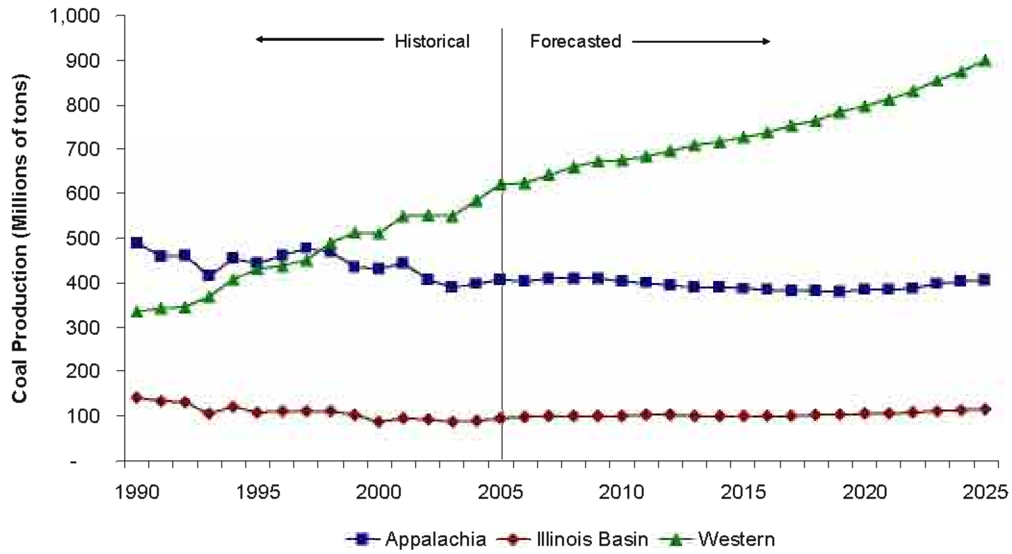


Source: Energy Information Agency, Energy Velocity

There are several reasons for the decline on production from the Appalachian Basin and the increase in the Western Basins, particularly the Powder River Basin. Appalachian Basin mines have been producing for far longer than Western Basin mines. This has led to some significant productivity and extraction cost challenges. The most critical factor, however, was the enactment of the Clean Air Act Amendments of 1990. When the Clean Air Act Amendments of 1990 were passed, it was anticipated that demand for low-sulfur coal would lead to an increase in prices in Western Basin coals. Ironically, the explosion of mining activity and productivity in the Powder River Basin initially led to an oversupply situation.

Compliance with Phase I of the Clean Air Act was generally easier than originally anticipated for utilities because of the availability of cheap low-sulfur coal and the relative ease of switching from Illinois or Appalachian Basin coals to Western Basin coals, Powder River Basin in particular. With the enactment of Phase II of the Clean Air Act in 2000, and more recently the enactment of the Clean Air Interstate Rule in the spring of 2005, the US Energy Information Agency expects the growth in Western coal production relative to Eastern coal production to continue (see Figure 4.6).

Figure 4.6
Historical and Forecasted US Coal Production by Basin (1990-2025)

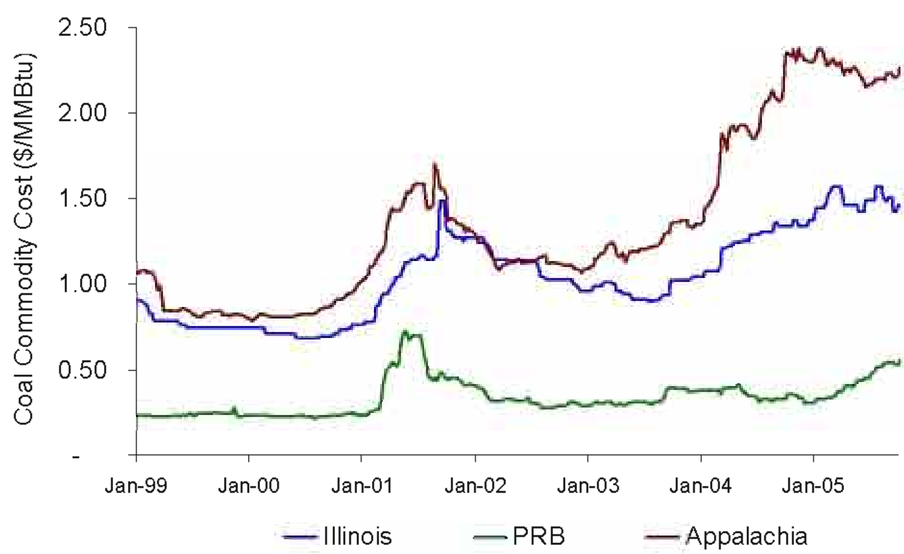


Source: Energy Information Agency, Energy Velocity

Coal Commodity Prices

These supply and demand phenomenon and many other factors (described more fully below) have given rise to a significant level of volatility in coal commodity pricing. Figure 4.7 shows coal commodity price behavior for various producing basins in the United States.

Figure 4.7
Recent Coal Commodity Price Behavior by Basin (1999- Oct. 2005)



Source: Bloomberg Financial

The volatility has been most pronounced in the Appalachian basin commodity pricing on an absolute basis rising $1.13/MMbtu since January 2003 or more than 105 percent. Powder River Basin coal has risen $0.29/MMBtu, or just under 90 percent in the same time period. Although AmerenUE uses primarily PRB coal in its coal plants and is therefore most concerned with its price behavior, the price phenomenon in the Appalachian Basin also has very important impacts on regional electricity prices (discussed more fully in Section 4.3). Powder River Basin coal prices are largely subject to the domestic demand impacts partially discussed above. The reasons for the volatility in the Appalachian Basin commodity prices go beyond supply effects and include declining productivity and increased exports of metallurgical and steam coal to Europe and Canada.

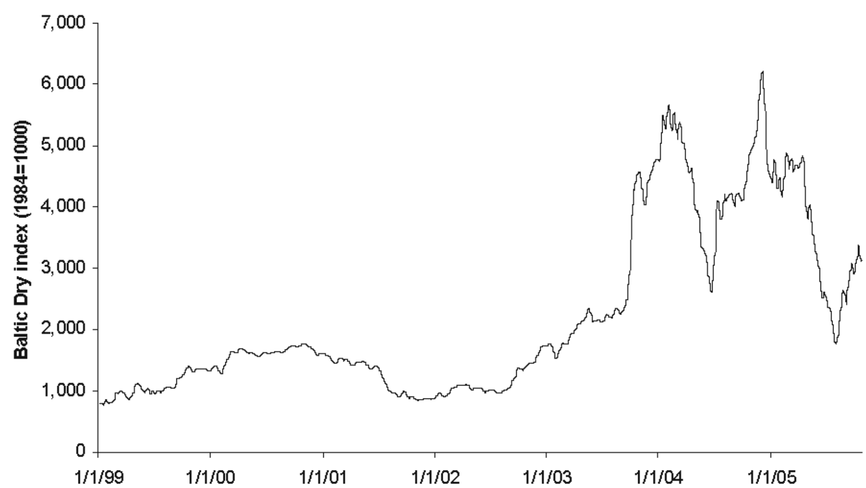
Overall, coal mining productivity in the United States has increased, but recent increases are driven purely by increases in the Western Basins. The increases in Western Basin productivity in fact mask significant decreases in Appalachian Basin productivity. The primary reason for this decline in productivity is the depletion of longwall mining operations. Central Appalachian mining productivity as measured on a ton-per-man-hour basis has seen a compounded annual decline of close to 4 percent per year since 1999, while Western Basins have seen compounded annual gains of over 1 percent per year in the same time frame. The loss of productivity in the Appalachian Basin is certainly a contributor to higher prices.

Historically, the United States has been a net exporter of coal. At one time, the United States was the largest exporter of coal in the world. The rise in value of the dollar relative to key importing country currencies in the 1990s caused the United States to become a marginal exporter to the world coal market, and by 2002 the country was exporting less than 40 million tons of coal. By 2004, exports had seen an increase of over 20 percent to close to 48 million tons, and 2005 is projected to be well over 50 million tons. The majority of exports in the United States are from the Appalachian Basin in the form of steam and metallurgical coals. There are two primary reasons for this resurgence in American coal exports relative to other exporting nations – the decline in the value of the dollar since 2002 and the increase in world wide shipping rates since 2002. Figure 4.8 shows the decline of the U.S. dollar as measured by the Dollar Index (DX) against the price increases seen in the Appalachian Basin, and Figure 4.9 shows the Baltic Dry Index of Worldwide Commodity Freight Rates.

Figure 4.8
Appalachian Coal Price vs. Dollar Exchange Index

Source: Bloomberg Financial, New York Board of Trade

Figure 4.9
Baltic Dry Index of Worldwide Commodity Freight Rates

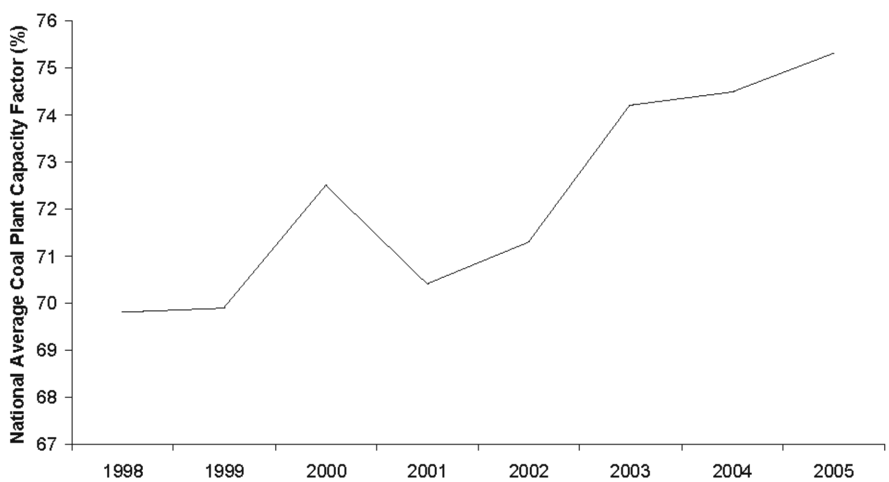


Source: Bloomberg Financial

The drop in the value of the dollar, all other things being equal, makes U.S. coal more attractive to importing nations, particularly the European Union and Canada who account for over 80 percent of U.S. exports. The attractiveness of dollar denominated U.S. exports is compounded by the recent dramatic rise in ocean-going shipping rates. Global demand for raw materials driven primarily by China has strained the supply of seafaring shipping vessels. More than half of all European coal imports come from South Africa (mostly steam coal), Colombia/Venezuela (all steam coal), and Australia (mostly metallurgical coal). The shipping distance from Baltimore to Rotterdam (about 3,570 nautical miles) is about half the distance from Richards Bay, South Africa to Rotterdam (about 7,160 nautical miles) and significantly less than the distance from Buenaventura, Colombia to Rotterdam (5,180 nautical miles). Queensland, Australia, is about 11,085 nautical miles from Rotterdam. Consequently, shipping rates from the United States to Europe are much lower than the rates from South Africa, Colombia/Venezuela or Australia to Europe.

While increased exports are an important contributor to the coal commodity price behavior of the last several years, the primary contributor has been an increase in domestic demand. It is important to note that exports comprise less than 5 percent of total U.S. coal production and growth in this area, while important, pales in comparison to growth in domestic consumption. Figure 4.10 shows how the weighted average coal plant capacity factors on a national basis have increased over the last several years.

Figure 4.10
National Average Coal Capacity Factors



Source: Energy Velocity, Energy information Agency

This increase in capacity factor has translated to an increase of over 31 million tons of coal consumption in the United States since 1998. By way of comparison, AmerenUE consumed slightly more than 36 million tons of coal in 2003, making this increase similar to adding another AmerenUE to the demand picture for domestic coal. The domestic demand increase weighs heavily on the coal markets in general, but as Figure 4.6 (production projection) shows, the Western Basins, and the PRB in particular, bear the brunt of this domestic demand growth. When considering the impact of this demand increase on the *delivered* cost of PRB coal as opposed to just the *commodity* cost of PRB coal, one must understand the impact of the transportation situation as well.

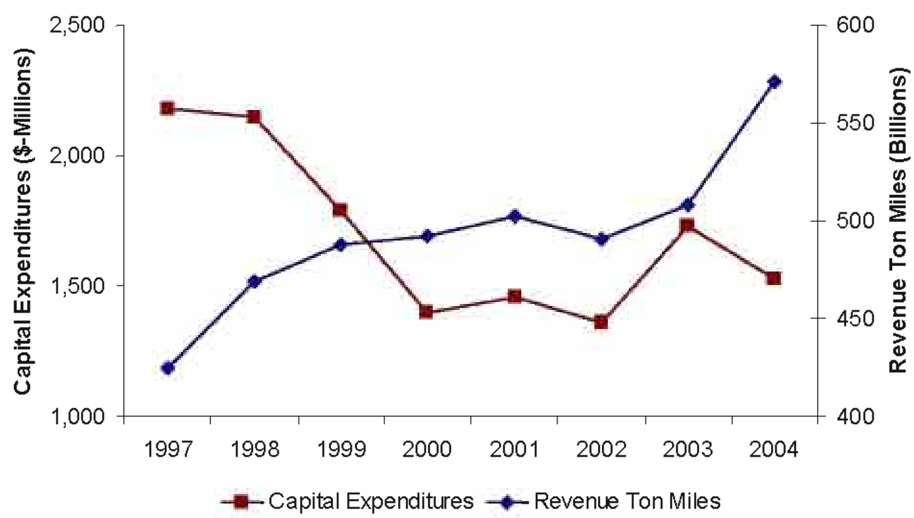
PRB Coal Transportation Issues

The transportation component of the delivered price of Powder River Basin coal can be as much as 75 percent, while the transportation component of the delivered price of

Appalachian Basin coal is typically less than 25 percent. Therefore, changes in transportation costs represent a significant risk to utilities that burn Powder River Basin coals. Structural changes in the both the rail industry and in the demand for Powder River Basin coals has dramatically increased the outlook for transportation costs faced by AmerenUE.

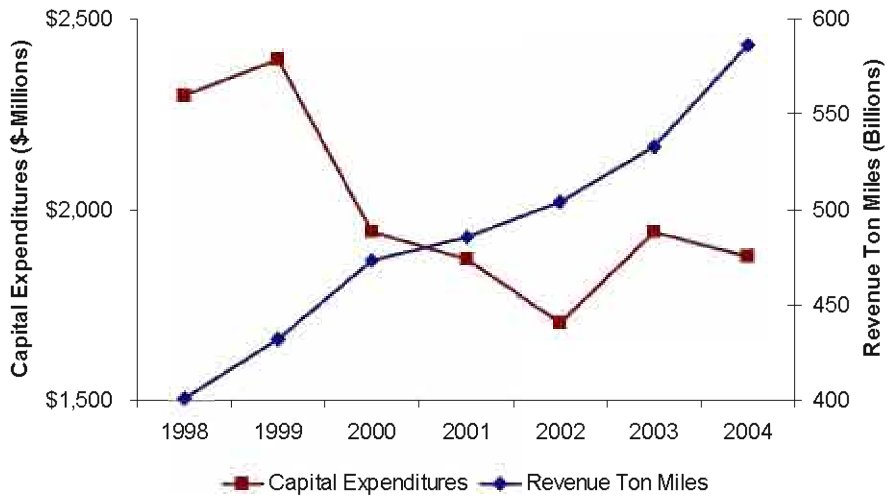
As the mines in the Powder River Basin have increased their production capability during the last fifteen years, the two originating rail carriers; the Burlington Northern Santa Fe (BNSF) and the Union Pacific (UP) railroads also improved their rail capacity into the area. Over the past five years, however, rail carriers in general, including UP and BNSF have experienced a significant increase in traffic while also significantly reducing capital investment. Since 1997, BNSF has experienced compound annual growth in revenue ton miles of traffic (a common traffic metric in the rail industry) in excess of 4.3 percent while at the same time reducing capital investment by close to 5 percent per annum. Since 1998, UP has experienced compound annual growth in revenue ton miles of over 6.5 percent while at the same time reducing capital investment by 3.3 percent per annum. Figures 4.11 and 4.12 show the increase in traffic and reduction in investment for BNSF and UP respectively.

Figure 4.11
BNSF Traffic and Capital Investment



Source: BNSF Annual Reports

Figure 4.12
UP Traffic and Capital Investment



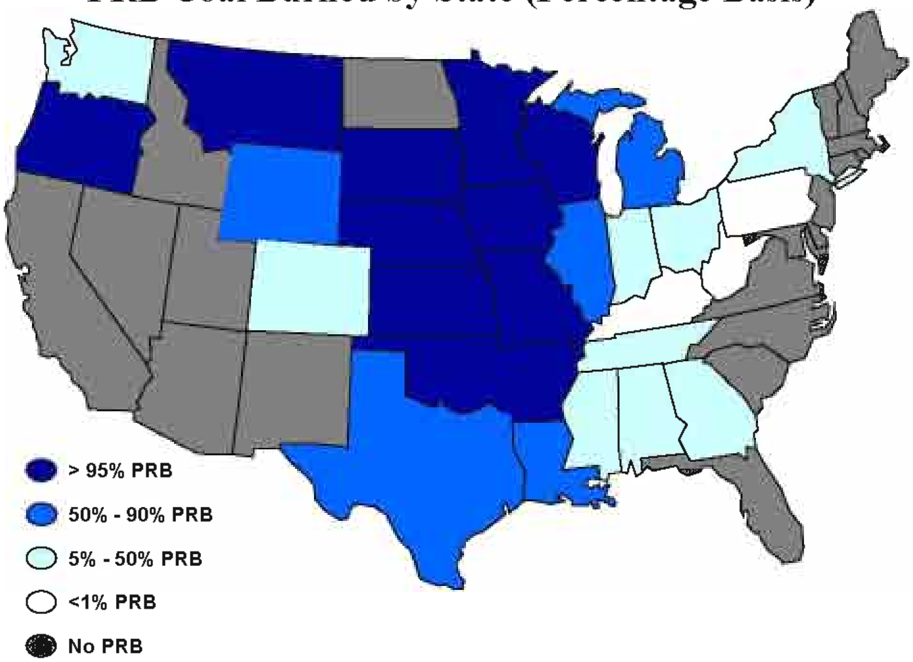
Source: UP Annual Reports

This decline in capital investment translates to fewer locomotives, less new track, fewer track upgrades, etc. As traffic has increased steadily into a declining capital investment environment, constraints have begun to emerge. These constraints have brought pricing power back to the rail carriers and have given rise to uncertainty in the ability of carriers to meet delivery schedules.

In 2004, for example, UP rolled out a corporate strategy that included a shift from bi-lateral contracting to one using only standard published tariff rates, rates that are a multiple of former bi-lateral rates. In 2005, the Joint Line (currently at 90 percent-plus throughput utilization) experienced maintenance issues that severely degraded its throughput capability and resulted in missed deliveries.

The key question going forward is whether increased demand for Western Basin coals will materialize as expected and if so, how the transportation markets will respond. As discussed above, most forecasts of coal production in the United States show a steady increase in PRB production/consumption. Figure 4.13 shows the percentage of PRB burned at coal plants on a state by state basis.

Figure 4.13
PRB Coal Burned by State (Percentage Basis)



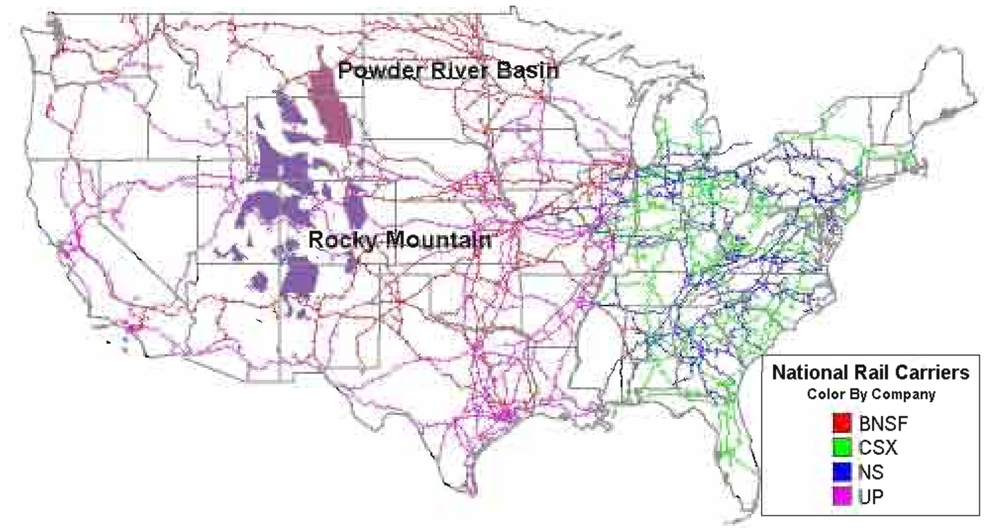
Source: Energy Velocity, Energy Information Agency

As discussed earlier, growth in the consumption of PRB can be tied directly to the enactment of the Clean Air Act Amendments of 1990. With the issuance of new emission limits by the EPA under the Clean Air Interstate Rule in March of 2005, utilities will be tempted to explore conversion of high sulfur coal burning units to Powder River Basin coal as a way of complying with the new SO_2 emission limits. This will be a particularly attractive option for smaller, or older facilities where the smaller investment associated with fuel switching ($75 - $100/kW) may make more sense than the larger investment associated with scrubbing ($200-$300/kW).

Adding to this potential demand for Powder River Basin coal east of the Mississippi, is the price disparity with Appalachian Basin coal. As figure 4.7 (historical commodity prices) detailed above shows, there is a widening spread between the commodity cost of Appalachian Basin and Western Basin coals. As the spread in coal commodity cost widens (Appalachian Basin becomes more expensive relative to Western Basin), incremental transportation costs necessary to haul Western Basin coal farther east can be absorbed. Regulatory and financial incentives aside, there are logistical issues that must be overcome in hauling Western Basin coal much further than the Mississippi River in any quantity.

There are four major rail carriers in the United States – Union Pacific (UP), Burlington Northern Santa Fe (BNSF), Norfolk Southern (NS), and CSX. Geographic issues associated with the track ownership of these carriers cloud the potential for increased usage of Western Basin coals east of the Mississippi River. Figure 4.14 shows the geographic track ownership of these four carriers.

Figure 4.14
Owned Track by Major Rail Carrier



Source: Energy Velocity, Company Annual Reports

Figure 4.14 shows that UP and BNSF are the only two major carriers that service Western Basin coal mines. As some burners of Powder River Basin coal have indicated in public financial disclosures (NRG's operations in New York in particular), logistical issues can arise when switching carriers from one of the Western (UP, BNSF) to one of the Eastern (CSX, NS) carriers.

Another issue related to the transportation of PRB coal to the Eastern United States is one of rail grade, or slope. Western rail carriers typically employ trains of greater than 100 cars to haul PRB across the plains; the Appalachian Mountains east of the Mississippi may cause issues related to train size and available routes for delivery adding further costs and potential logistical delays. These transportation issues are compounded by the fact that PRB coal has a lower heat value (typically 8,400 – 8,800 Btu/lb) than the Appalachian coals (as high as 13,000 Btu/lb), and thus more physical tons of PRB coal would need to be shipped to a facility to produce the same level of output.

Delivered Coal Price Outlook

For reasons detailed in the General Discussion of Commodity Markets, AmerenUE has decided to use a detailed fundamental forecast of spot coal prices as the basis for coal plant dispatch costs underlying the multi-area market price forecast for electricity. AFS contracted Hill & Associates, a leading coal consulting firm, to model delivered (commodity plus transportation) coal prices for the entire United States.

Hill & Associates employs a fundamental supply and demand model utilizing cost curves developed for more than 1,000 coal mines across the country. Demand is modeled based on GDP growth projections in conjunction with energy intensity projections. For a complete discussion of the assumptions, methodology and results of the Hill & Associates 2005 Annual Coal Outlook please see the Appendix.

Figure 4.15 details the delivered price results for selected coal types on a weighted average basis.

Figure 4.15
Average Delivered Coal Cost by Basin

[redacted]

Source: Hill & Associates

Hill & Associates' forecast for AmerenUE plants was vetted internally by AFS as a check on the broader forecast. Figure 4.16 shows the AmerenUE delivered coal prices forecast by Hill & Associates (See the Appendix for an internal memorandum vetting AmerenUE's forecast of delivered coal prices).

Figure 4.16
Forecasted Delivered (Non-Contract) Coal Prices for AmerenUE
(in $/MMBtu)

[redacted]

Source: Hill & Associates

AmerenUE's Position in the Coal Markets

AmerenUE's forecast of coal prices and transportation rates are based on existing contracts, published data, reports from various forecasting organizations, and in-house knowledge of the coal markets. There are a number of factors that may impact the delivered cost of coal- demand for PRB coal, competition among rail/barge carriers, consolidation of the coal industry, environmental regulations, fuel costs for coal production and transportation, rail capacity constraints, and increasing mining ratios in the PRB, among many others.

Delivered coal price forecasts for 2006 through 2009 are primarily based on current contracts and in-house price forecasts. Price projections for later years are based on in-house price forecasts combined with published forecasts from industry experts.

Approximately 97 percent of AmerenUE's coal is supplied from the Powder River Basin (PRB) in Wyoming. AmerenUE's four coal-fired power plants, Labadie, Rush Island, Sioux, and Meramec have completed the switch to PRB coal to the extent practicable.

Labadie, Meramec, and Rush Island plants burn 100 percent PRB coal. Sioux Plant burns approximately 80 percent PRB coal. The balance of Sioux Plant's fuel is Illinois Basin Coal (sweetener coal), tire-derived-fuel (TDF) and sometimes petroleum coke. Sioux Plant requires sweetener fuels to achieve a higher capacity level.

AmerenUE has rail transportation agreements in effect that will dampen the impact of rate increases in the short term. However, significant increases will likely take effect in [redacted] In the longer term, significantly higher rail rates are expected as contracts expire. In addition, fuel surcharges are in effect under most railroad contracts. These fuel surcharges rise and fall with fuel prices, which have recently seen all-time highs. Fuel surcharges make up 10 percent to 20 percent of rail rates.

In addition to rail rate risk, AmerenUE's coal-fired fleet faces delivery risks. The western railroads experienced significant problems meeting demand in 2005 due to maintenance issues on the joint line rail. As a result, coal inventories dropped in the AmerenUE system. Ameren Energy Fuels & Services (AFS) believes that the best way to manage transportation rates and to cope with delivery risk is to continue to develop transportation alternatives and maintain fuel flexibility.

In order to compensate for the increased risk of disruption of deliveries out of the Powder River Basin to all of our plants, a new inventory policy was implemented in 2002. The policy raised target inventories to significantly higher levels from previous targets. As a result of the 2005 delivery problems and attendant inventory crisis, the inventory policy is being reevaluated again. [redacted]

[redacted]

4.1.4 NATURAL GAS FORECAST DISCUSSION

Current State of the Natural Gas Markets

Natural gas (commonly referred to as gas) is an abundant gaseous fossil fuel consisting primarily of methane. It is found in oil fields and natural gas fields, as well as—in smaller quantities—in coal beds. The U.S. Energy Information Agency predicts that natural gas will be the fastest growing primary energy source in the world for the next 20 years. As of January 1, 2005, proven world natural gas reserves, as reported by the U.S. Energy Information Agency were estimated at 6,040 trillion cubic feet. The U.S. Geological Survey has estimated the world-wide undiscovered *recoverable* gas reserves at over 4,000 trillion cubic feet. With worldwide consumption at approximately 100 trillion cubic feet per year, there is over 60 years of known (and recoverable) reserves in the world. With methane hydrates, and other *non-conventional* sources of natural gas, the worldwide supply of natural gas is potentially an order of magnitude greater than with traditional sources.

The natural gas industry in the United States has undergone significant change in the last two decades. The industry has had three phases of restructuring and reform. The first was wellhead deregulation. In response to natural gas shortages in interstate markets, Congress passed the Natural Gas Policy Act of 1978. The act called for the phase-out of wellhead regulation. Total deregulation of wellhead gas was completed by January 1, 1993.

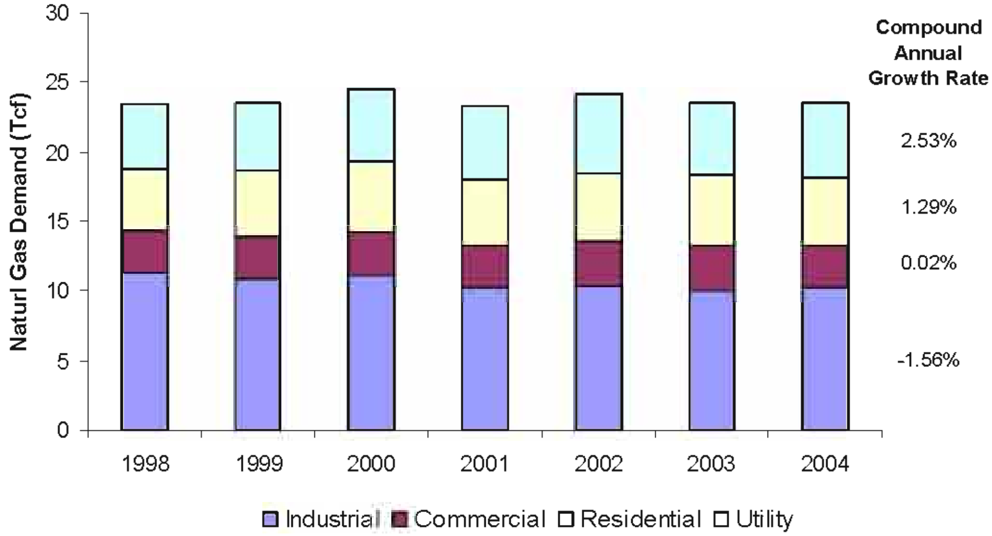
Pipeline reform started in 1984 when the FERC issued Order 380. This order eliminated the variable-cost component of an LDC's minimum bill requirements. This made it economically feasible for many LDCs to switch gas suppliers. Shortly afterwards came orders 436 and 500. Order 436 allowed for voluntary open pipeline access in return for a blanket certificate to transport third-party natural gas. Order 500 required gas producers to credit against a pipeline's take-or-pay liability any natural gas transported for them.

As a final federal regulatory reform, the Federal Energy Regulatory Commission's Order 636 was issued in 1992. The order prohibited pipelines from providing bundled gas service; established a capacity-releasing program; redesigned pipeline rates on the basis of the straight fixed-variable methodology; and generally gave transport customers nondiscriminatory rights to the pipeline network.

Natural Gas Commodity Supply and Demand

Demand for natural gas has also evolved over time. Figure 4.17 shows the major components of natural gas demand.

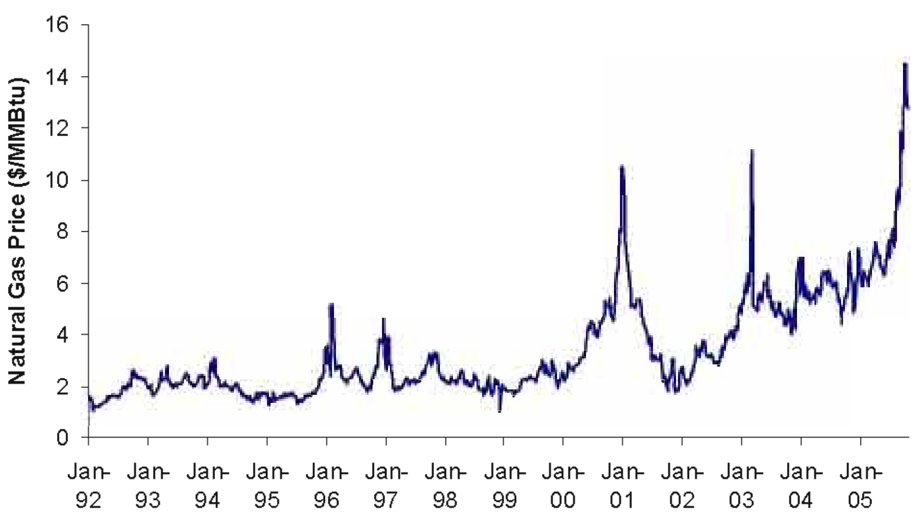
Figure 4.17
U.S. Natural Gas Demand



Source: Energy Information Agency

Residential use and utility use of natural gas are the only growing sectors of the demand stack at 1.29 percent and 2.53 percent per year respectively. Commercial growth has been flat, and industrial demand has fallen significantly at 1.56 percent per year. The falloff in industrial demand has been widely attributed to price volatility in the same time period. Figure 4.18 shows the historical spot price of natural gas.

Figure 4.18
Historical Natural Gas Spot Prices

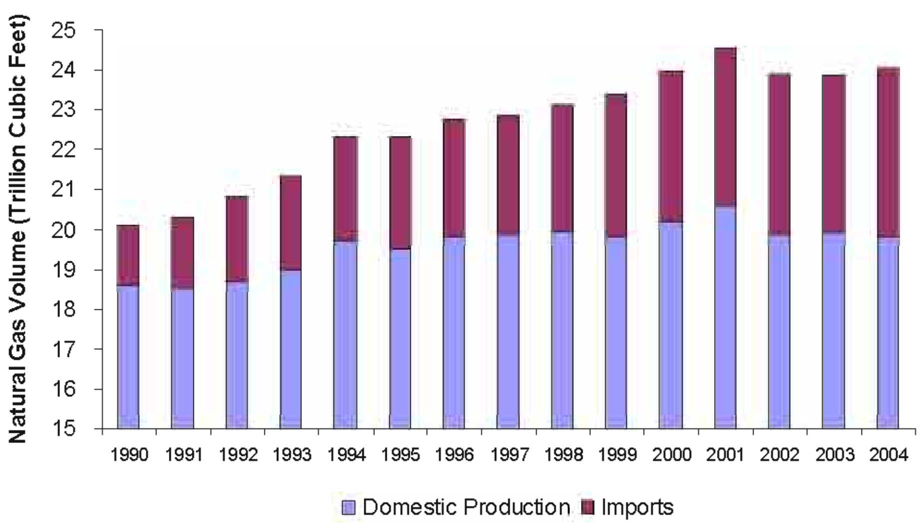


Source: Bloomberg Henry Hub Spot Index

Natural gas intensive businesses such as chemical manufacturing, particularly the fertilizer business have shut U.S. plants and have moved operations overseas as natural gas prices have escalated. Since January 2000, prices have grown at a compound rate of over 40 percent per year. The U.S. GAO (General Accounting Office) has reported that high gas prices, which account for up to 90 percent of fertilizer costs, have forced nine nitrogen fertilizer plants to close or cease operations since January 2001, remaining facilities have only operated at 50 percent capacity. The Wall Street Journal has recently reported that U.S. chemical makers have lost an estimated 78,000 jobs since natural gas prices began to rise in 2000. There are profound fundamental changes in the natural gas supply market that go well beyond the high growth in utility demand that are driving these high prices.

Natural gas has traditionally been a domestic market in North America with the vast majority of production coming from the United States. Figure 4.19 shows the mix of domestic gas production and imports since 1990.

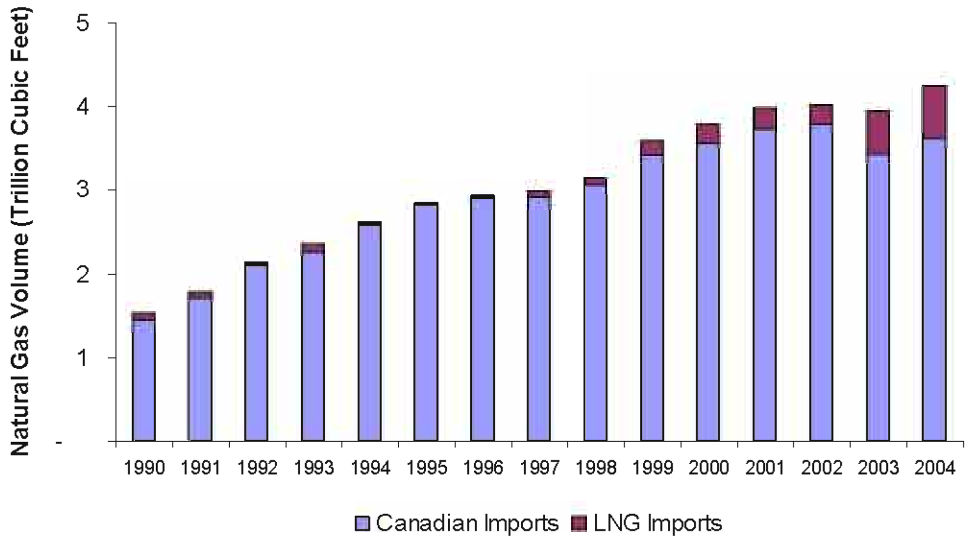
Figure 4.19
U.S. Natural Gas Supply Mix



Source: Energy Information Agency

Figure 4.19 shows several interesting phenomenon; most of the growth in U.S. consumption over the last 15 years has been made up for with imports. Also, in 2001, domestic natural gas production reached a peak of 20.6 Tcf and it has been declining ever since. By 2004, imports had grown to their largest level ever at 4.3 Tcf. Imports have historically been from Canada, but as Figure 4.10 shows, those imports have peaked as well and Liquefied Natural Gas (LNG) from non-North American locations has begun to pick up the slack.

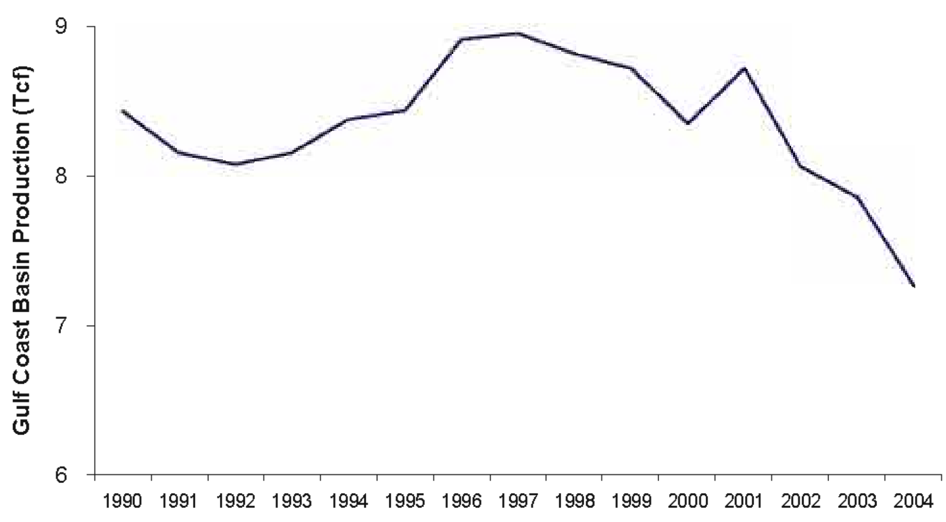
Figure 4.20
Sources of U.S. Natural Gas Imports



Source: Energy Information Agency

The decline in Canadian imports and in domestic production as well signals a growing trend in natural gas production, traditional natural gas basins have reached their peak in production and are declining in productivity. Nowhere is this trend more pronounced than in the Gulf of Mexico, the largest producing basin in North America. Figure 4.21 shows the precipitous decline in production since its peak in 1997.

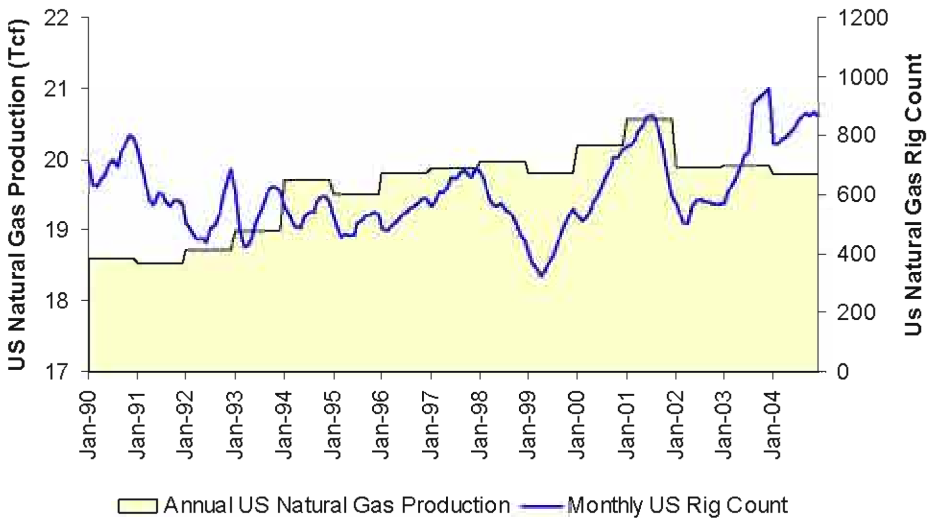
Figure 4.21
Gulf Coast Basin Natural Gas Production



Source: Energy Velocity, Energy Information Agency

Another indication of declining productivity is the dramatic decrease of drilling well productivity in the United States. Figure 4.22 charts U.S. domestic production vs. total drilling rigs.

Figure 4.22
U.S. Domestic Production vs. Total Drilling Rigs



Source: Energy Velocity, Energy Information Agency, Baker Hughes Rig Counts

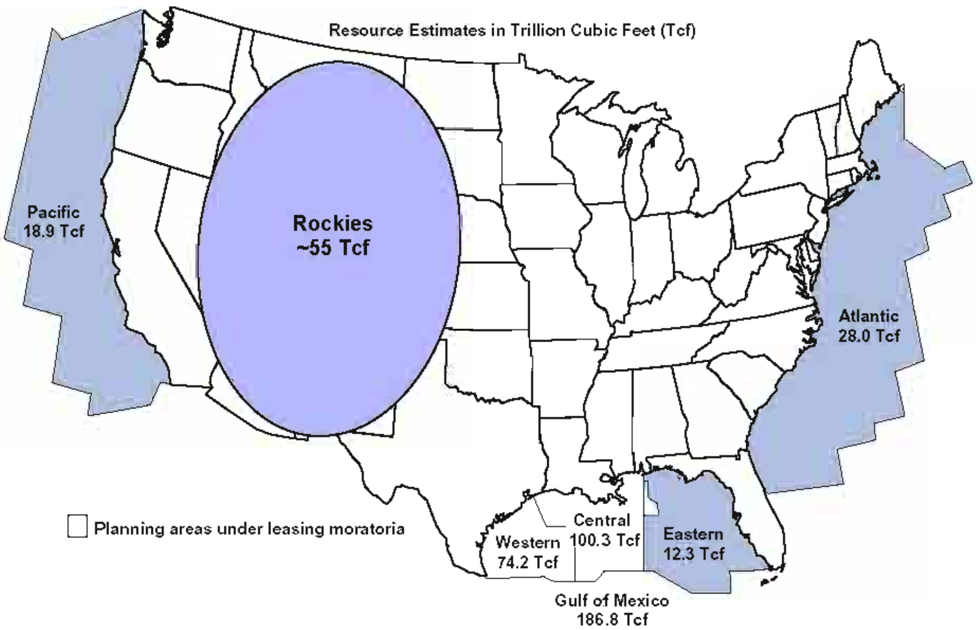
Two periods are of keen interest in Figure 4.22, from 1999 to 2001, rig counts roughly doubled and resulted in approximately 1 Tcf of additional production. From 2002 to 2004, however, rig counts increased by close to 75 percent while production actually declined by 0.1 Tcf.

With productivity and actual production declining in the United States, new sources of natural gas must be found to meet growing demand. There are two primary sources that can be exploited in the coming years to meet this demand. Both present a unique set of risks and uncertainties - domestic drilling either in regions containing unconventional reserves (e.g. coalbed methane, tigh sands, shale, etc.) or that are currently under drilling moratoria and dramatically increasing LNG imports.

Develping unconventional reserves has attracted the attention of many smaller independent exploration and development entities and is beginning to attract the attention of the larger multi-national oil companies. The technology necessary to recover these reserves is, however, largely still under development. As these technologies are developed and mature it is still possible that the extraction costs will be a multiple of current conventional extraction costs.

The Mineral Management Service of the U.S. Department of the Interior is responsible for periodically updating the estimated undiscovered reserves of extractable resources on the United States and off the shore of the United States. Many areas in the United States are under drilling moratoria due to no access restrictions resulting from National Parks, National Historic Preservation Act, Clean Water Act, and other Environmental restrictions. Many areas have rolling moratoria on lease issuances, e.g. offshore of eastern seaboard, Western Florida coast, etc. Figure 4.23 shows recoverable conventional reserves as of 2000.

Figure 4.23
U.S. (Lower 48) Natural Gas Reserves under Drilling Moratoria



Source: Minerals Management Service – OCS reserves

Alaska has significant natural gas reserves as well. Crude oil drilling operations in Prudhoe Bay have been pumping natural gas back into the earth for years, and estimates are that over 30 Tcf of recoverable reserves exist there alone. The U.S. Energy Information Agency estimates that over 250 Tcf in recoverable reserves exist in onshore and offshore fields in Alaska. Clearly, the issue with Alaska is pipeline transportation, but many experts forecast that by the middle of the next decade, a pipeline will be constructed connecting the untapped fields to the continental United States.

Beyond Alaska, however, the political will to explore areas currently under moratoria is lacking and will likely remain lacking so long as there is a viable alternative. The viable alternative is liquefied natural gas (LNG). LNG, however, in the quantities necessary to make up for projected increases in demand and reductions in existing domestic basin productivity over the next couple of decades, will fundamentally alter the current market for natural gas in the United States. (As discussed in the gas forecast portion of this section, over 7 Tcf of LNG will be necessary to close this gap).

LNG is a *global* commodity with a supply chain that will add considerable risk and uncertainty to domestic markets, risk and uncertainty that has not existed in the past.

Japan, South Korea, and Taiwan have historically been the primary importers of LNG with over 68 percent of the market. Japan supplies 100 percent of its natural gas through LNG imports. Figure 4.24 illustrates the four primary components of the LNG supply chain.

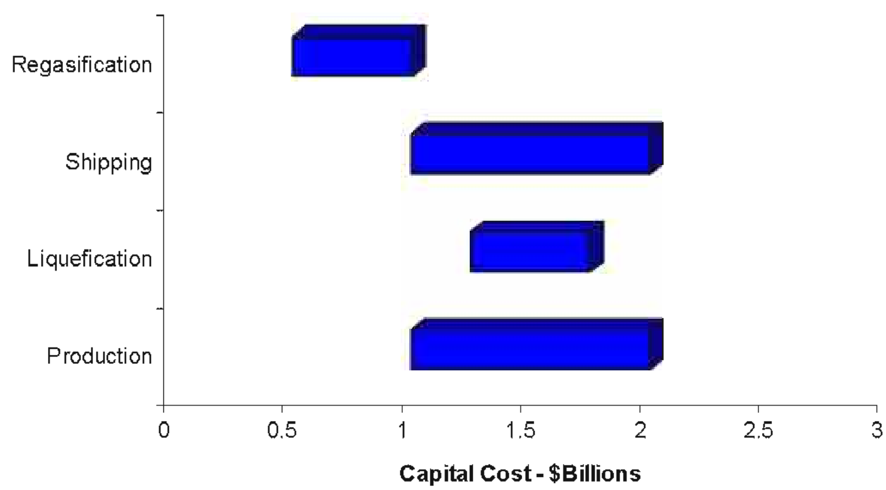
Figure 4.24
Global LNG Supply Chain

British Gas Platform - Trinidad | Liquification facility in Qatar | ConnocoPhillips LNG Tanker | Lake Charles Import Terminal – Southern Union Co. Louisiana

Production | ***Liquefication*** | ***Transportation*** | ***Regasification***

Each of the components of this supply chain has distinct market participants and market characteristics that will add to risk and uncertainty to the future spot price of natural gas. The entirety of the supply chain is very capital intensive; adding and incremental 0.4 Tcf capacity to the entire supply chain would require capital outlays of $3.75 - $6.75 billion. Figure 4.25 shows the capital cost breakdown associated with adding an incremental 0.4 Tcf to the supply chain, including the 5 tankers it would take to serve it.

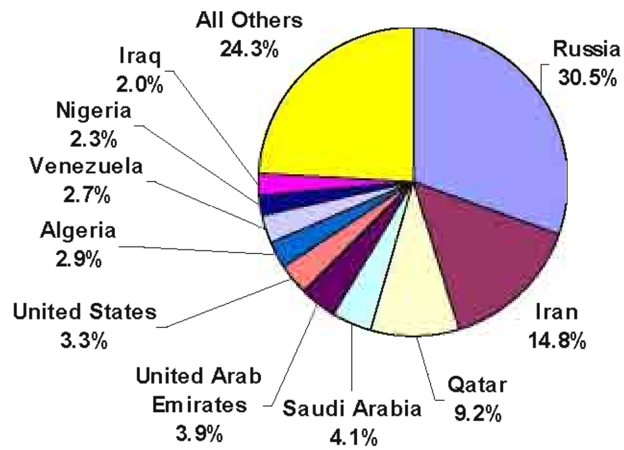
Figure 4.25
Capital Costs in the LNG Supply Chain



Source: Gas Technology Institute

In the production phase of the supply chain, natural gas is pumped from onshore and offshore wells as it is in North America. Figure 4.26 shows the breakdown of worldwide proven natural gas reserves:

Figure 4.26
Worldwide Proven Natural Gas Reserves



Source: Energy Information Agency

Russia and Middle Eastern countries control over two thirds of worldwide proven reserves. These nations with Algeria, Venezuela, and Nigeria control close to 75 percent of proven reserves. These nations are not the most politically stable and oftentimes have limited rule of law, much less market or free enterprise systems. Reliance on these types of suppliers in the future will introduce the kind of uncertainty that currently exists in the crude oil market with the potential for supply shocks that simply do not exist in today's domestic natural gas market. The State-run and international oil corporations poised to exploit these reserves will be deploying their limited capital in competition with capital deployed to develop crude oil resources. These factors will likely cause oil and natural gas to become even more closely correlated.

Liquefaction is the process of cooling natural gas to about -260°F. Individual liquefaction lines are known as trains; liquefaction plants may have one or several trains. The liquefaction reduces the volume of natural gas to approximately 1/600th of its original volume. This reduction in volume permits transportation of LNG to be economically viable. Worldwide liquefaction capacity was 6.6 Tcf in 2003. Only a handful of countries liquefy gas for export. Figure 4.27 details the historical exports of liquefying countries.

Figure 4.27
Natural Gas Liquefying Countries (in Tcf)

	1996	1997	1998	1999	2000	2001	2002	2003
Indonesia	1,260	1,305	1,405	1,300	1,300	1,229	1,108	1,245
Algeria	915	860	841	951	951	884	935	968
Malaysia	739	720	731	740	740	774	741	822
Qatar	6	68	311	517	517	596	676	669
Trinidad and Tobago	-	-	75	141	141	135	189	419
Nigeria	-	-	31	162	162	273	394	405
Australia	356	372	363	368	368	373	367	371
Brunei	301	295	308	319	319	326	341	341
Oman	-	-	-	93	93	245	280	326
United Arab Emirates	273	279	255	249	249	266	254	256
United States	61	63	60	66	66	66	64	65
Libya	38	32	34	27	27	28	21	25
Total	**3,950**	**3,992**	**4,415**	**4,933**	**4,933**	**5,194**	**5,370**	**5,912**

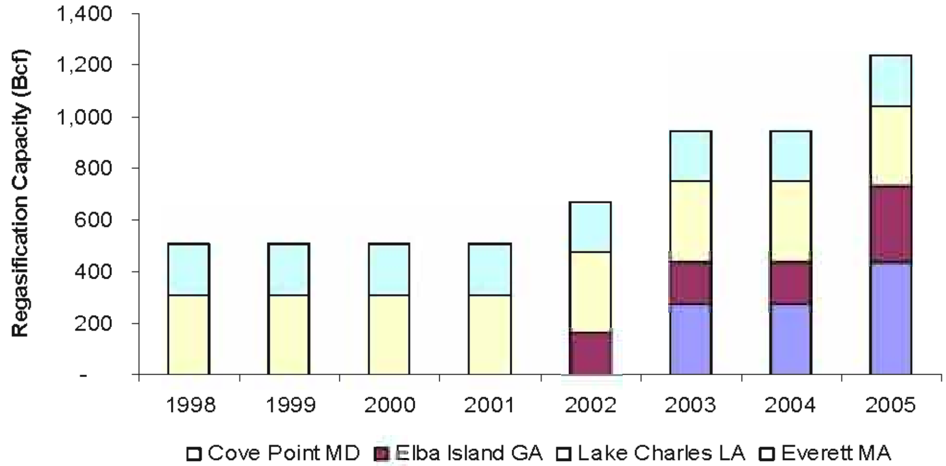
Source: Energy Information Agency

ConocoPhillips has liquefied natural gas at a small facility in Valdez, Alaska for shipment to Japan for many years. Indonesia has been the largest exporter of LNG for years, shipping exclusively to Japan, South Korea, and Taiwan. Trinidad & Tobago and Oman recently entered the liquefaction business. New projects under construction in Australia, Russia, Norway, and Egypt, together with expansions of existing facilities throughout the world, will increase annual liquefaction capacity by 2.8 Tcf (58 million tons) by 2007, increasing global capacity to 9.4 Tcf (197 million tons) per year. Potential new exporters such as Iran, Yemen, Equatorial Guinea, Angola, Venezuela, Bolivia (via Peru or Chile), and Peru are looking to LNG exports as a way of monetizing their natural gas resources.

According to the U.S. Energy Information Agency, 151 LNG tankers were in service in 2003 with 88 under construction. Modern tankers range in size from 138,000 cubic meters (cbm) (2.8 Bcf) to 250,000 cbm (5.3 Bcf). The addition of new ships to the fleet will raise total fleet capacity 44 percent from 17.4 million cbm of liquid (equivalent to 366 Bcf of natural gas) in October 2003 to 25.1 million cbm of liquid (equivalent to 527 Bcf of natural gas) in 2006. Tanker costs have declined to about $155 million today from a peak of $280 million in the mid-1980s (on average for a 138,000 cbm ship), in part due to more shipyards entering the LNG tanker market, enhancing competition. This is still 2 to 3 times the cost of a crude oil tanker of similar size (which carries 4 to 5 times the energy) because of the sophisticated cryogenic systems necessary to keep the LNG at temperature.

The United States currently has four LNG import and regasification facilities with a combined peak capacity of 1.2 Tcf. All four terminals either have recently completed an expansion or have been brought back on line in the regasification capacity. Figure 4.28 shows the historical regasification capacity at these facilities.

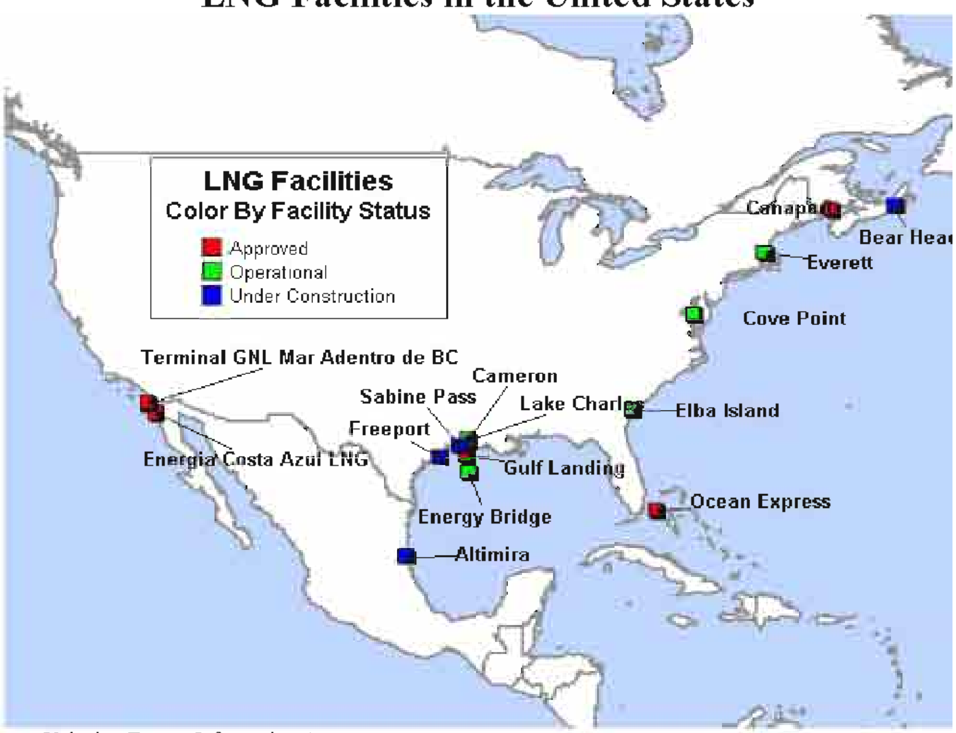
Figure 4.28
U.S. Regasification Capacity



Source: Energy Information Agency

Dozens of LNG regasification facilities have been announced in North America. Very few, however, have received approval, much less, started construction. It is expected that by 2010, LNG imports will be approaching 2.0 Tcf by 2010. Figure 4.29 shows the facilities that are currently in operation, those under construction, and those that have received construction approval.

Figure 4.29
LNG Facilities in the United States



Source: Energy Velocity, Energy Information Agency

LNG import costs to the United States range from $3.50 to $4.50/MMBtu. This cost, however, does not translate directly to market price. Rather, this becomes a cheaper resource in a more expensive stack of resources. LNG is anticipated to reduce the marginal cost of gas, but it is unlikely, all things being equal that the price of gas in the United States will fall to the levels of LNG on a consistent basis. LNG essentially will form a floor on natural gas prices in the United States.

AmerenUE's Natural Gas Price Forecast

For reasons detailed in the General Discussion of Commodity Markets, AmerenUE has decided to use a detailed fundamental forecast of spot natural gas prices as the basis for gas plant dispatch costs underlying the multi-area market price forecast for electricity. Corporate Planning contracted Navigant Consulting Inc. (NCI), a leading energy consulting firm, to model delivered (commodity plus transportation) natural gas prices for the entire United States.

NCI employs a fundamental natural gas model maintained by Energy & Environmental Analysis, Inc (EEA). EEA uses its Gas Market Data and Forecasting System to track and analyze monthly behavior in the North American natural gas market. At the heart of the system is a comprehensive gas transmission network that solves for natural gas supply and demand for the United States, Canada, and northern Mexico. Specifically, the model solves for monthly natural gas production and demand, storage injections and withdrawals, pipeline flows, natural gas prices, locational basis, and seasonal basis for a very detailed natural gas pipeline network comprised of 91 nodes (or market hubs). The model simulates monthly behavior out to 2020, considering the impact of:

- Weather
- Economic Growth Rates
- Growth Rates for Residential, Commercial, and Industrial Gas Demand
- Growth Rates for Electricity Demand
- Oil and Coal Prices
- Power Generating Capacity
- Nuclear Retirements/Additions
- Limitations/Environmental Restrictions on Coal Unit Capacity Utilization
- Gas Supply Capability (Deliverability)
- Gas Pipeline and Storage Expansions
- LNG Imports/Exports
- Mexican Imports/Exports
- Seasonal LNG Requirements

Figure 4.30 shows AmerenUE's natural gas price forecast with a selection of Henry Hub futures prices (at 2 percent escalation beyond the last price quote).

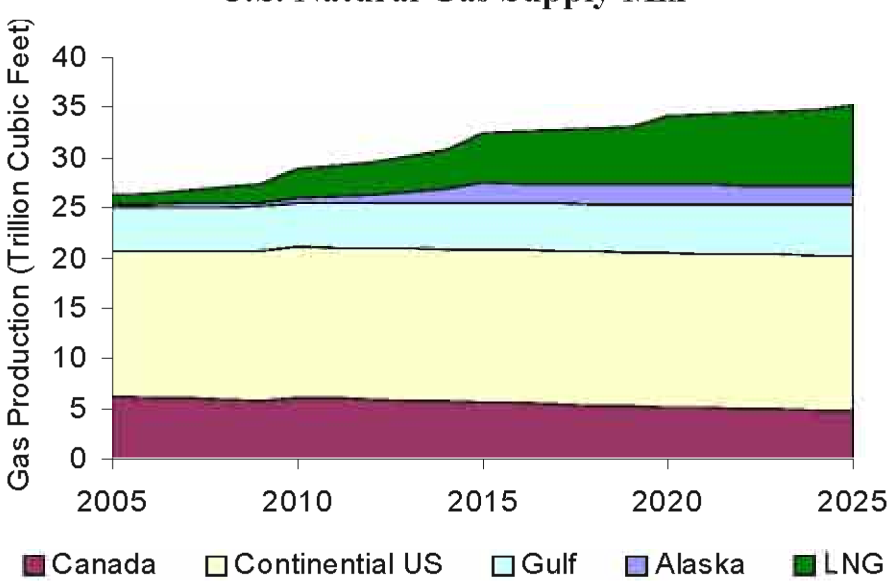
Figure 4.30
AmerenUE's Natural Gas Forecast

[redacted]

Source: NYMEX Henry Hub, NCI/EEA Gas Market Forecast

The Appendix contains the assumptions and results of the NCI/EEA North American natural gas forecast. Of particular interest is the supply mix that makes up the domestic demand. Figure 4.31 details the projected supply mix.

Figure 4.31
U.S. Natural Gas Supply Mix



Source: NCI/EEA Gas market Forecast

Several critical points can be made from this figure. Natural gas demand is expected to increase by over 10 Tcf in the next 20 years. Canadian imports are expected to decline by over 20 percent in the next 20 years. The almost 2 Tcf of new supply expected to come from Alaska will require a pipeline to bring to market.

Most importantly, LNG imports are expected to grow close to 8 Tcf in 20 years comprising almost 25 percent of the supply mix. This level of LNG importation represents close to a doubling of the current *worldwide* market for LNG and will require significant capital investment across all points of the supply chain. Domestically, it will require close to a seven-fold increase in regasification capacity. The risks associated with this increase in LNG are not something the historical prices have ever reflected.

AmerenUE's Position in the Natural Gas Market

AmerenUE is well positioned to utilize natural gas a source of generation fuel. The transportations system in the Mid-Continent is robust and connecting new generation to the existing system can be done with relative ease – to a point. In some unlikely scenarios involving a step change up in natural gas demand resulting from any number of scenarios, large nuclear retirement, draconian carbon restrictions, etc., the deliverability of natural gas may become an issue.

Aside from these unlikely scenarios, the primary issue with respect to natural gas is the price. AmerenUE utilizes natural gas for peaking generation purposes only, and thus is relatively shielded from very high gas volatility or even sustained high gas prices.

4.1.5 FUEL OIL FORECAST DISCUSSION

AmerenUE Fuel Oil Price Forecast

Fuel oil prices are generally influenced by supply, demand, weather and political events. Supply and demand affect prices over the long term, while weather and political events tend to contribute to short-term fluctuations. Figure 4.32 provides the AmerenUE forecast for No. 2 and No. 6 fuel oil.

Figure 4.32
AmerenUE Fuel Oil Price Forecast

[redacted]

The following factors provide the basis for Ameren's price forecasts: Currently, the world wide demand for all energy products is very strong. In fact demand has been the major force in driving heating oil to $2.00 to $2.20 per gallon and crude oil to $65.00 to $70.00 per barrel in the Fall of 2005. Oil markets are in a period of transition as producers attempt to bring additional supply to market to satisfy increased world wide growth. Additionally, the Gulf of Mexico sustained back-to-back hurricanes during the early Fall of 2005. The effects crippled the area's ability to produce, refine, and transport crude oil, natural gas, and related distillate products. It will take many months before normal operations resume.

In the long term, tension in the world oil markets in response to terrorist attacks, natural disasters, and expanding world wide economies will keep uncertainty in the market. Additionally, multiple interest rate hikes by the U. S. Federal Open Market Committee, the recent multi year highs seen in all energy commodities, and the aftermath of the recent hurricane's will continue to weigh on domestic demand and create a volatile energy environment. From a technical view, following the extreme rise in prices over the past year, the oil energy markets appear to have recently put in a long-term peak. The near-term trend appears toward sideways to lower prices followed by renewed buying pressure.

From the perspective of directly setting market prices through its use as a fuel source, oil has a very minimal impact in most of the Eastern interconnect. Oil, however, has a significant indirect impact on market prices by influencing other commodity prices. Diesel fuel is a large component of the cost structure of rail transportation, 12 percent-20 percent, and rail carriers have begun to impose fuel surcharges on delivered coal. This diesel issue also extends up the coal value chain to mining operations as well.

Oil's impact on natural gas prices is perhaps even more significant. As commodity markets become more global (see previous natural gas/LNG discussion) price movement in one commodity will impact price movement in another. Figure 4.33 shows historical oil and natural gas price movements.

Figure 4.33
Crude Oil and Natural Gas Price Movements

Source: Bloomberg Financial

4.1.6 NUCLEAR FUEL FORECAST DISCUSSION

AmerenUE Nuclear Fuel Price Forecast

The nuclear fuel cycle for nuclear generation units consists of the following components: 1) uranium, 2) conversion of uranium into uranium hexafluoride, 3) enrichment of uranium hexafluoride, 4) conversion of uranium hexafluoride into uranium dioxide and the fabrication into nuclear fuel assemblies, and 5) the disposal of spent nuclear fuel. There is also a federal government charge for the decontamination and decommissioning of U.S. DOE uranium enrichment facilities.

Since 2003, the markets for front end nuclear fuel components (uranium, conversion services, and enrichment services) have undergone substantial change from a buyer's market to an expected protracted period (10-15 years) of a seller's market where security of fuel supply will be paramount for the operation of a nuclear plant.

Uranium prices have increased from \$10/lb. to \$32/lb; prices for conversion services have risen from \$5/KgU to \$12/KgU; and enrichment pricing has increased from \$107/SWU (separative work unit) to almost \$114/SWU. The major cause for such change, in all markets, is the elimination of the draw down over several years of inventories of nuclear fuel, which kept prices depressed and resulted in financial constraints for supply expansion. The need for building new capacity in the supply sector now exists, and prices have reacted accordingly.

[redacted]

Ux Consulting (UxC), a leading nuclear fuel market consulting company, forecasts uranium prices over the next 10 years to be between $25 and $40/lb, with many uncertainties potentially affecting such forecasts. [redacted] The conversion market is considered to be currently in balance with recently announced capacity expansions improving an otherwise tight supply situation. However, supply shocks have occurred in the past and could again occur.

The enrichment needs for the operation of Callaway are satisfied through [redacted] There is upward pressure on enrichment prices due to increased demand. As a result of higher uranium prices, utilities have optimized procurement by purchasing less uranium in conjunction with procuring an increased amount of enrichment services.

Enrichment demand is near world-wide capacity. The highest cost producer, USEC (United States Enrichment Corporation), sets the market price. USEC is now facing much higher power costs beginning in May 2006 and that may cause the market enrichment price to rise from current levels. Three new enrichment facilities are in various stages of planning and licensing. New capacity in the industry is projected to be complete in the 2009-2012 time period.

In the fabrication area, AmerenUE has a [redacted] reload fabrication contract with Westinghouse Electric Company, LLC. Such contract covers Callaway reload requirements through the [redacted] reload. This contract provides price stability and is incorporated into the base case cost projection.

Under the Nuclear Waste Policy Act of 1982, the DOE (Department of Energy) is responsible for the permanent storage and disposal of spent nuclear fuel. DOE charges $1.00 per each MWh generated and sold from Callaway for spent fuel disposal. For AmerenUE, this results in a net charge of about $0.94 per MWh to nuclear fuel costs. DOE is not expected to have a permanent storage facility for spent fuel available until at least 2012. The Callaway Plant has installed onsite storage capacity sufficient to meet its needs until at least 2020.

The Energy Policy Act of 1992 instituted a charge to DOE enrichment customers for the decontamination and decommissioning of the DOE uranium enrichment plants. For AmerenUE, this charge is approximately $0.15-0.22 per MWh net and is scheduled to continue through October 2007. It is uncertain if such charge will be continued beyond that time.

4.2 EMISSION ALLOWANCES AND PRICES

The Environmental Issues section of the appendix contains a more detailed discussion of current environmental issues facing AmerenUE. The following sections discuss the three major pollutants considered in the Integrated Resource Analysis.

4.2.1 SO_2

Background

The U.S. Environmental Protection Agency's (EPA) Acid Rain Program is well established, with a defined and homogenous tradable instrument – the SO_2 Emission Allowance. The Acid Rain Program falls under Title IV of the 1990 Clean Air Act Amendments and was established to achieve significant reductions in the emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_X). The regulations state that emissions of SO_2 in the United States must be reduced by 10 million tons below the 1980 emission levels. Essentially, every major fossil fuel-burning electric production facility in the United States is affected under Title IV.

The Acid Rain Program was modified on March 10, 2005 by the issuance of the Clean Air Interstate Rule (CAIR). This rule was issued to further reduce the emissions of SO_2 and NO_X across 28 eastern states and the District of Columbia beginning in 2010.

The Acid Rain program is based on a "cap-and-trade" design. In the SO_2 Allowance Program, affected utility units are allocated allowances based on their historic fuel consumption (1985-1987) and a specific emissions rate (the lower of actual emissions rate during the baseline years or 1.2 lbs. SO_2 per million BTU fuel input). Currently we are in Phase II of the program (beginning in 2000) when the Act sets a permanent cap for a total of 8.95 million allowances to the affected utilities.

Each allowance permits a unit to emit one ton of SO_2 during or after a specified year. SO_2 allowances are recorded by the EPA in a central database called the Allowance Tracking System (ATS). Allowances are currently issued in the ATS on a vintage-year basis through 2035. On an annual basis, for each ton emitted, one ton is then retired in the ATS. This reconciliation process takes place by "freezing" the regulated unit's ATS account for the given vintage year or previous vintage year allowances on March 1st of the following year.

After the EPA has reviewed all documentation to justify the actual emissions levels for the previous year, the corresponding number of allowances is deducted from the unit accounts and the accounts are unfrozen (usually within 60 days).

CAIR reduces emissions by requiring additional allowances for compliance. Starting in 2010, two SO_2 emission allowances will be required for every ton of SO_2 emissions at AmerenUE power plants. Starting in 2015, 2.86 SO_2 emission allowances will be required for every ton of SO_2 emissions at AmerenUE power plants.
Affected sources with a shortfall of allowances may buy them from sources that have reduced emissions below their allocated level. Unused allowances of a given vintage year may also be "banked forward" to the next or future years. Participation in the SO_2 allowance market is not limited to affected sources; any individual or entity may open a general account with the EPA and acquire allowances.

The SO_2 program is the most liquid of the environmental markets and trades actively on a daily basis. Figure 4.34 shows the historical bid/offer spreads for SO_2 transactions. Figure 4.35 shows the price for actual historical trades of SO_2 allowances.

Figure 4.34
SO_2 Transactions – Historical Bid/Offer

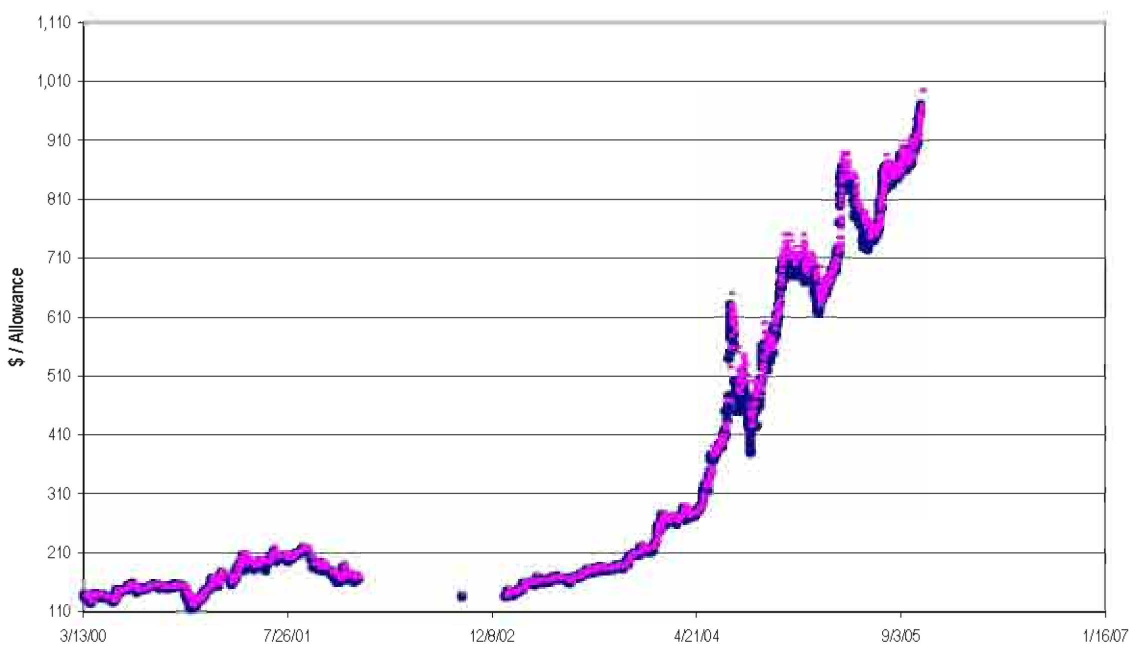
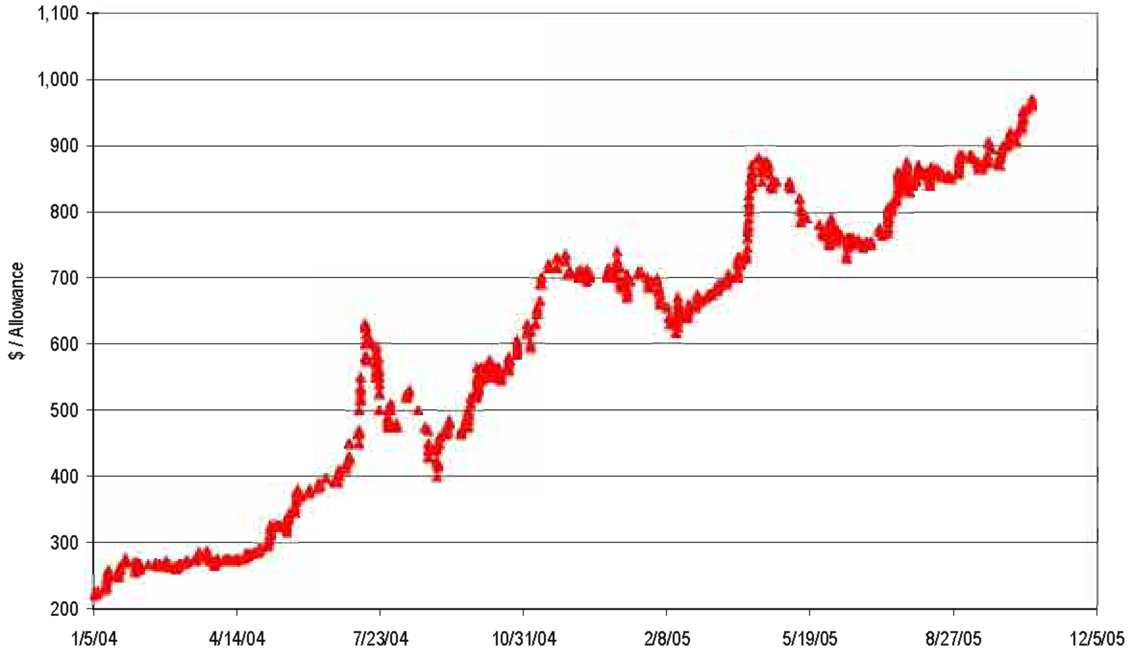


Figure 4.35
SO_2 Allowances – Actual Historical Trades



Forecast

Allowance prices are impacted primarily by regulatory change, regulatory perceptions and technology change. Currently, the allowance market believes that future regulatory changes will require the installation of additional emission reduction equipment in the 2007-2010 timeframe.

The CAIR also has had a profound impact on pricing of later vintages. Thus, the future price curve for SO_2 allowances has a distinct negative tilt as we move into the later vintages.

The current forward curve is based on prices that are indicative of where counterparties will transact right now for future delivery and payment, or the escalated value of immediate settlement prices for future vintages using the forward market interest rate curve. Figure 4.36 shows the forecasted SO_2 prices used in the integrated resource analysis.

Figure 4.36
Forecasted SO_2 Prices

[redacted]

4.2.2 NO_X SIP CALL

Background

NO_X Emission Allowances were originally created under regulations implemented by a coalition of northeastern state air regulators called the Ozone Transport Commission (OTC). In 1995, EPA and the Environmental Council of the States formed the Ozone Transport Assessment Group to begin addressing the problem of ozone transport in the eastern United States.

In 1998, based on the group's findings and other technical analyses, EPA issued a regulation to reduce the regional transport of ground-level ozone. This rule, "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone," commonly called the NO_X SIP Call, requires states to reduce ozone season (May through September) NO_X emissions that contribute to ozone nonattainment in other states.

Compliance with the NO_X SIP Call was scheduled to begin in 2003. The OTC states adopted the original compliance date of May 1, 2003, in transitioning to the NO_X SIP Call. In states outside the OTC region, however, litigation delayed the initial deadline until May 31, 2004. For those states, the first compliance period (2004) was for a shorter than normal ozone season. In addition, litigation delayed the start date for portions of Georgia and Missouri until 2007.

The NO_X SIP Call did not mandate which sources must reduce emissions; rather, it required states to meet an overall emissions budget and gave them flexibility to develop control strategies to meet that budget. All affected states chose to meet their NO_X SIP Call requirements by participating in the NO_X Budget Trading Program (NBP).

More than 2,500 units were affected under the NBP in 2004. These include electric generating units, which are large boilers, turbines and combined cycle units used to generate electricity for sale. Electric generating units constitute more than 85 percent of all regulated units. The program also applies to large industrial units that produce electricity and/or steam, primarily for internal use. Examples of these units are boilers and turbines at heavy manufacturing facilities, such as paper mills, petroleum refineries, and iron and steel production facilities. These units also can include steam plants at institutional settings, such as large universities. Some states have included other types of units such as petroleum refinery process heaters and cement kilns.

While regional and seasonal in scope, the regulations and marketplace are quite similar to the nationwide SO_2 Emission Allowance cap-and-trade program. A defined and homogenous tradable instrument, the NO_X Emission Allowance has been created for vintage years through 2009 in some states. While the program is implemented on a state-by-state basis, the regulations governing the trading of NO_X Emission Allowances are fairly consistent from one state to another and there have been no interstate restrictions placed on the transfer and use of credits throughout the region (i.e., New York State NOx allowances may be used for compliance in Massachusetts, or any other state in the region).

Affected sources are allocated allowances by their respective state governments. One allowance permits an affected source to emit one ton of NO_X during the control period (May through September) for a given vintage year. Allowances and transactions are recorded in the EPA NO_X Allowance Tracking System (NATS). The NO_X emissions market allows sources to trade (buy and sell) allowances throughout the year. At the end of every ozone season, each source must surrender sufficient allowances to cover its ozone season NO_X emissions.

On an annual basis, for each ton emitted during the ozone season, one ton is then retired in the NATS. This reconciliation process takes place by “freezing” the regulated unit’s NATS account for the given vintage year or previous vintage year allowances on the last business day of December of the vintage year. After the states have reviewed all documentation to justify the actual emissions levels for the specific ozone season, the corresponding number of allowances is deducted from the unit accounts and the accounts are unfrozen (usually within 90 days). Affected sources with a shortfall of allowances may buy them from sources that have reduced emissions below their allocated level.

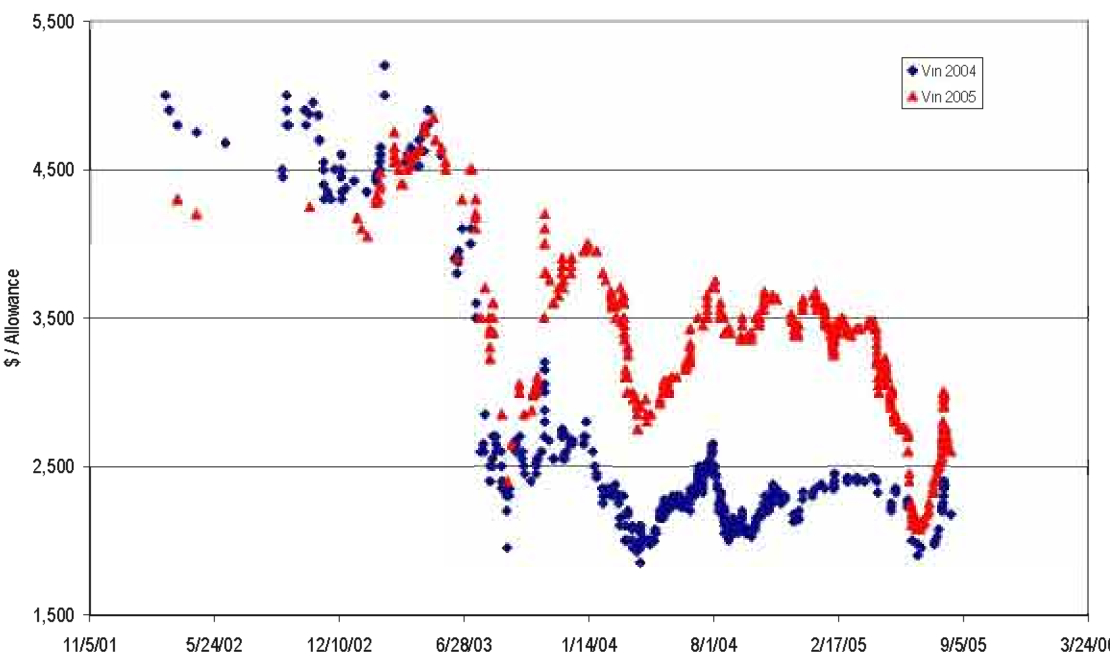
Unused allowances of a given vintage year may also be “banked forward” to the next or future years. However, the OTC states have imposed a restriction on banking in the form of “progressive flow control” (PFC). PFC requires that there be discounted compliance value to previous vintage year NO_X allowances if the region-wide surplus of previous vintage year NO_X allowances exceeds 10 percent. The discount factor is not linear and is cumulative.

What this means is that if you hold 100 vintage 2004 allowances at the end of 2005, you can use the first 25 tons at a 1:1 rate for 2004 compliance. The remaining 75 tons can only be used at a 2:1 rate for 2001 compliance. So the effective yield of 2004 vintage allowances for use in 2005 is .25 + (1 - .25)/2 = 0.625.

The official flow control ratio for use of previous vintage year allowances is usually not known until March of a given vintage year when the EPA releases region-wide emissions data for the previous year. Because of this PFC mechanism, previous vintage year allowances usually trade at a discounted price to current vintage (if PFC has been activated). For example, if vintage 2005 allowances are trading for $2,700/ton and PFC is 25 percent, then vintage 2004 allowances should theoretically trade around ($2,700 X 0.625) or $1,687.50/ton. But, other factors can influence the price of banked allowances and they may trade at a higher price.

Participation in the NO_X allowance market is not limited to affected sources; any individual or entity may open a general account through the EPA and acquire allowances. The NO_X program is a fairly liquid environmental market and routinely trades on a daily basis. Figure 4.37 shows the actual price for historical NO_X allowance transactions.

Figure 4.37
NO_X Allowance Transactions – Historical Prices



CAIR has instituted some changes in the NO_X SIP Call program to further reduce NO_X emissions. The ozone season component has been retained, but an annual trading program has been added. Starting in 2009, affected sources will have to surrender ozone season allowances for every NO_X ton emitted between May 1 and September 30.

Additionally, an annual season allowance will have to be surrendered for every NO_X ton emitted for the entire year.

Forecast

The NO_X SIP Call allowances have been actively trading since 2003. The allowance price is driven primarily at this time by market fundamentals – the price of technology required to reduce emissions versus the aggregate demand for allowances. Technology for NO_X reduction varies considerably depending on the boiler design and fuel properties, but can be as low as a few thousand dollars per ton removed to more than $10,000 per ton removed. As prices increase for NO_X, more equipment will be installed that will reduce the demand for allowances and bring prices back down.

The current forward curve is based on prices that are indicative of where counterparties will transact right now for future delivery and payment or the escalated value of immediate settlement prices for future vintages using the forward market interest rate curve.

For the integrated resource analysis, SO_2 was assumed to be traded throughout the study, whereas NO_X will be traded in Illinois beginning in 2004 and Missouri beginning in 2007. Each generating unit is currently allocated SO_2 allowances. In the analysis, those allowances were assumed to be sold at the market price of the allowances and the actual emissions were expensed at the same market price. NO_X was treated in a similar fashion. Figure 4.38 shows the forecasted NO_X prices used in the integrated resource analysis.

Figure 4.38
NOx – Forecasted Prices

[redacted]

4.2.3 MERCURY

On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants for the first time ever. This rule makes the United States the first country in the world to regulate mercury emissions from utilities. The Clean Air Mercury Rule will build on EPA's Clean Air Interstate Rule to significantly reduce emissions from coal-fired power plants – the largest remaining sources of mercury emissions in the country. When fully implemented, these rules will reduce utility emissions of mercury from 48 tons a year to 15 tons, a reduction of nearly 70 percent.

The Clean Air Mercury Rule establishes "standards of performance" limiting mercury emissions from new and existing coal-fired power plants and creates a market-based cap-and-trade program that will reduce nationwide utility emissions of mercury in two distinct phases. The first phase cap is 38 tons, and emissions will be reduced by taking advantage of "co-benefit" reductions – that is, mercury reductions achieved by reducing sulfur dioxide and nitrogen oxides emissions under CAIR. In the second phase, due in 2018, coal-fired power plants will be subject to a second cap, which will reduce emissions to 15 tons upon full implementation.

While EPA has proposed a cap-and-trade approach to mercury, several entities have sued in federal court to force EPA to utilize a MACT approach. It is currently unclear how mercury emission reductions will be achieved due to this pending litigation. Due to this uncertainty a mercury allowance trading market has yet to be established. Therefore, it was decided that it would be too speculative to assume price points for mercury allowances at this time. As a result of this uncertainty, the integrated resource analysis did not incorporate any costs due to mercury emissions. AmerenUE is monitoring the mercury issue and will work to achieve compliance with the rules once litigation has been concluded.

4.3 ELECTRIC MARKET

4.3.1 HISTORICAL OVERVIEW

Prior to the advent of the Midwest Independent System Operator (MISO), AmerenUE operated under the direction of the Mid-America Interconnected Network (MAIN), which was responsible for performing the reliability function for its members. AmerenUE dispatched its system in conjunction with MAIN procedures and guidelines, and the objective was to optimally dispatch its resources to meet native load on an hourly basis while maintaining system reliability and integrity through the direction and function of MAIN.

Sales of surplus power or purchases to meet energy deficiencies were primarily transacted through a tight network of other utilities within the geographic region through bilateral agreements. Although off-system transactions were common, the primary objective was to optimize daily operations and balance ephemeral events through exchanges. Transparency and market depth were extremely limited as most participants were focused on efficiently balancing their respective systems rather than regarding off-systems transactions as an enterprise.

As the wholesale electric markets began to open, this network of trading counterparties grew to include marketing and trading organizations, as well as the expanded operations of the previous utility counterparts. This influx of market participation encompassed a broader range of objectives – from pure speculation to physically supplying load obligations obtained through market activity. While the number of participants increased, transactions essentially occurred as before; traders/marketers would call around within the network to buy or sell power and power brokers emerged as intermediaries to procure transactions.

While this expansion of market participants created greater market liquidity and depth, transactions were primarily limited to proximity of supply and load obligations that limited the depth and transparency of regional prices. The pancaking of transmission tariffs, physical transmission congestion, and lack of firm transmission rights limited the market to regional transactions and prevented a wider level of market participation.

Under this market structure, AmerenUE was limited as to the amount of off-system transactions that it could reasonably anticipate. Since the depth of the market, as well as price, were unknown, operations continued to focus on optimizing its generation fleet in order to serve native load rather than capturing potential benefits accruing through a broader participation in the wholesale market. Therefore, the "external" market was regarded as a balancing mechanism to facilitate the optimal operations of meeting native load.

The Federal Energy Regulatory Commission's (FERC) Order No. 2000 in December of 1999 introduced the beginning of a fundamental transformation of the wholesale electric energy market that has dramatically increased the breadth and depth of the market. Most of the functions previously performed by the regional reliability councils moved to Regional Transmission Organizations (RTOs) as well as the generation dispatch functions.

Additional market development initiatives including financial congestion, energy, and ancillary services markets and the elimination of intra-regional transmission rates have dramatically expanded the market in which AmerenUE currently participates. A description of the current market structure in the Midwest follows, and the resulting impacts of market evolution and expansion will be discussed later in this section.

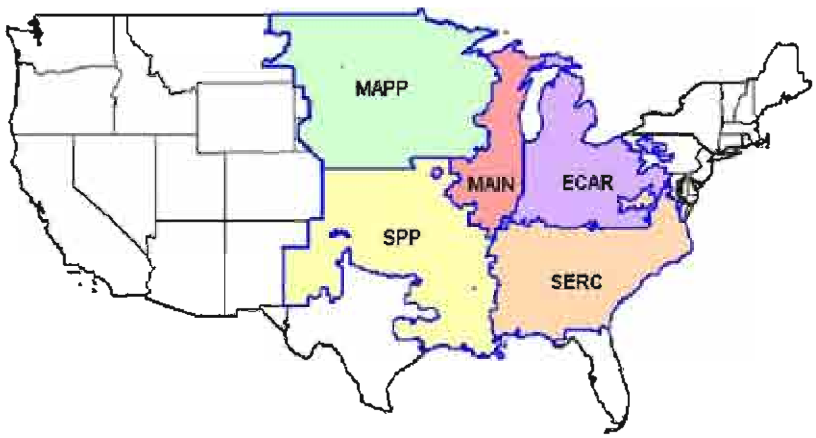
4.3.2 Regional Transmission Organizations in the Midwest

There are three RTO operations that impact the Midwest region; the Midwest ISO and PJM currently operating as RTOs, and SPP which has received preliminary RTO status.

The Midwest region represents one of the largest geographic areas in the United States. It encompasses several of the traditional NERC regional reliability councils, including the Mid-America Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP), and parts of the East Central Area Reliability Council (ECAR), and the Southwest Power Pool (SPP).

Collectively, the region spans all or portions of 21 states from Pennsylvania to Wisconsin. The service territories of more than 39 investor-owned utilities and numerous cooperatives, municipalities, and federal agencies are part of the region. Figure 4.39 illustrates the region under discussion.

Figure 4.39
Midwest NERC Regions (MAIN, MAPP, SPP, ECAR)



Although historically the regional electric councils in the Midwest have operated somewhat independently, the push toward complying with FERC Order 2000 through RTO activities has led to formation of the MISO, SPP's current RTO development initiatives, and the operation of PJM in the Midwest region. Compliance includes efforts to reduce seams issues (i.e., pancaking of transmission rates, joint dispatch, etc.) as joint operating agreements between RTOs are developed and implemented.

MAPP encompasses Minnesota, Nebraska, North Dakota, Manitoba, Saskatchewan, and parts of Wisconsin, Montana, Iowa and South Dakota. MAIN's members include 14 electric utilities that serve customers in parts of Wisconsin, Illinois, Missouri and Michigan, along with more than 40 other organizations involved in regional energy markets.

MAIN has direct interconnection with several other regions, including ECAR, MAPP, SERC and SPP. SPP serves more than 4 million customers, covers a geographic area of 400,000 square miles, and encompasses the states of Oklahoma and parts of New

Mexico, Texas, Arkansas, and Louisiana. ECAR includes the states of Ohio, Indiana, Michigan, Kentucky, and parts of Pennsylvania, North Carolina, West Virginia, and Maryland.

4.3.3 THE MIDWEST ISO

The AmerenUE control area lies within the footprint of the Midwest Independent Transmission System Operator (MISO). Formed in 1996, MISO is responsible for monitoring the electric transmission system within its footprint, ensuring equal access to the transmission system, and maintaining and improving system reliability in the Midwest. Figure 4.40 depicts the MISO footprint which includes major portions of the MAIN, ECAR and MAPP regions.

Figure 4.40
The Midwest ISO footprint

As a FERC-approved RTO, the Midwest ISO serves the regional hub for the flow of electricity in the 15-plus states of its membership. MISO is responsible for the full functional control of its members' transmission systems and performs analytical functions designed to enhance grid reliability. Unlike other RTOs, MISO has thus far maintained all of the control areas within it, positioning MISO as transmission system monitor/administrator rather than the central operator/administrator of the entirety of the market (commodity and transmission).

To manage the immense size of this market, MISO has divided itself into five sub-regions. The largest in terms of generation (generation defined to include non-operating units in shutdown but not retired) is ECAR, with more than 76,000 MW of capacity. The second-largest region is MAPP, with more than 33,000 MW. South MAIN is the third-largest region, with more than 19,000 MW, followed by WUMS, containing most of

Wisconsin and the Upper Peninsula of Michigan, with more than 13,000 MW. The smallest region is the Iowa/MPS region, which includes Iowa and Missouri Public Service, with more than 12,000 MW. MISO sells transmission service under its tariff through its OASIS site and provides settlement, billing, scheduling and tagging services for market participants in each of these sub-regions.

In April 2005, the MISO energy market commenced operations. Under the energy market structure, the MISO administers a Day-head (forward) and Real-time (balancing) energy market which clears all energy transactions occurring within, and through, the MISO footprint. In addition, the MISO administers a financial congestion management market that replaced physical interruption of energy flows with economic stimulus. A more detailed description of each of these market functions is provided in the MISO Operational Structure section below.

RTO Joint Operating Agreements

In January 2002, the MISO, PJM, and SPP announced plans to develop a joint and common wholesale market for electricity producers and consumers in their combined markets, which encompass all or parts of 27 states, the District of Columbia, and the Canadian province of Manitoba. This proposed combined market will be a "one-stop shop" that offers benefits to all customers, regardless of the pace of retail deregulation. This initiative is in response to FERC’s efforts to create more integrated electricity markets and to reduce seams. This integration is to be accomplished with a set of Joint Operating Agreements (JOAs) between the RTOs.

In December 2003, the MISO and PJM executed and filed a preliminary JOA with the FERC. The major areas of focus identified in the JOA include enhancement of reliability between MISO and PJM, establishment of technical procedures and protocols to the coordinated administration of the MISO and PJM joint and common market, and facilitation and integration of new members. The agreement establishes a number of protocols and procedures that are designed to strengthen reliability and are the foundation by which the Midwest ISO and PJM will create seamless operations to serve wholesale electricity customers across the MISO-PJM footprint. The agreement is expected to improve coordination of interregional congestion management, operational data exchange, real-time communications, emergency protocols, system planning and market monitoring.

The operational and financial impacts of the MISO/PJM JOA have yet to be fully established, however in general the following key areas pertain to the JOA:

- Expanded market depth
- Congestion hedging and mitigation between markets
- Financial hubbing and indexing
- Resource adequacy
- Load and generation bidding

- Reliability redispatch
- System reliability compensation
- Demand participation

In 2004, SPP executed a memorandum of understanding to address seams issues with the Midwest ISO, and is currently engaging its stakeholder processes to further develop details and recommendations for developing a JOA with the MISO.

The result of these JOAs will be to reduce/eliminate seams issues (including through and out tariff rates) between RTOs, thereby providing suppliers and load serving entities with expanded access to markets. The likely result will be additional price transparency, market-driven congestion pricing, and improved system coordination and reliability.

MISO Operational Structure

Under the new market structure, the MISO is a market operator with functions and responsibilities very close to those of PJM. MISO performs a security-constrained least-cost dispatch for its entire system. The dispatch includes both a day-ahead and real-time energy market. The day-ahead market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day based on generation offers, demand bids, virtual supply offers, virtual demand bids and bilateral transaction schedules submitted into the day-ahead market. In the real-time energy market, the clearing prices are calculated every five minutes based on the actual system operations security-constrained economic dispatch. The day-ahead price calculations and the real-time price calculations are based on Locational Marginal Pricing (LMP). The day-ahead market reflects a forward market, in which firm supply and demand bids are cleared, with the real-time market primarily serving as a balancing market. The critical design elements in MISO's two-settlement energy market system include:

- **Real-Time Centralized Dispatch**. MISO determines which resources to dispatch at what operating levels to meet real-time needs based on transmission constraints, local reliability needs, and generator operating constraints, as well as system imbalance energy needs.

- **Day-Ahead Energy Market.** The day-ahead energy market is a *forward market* in which hourly clearing prices are calculated for each hour of the next operating day based on the concept of Locational Marginal Pricing (LMP). The results of the day-ahead energy market clearing include hourly LMP values, hourly demand and supply quantities, and hourly control area tie schedules. All schedules submitted in the Day-ahead market are firm commitments.

- **Real-Time Energy Market.** The real-time energy market is a "balancing" market in which the clearing prices are calculated every five minutes, based on actual system operations security-constrained economic dispatch. Real-time LMPs are calculated based upon actual system operating conditions, as described by Midwest ISO's State Estimator.

- **Day-Ahead Settlement.** The day-ahead settlement is based on scheduled hourly quantities and on day-ahead hourly prices. The day-ahead energy market LMPs are also used to establish the settlement value of Financial Transmission Rights (FTRs).

- **Real-Time Settlement.** The real-time settlement is based on actual hourly quantity deviations from the day-ahead scheduled supply and/or load quantities and on real-time prices integrated over the hour. All purchases and sales in the balancing market are settled at real-time LMPs.

- **Integrated Energy and Congestion Management Day-Ahead Market.** Supply offers and demand bids are cleared each hour utilizing optimization modeling to allocate transmission capacity to day-ahead schedules by resolving transmission congestion and to commit unscheduled resources at least-cost to meet the energy and congestion management requirements.

- **Locational Marginal Pricing (LMP).** MISO's energy market established LMPs in the forward market for each hour in the operating day, and for each 5-minute interval in the real-time energy markets for each node in the MISO network.

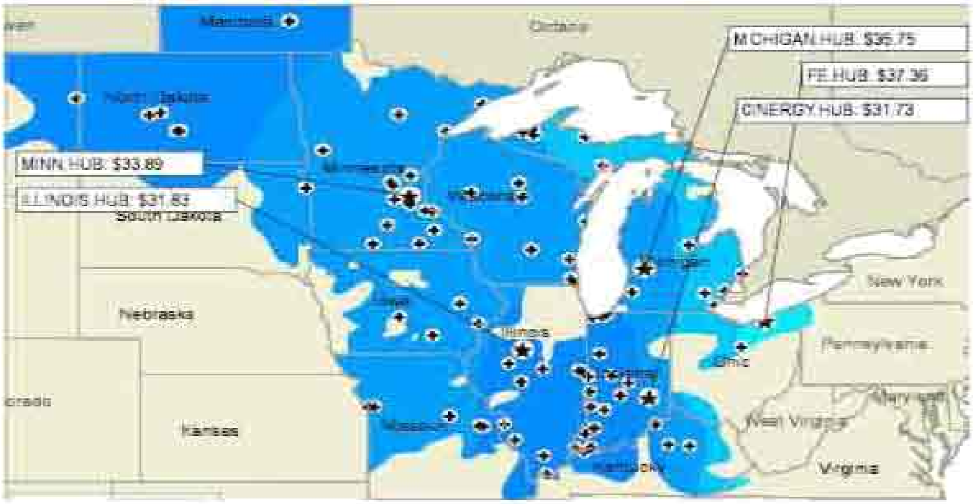
- **Financial Transmission Rights.** Financial Transmission Rights (FTRs) were offered through an initial allocation process in September 2004 to provide a financial hedging mechanism to manage the risk of congestion charges incurred while scheduling energy transactions in the day-ahead market. An annual allocation of FTRs will afford congestion protection as the system evolves.

Market participants in the MISO market make generation offers and/or demand bids into the day-ahead market, submit virtual generation offers and/or demand bids (financial hedging/speculative energy products), or schedule bilateral transactions, which will settle outside of the MISO settlement process. All deviations from day-ahead schedules will settle in the real-time market at the prevailing LMP.

Trading hubs represent specific regions demonstrating price parity within the MISO footprint. Aggregating a representative selection of busses in a region reduces price volatility and provides a price signal for the region that is more predictable, and more importantly provides a common pricing point for financial transactions. Hub prices are the weighted-average LMPs of the specified busses constituting the hub, and can also represent sources and sinks in transactions. There are five trading hubs in the MISO footprint, as illustrated in Figure 4.41 below:

Figure 4.41

MISO Trading Hubs (Financial Indexes)



Market Participants. The MISO market includes load-serving entities, generators, aggregators, distributors, and wholesale buyers and sellers. Market support services providers act as scheduling agents who physically exchange market information, such as submitting schedules, transactions, bids, and offers on behalf of market participants, metering data agents, and billing agents.

4.3.4 CONGESTION MANAGEMENT – FINANCIAL VS. PHYSICAL CURTAILMENT OF ENERGY FLOWS

Physical Transmission Interruption

Prior to the implementation of a financial congestion management process, the MISO (and MAIN prior to MISO) curtailed the flow of electricity across congested paths through Transmission Loading Relief (TLR) protocols. Owners of network and firm transmission rights were curtailed only under extreme system events, however non-firm transmission could be interrupted at any time. While this system protected the grid and maintained integrity, it provided no ability for market participants to make economic decisions regarding alternative supply options or financial optimization of meeting load requirements. Queue position and transmission product dictated priority of service, providing no economic impetus for optimization of the system at large.

The advent of the MISO energy markets established a financial rather than physical mechanism to deal with the impacts of system loading and transmission limitations and congestion. This financial framework has significantly impacted, and will continue to impact, how market participants react and respond to congestion in light of their supply opportunities. Prior to financial congestion management, market participants were physically prevented from accepting delivery from a specific generation resource if their rights to transmission were curtailed due to a TLR. Under financial congestion management, curtailment is replaced with congestion costs that allow transactions to proceed under an economic "penalty". In many cases, it is economic to incur the cost of congestion and continue with the transaction, which alters the entire characteristics of the system from the perspective of physical interruption. Additionally, through financially controlling for congestion and providing hedging instruments to protect against the adverse impacts of congestion, the market takes on a completely new dynamic that encourages efficiency and facilitates lower supply costs across the entire system.

4.3.5 Financial Transmission Rights

The introduction of LMP facilitated establishment of financial transmission rights (FTRs), which allow the market to efficiently alleviate transmission loading, or congestion, through financial rather than physical means, allowing market participants to determine the price they are willing to pay in order to avoid interruption. FTRs will provide a financial hedge to manage the risk of congestion charges incurred while scheduling energy transactions in the day-ahead market.

Market participants who own FTRs will be protected against paying congestion charges for scheduling power injections at one location, and power at a different location in the day-ahead market. FTRs will not protect market participants from congestion charges related to scheduling power in the real-time energy market, deviations from scheduled amounts from the day-ahead market, or from owning FTRs between Sources and Sinks that differ from day-ahead scheduled power injections and outtakes. Additionally, FTR obligations are bidirectional, meaning that FTR holders also have financial exposure in the event that system dynamics cause point of receipt/delivery congestion to "flip" or reverse.

4.3.6 Market Characteristics from AmerenUE Perspective

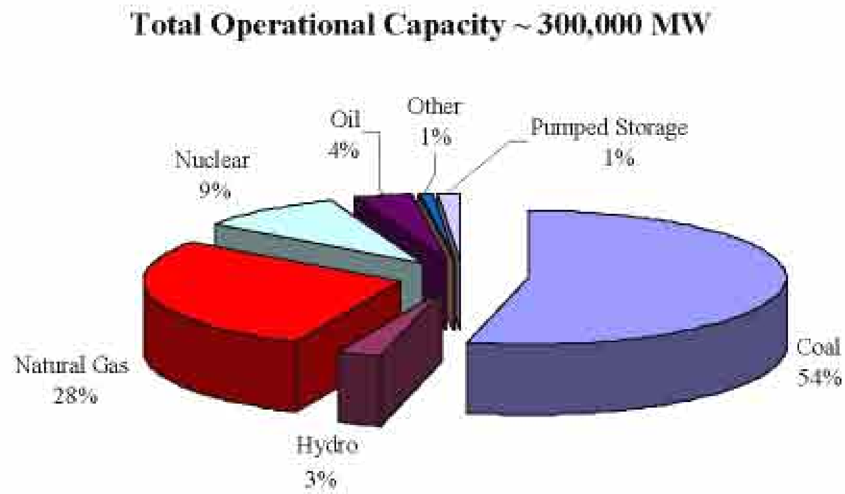
Definition of Market for AmerenUE

For purposes of determining the market in which AmerenUE participates, because the MISO and PJM markets are closely structured, geographically tied, and joint dispatch initiatives are currently under development, these two RTOs represent the regional market interface for the AmerenUE system. The MISO represents the primary market for AmerenUE since the control area is physically located within the MISO footprint, and PJM reflects the second-tiered market interface. As such, for purposes of identifying the market structure in which AmerenUE will participate regarding off-system transactions, the Midwest market region is broadly defined hereafter as the region encompassing the MISO and PJM footprints.

Midwest Market Region Generation Supply

The Midwest market region has historically had a relatively high proportion of coal generation, which has been diluted with the construction of over 43,000 MW of new natural gas-fired generating capacity. Since early 2000, over 16,000 MW of Combined Cycle Gas Turbine facilities (CCGT) have been constructed and over 27,000 MW of Combustion Turbine facilities (GT) have been installed in the Midwest market region. The preponderance for coal was primarily a function of the proximity to coal reserves in the region, however, given the high sulfur content of Midwest coal reserves, a recent move toward low sulfur retrofitting and emissions remediation has been occurring. Figure 4.42 demonstrates the installed capacity by fuel type for the Midwest market region.

Figure 4.42
Midwest market region generation capacity mix



Source: Energy Velocity and AmerenUE Analysis

Coal is the predominant fuel in the Midwest market region accounting for over one-half of the installed capacity, and the median age of the Midwest coal fleet is approximately 45 years. Nuclear generation accounts for roughly 10 percent of the installed capacity in the Midwest region, with most units constructed in the 1970s and 1980s. Most of the natural gas-fired generation facilities in the Midwest market region have been built within the past five years. Simple cycle units (or peaking units) account for approximately two-thirds of the newly installed capacity, while combined cycle and cogeneration facilities represent one-third. Approximately 85 percent of simple cycle construction has occurred within the ECAR and MAIN regions.

Deregulation in several Midwest markets has brought several new market participants to the region in addition to multiple independent power producers (IPPs). Additionally, several major utility companies have entered the marketplace with the intention to grow their asset base in the region. Exelon, AEP, FirstEnergy, Cinergy, and Ameren are the largest single owners of generation capacity, controlling in excess of 80,000 MW of installed capacity in the Midwest market region.

4.3.7 Midwest Demand Profile

Historically, electricity demand growth in the Midwest market region has been closely correlated to economic growth and peak and energy growth have historically been highly correlated. While most of the Midwest market region observes a dual peaking profile (summer and winter), the maximum load requirement generally peaks in late July and early August. These peak periods have exhibited significant price volatility over the past six years, however, given the recent capacity additions and resultant over supply of generation, most of the current volatility is attributable to system events and/or localized constrained load pockets. In 2005, summer peak load for the Midwest market region was approximately 240,000 MW (MISO and PJM). Correspondingly, the total energy consumption for 2004 was approximately 1.2 million GWh. The Midwest market region typically observes an average load factor of approximately 60 percent for the year.

4.3.8 Market Deregulation in the Midwest Market Region

Restructuring activity in the Midwest market region has been fairly limited to date. Currently only three states – Illinois, Michigan, and Ohio, have implemented full retail choice. Arkansas was prepared to offer limited retail access in October 2003 and full retail access by October 1, 2005, but in February 2003 the state legislature repealed the Restructuring Act and stated a preference for continued regulation. Most states in the Midwest have not commenced any restructuring activities at this time.

4.3.9 Implications of Market Evolution and Structure for AmerenUE Resource Planning

Previous assumptions regarding market depth and the potential for off-system sales were derived from actual transaction data provided by the AmerenUE generation dispatchers. Prior to the evolution to an ISO energy market structure, the market for excess generation sales or purchases was limited and fairly constant. Traders interacted with a relatively small network of market participants and realized limited access to broader market activity due to multiple factors including transmission costs and constraints and limited counterparties and firm transmission rights. For modeling purposes, AmerenUE utilized observable off-system transaction volumes to model prospective market transactions.

After the launch of the MISO energy markets in April 2005, a new dynamic was observed relative to off-system transactions. With all resources and load across the MISO footprint bidding into a central energy market, the market for AmerenUE off-system transactions expanded. Essentially, what was once a very limited network of counterparties became a more liquid market place perpetuated by the structure and mechanisms previously discussed. Since physical transmission curtailments were supplanted with economic incentives (congestion pricing) and the supply market became completely transparent (through bidding), the market for off-system energy transactions expanded.

Although there is limited data to base assumptions regarding off-system transactions, there are a number of observations and conclusions that have been incorporated into the latest assumptions supporting the prospective modeling process. First, it is evident that the market for cheaper coal-fired generation has expanded, particularly in the off-peak periods, relative to the volumes observed prior to the advent of the energy market. This increase in demand was tempered to a significant degree as the decreased load impacts of hurricane Katrina were observed in the early fall of 2005. The corresponding reduction in demand demonstrates a clear indication of the inherent risk associated with the volumetric of off-system transactions and provides critical insight into the economic sensitivity of off-system transactions assumptions supporting any resource expansion plan.

LMP data as reported by the MISO reveal that the additional demand for AmerenUE generation during off-peak and shoulder periods has impacted congestion pricing on the system. While market depth has expanded under the MISO, congestion pricing and losses will ensure that market depth is not unlimited. Congestion pricing and losses create an economic limitation on the volumetric of energy delivered from any point on the system, and with transparent LMP at each injection and delivery point on the system, purchasers of energy can quickly determine the economic benefits or detriments associated with their resource purchases and alter their decisions as economics dictate.

As the MISO continues to make changes to its market processes and refines the rules that will impact how the market responds, market participants will likely change their practices in the future as more information is available. This can be observed through the evolution of the PJM market.

The addition or retirement of system resources in the future will also impact energy flows and resulting congestion pricing, adding to the economic complexity and uncertainty of prospective energy transactions. Additionally, as joint dispatch agreements between RTO/ISO's are finalized, modified or abandoned, the implications of these outcomes will impact the amount of economic energy transactions that will occur within the market.

In light of these issues, it is difficult to draw meaningful conclusions about the market's future behavior based on the first seven months of the MISO operations. It is evident from these observations that a shift in off-system transactions has resulted, although projecting this shift into the future is difficult at best. In light of current observations, historical transaction data, and economic constraints, for analysis purposes the volumetric level of potential off-system transactions moving from the AmerenUE system to the market reflects a maximum of 2,000 MW for any peak period during the summer months (June, July, August) and 3,000 MW maximum for any peak period during the non-summer months.

Off-peak, off-system transactions moving from the AmerenUE system reflect a limit of 1,000 MW maximum during and period for both summer and non-summer off-peak periods. These limitations acknowledge the observed increase in volumes transacted after the MISO energy market commencement while recognizing that as volumes continue to increase, a point of economic indifference will result due to increased congestion costs and losses. AmerenUE believes that these market transaction limits represent a reasonable assumption upon which to perform an evaluation and will monitor market activity and data as the MISO market evolves and matures.

A market depth sensitivity was performed to evaluate the impact of increasing AmerenUE to market transaction limits to reflect additional access to counterparties and supply sales. The results of this sensitivity are provided in Section 8. *Results*.

4.3.10 WHOLESALE ELECTRIC MARKET PRICE SIMULATION

The determination of optimal generation resources is significantly influenced by the fundamental development of electricity forecast(s) of wholesale market prices. The commodity nature of a wholesale electric market anticipates that reasonable, well-informed parties will possess different market expectations and will participate in the market based upon these expectations. The challenge in determining the optimal generation supply mix is to determine a pricing path that best achieves the identified objectives, irrespective of achieving an exact match of market prices in the future. The model that AmerenUE utilizes to develop its fundamental wholesale electricity price forecast is MIDAS, and the following provides an overview of the MIDAS model.

MIDAS Model Overview

AmerenUE utilizes the MIDAS Transact electric market price forecasting model, an hourly, chronological wholesale market clearing price dispatch model that fundamentally develops prices that reflect specific inputs and data. The following represents the major characteristics of the modeling platform and the simulation variables required:

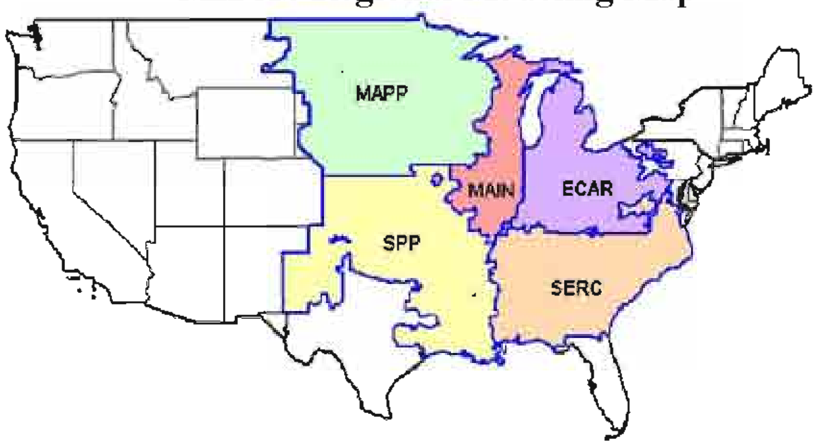
1. The central portion of the Eastern Interconnect (NERC regions including MAIN, MAPP, SPP, SERC, and ECAR) is modeled on an hourly basis for the term of the analysis, including all the loads, thermal unit data, and the interconnected transmission system transfer limits. Loads and resources are grouped according to the bulk system to represent known constraints and limits on electricity transfers.
2. Generation supply cost curves are developed for each load center based on fuel price forecasts, variable dispatch costs (e.g. variable O&M, emissions, etc.), and fuel conversion/efficiency rates. This curve represents a variable cost supply stack of generation resources, stacked from lowest to highest dispatch cost.
3. The model determines an efficient dispatch and import/export of generation, respecting regional transmission limits and any wheeling rates, to minimize the cost to meet hourly demand on the system. The hourly market clearing price reflects the dispatch cost of the unit on the margin for each load center, given transmission and operational constraints.

4. Additionally, the model simulates the addition of various pre-specified economic new generation resources by technology in response to market prices. A new resource will be automatically added to the supply of resources when market prices are sufficient to recover the costs of that new resource, including capital recovery. If not capable of achieving economic new entry, the model will add resources to meet pre-determined reserve margin specifications.
5. Input variables driving the chronological, marginal cost dispatch within the model include all fuel price forecasts, variable O&M, emission costs, and escalation factors.

Regional Market Definition

The MIDAS Transact market dispatch model comprises the MAIN region along with the four surrounding NERC regions. In total, these five regions encompass portions of 26 states in the Midwest, East and South. Figure 4.43 illustrates the modeling region.

Figure 4.43
MIDAS Regional Modeling Map



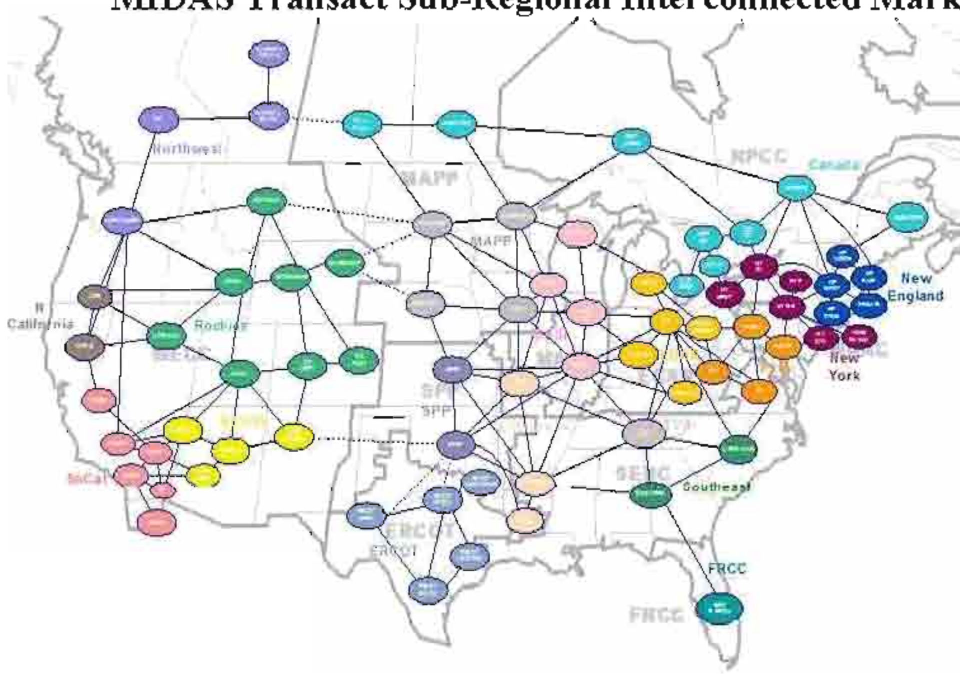
Based on existing transmission transfer capabilities, the model can be broken down into 21 market areas, generating hourly prices for each of these market areas.

APS (ECAR)	AEP (ECAR)	W-ECAR (ECAR)
First Energy (ECAR)	Kentucky (ECAR)	MECS (ECAR)
Alliant West (MAIN)	CE/NI (MAIN)	SMAIN (MAIN)
WUMS (MAIN)	Iowa (MAPP)	AECI (SERC)
TVA (SERC)	VP (SERC)	SPPC (SPP)
SPPN (SPP)	NPCC (Border)	SW-SERC (Border)
CAR/GA/FL (Border)	N-MAPP (Border)	PJM (Border)

The forward view price forecast that best describes the AmerenUE system is represented as SMAIN (the southern MAIN region).

Prices generated reflect transfers across interconnections between transaction groups where transaction groups are defined as NERC sub-regions. Trading is limited by transmission paths and constraints quantities. Figure 4.44 represents the sub-regions modeled in MIDAS Transact.

Figure 4.44
MIDAS Transact Sub-Regional Interconnected Markets



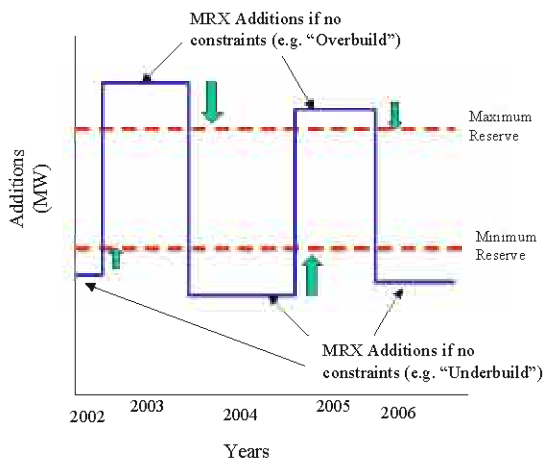
Source. Global Energy

The MIDAS Transact data set is populated with Global Energy Intelligence – Market Ops Strategic Planning Edition information and includes:

- Operational information provided for over 10,000 electrical generating units
- Load forecasts by zone (where zone may be best defined as utility level) and historical hourly load profiles
- Transmission capabilities

The market based resource expansion algorithm (MRX) builds new resources by planning region based on user-defined profitability and/or minimum and maximum reserve margin requirements. In addition, strategic retirements are made of non-profitable units based on user-defined parameters. Figure 4.45 illustrates this process.

Figure 4.45
MRX Resource Expansion Methodology



Source: Global Energy

The MIDAS Transact markets module simulation process performs the following steps to develop hourly prices:

- Hourly loads are summed for all customers within each Transaction Group.
- For each Transaction Group in each hour, all available hydro power is used to meet firm power sales commitments.
- For each Transaction Group and Day Type, the model calculates production cost data for each dispatchable thermal unit and develops a dispatch order.
- The model calculates a probabilistic supply curve for each Transaction Group considering forced and planned outages.
- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur among Transaction Groups.

- The model records and reports details about the generation, emissions, costs, revenues, etc. associated with these hourly transactions.

Data Sources

The primary data source for the MIDAS Transact market model is the Energy Velocity database. This database contains unit specific data for each generating unit in the modeling regions as well as inputs such as load shapes and forecasts for each market area, announced unit retirements and transmission constraints. Some examples of the unit specific data include the following:

- Capacities	- Heat Rates
- Forced Outage Rates	- Planning Outages
- Must-Run Status	- Dispatching Costs
- Fuel Costs	- Variable O&M
- Emissions Dispatching	- Dispatch Multiplier

New Capacity Additions

Developing a long term market price forecast that includes an assumption of load growth requires a methodology to meet increased annual demand. In a deregulated electric marketplace, a primary driver on new unit decisions is economics, and MIDAS Transact incorporates economic new entry when deriving market clearing prices through the building of new capacity.

Initially, discrete capacity additions are included based on AmerenUE's view of announced capacity additions and retirements in the market place. These additions are those new capacity projects that are in various levels of development and expected completion dates for operation. However, this new capacity is only projected out a few years into the future and does not reflect a complete view of what can be expected with regards to new capacity additions into the next 20 to 30 years.

To account for this, the model is allowed to add a mix of new simple cycle, combined cycle and pulverized coal units to maintain an approximate 15 percent reserve margin in the MAIN region. This allows the generation base to continue to grow with load beyond this short term horizon. This reserve limit is only a lower limit to which the model must meet with regards to capacity planning requirements. The Midas model will also build capacity on a purely economic basis if the market price will provide a positive return on the invested capital of the additional capacity.

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
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[redacted]

[redacted]

Environmental Modeling

The market model has the capability of modeling up to five environmental parameters, and AmerenUE currently models unit specific SO_2 and NO_X data for each generating unit in the modeling region, allowing MIDAS to calculate tons of emissions based on unit dispatch.

Fuel Forecasts

Monthly fuel forecasts derived from third-party vendors are utilized in the market model. A comprehensive discussion of each fuel commodity is provided in Section 4.1 of this report.

Global and Regional Market Modeling Processes

AmerenUE utilizes the MIDAS Transact model for two separate tracks of modeling wholesale market clearing prices. A multi-area simulation of the broader market (the central Eastern Interconnect region) is performed, with common commodity and volatility assumptions. All units within the central Eastern Interconnect region are dispatched to meet hourly load on a marginal cost basis, constrained by the transmission system limitations and constraints. The purpose of developing a multi-area wholesale price forecast is to establish an hourly market "interface" price between the AmerenUE system and the interconnected system beyond the AmerenUE border.

The results of the multi-area modeling process, as reflected by an hourly wholesale interface market clearing price, are used as inputs to the single-area simulation of the AmerenUE system. The single-area simulation models the AmerenUE system characteristics and utilizes the interface price developed from the multi-area simulation to emulate economic purchases and sales with the broader market.

While AmerenUE utilizes global, generic unit assumptions in developing the multi-area price curves (to prevent bias and skewed results), the single-area simulation incorporates internal knowledge of the AmerenUE units and operational characteristics.

Deterministic vs. Simulation Methodologies

It is important to make a distinction between deterministic modeling and simulation modeling for risk purposes. A deterministic process implicitly reflects perfect information in the modeling process. That is, all variables and world states are fixed and known, providing results that correspond precisely with the expected outcome of steady-state variables and conditions. As such, a deterministic or single-point modeling result reflects an anticipated outcome in light of perfectly executed and implemented assumptions and conditions.

Simulations are used when key assumptions can be expected to change during the valuation period, but the timing, magnitude, and duration of the changes are unknown. Descriptive parameters such as standard deviation, volatility, distribution characteristics (e.g. normal, lognormal, binary, etc.), correlation, etc. are used to describe the independent and interdependent movement of assumption variables during the modeling process.

Simulations produce multiple iterations of results that, when aggregated, reflect an average or expected outcome and provide a distribution of results around the mean that describe the level of uncertainty that can be expected in light of random movements associated with the descriptive parameters. Simulation methodology and related processes are important in effectively modeling uncertainty. Moreover, the development of the descriptive parameters that drive the variation captured through simulation modeling provides the foundation upon which all simulation results are predicated.

Deterministic vs. Simulation Pricing Results

Figures 4.52 through 4.54 illustrate the monthly prices for the deterministic and stochastic modeling results for the AmerenUE (South MAIN) market interface. The average all hours (7 x 24), average peak (5 x 16, M-F), and average wrap (5 x 8 M-F, 7 x 24 SS) pricing are shown.

As observable from the pricing data, the average stochastic pricing results are slightly higher than the average deterministic results, which should be the case in light of the assumptions utilized in the development of the stochastic parameters, namely that the distributions of the commodity input assumptions are lognormally distributed, meaning that the average falls to the right of the distribution when compared with a normally distributed profile. The non-negative, positively skewed nature of commodity pricing results in a slightly higher price when the results of multiple iterations are averaged relative to a deterministic, single-point result. Figure 4.51 demonstrates the right-centered mean of a lognormally distributed price profile with respect to a normal distribution profile.

Figure 4.51
Lognormal vs. Normal Distribution Means

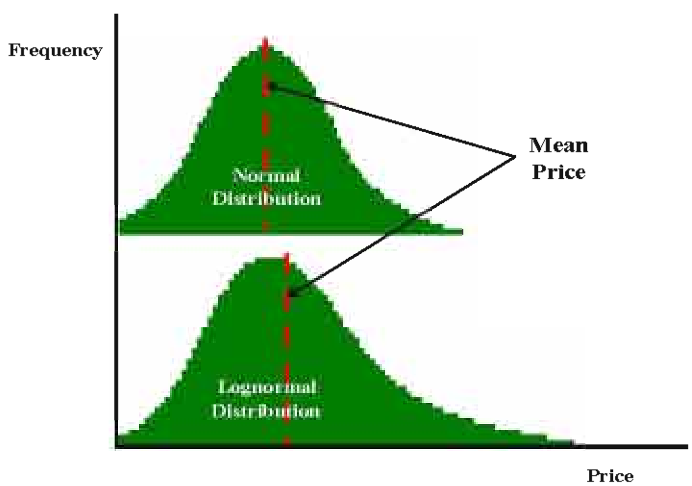


Figure 4.52
AmerenUE South MAIN 7 x 24 Pricing Results

[redacted]

Source: AmerenUE market modeling

Figure 4.53
AmerenUE South MAIN Peak Pricing Results

[redacted]

Source: AmerenUE market modeling

Figure 4.54
AmerenUE South MAIN Wrap Pricing Results

[redacted]

Source: AmerenUE market modeling

4.4 PLANNING STANDARD

4.4.1 BACKGROUND

To provide reliable electric service in the event of system contingencies related to either extreme weather or forced outages of generating plants, utilities maintain resources in excess of forecasted demand. This excess supply is referred to as reserve margin. In the Mid-American Interconnected Network, reserve margin levels are set annually based on MAIN Guide 6 engineering studies.

The MAIN Guide 6 studies are based on calculations of Loss of Load Probability (LOLP) and Loss of Load Expectation (LOLE). The LOLE for a study year is the sum of daily LOLP values for each workday during the year. The adequacy criterion used by MAIN is an annual LOLE of no more than 0.1 day per year. A composite system size of MAIN times four (MAIN x 4) is used to represent MAIN and the neighboring interconnected systems. The studies assume that no transmission limitations to deliverability exist, either within MAIN or from neighboring systems. Transmission assessments are performed by MAIN in other studies.

The calculations consider the population of existing and future generation units, both those owned by utilities and those owned by IPPs, expected generator availability, firm and non-firm net scheduled imports and the emergency support anticipated being available from other regions. They also consider load forecast uncertainty (LFU) at two levels: uncertainty attributable to weather conditions only and uncertainty due to all factors. The latter includes uncertainty due to economic conditions and random variability in addition to weather uncertainty. An LFU multiplier reflects some independence of load forecast uncertainties among regions.

Partial and complete forced outage data for the studies is generated by the North American Electric Reliability Council (NERC) Generation Availability Report (pc-GAR) program, which accesses the NERC Generator Availability Data System (NERC-GADS). The NERC-GADS database is populated with information from generating companies throughout the United States and Canada. The NERC GADS program is recognized as the standard for the power generation industry with respect to unit availability and outage data reporting and tracking.

The LOLE program utilized for these studies considers forced outages of each generating unit to occur randomly, independent of the forced outages of all other units, and at a uniform rate through the year. Common mode outages, whether due to incidents such as tornadoes and floods affecting multiple units at a given site, failures of fuel supply affecting units at various sites, or even terrorism, are not considered. This is because (1) they occurred infrequently, and (2) the capacity at a single site is a small fraction of total regional reserves. Furthermore, the NERC GADS data collection does not provide a basis for estimating the frequency and duration of such events for any site or class of generating units.

The most recent MAIN Guide 6 study was completed in September 2005 and covers the years 2005 through 2009 and 2014. See "MAIN Guide #6 - Generation Reliability Study - 2005-2014" in the Appendix. The Guide 6 Working Group recommended that the planning reserve margin remain at a minimum of 14 percent for the short-term (up to one year ahead). The Working Group further recommended that the planning reserve margin be reduced to a range of 15 percent to 18 percent (from 16 percent to 19 percent) for long-term resource planning and assessment.

A minimum short-term reserve margin of 15 percent was informally observed for many years and was formally adopted in December 2002; this was reduced to 14.12 percent in June 2003, and to 14 percent in September 2004 based on studies performed by this working group. A minimum planning reserve margin of 17 percent to 20 percent was recommended from 1996 to 2002, and 16 percent to 19 percent in 2003 and 2004. Over the past several years, improvements in the performance of nuclear units have slightly reduced the Generation Reserve Goals.

4.4.2 AMERENUE PLANNING CRITERIA

AmerenUE bases its planning reserve margins on the results of the MAIN Guide 6 LOLE studies. AmerenUE currently plans to a [redacted] percent short-term and a [redacted] percent long-term planning reserve margin to meet any system contingencies related to either extreme weather or forced outages of generating plants.

4.4.3 M.S. GERBER & ASSOCIATES ECONOMIC RESERVE MARGIN STUDY

In 2001, AmerenUE engaged M.S. Gerber & Associates (MSG) to perform an analysis of the optimum planning reserve margin for Ameren (AmerenUE plus AmerenCIPS). The purpose of this study was to take an economic perspective in establishing an optimum planning reserve margin for Ameren over a 10-year planning horizon. Generally speaking, when reserve margins are low, the utility is more likely to purchase from the wholesale market and less likely to sell to the wholesale market. The goal of this study was to determine whether increasing or decreasing the Ameren reserve margin over a broad range of uncertainty factors would increase or decrease the present value of net costs to Ameren. The reserve margin that minimized the present value of net costs was selected as the optimum planning reserve margin.

MSG issued their final report on June 28, 2002. See *Analysis and Valuation of Ameren's Planning Reserve Margins – Final Report* in the Appendix. The analysis showed that the optimum planning reserve margin for Ameren was [redacted] percent. See Figure 4.55 below. Key observations in selecting [redacted] percent included:

- In analyzing 100 different forward price scenarios, the present value of net costs to Ameren was minimized at a [redacted] percent planning reserve margin in 58 percent of all scenarios.

- In considering the impact that transmission constraints have on Ameren export and import capabilities, the present value of net costs was minimized at a [redacted] percent planning reserve margin in 60 percent of all scenarios.
- In analyzing different Ameren load growth cases, the present value of net costs was minimized at a [redacted] percent planning reserve margin in 48 percent of all scenarios.

The analysis showed that market price volatility and transmission constraints were significant drivers in setting the optimum planning reserve margin. For example, when market prices are low, maintaining a lower planning reserve margin can be economic in certain cases. Conversely, when market prices are high, maintaining a higher planning reserve margin can be economic in certain cases. The reason for this is simple: when market prices are low, the cost of purchased power is less than the cost of owning and operating new resources. When market prices are high, cost of purchased power is greater than the cost of owning and operating new resources.

With the electric market price volatility and transmission constraint assumptions included in this study, MSG recommended that Ameren maintain a minimum of a [redacted] percent planning reserve margin over a 10-year planning horizon.

Figure 4.55
NPV of Net Cost vs. Reserve Margin

[redacted]

4.4.4 Ongoing Developments

It is expected that the September 2005 MAIN Guide 6 study will be the final reserve margin study conducted by MAIN. MAIN will cease operations after December 31, 2005. Some members of MAIN, together with East Central Area Reliability Coordination Agreement (ECAR) and Mid-Atlantic Area Council (MAAC), will form the Reliability First Corporation (RFC), a new NERC region. Others are expected to join the Midwest Reliability Organization (MRO), which replaced the Mid-Continent Area Power Pool (MAPP) on January 1, 2005.

In October 2005, Ameren decided to join the Southeastern Electric Reliability Council (SERC), effective January 1, 2006. As a sub-region within SERC, Ameren is responsible for establishing its sub-regional standard to comply with the annual LOLE of 0.1 day per year. As such, Ameren will continue to base its planning reserve margins on the results of the last available MAIN Guide 6 LOLE study. Currently Ameren plans to a[redacted]percent short-term and a[redacted]percent long-term planning reserve margin.

With regard to its reserve sharing arrangements, a large majority of the participants in the MAIN Reserve Sharing Group have decided to continue the reserve sharing arrangements in substantially the same form as the MAIN Reserve Sharing agreement through the calendar year 2006. Participants include: the Ameren Operating Companies, PJM (on behalf of Commonwealth Edison), and the Wisconsin MAIN Members. The hardware and software to support the Reserve Sharing Group will be contracted for via a private vendor rather than be provided by MAIN.

4.5 Financial Parameters

The IRP Financial Model includes electricity supply system costs for fuel, variable plant O&M, emission allowance cost, start-up costs, market contracts, spot market purchases and sales, and production tax credits. It also includes all of the revenue requirement costs associated with adding incremental investment in new resources and new transmission. In addition, it includes costs for existing generation assets' capital revenue requirement, existing generation assets' fixed O&M, and other non-electricity supply costs such as distribution, transmission and general plant capital and operating costs. However, the costs that are deemed common to all IRP portfolios are meant to be representative not absolute.

Because the costs common to all portfolios are representative, the impact calculation is only relevant when comparing one IRP portfolio against another. While the impact calculation provides yearly directional implications of rate changes associated with the IRP, it cannot provide a projection of total AmerenUE revenue requirement impacts. Likewise, the IRP impacts assume immediate ratemaking treatment.

4.5.1 CAPITAL COSTS

For the integrated resource analysis, financial assumptions included in Ameren's corporate budget were utilized. For AmerenUE, this included a debt to equity ratio of [redacted] percent to [redacted] percent, a debt interest rate of [redacted] percent LTD and [redacted] percent STD, an equity rate of [redacted] percent and an after-tax discount rate of [redacted] percent.

If a new nuclear generation facility were to be considered as one of the preferred resources, it would increase the Company's risk, as viewed from an investor's perspective, consequently increasing the required returns on equity. For purposes of this analysis, AmerenUE did not estimate the expected increase, but could derive an estimate in the future should one become necessary.

4.5.2 FIXED AND VARIABLE O&M COSTS

The corporate budget contains estimates of the fixed and variable O&M (operations and maintenance) expenses required for operation of the AmerenUE's units. Estimates of fixed and variable O&M costs for the new resource options are from the *Generation Technology Assessment Report* developed by Burns & McDonnell. A summary of the O&M values used in the analysis are contained in Section 6. *Supply-Side Resources*, Generation Technologies. These costs were escalated at [redacted] percent per year.

5 DEMAND –SIDE RESOURCES

5.1 EXISTING PROGRAMS AT AMERENUE

5.1.1 ENERGY EFFICIENCY PROGRAMS

Refrigerator Buy-Back Program

In 2004, AmerenUE contributed an initial $400,000 to the newly established Residential and Commercial Energy Efficiency Fund, which offers AmerenUE Missouri electric residential customers in the St. Louis area rebates for purchasing energy-efficient refrigerators and bounties for giving up old units. Through this program, AmerenUE Missouri customers also get pick-up and disposal of up to two old refrigerators.

Light Bulb Program

On October 1, 2003, AmerenUE contributed $170,000 to a newly established residential lighting initiative – the Change-A-Light Program, which offered electric residential customers throughout Missouri a rebate on ENERGY STAR® lighting products found in hardware stores across the state.

Energy Toolkit Program

The toolkit also allows customers to analyze their bills, calculate the savings potential of energy efficient appliances or find out what portion of their energy use goes to heating, cooling, laundry and other activities. Once customers know where energy is being used, they can learn ways to reduce energy costs. In fact, customers can even calculate what a new addition or some other change in their homes has cost – or saved – them. Creation of this Web-based tool – a $1 million, four-year initiative – is one of a number of programs that are part of the joint Missouri retail electric rate settlement.

Commercial Facility Energy Audit

The Walk-though Energy Audit program is designed to encourage customers to change their internal processes, replace inefficient energy consumption equipment or improve facilities which waste energy by providing a rebate for the costs of energy audits. The program is designed for electric commercial facilities, served by AmerenUE, which are located in Missouri. AmerenUE will credit the customer's account for 50 percent of the initial energy audit cost up to $500. If potential energy efficiency savings are identified, a follow-up detailed energy audit will be performed per customer's request. After the follow-up audit is performed, the remaining 50 percent of the first audit cost, up to $500, will be credited to the customer account. Upon completion of some of the recommended changes identified in the audit and associated with energy efficiency improvements and verification of the changes, AmerenUE will credit the customer's account for 33 percent of the cost of energy efficiency implementation projects. The total for credits, audit costs and implementation projects cannot exceed $5000.

Motor Miser

AmerenUE's Motor Miser program can helps customers evaluate the efficiency of existing electric motors, make effective decisions on motor replacement or repair and develop their own motor management system to achieve energy savings and improve motor reliability. With motor miser, Ameren analyzes the efficiency of motors for customers or businesses that wish to expand, relocate or modernize their facilities, finding the best (least-cost) financing can be a significant challenge.

BOC Certification

AmerenUE contributed $300,000 to initiate in Missouri the nationally recognized Building Operator Certification Training Program. Over the next two years, AmerenUE's support will also help 210 applicants attend 80 hours of classroom training and project work on building systems operations and maintenance to earn their Building Operator Certification (BOC).

This training provides an overview of preventive maintenance, energy efficiency principles and the fundamentals of building systems equipment and operations for commercial building operators. It focuses on energy conservation techniques and efficient lighting fundamentals. It also covers heating-ventilation-air conditioning systems and controls, indoor air quality and environmental health and safety regulations.

The Energy Center of the Missouri Department of Natural Resources, with the Midwest Energy Efficiency Alliance, provides BOC training at a cost of $2,300, but qualified applicants who are working at organizations in AmerenUE's service area will pay $1,150 thanks to the AmerenUE support.

The initial BOC classes are offered in St. Louis at AmerenUE's 1901 Chouteau Ave. Downtown St. Louis headquarters with 7:30 a.m. to 3:30 p.m. Sessions were held Oct. 26, Nov. 22, and Dec. 13 in 2005, and in 2006 are scheduled on Jan. 17, Feb. 13, Feb. 14, March 9, and April 12. The Missouri Department of Natural Resources 1738 East Elm Street Conference Center is the site for Jefferson City sessions set for 8 a.m. to 4 p.m. Sessions were held on Oct. 19, Nov. 17, Dec. 15 in 2005, and in 2006 are scheduled on Jan. 26, Feb. 22, Feb. 23, March 16, April 13.

Low-Income Weatherization Funded Programs

AmerenUE contributed $4 million to the Low Income Weatherization Assistance Program administered by the Missouri Department of Natural Resources Energy Center. The contribution is earmarked to help low-income AmerenUE Missouri electric residential customers reduce their bills by conserving energy. This ranks as the single largest private contribution ever made to this program in Missouri.

5.1.2 Demand Response Programs

Voluntary Curtailment Rider (VCR) – Rider L

This Rider is applicable to industrial and large commercial customers. It started in the summer of 2000 with the purpose of providing credits to customers who, at the company's request, voluntarily curtail electrical usage normally served by AmerenUE. Participating customers view and accept offers via an internet-based system.

Options Based Curtailment Rider (Options) – Rider M

This Rider is applicable to industrial and large commercial customers. It started in the summer of 2000 with the purpose of providing customers the option to grant AmerenUE the right, not obligation, to call for curtailment of a certain level of customer's energy consumption, based upon various curtailment options and associated prices offered by AmerenUE, selected by the customers and specified by a contract.

5.2 Collaborative Pilot Programs

5.2.1 Two-Part RTP Pilot

The purpose of this program is to evaluate the viability of a non-residential two-part real-time pricing rate as a demand response option. The pilot is a result of a collaborative group as governed by the Stipulation and Agreement in Missouri Public Service Commission Case No. EC-2002-1. The primary feature of this pilot-rate application is the providing of day-ahead market pricing for incremental or decremental loads from previously established hourly loads of eligible individual customers opting to participate in the pilot.

5.2.2 Residential Time-Of-Use Pilot

The purpose of this rate is to evaluate the viability of a residential time-of-use rate. This pilot is a result of a collaborative group as governed by the Stipulation and Agreement in Missouri Public Service Commission Case No. EC-2002-1. The primary feature of this pilot application is providing rates that vary during different times of the day and evaluating the customers' response to the variations in these rates.

5.3 Screening Analysis

5.3.1 Energy Efficiency

A complete description of the screening analysis of energy efficiency programs is described in the Appendix of the *Demand-Side Management Briefing*.

The types of programs that AmerenUE evaluated in its DSM analyses in the mid-1990s, and has implemented as pilot programs, or continues to operate, are similar to those found to be most popular around the country. Combining information from AmerenUE and the ACEEE report, the following generic programs were subjected to a screening analysis.

1. *Small commercial and industrial audit program, with focus on lighting*
2. *Large commercial and industrial audit program, with focus on lighting*
3. *Residential new construction*
4. *Residential appliance buy-back program*
5. *Residential lighting*

A description of each generic program is:

1. *Small commercial and industrial audit program, with focus on lighting*. This program would operate similarly to AmerenUE's existing commercial facility energy audit program, and be aimed at small commercial and industrial customers. It would offer reduced costs on energy audits to identify energy efficiency opportunities and possible credits for verified energy efficiency improvements undertaken by customers as a result of the audit. The audits would have a primary focus on lighting improvements, and could also include evaluations of motor efficiency improvements for industrial customers.
2. *Large commercial and industrial audit program, with focus on lighting*. This program would operate similarly to one included in AmerenUE's last DSM assessment aimed at large commercial and industrial customers. It would offer reduced costs on energy audits to identify energy efficiency opportunities and possible credits for verified energy efficiency improvements undertaken by customers as a result of the audit. The audits could have a primary focus on lighting improvements and could also include evaluations of motor efficiency improvements for industrial customers.
3. *Residential new construction*. This program would involve AmerenUE working with builders, developers, contractors, and real estate agents to promote improvements in building shell and appliance efficiencies beyond basic building code and standard practice levels. The program could be operated at relatively low cost by primarily providing information and encouragement or at a higher cost by offering financial incentives tied to specific efficiency improvements. It could be aimed at both single-family and multi-family homes.
4. *Residential appliance buy-back program*. This program would operate like AmerenUE's existing refrigerator buy-back program to provide incentives for purchase of high-efficiency refrigerators and free disposal of old refrigerators. The program could be extended to offering incentives for high-efficiency room air conditioners along with free disposal of old units.
5. *Residential lighting*. This program would continue AmerenUE's involvement in efforts to reduce the market price and encourage customer purchase of compact

fluorescent lamps. Programs of this type can carry over into the small commercial customer market to the extent that they purchase through participating hardware stores.

Note that low-income weatherization programs are not on the above list, even though AmerenUE currently operates such programs. The available data from other programs suggest that the costs of running such programs are relatively high for the load impacts achieved. However, they may well produce other social benefits that justify their funding through public benefits funds.

5.3.2 DEMAND RESPONSE

A complete description of the screening analysis of potentially viable demand response (DR) programs is described in the Appendix of the *Demand Side Management Briefing*.

Traditional demand response programs provided a rate discount (e.g., a 50 percent discount on a demand charge) for the right to interrupt a customer's load for a limited number of hours per year, usually under conditions of low reliability. The customer received no monetary incentive at the time of interruption, faced a stiff penalty for non-compliance and received no compensation for over-complying. As a result of this type of structure, calls for interruptions were perceived as very negative events for customers.

Market-based interruptible load programs will be structured quite differently. These programs are characterized by "'pay for performance," in which customers will receive an incentive tied to the wholesale price of power for each unit of load that they are willing to reduce during high-price or low-reliability periods.

Demand response programs may be classified into two broad types. One consists of *dynamic pricing options* in which consumers face retail prices that reflect wholesale market costs on a timely basis. The dynamic prices may apply all of the time, as in real-time pricing (RTP), or only during periods of unusually high wholesale costs, such as critical peak pricing (CPP).

The other broad category consists of various types of "buy-back" or *curtailable-service* programs in which consumers either receive a price discount in return for a requirement to curtail when requested or are offered a payment in return for curtailment during high-cost or emergency conditions. This category includes traditional interruptible/curtailable (I/C) programs aimed at large customers, air conditioner cycling programs aimed at smaller customers, as well as more market-based programs that pay customers for their load curtailment performance, where the payments reflect the market value of the curtailments.

The screening analysis project proceeded in two steps. The first step involved developing a list of potentially viable programs to be subjected to a benefit-cost screening analysis, and characterizing the nature of those programs for purposes of this analysis. The second step was to conduct the screening analysis.

The list below presents candidate DR products for each of the three main rate classes residential, commercial and industrial. Large customers, with general access to hourly interval metering, can use programs with hourly pricing or with signals that induce response that must be recorded on an hourly basis. Real-time pricing reflects the former while the family of I/C programs reflects the latter. As noted above, I/C programs are classified into two main groups. The first uses market prices to identify curtailment periods as well as the basis for crediting customers for load curtailments and charging them for the right to buy through curtailments, *i.e.* exceed contract firm power levels. Note that AmerenUE is considering all potential demand response options. This does not mean that AmerenUE considers a customer "buy through" option as a viable DR option. The second group involves mandatory curtailments in return for up-front price discounts, including some very short-notice programs typically triggered by system emergency conditions.

Smaller customers, both commercial and industrial, as well as residential, for whom hourly metering cannot be presumed, may also be candidates for demand response provided that such metering can be provided cost effectively. Two forms of time-dependent service, the traditional time-of-use (TOU) structure and the more advanced CPP products that are designed to reflect market conditions on a limited number of days of unusually high wholesale costs are included in the analysis. Additionally, in the interest of comprehensiveness, the residential air conditioner cycling programs which has been piloted at AmerenUE as the leading non-price based demand response vehicle for small consumers is included.

Large Commercial and Industrial Customers

1. Real-time pricing
2. Market-based I/C service (with buy-through)
3. Traditional I/C service
4. Short-notice/emergency I/C service

Small Commercial and Industrial Customers

1. Critical peak pricing
2. Traditional TOU service

Residential Customers

1. Critical peak pricing
2. Traditional TOU service

Air conditioner cycling based on price signals or market conditions

A description of each generic program is:

1. **Real-time pricing.** This product family quotes prices for short time intervals (typically one hour) at short notice (day-ahead or hour-ahead). The most popular version at present is day-ahead hourly pricing in a two-part structure, in which the price applies to departures from a contract quantity called the customer baseline load. The CBL reflects historical usage patterns and is priced in regulated markets under the customer's standard tariff. This standard bill or "base bill" collects regulated revenue on the CBL quantity and contains an implicit hedge

against RTP price variability, as the RTP price applies to load changes only. Ameren's RTP collaborative pilot program is an example of this family.

2. **Market-based interruptible/curtailable products.** This family offers traditional pricing except in curtailment periods. During such periods, a price reflecting market conditions applies to consumption above, and sometimes below, a contract or firm power level (FPL). Structural features to choose include advance notice of curtailment, duration of individual periods and maximum number of curtailments per period (month and/or year), conditions in which curtailments can be called, discount for participation (amount and form), FPL and duration of contract commitment. An innovative product that conforms to both regulated and deregulated markets allows the customer to choose their FPL, has a contract length of a year or two, offers a modest discount from standard rates for participation, and provides payment for curtailment below FPL and charges for buy-through at prices based on and close to forecasted market price. Degree of advance notice is a matter of some discretion depending on customer characteristics. Program acceptance can be broadened by offering customers choices among structural configurations at different prices. Additionally, programs can allow customers to choose the price at which curtailment occurs. Ameren's two I/C products belong in this family, although the second is closer in spirit to the short-notice programs described below.

3. **Traditional I/C products.** This family consists of products whose unifying theme is to treat I/C customers as a peaking generation unit. Their characteristics typically include long contract periods, large (demand charge) discounts for participation, no or low (and nonmarket-based) payments for curtailment, heavy penalties for failure to curtail (i.e. no market-based buy-through). The usual choices regarding advance notice, curtailment interval duration, maximum hours of curtailment, etc. apply.

4. **Short-notice (emergency) I/C products.** This family of products covers non-price based products that obtain load reductions primarily in situations in which buy-through is prohibited. The traditional structural alternatives apply: maximum duration, maximum hours per year, length of curtailment, FPL, length of contract, etc. This family serves a special, narrow and important purpose, to provide the equivalent of spinning reserves. Again, customers are treated as peaking units and only customers with very low outage costs can provide this service or will be willing to do so. The products can be made market-oriented in that the up-front payment can be set seasonally, so that customers can opt in or out by season. However, this flexibility can conflict with the provider's desire for long-term contracting of this service. The product can be paired with other market-based products for individual customers, though. For example, Georgia Power Company offers hour-ahead RTP service and an interruptible rider of the emergency sort to its largest customers.

5. **Traditional time-differentiated service.** This family of products features pricing by season and by time of use to induce demand response relative to flat pricing, as a by-product of traditional efforts to better match cost of service to customer type. Prices are generally based on embedded cost concepts and on-

peak to off-peak price ratios are often around 2:1. Such price differentiation is not typically sufficient to generate sufficient benefits to attract participants to a voluntary program. Mandatory programs tend to fare better due to the loss of the opportunity for self-selection by customers. The issue at many utilities is whether and how residential TOU pricing programs should be introduced. A traditional candidate might involve some market-based pricing (with consequently higher price ratios and narrower peak periods, perhaps, than those in current use in the industry). In this case the market basis of prices is wholesale price forecasts for the coming year. Pricing would be updated each year in this case.

6. **Critical Peak Pricing (CPP).** This family consists of products in which key hours have special (high) prices assigned to them, with the announcement of key hours received at short notice. Product structure choices include: applicable time period, degree of advance notice of prices, degree of pre-specification of prices, basis of price formation, manner in which price information is used (human or automated response), number of periods of short-notice pricing and maximum duration of period. Ameren's Residential Time-of-Use pilot program, with its critical peak price of 30¢/kWh for Groups 2 and 3, is a member of this family.
7. **Residential air conditioner cycling programs.** This product is a form of direct load control for small customers in that under provider-controlled conditions, whole-house air conditioners convert from a full to a partial duty cycle. A price-based variant might be one that allows customers to choose the market price at which cycling begins. Smart technologies will increase the variety of forms that this product can take, moving it away from direct load control.

5.3.3 RESULTS

The following table, Table 5.1, summarizes the cost-effectiveness of each proposed program.

Table 5.1
Net Benefits by Cost Scenario and Program ($000)

[redacted]

Table 5.2 presents a summary of the present discounted value of net benefits from these programs. The top half of the table reports the results for the CAIR marginal cost scenario and the bottom half reports the GGAS results. The "Base" results exclude the capacity benefits while the "Adjusted" column includes them.

"Capacity benefits" refers to a scenario that assumes that wholesale markets do not fully reflect avoided capacity costs. Consequently, a relatively modest avoided capacity cost component was added to the wholesale market price. See the Appendix for the avoided capacity costs that were assumed.

The quantitative analysis of the candidate demand response programs indicates that all are viable in one marginal cost scenario (CAIR) if the assumed potential additional capacity benefits are included in the estimate. If these benefits are excluded, all but the short-notice I/C program are viable, although the AC cycling program is barely viable.

Some programs are viable under the GGAS scenario as well. RTP is viable under the basic definition of net benefits while the short-notice I/C program also succeeds in being viable under the assumption of additional capacity benefits. The other three programs are not viable under the GGAS scenario.

Demand response provides more net benefits in every program under the CAIR scenario than under GGAS, due to the relatively lower price variability of the GGAS world [redacted], which yields relatively fewer chances for obtaining price response benefits.

The estimated load impacts of DR programs are listed in Table 5.2:

Table 5.-2

[redacted]

It is important to note that Table 5.2 was created under the assumption that each program was analyzed in isolation or independent from the other programs. The reality is that multiple offerings within rate classes will reduce these benefits to some extent. Appendix 6 of the *Demand-Side Briefing* is a technical discussion of the basis for the preceding issue. It is important to note that AmerenUE has existing demand response programs which may further reduce the MW potential for the demand response programs listed in Table 5.2. Finally, the demand response reductions in Table 5.2 do not include an adjustment for capacity equivalence. AmerenUE does not have experience with determining the reliability contribution, or capacity equivalence, for RTP products.

AmerenUE has historical data for capacity equivalence for direct residential A/C control programs and traditional interruptible programs.

AmerenUE expects to gather more intelligence on demand response through its participation in the United States Demand Response Coordinating Committee (DRCC). DRCC is a non-profit organization formed in 2004 to increase the knowledge base in the United States on demand response and facilitate the exchange of information and expertise among demand response practitioners and policy makers. In addition to its U.S. focus, the DRCC has been designated by the U.S. Department of Energy (DOE) as the official Expert Body to represent the United States in the Demand Response Project of the International Energy Agency (IEA). DRCC members include American Electric Power, CEC/LBL PIER Demand Response Research Center, ISO-New England, Midwest ISO, National Grid, NYISO, NYSERDA, Pacific Gas & Electric, PJM Interconnection, San Diego Gas & Electric, Salt River Project, Southern California Edison, and Southern Company. Representatives from DOE, the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA) and the National Association of Regulatory Utility Commissioners (NARUC) serve on the DRCC's Advisory Board.

The Ameren Corporation operating companies, including AmerenUE, joined the DRCC in September 2005 and will leverage benefits from working with national and international experts on the implementation of demand response programs with the AmerenUE demand response and energy efficiency collaborative teams proposed in the preceding paragraphs.

6 SUPPLY-SIDE RESOURCES

6.1 OVERVIEW

AmerenUE continuously reviews projects to increase capacity and improve efficiency at existing generating plants. However, continuing load growth will eventually require the addition of new generating resources. Supply side resources considered included:

- Existing resources (Table 6.1)
- Efficiency improvements at existing plants
- Capacity increases at existing plants (Table 6.2)
- New generating technologies (Tables 6.3 – 6.8)
- Power supply agreements
- Purchases of existing plants

AmerenUE considered and evaluated a number of generation technologies as potential supply-side resource options for capacity additions. The options ranged from mature technologies, such as combustion turbine generators, to new technologies in various levels of development, such as Integrated Gasification Combined Cycle. Resources may be utility-owned or purchased from another party.

AmerenUE's New Generation and Environmental Projects Department maintains expertise in the costs and performance characteristics of available generation technologies. This group, with the help of several consultants, performed assessments of the technologies to select the best potential supply-side resources to satisfy system needs. The reports generated from this consultation are shown in the *Generation Technology Reports* document. All technologies were subjected to an initial screening analysis. Technologies considered significantly inferior in development potential, cost, performance or applicability were eliminated from further quantitative evaluation.

Summaries of costs and performance data for the various technologies are provided in Tables 6.3 through 6.8. The construction cost estimates include engineering, equipment, construction, land and inventory. Labor, consumables and waste disposal costs are included in the operation and maintenance cost estimates. Transmission facility costs associated with these technologies are included in the construction cost estimate. Lead time estimates are based on the length of time from the point when a substantial financial commitment is required until the point when the unit is ready for service. The estimates include the time for permitting, design, construction, testing, and startup.

For discussion purposes the technologies are divided into the following groups:

- Gas-Fueled Technologies
- Coal-Fueled Technologies
- Renewable-Resource Technologies
- Pumped-Storage Technologies
- Nuclear Technologies

6.2 EXISTING RESOURCES

The AmerenUE system relies on a diverse mix of generating technologies to supply electrical power. The vintage of the plants ranges from 1913 for the Keokuk Hydroelectric Plant to 2005 for the most recent addition (Unit 5) at the Venice Power Plant.

Each generating technology has unique attributes that enhance the reliability and the flexibility of its operation. Table 6.1 lists the existing units and summarizes their characteristics. Power plants are generally categorized by the type of load they serve: base, intermediate or peaking. Note that AmerenUE presently does not have any intermediate capacity.

6.2.1 BASE CAPACITY

Base capacity for the AmerenUE system is provided by the Callaway, Keokuk, Labadie, Rush Island, Sioux and Meramec power plants. These plants represent 75 percent of the total system-owned capacity.

Callaway – The Callaway Plant, located in central Missouri, was placed in service in 1984. It consists of one pressurized water reactor nuclear power unit. The net capacity of the plant varies from 1,147 MW in the summer to 1,175 MW in the winter. Refueling of the unit occurs approximately every 18 months. The most recent refueling was completed in November 2005.

Rush Island – The Rush Island Plant is located on the Mississippi River near Festus, Missouri. The plant is composed of two pulverized-coal-fired units. Both units have a net summer capacity of 604 MW, as a result of high pressure/intermediate pressure (HP/IP) turbine retrofits completed in 2001 and 2004. These units were placed in service in 1976 and 1977. Low sulfur Powder River Basin coal for the plant is delivered by rail and barge.

Both units, although designated as Phase II units under the provisions of the Clean Air Act Amendments (CAAA) of 1990, have received Phase I permits as substitution units. Low NO_X burners have been installed on the units, and both burn low sulfur Powder River Basin (PRB) coal.

Labadie – The Labadie Plant, located on the Missouri River in eastern Franklin County, Missouri, consists of four pulverized-coal-fired units placed in service from 1970 to 1973. Units 1 and 2, having received upgraded HP/IP turbines in 2002 and 2001, respectively, have a net summer capacity of 597 and 594 MW, respectively. Units 3 and 4 have a net summer capacity of 612 MW each, having received HP/IP and LP turbine upgrades in 2003. Thus the total plant rating is 2,415 MW. Low sulfur PRB coal for the plant is delivered by two rail lines. Low NO_X burners have been installed on the units.

Sioux – The Sioux Plant is located on the Mississippi River in eastern St. Charles County, Missouri. The two units use cyclone boilers and have a summer net capacity of 497 MW each, resulting from LP turbine upgrades completed in 1998-1999 and HP/IP turbine upgrades completed in 2004-2005. Full capacity requires a mixture of 40 percent high-Btu Eastern coal and 60 percent PRB coal. The units are limited to 460 MW each when burning 100 percent low sulfur PRB coal. The units were placed into service during 1966 and 1968. Coal is delivered to the plant by rail and barge. Over-fired air systems were recently installed to reduce NO_X emissions.

AmerenUE began an experiment to burn used tires at the Sioux Plant in 1992. The results showed that a mixture of tires and coal could be economically burned in the boilers without adversely impacting compliance with environmental regulations. The company is presently burning a mixture of approximately 2 percent chipped tires and 98 percent coal. The plant has burned more than 17 million tires since 1992.

Meramec – The four-unit Meramec Plant is located in southern St. Louis County, Missouri, on the Mississippi River. Units 1 and 2, placed in service in 1953 and 1954, have a net summer capacity of 122 MW and 120 MW, respectively. The third unit has a summer net capacity of 269 MW and was placed in service in 1959. Unit 4, currently rated at 347 MW, was placed in service in 1961 and upgraded in 2005 with new HP and LP turbine components.

The primary fuel for all four units is low sulfur PRB coal, which is delivered by rail or barge. Low NO_X burners have been installed on Units 1, 2 and 4. Units 1 and 2 have the ability to achieve full rated capacity on either coal or natural gas. Up to 30 percent of Unit 3's output can be fueled by natural gas.

The units at the Meramec Plant, which are designated as Phase II units according to the CAAA, have received Phase I permits as substitution units.

Keokuk – The Keokuk Hydroelectric Plant, located on the Mississippi River near Keokuk, Iowa, was placed in service in 1913. The facility includes fifteen run-of-river hydroelectric generators that have a total net capacity of 134 MW during expected summer river conditions. Since 2001, seven of the 15 units have been upgraded with more efficient turbine runners and components to increase the nominal unit capacities by 2 MW per unit. The plant is not subject to license renewal requirements under the Federal Power Act.

6.2.2 PEAKING CAPACITY

Peaking capacity is supplied by a variety of technologies that utilize oil, natural gas, hydroelectric and pumped storage. Approximately 25 percent of the company's total capacity is considered peaking capacity.

Osage – The Osage Hydroelectric Plant is located at Bagnell Dam on the Lake of the Ozarks, in central Missouri. The first six units were placed in service in 1931, and units 7 and 8 were placed in service in 1953. The eight hydroelectric generators result in a total plant capability of 226 MW. Units 3 and 5 have been upgraded with high efficiency turbine runners. The Osage Plant is licensed until 2006 under the Federal Power Act. Renewal of the license is currently being finalized.

Taum Sauk – The Taum Sauk Plant is a pumped-storage facility located 90 miles southwest of St. Louis, Missouri. The plant has a net summer rating of 440 MW and includes two reversible pump-turbine units and upper and lower reservoirs. Both units were placed in service in 1963 and were upgraded in 1999 with high-efficiency turbine runners. The plant operates by pumping water from the lower reservoir to the upper reservoir during times of low system load and low energy cost. During peak demand periods the water is released from the upper reservoir for generation by the two water turbines.

Combustion Turbine Generators – The company's 28 combustion turbine generators (CTGs) are located at 12 sites throughout the Ameren service area and have a total net summer capacity of 1,680 MW. The units were installed from 1967 through 2005.

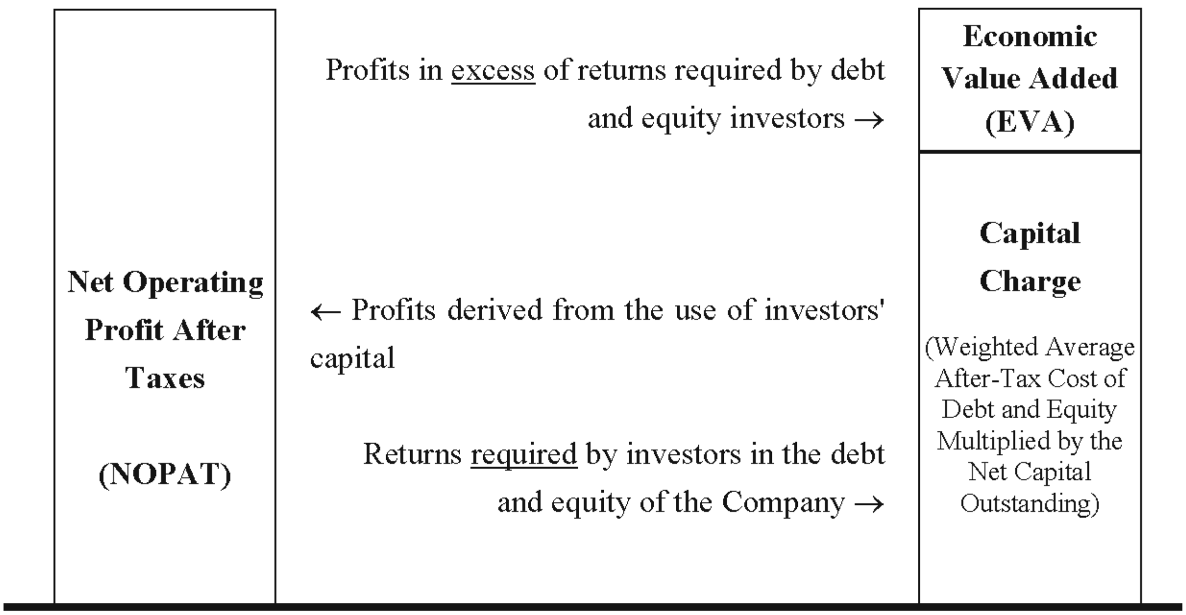
Table 6. 1
AmerenUE 2005 Generating Capability – Existing Units

		Net Capability (MW)			Transportation
Station Unit	Type	Summer	Winter	Fuel Type	Method
Callaway	Base	1,204	1,242	Uranium	Truck
Rush Island 1	Base	604	609	Coal	Rail,Barge
Rush Island 2	Base	604	609	Coal	Rail,Barge
Labadie 1	Base	597	604	Coal	Rail
Labadie 2	Base	594	601	Coal	Rail
Labadie 3	Base	612	617	Coal	Rail
Labadie 4	Base	612	617	Coal	Rail
Sioux 1	Base	497	504	Coal	Rail,Barge
Sioux 2	Base	497	504	Coal	Rail,Barge
Meramec 1	Base	122	126	Coal/NG	Rail,Barge/PL
Meramec 2	Base	120	124	Coal/NG	Rail,Barge/PL
Meramec 3	Base	269	276	Coal/NG	Rail,Barge/PL
Meramec 4	Base	347	364	Coal	Rail,Barge
Total Steam Turbine		6,679	6,797		
Keokuk (15 Units)	Base	134	130	Hydro	
Osage (8 Units)	Peak	226	219	Hydro	
Total Hydro		360	349		
Taum Sauk (2 Units)	Peak	440	330	Hydro	
Total Pumped Storage		440	330		
Venice (Unit 1)	Peak	26	30	#2 Oil	Truck
Howard Bend	Peak	43	46	#2 Oil	Truck
Meramec CTG-1	Peak	55	61	#2 Oil	Truck
Fairgrounds	Peak	55	61	#2 Oil	Truck
Mexico	Peak	55	61	#2 Oil	Truck
Moberly	Peak	55	61	#2 Oil	Truck
Moreau	Peak	55	61	#2 Oil	Truck
Meramec CTG-2	Peak	53	56	NG/#2 Oil	PL/Truck
Venice (Unit 2)	Peak	49	53	NG/#2 Oil	PL/Truck
Peno Creek (Units 1 - 4)	Peak	188	204	NG/#2 Oil	PL/Truck
Kinmundy (Units 1-2)	Peak	232	224	NG/#2 Oil	PL/Truck
Venice (Units 3 & 4)	Peak	338	358	Nat Gas	Pipeline
Venice (Unit 5)	Peak	117	120	Nat Gas	Pipeline
Pinckneyville (Units 1-4)	Peak	176	152	Nat Gas	Pipeline
Pinckneyville (Units 5-8)	Peak	144	160	Nat Gas	Pipeline
Kirksville	Peak	13	14	Nat Gas	Pipeline
Viaduct	Peak	26	30	Nat Gas	Pipeline
Total Combustion Turbine		1,680	1,752		
Base Load		6,813	6,927	75%	
Peaking		2,346	2,301	25%	
Total Company		**9,177**	**9,228**	**100%**	

6.3 PROJECT JUSTIFICATION PROCESS

To provide a consistent methodology for evaluating alternatives outside the more structured integrated resource planning process, the Company developed a corporate justification procedure referred to as Economic Value Added (EVA). See Figure 6.1. This procedure establishes economic parameters used for internal justification of large projects not evaluated through the resource planning process. It addresses capital and operating costs, as well as energy and demand costs/savings. The parameters in EVA are reviewed annually and updated as necessary.

Figure 6.1
Economic Value Added



EVA is mathematically calculated annually over the period of an analysis as follows:

	Revenues
Less:	Operating Costs
Less:	Book Depreciation
Less:	Taxes
=	Net Operating Profit After Tax (NOPAT)
Less:	[Net Capital x Capital Charge Rate (%)]
=	Economic Value Added (EVA)

The annual EVA values, calculated using the above formula, are each discounted back to present values at the beginning of the analysis period. The capital charge rate is used as the discount rate in this present value calculation process. The present values of the annual EVAs are summed up on a cumulative, year-by-year basis over the period of analysis. When the cumulative present value of the annual EVAs reaches "0", it implies that the return assumptions implicit to the capital charge rate have been satisfied.

The point at which a positive EVA is achieved is not, however, necessarily indicative of the point at which the full investment in the project has been recovered. Depending on the economic life of the investment, capital recovery may take place over many additional years. The point at which the cumulative discounted EVA exceeds the remaining capital balance (adjusted for the effect on NOPAT due to any income tax benefit resulting from a write-off) would be considered the point at which the investment in the project has been recovered.

6.4 POTENTIAL POWER PLANT EFFICIENCY IMPROVEMENTS

Changes in unit efficiency occur over time for various reasons, such as the desire to burn coal of a different quality than the coal for which the boiler was originally designed, new governmental regulations, etc. AmerenUE continually reviews its existing units to determine the economic value of improving plant efficiency.

Periodically, projects are evaluated for maintaining and improving availability and/or efficiency. Boiler components, heat exchangers, controls, etc., are evaluated and replaced or improved, if justified. Economic justifications are reviewed using the Company EVA expenditure justification procedure.

6.5 POTENTIAL CAPACITY INCREASES AT EXISTING SITES

Expansion of capacity at existing AmerenUE generating stations is currently under consideration. Potential projects require cost justification to receive funding. Base load plant projects currently under investigation consist of hydro-turbine runner upgrades and coal plant turbine upgrades to state-of-the-art technology to improve efficiency. Peak load hydro-plant projects currently under investigation consist of hydro-turbine runner updates. Because peak load fossil-fueled plants have little or no spare transmission outlet capacity, they are generally not good candidates for capacity expansion. Converting a facility from simple cycle to combined cycle is also limited by availability of adequate water for steam generation, with the exception of the Venice Plant. Facilities may be expanded if future economic conditions warrant and environmental regulations allow. Table 6.2 shows potential capacity increases at existing AmerenUE sites.

Callaway – The steam generators and turbines were replaced during the recently completed fall 2005 refueling outage. Upon completion of the outage, the net capacity of the plant is expected to vary from 1,204 MW in the summer to 1,242 MW in the winter.

Labadie – Low pressure (LP) turbine retrofits are anticipated on Labadie Units 1 and 2 within the next 10 years. These projects would result in a net capacity increase of 20 MW per unit.

Rush Island – LP turbine retrofits are anticipated within the next 10 years. These projects would result in a net capacity increase of 15 MW per unit. The Rush Island site is being considered for an additional 750 MW pulverized-coal unit or three 250 MW integrated gasification combined cycle units.

Meramec – Turbine upgrades to Unit 3 could increase this unit's capacity by an additional 20 MW.

Keokuk – Two additional unit upgrades are scheduled to be completed in 2007. Expected nominal capacity increase is 2 MW per unit. The remaining six units are being evaluated for upgrades.

Osage –Two additional main unit upgrades are scheduled to be complete in 2008. Two service-unit upgrades are being evaluated for installation in 2008.

Venice – Units 3 and 4 have the potential to be converted from peaking to combined cycle operation. This conversion would add about 240 MW.

Table 6.2
Potential Capacity Increases, MW

Station/Unit	Equipment	Potential Capacity Increase
Rush Island 1	LP Turbine Upgrades	15
Rush Island 2	LP Turbine Upgrades	15
Labadie 1	LP Turbine Upgrades	20
Labadie 2	LP Turbine Upgrades	20
Meramec 3	HP & LP Turbine Upgrades	20
Keokuk 1-6, 14, 15	Turbine Runner Upgrades	16
Osage 1 and 7	Turbine Runner Upgrades	15
Osage Service Units	Turbine Runner Upgrades	2
Kinmundy	Additional CTGs or Conversion to Combined Cycle	??
Pinckneyville	Additional CTGs or Conversion to Combined Cycle	??
Venice	Conversion of Units 3 & 4 to Combined Cycle	240
Total Company		**363**

6.6 GENERATION TECHNOLOGIES

6.6.1 GAS-FUELED TECHNOLOGIES

Gas-fueled technologies typically include combustion turbines in simple cycle (combustion turbine generator, or CTG) and combined cycle (CC) configurations. This category could also include gas-fired internal combustion engines, steam boilers, compressed air energy storage and fuel cells. But the gas turbine cycle is one of the most efficient cycles for the conversion of premium gaseous fuels to electricity. Gas-fired steam systems are less efficient. Internal combustion engines cannot take advantage of the economies of scale that gas turbines do. Compressed air energy storage projects are highly site specific and are not technologically mature. Fuel cells are small scale and are still in the development stage. Table 6.3 shows performance and cost data for gas-fueled technologies.

CTGs have relatively low installation costs and short construction times, but the energy production cost is high. They are used to meet peaking requirements. We evaluated dual-fueled CTGs – those that could burn either natural gas or fuel oil. Although dual-fuel capability increases the capital cost, the cost is justified by the fuel flexibility and improved system reliability, especially in the winter. Combined cycle units combine combustion turbines, heat recovery steam generators (HRSGs), and steam turbines. Part of the heat in the exhaust of the combustion turbine is recovered in the HRSG to produce steam for the steam turbine. The additional equipment required for a CC unit increases the installation cost but improves efficiency. This technology is most applicable for intermediate loads. CTG and CC technologies are quite mature.

There are three basic types of CTG units: aero-derivative, small frame, and large frame. Specifically, we modeled the General Electric brands of these types: LM6000, 7EA, and 7FA, respectively. Each of these types has different operational capabilities and cost structures and performs a specialized function. Accordingly, depending on the fleet mix and particular system requirements, different CTGs are better suited for different tasks. AmerenUE has a need for all three types of CTGs. Selection of machine type requires multiple criteria to be balanced as there is no single perfect machine.

Aero-derivative CTGs are small (the GE LM6000 is 45 MW) units whose combustion turbine was designed to hang on an aircraft wing. Their advantages include:

- Fast start capability
- Intraday cycling capability
- Low heat rate
- Low capacity (small capacity increment or decrement)
- Low start cost

But these operational advantages come at a cost: the capital cost for an aero-derivative CTG is about 25 percent higher than that of a small frame CTG and 65 percent higher than that of a large frame CTG.

Small frame CTGs have low to medium capacities (the GE 7EA is 75 MW). Their advantages include low capacity, moderate start time and start cost, and moderate capital cost. A disadvantage is their relatively high heat rate.

Large frame CTGs have high capacities (the GE 7FA is 160 MW). The size and complexity of their design require that they run for at least several hours at a time. Their advantages include very low capital cost and the ability to be converted to CC operation. Their disadvantages include very high start costs, high capacity and low operational flexibility.

Combined cycle plants consist of one, two or three CTGs, with a HRSG for each CTG and one steam turbine. Although other configurations are possible, the 2x2x1 configuration is the most commonly used in the industry. AmerenUE considered two CC plants: conversion of the Venice CTG 3 and 4 units to CC and a greenfield CC plant. Advantages to the Venice project over a greenfield project include the use of existing land and infrastructure, water supply, and proximity of the site to load. Disadvantages include higher construction cost and the fact that the Venice site is in an ozone nonattainment area.

6.6.2 Coal-Fueled Technologies

Coal-fueled technologies generally have low energy production costs and high installation costs. See Table 6.4 for performance and cost data for coal-fueled technologies. These types of technologies are normally applicable for base load operation where the low production costs offset the higher construction charges. Coal fueled technologies identified for evaluation were pulverized coal (PC), integrated gasification combined cycle (IGCC), and fluidized bed combustion (FBC).

Pulverized Coal

The PC technology is fully mature, with the lowest construction cost and performance risk of the three. Supercritical PC technology employs boilers that produce higher pressure and temperature steam compared to subcritical PC technology. The resulting improvement in efficiency comes at a slightly higher capital cost. Although few supercritical PC units have been built in the United States in recent years, they represent a mature technology that has been the PC technology of choice in the rest of the world. We modeled the supercritical PC at both a brownfield site (Rush Island) and a greenfield site. Advantages to the Rush Island site include the use of existing land and infrastructure and operational synergies with the existing units. A disadvantage is the fact that the plant is in an ozone non-attainment area. This would require the installation of selective catalytic reduction on Rush Island Units 1 and 2 to offset emissions from the new Unit 3. For more detailed information on PC technology, see the following reports in *Generation Technology Reports:*

- Strategic Siting Study
- Missouri Pumped Storage Project Concept Study
- Rush Island Unit 3 Feasibility Study
- Rush Island Unit 3 Conceptual Cost & Performance Study
- Generation Technology Assessment

Integrated Gasification Combined Cycle

IGCC consists of four major components: gasifier, combustion turbine, heat recovery steam generator, and steam turbine. The gasifier converts coal into a synthesis gas – "syngas" – that consists of hydrogen, carbon monoxide, and carbon dioxide. Note that other carbon-containing fuels, like petroleum coke, lignite, oil distillates and residues, can be used. The syngas is then cleaned of particulates, sulfur, and other contaminants before being combusted in a CTG. As with conventional CC, the CTG exhaust gas is used in a HRSG to produce steam to drive an additional turbine generator. For more detailed information on IGCC, see the "IGCC Technology Assessment Report" in *Generation Technology Reports*.

Compared to the PC technology, the IGCC technology is more efficient and produces lower emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulates, carbon monoxide and carbon dioxide (CO_2). Emissions of mercury and volatile organic compounds are similar for PC and IGCC technologies. IGCC has better fuel flexibility than PC. Gasification technology for power generation has been tested on a wide array of fuels, including eastern bituminous, mid-western bituminous and sub-bituminous coals, lignite and pet coke. Capital cost and performance of the gasifier is more sensitive to fuel selection than are current designs for PC plants, however. Also, IGCC has lower variable operation and maintenance (O&M) costs.

Another advantage of IGCC over PC is the potential for significantly lower cost of CO_2 capture and sequestration, should future environmental regulations require it. "CO_2 capture" refers to the capture and purification of the CO_2 produced by gasification of the fuel, while "CO_2 sequestration" refers to disposing of the CO_2 in a manner such that it is not released into the air. If a high tax rate or a limit on CO_2 emissions is implemented in the future, an IGCC plant will have a competitive advantage over other coal technologies. Published reports indicate that the cost of adding CO_2 capture would add about 65 percent to the capital cost of a supercritical PC unit but would add only about 30 percent to an IGCC unit. This does not include the cost of sequestration. Extensive research and large-scale demonstration projects would be needed before a commercial IGCC or other coal plant would be in a position to sequester CO_2.

But there are significant disadvantages of the IGCC technology compared to PC. IGCC is not a mature technology; it has higher capital costs, fixed O&M costs, performance risk, and forced outage rate. In fact, fixed O&M costs for IGCC units are estimated to be [redacted]kw-year compared to [redacted]kw-year for supercritical PC units. And staffing requirements for an IGCC plant are approximately 40 percent higher than those for a supercritical PC plant. IGCC has less operating flexibility. Load following and cycling are currently not well understood, because the IGCC processes have not been demonstrated in facilities with multiple gasifier trains and CTGs. The allowable loading and unloading rates for gasification systems are lower than for PC and CC plants. And the operating range for CTGs is typically 60 to 100 percent, with heat rate deteriorating at lower loads.

The lack of commercial IGCC experience results in higher technical, schedule, regulatory and commercial risks than for a new PC unit. Indeed, there are only two large commercial coal-fired IGCC units operating in the United States: the 262 MW Wabash River Project in Indiana and the 250 MW Polk Power Station in Florida. These units began commercial operation in 1995 and 1996, respectively. The United States Department of Energy shared 50 percent of the cost for both plants. Even after the initial start-up phases for these plants were completed, the overall availabilities were low compared to PC technologies.

The failure of the Pinion Pine IGCC project in Nevada demonstrates that the risk involved with utilizing unproven technologies is real. The final report on that project stated that the gasifier failed in each of the 18 start-up attempts during the reporting period. The Pinion Pine gasification plant was eventually mothballed; the final cost was $3,393/KW. In Wisconsin, the Public Service Commission recognized the costs and risks of IGCC technology when they recently approved construction permits for two PC units but denied the construction permit for an IGCC unit at Wisconsin Energy's Elm Road Generating Station. And in Ohio, American Electric Power has proposed building a 600 MW IGCC plant, but they are seeking a guarantee of cost recovery from state regulators before they commit to the project.

Currently, there is a renewed effort among government, environmental, and industry organizations to implement and commercialize IGCC. The Energy Policy Act of 2005 created a number of financial incentives for new coal-fueled power plants using "clean coal" technologies, such as IGCC. These incentives include funding, tax credits and loan guarantees, but the available funding is limited. Some developers are trying to act quickly to ensure that their projects qualify for these incentives. There have been a number of joint ventures announced between gasification technology owners and engineering firms. ConocoPhillips and Fluor, General Electric and Bechtel and Uhde and Black & Veatch have all announced alliances to offer turnkey services for IGCC facilities. More than 20 IGCC projects have been announced in the United States; most are in the early stages of development.

We modeled IGCC at both a brownfield site (Rush Island) and a greenfield site. Site advantages and disadvantages are the same as for the PC unit. Also, we modeled the brownfield IGCC unit under two different fuel assumptions - low sulfur and high sulfur coal.

Fluidized Bed Combustion

The FBC technology, though more mature than the IGCC technology, has similar capital cost but produces higher emissions. It does not compare favorably to IGCC or PC technologies. FBCs are classified as atmospheric or pressurized. Atmospheric FBC technology is more mature than pressurized. AFBCs are classified as either bubbling fluidized bed or circulating fluidized bed (CFB). The CFB technology is more mature than bubbling fluidized bed. Advantages of CFB technology include its ability to burn fuels with highly variable characteristics, such as waste coal, and its ability to control SO_2 via addition of limestone and flyash into the combustion process. Disadvantages include its high capital cost and heat rate.

6.6.3 RENEWABLE RESOURCE TECHNOLOGIES

Renewable energy resources are generally considered to be either non-depletable or naturally replenishable. See Table 6.5 for performance and cost data for renewable technologies. There are a number of different technologies currently being developed in areas throughout the world that take advantage of unique geographic features, such as high wind, solar, or geothermal energy densities. Each of these technologies requires a large, reliable supply of renewable energy to be economically viable. The basic renewable resource technologies include solar, wind, hydropower, biomass and geothermal, along with those that use fuels such as ethanol from biomass, landfill gas and gas from waste treatment.

With the rising price of fossil fuels, such as coal and natural gas, the renewable energy industry is gaining attention. Technological advancements in the capabilities of renewable generation resources coupled with the extension of the Production Tax Credit have led to significant growth in the green power industry. There are now 600 utilities across the nation, covering 34 states, that offer green power programs to their customers.

According to the Department of Energy (DOE), in 2004 approximately 4,390 million MWh of green power was purchased by more than 520,000 customers. The average green power price premium has steadily declined since 2000. At that time the green power premium averaged 3.48 cents/ KWh, but by 2004 it was closer to 2.45 cents/KWh.

Investment in this generation segment has also seen rapid growth. Investments are anticipated to reach $1.5 billion in 2005, a 25 percent increase from 2004.

Wind Resources

Wind generation continues to see the largest growth among renewable generation resources as it continues to have the most economic advantage over solar, biomass and other types of renewables. Costs have dropped significantly, and some units in high wind areas have experienced capacity factors in the 20 to 30 percent range. There is currently 6,940 MW of wind generation capacity in the United States. It is anticipated that another 2,500 MW will be added in 2005 and that an additional 2,000 MW will be added in each of the following three years.

In the fall of 2004, Ameren created several teams to assess and evaluate the potential for renewable energy generation resources. These teams have been meeting with a variety of renewable resource developers, but have primarily focused on wind developers who are assessing the potential for wind farms throughout the region. This emphasis is due to the fact that wind resources offer the highest potential for generation of all renewable sources.

Ameren has also provided funding for the “Tall Towers” research program in Missouri to assess the wind capacities of certain regions in the state. Preliminary assessments from previous research done by various wind developers indicated that wind resources in Missouri show the greatest promise in the northeast and northwest corners of the state as well as in the Ozark Plateau of southern Missouri and northwestern Arkansas. Data from the Springfield, Missouri airport has indicated an annual wind resource in the class 2 range. Because the airport is located at a lower elevation than the crest of the Plateau, experts anticipate an average class 3 wind for the area, with the potential to reach class 4 speeds in the winter and spring before dropping down to class 2 in the summer.

The economic viability of a wind power station depends on the magnitude, duration, and coincidence of wind with utility system demand. However, wind power is intermittent and not dispatchable. A review of wind data has shown that wind power is more prevalent in the autumn, winter, and spring. In the summer afternoons when capacity is needed the most, wind is scarce. Therefore, some form of backup power is needed. Wind power's potential value for a utility is in the production of energy rather than providing capacity.

Advancing design and technologies related to wind turbines have caused additional regions, once thought to be less viable for wind, to demonstrate promise for development. Extending the overall blade length, which increases the sweep of the area by the blades, coupled with the taller turbine towers, is yielding better productivity and capacity. This allows lower wind speeds to be tapped, resulting in generation capabilities previously not considered. Standard turbine size has increased from 720 KW machines to 1.5 MW machines in the last several years. Newer installations are utilizing 1.65 MW machines, and several larger proposed wind farms are contemplating the use of 2.0 MW turbines.

The extension of the production tax credit for two additional years until December 31, 2007, has caused a renewed demand for wind turbines. This in turn has contributed to a price increase for turbines. Turbine prices have increased by as much as 25 percent over those of just one year ago. Manufacturing capabilities have been stretched worldwide to the point that demand is exceeding the supply for 2006, with production demand for 2007 rapidly approaching the maximum as well.

The process for permitting and construction of a large scale wind farm includes several critical path activities:

- Gathering wind data at various levels (50-80-120 meters)
- Evaluating the wind resource data
- Acquiring land
- Permitting
- Construction

In attempting to locate the optimal sites, meteorological data must be reviewed. Most developers look for sustained wind speeds in the 13-17 mph range. This provides a general area in which to focus more exact measurements of wind speed. Transmission analysis is done concurrently to ensure the ability to move power generated by the turbines. A boundary map is then developed to determine land ownership. Land owners are then contacted to determine the level of interest in locating wind turbines on their property. At this point it is generally best to determine overall community support for such a project; so many developers participate in town meetings in order to address any questions or concerns that local residents may have.

Once it is determined that local community support is sufficient to move forward, negotiations between the developer and landowners regarding the placement of test towers and options for land leases are finalized. Wind developers are currently paying $3,000-$4,000 per turbine per year to site turbines on private property.

Site plans are drawn up to determine the potential wind farm configuration. Monitoring of the wind takes one to two years.

Acquisition of any necessary federal, state and/or local permits takes place simultaneously with the collection of wind data. This includes any environmental assessments and analyses that are required.

Transmission studies are requested and performed, and any related interconnection agreements are then negotiated. This allows the wind developer to start negotiations to acquire an off-take agreement for the power.

The construction phase for a utility scale wind farm (80+ MW) may take between eight months and one year. During this phase, construction employment may be between 150 and 275 people depending on the overall number of turbines to be installed. Once in operation, a 150 MW wind farm requires a staff of approximately eight individuals.

In 2005 dollars, all-in capital requirements for a 1.5 MW turbine currently average $1,500 to $1,800 kWh installed. A contract for wind under a standard Power Purchase Agreement is generally for 15 to 20 years, with pricing for wind from these developments in the range of $45 to $55 per MWh. These prices are expected to see continuing increases as the demand for turbines stays strong and the overall construction costs are also expected to rise.

Ameren continues to work with developers to assess viable sites within Missouri that will provide economical wind resources for generation. AmerenUE modeled 100 MW of wind generation in northwestern Missouri in three of its resource portfolios. (See Section 7 below.) Hourly energy profiles were developed for a representative week of each month of the year. This profile was based on past wind studies for northwestern Missouri, along with more recent wind data at higher elevations above ground level.

Landfill Gas

Ameren's Renewables Team is also developing its evaluation process related to the potential capture of landfill gas for generation purposes. The EPA estimated in a report issued December 5, 1998, that Missouri had the potential of generating 119 MW from landfill gas developments. Current projects total 25 MW, candidate projects have the potential for 64 MW, and other projects account for an additional 30 MW.

Currently there are eight operational or under construction projects in Missouri, with only one that appears to be producing electricity. The energy from the other projects is being used for greenhouses or direct heating.

Ameren is beginning its process to determine generation opportunities associated with landfill gas and is starting a dialogue with current operators in order to integrate this resource into the generation mix. Further meetings with equipment manufacturers are being set up to determine the most cost-effective and efficient types of generators that can utilize landfill gas.

Agricultural Methane

Members of Ameren's Renewables Team have met several times with representatives of the Missouri Department of Economic Development as well as the Director of the Missouri Department of Agriculture to review the opportunities associated with generation from methane gas collected from animal waste and by-products. Anaerobic digester systems are in place in a variety of agricultural settings throughout the United States and the world. These collection systems, though generally small in generation capacity, are capable of eliminating methane from farming operations. This naturally occurring methane is considered 21 times worse than carbon dioxide in its effect on the environment.

Ameren is working with an international company on a digester system that could be utilized at hog farm operations in the state. With Missouri producing more than 9.3 million head of hogs each year, this technology may be a viable resource option. Economic evaluations are presently being prepared.

Solar Photovoltaic

Generation from photovoltaic technology remains the most expensive renewable energy option for Ameren. The southwestern portion of the United States possesses the greatest potential for solar development.

AmerenUE is currently funding a program called Missouri Schools Going Solar and is assisting in the cost of hooking up small-scale systems for use by the schools. This effort will help explain how solar works and provide a broader base of understanding for Ameren's customers.

However, the cost of concentrating solar power (CSP) technologies currently ranges from $90 to $120/MWh. Combining CSP plants with conventional natural gas combined cycle or coal plants does appear to lower the costs to $80/MWh. Further advances are anticipated to drop the cost to $40 to $50/MWh, but those cost levels are not expected to be achieved for a few decades.

Hydroelectric

New hydroelectric resources are extremely difficult to develop due to environmental restrictions. With the exception of upgrades to existing hydroelectric plants, discussed above, AmerenUE is not evaluating any hydroelectric projects at this time.

Summary

The renewable teams assembled by Ameren continue to gather critical data and information throughout the renewable industry to determine the most viable renewable generation resource options on both a practical and economic basis for Ameren's customers.

6.6.4 PUMPED-STORAGE TECHNOLOGIES

A pumped-storage project pumps water from a lower reservoir to a higher reservoir during off-peak hours, when there is unused capacity available from base load generating units. During on-peak hours water flows from the upper reservoir through turbine generators back to the lower reservoir. The economic and technical feasibility of these technologies are dependent on the characteristics of the system load profile, local conditions, and the difference between on-peak and off-peak power prices. The charging energy must be sufficiently below the cost of the peak energy to recover the losses and capital costs of the device.

The AmerenUE system has a significant amount of base load generation available during off-peak hours; but it also already has 226 MW of ponded storage capability at the Osage plant and 440 MW of pumped hydro storage capability at the Taum Sauk Plant. Advantages of pumped storage include increased utilization of existing base load plants, reduced cycling of existing base load plants, and ancillary benefits, such as operating reserve, load following, reactive compensation of the system, and black start capability. A disadvantage is exposure to the possibility of a decreasing difference between on-peak and off-peak power prices.

AmerenUE sponsored a detailed study of a representative pumped storage project. See the "Missouri Pumped Storage Project Concept Study" in *Generation Technology Reports*. Also, Table 6.6 shows performance and cost data for pumped storage technologies.

6.6.5 NUCLEAR-FUELED TECHNOLOGIES

For the past two decades the lengthy construction period, great financial burden and regulatory uncertainties have discouraged utilities from considering nuclear technology for capacity additions. But with the improved performance of U.S. nuclear power plants, increases in fossil fuel prices and concerns about climate change, interest in building nuclear plants has increased. This is evident in the provisions of the recently passed Energy Policy Act of 2005. Even so, the barriers to building nuclear power plants remain high and commitments to building such plants may still be years in the future.

Nuclear power plants are base load plants with very high capital costs and low operating costs. If carbon dioxide emissions become regulated, nuclear technologies would have a significant advantage over any fossil-fueled technology. Commercial nuclear power plants in the United States are either boiling water reactors or pressurized water reactors. NuStart, a consortium of Constellation, Duke, EDF, Entergy, Florida Power and Light, Progress Energy, The Southern Company, The Tennessee Valley Authority, Westinghouse, and General Electric, is focusing on two existing nuclear technologies – the Westinghouse PWR AP1000 and the General Electric BWR ESBWR. In this IRP analysis, AmerenUE chose to focus on these two nuclear technologies.

Table 6.7 shows performance and cost data for these technologies.

Table 6.3
Generation Technology Cost and Performance Data – Gas Technologies

[redacted]

(1) Source Jeff Fassett 7EA Budgetary Estimate dated 6/11/04
(2) Source Black & Veatch Venice Combined Cycle Study dated December 2002
(3) Source Ameren internal operating data
(4) Source Burns & McDonnell Technology Assessment dated September 2004

Table 6.4
Generation Technology Cost and Performance Data – Coal Technologies

[redacted]

(1) Performance based on ISO conditions & Pet Coke as the fuel
(2) Escalation is included in the capital costs for a 2013 in service date This estimate is based on an as spent cash flow
(3) The capital costs for these plants include property tax on construction work in progress

Table 6.5
Generation Technology Cost and Performance Data – Renewable Technologies

[redacted]

Source: Burns & McDonnell Technology Assessment dated September 2004

Table 6.6
Generation Technology Cost and Performance Data – Pumped Storage Technologies

[redacted]

Source: MWH Missouri Pumped Storage Project Concept Study dated September 2004

Table 6.7
Generation Technology Cost and Performance Data – Nuclear Technologies

[redacted]

Table 6.8
Generation Technology Cost and Performance Data – Notes

[redacted]

6.7 PURCHASES

6.7.1 LONG-TERM POWER SUPPLY AGREEMENTS

AmerenUE does not issue requests for proposals (RFPs) solely for the sake of information gathering. To do so would harm AmerenUE's credibility in the wholesale markets. In addition, potential suppliers assign low probabilities of success to RFPs that do not carry a firm commitment to work towards a transaction. The quality of bids, under an information-gathering scenario, reflects the quality of the RFP.

There is a place for RFPs for short-term and intermediate-term power supply agreements at AmerenUE. An RFP would primarily be used by AmerenUE to solicit capacity to meet AmerenUE's short- and/or intermediate-term needs for reserves. Products like these may be needed during construction periods to build new generation.

This power purchase strategy is particularly relevant for AmerenUE because of its existing capacity mix. Moreover, because of its abundance of base load capacity, it is unlikely that AmerenUE will be able to purchase energy from the market at a lower cost than it would incur by generating that energy from its existing plants.

Long-term power supply agreements for both capacity and energy have inherent risks that make their usefulness questionable. As Missouri Public Service Commission (PSC) staff witness Dr. Michael Proctor stated in his cross-surrebuttal testimony in the AmerenUE Metro East transfer case, the longer the term of the contract, the less likely that any existing generation will be able to meet the terms of the contract. Thus, long-term contracts usually involve building a new plant. Even if an existing Independent Power Producer has existing capacity and is willing to enter into a long-term contract, the price of such a contract will likely reflect the cost of a new plant. At that point, it makes more sense for AmerenUE to build the plant itself than to incur the risk of higher costs when the contract expires.

Power purchase agreements, in general, may be viewed as the deferral of the need to build capacity. In several forums the MPSC stated their preference for the surety and reliability of dedicated assets to meet AmerenUE load requirements to protect AmerenUE customers from price spikes and curtailment issues.

6.7.2 AMERENUE RFP TO BUY EXISTING COMBUSTION TURBINE GENERATOR PLANTS

AmerenUE issued an RFP in June 2005 to purchase 500 to 800 MW of existing gas-fired plants within the Midwest ISO footprint prior to June 2006. The need for capacity in 2006 was due to the acquisition of approximately 500 MW of new retail load in 2005.

The most significant product specifications in the RFP were:

1. The unit(s) had to have become commercial since 1999.
2. The unit(s) had to be located within the Midwest ISO footprint.
3. The minimum size for the unit(s) was 50 MW.
4. Complete title transfer to the facility was necessary.
5. Unit(s) had to be capable of being declared a designated network resource in the Midwest ISO and meet Mid-American Interconnected Network (MAIN) qualifications for use as reserve capacity.

AmerenUE chose Burns & McDonnell to be the independent third-party administrator of the RFP.

Nineteen facilities were identified that could be potential candidates. The RFP was emailed directly to the companies who owned the facilities. Follow up with the recipients was made to insure that they received a copy of the RFP.

In addition to the direct mailing, the RFP was advertised in the Platt's MegaWatt Daily publication for five days. A website was listed for interested parties, which could download a copy of the RFP from the site. The advertisement ran in the MegaWatt Daily publication on June 30, July 1 and July 5-7, 2005.

Responses were received from four companies representing five generating stations. The bids represented approximately 2,300 MW of nameplate capacity.

Evaluation factors for the proposals included:

1. Amount of capacity deliverable to the market based on the latest Midwest ISO deliverability report
2. Price offered for the facility
3. Adjustments to bid price based on evaluation of Midwest ISO congestion, loss and locational marginal pricing for a 20-year period
4. Operating cost information
5. Current contracts and obligations to third parties
6. Results of due diligence review

The RFP was open and fair and met the requirements of the Federal Energy Regulatory Commission (FERC) Edgar standards. The product was well-defined with evaluation criteria described and applied equally. The results of the RFP identified sufficient capacity to allow AmerenUE to meet the requested 500 to 800 MW of combustion turbine capacity. In fact, AmerenUE received bids for approximately 1,350 MW of existing CTG plants at prices that were below the cost to build new. These resources were factored into the AmerenUE 20-year integrated resource plan analysis as two options:

1. purchase 600 MW at a capital cost of $199/KW
2. purchase 1,350 MW at an average capital cost of $215/KW

6.7.3 Joint Ownership of Future Generating Plants

An option for meeting AmerenUE's future energy resource needs is to build generating plants with other electric utility companies. There are advantages and disadvantages to this approach that will need to be investigated when a decision is required to proceed with a base or intermediate load plant.

6.8 Cogeneration, Independent Power Producers and Non-Utility Generators (NUG)

In its prior Integrated Resource Plan filing, AmerenUE identified 88 MW of non-utility generation, excluding emergency diesel backup generators, in its service area. Today, the number is less than 50 MW as existing retail customers with generation make decisions to retire aging generators rather than to repair or replace them.

AmerenUE has considered renewable energy, landfill gas and anaerobic digester as potential resources within its service area. However, data is still in the process of being acquired for site specific evaluations.

6.9 Transmission and Distribution Planning

6.9.1 Overview

The Ameren transmission system has always been a key element in the AmerenUE integrated resource planning. The original purpose of the transmission system was to cost-effectively deliver network generation resources to native bundled load. Transmission interconnections were later established with neighboring utilities as a means of reducing generation capacity margin requirements and to enhance the overall reliability of the bulk electric system (BES). The resulting interconnected BES provided the ability to exchange power between neighboring utilities during periods of generation deficiencies and also enabled the sale and/or purchase of capacity and energy prior to the establishment of local or regional markets.

However, three major changes have occurred over the last several years that impact the use of the Ameren transmission system regarding integrated resource planning. These changes are:

1. FERC Order 888 which introduced the concept of "open access" to the BES,
2. Ameren's entry in the Midwest Independent System Operator (ISO) regional transmission organization (RTO), and
3. The opening of the Midwest ISO energy markets

Open access required that the transmission systems of Ameren and other FERC jurisdictional utilities be made available to all potential users of the transmission system on a "first-come, first-served" basis so as to create a competitive wholesale energy market. Ameren's entry into the Midwest ISO RTO transferred the overall control of the Ameren transmission system to an independent regional entity and provided a mechanism to roll up Ameren's local transmission planning efforts into a broader regional plan. Finally, the advent of the Midwest ISO energy markets has changed the way the Ameren system is utilized in that it has become part of a regional system used to deliver market based energy across the entire Midwest ISO footprint.

Going forward, all of these changes can impact how the Ameren transmission system is planned and operated. However, the core of the Ameren planning philosophy continues to be the maintenance of the overall reliability of the Ameren system through the consideration of all reasonable alternatives on a least-cost basis.

6.9.2 AMEREN TRANSMISSION STRATEGY

Ameren's transmission strategy to meet the changing requirements of the utility industry includes least-cost local area planning, participation in regional planning activities, participation in regional generation connection evaluations, coordination with the Midwest ISO to improve overall regional operations and engagement with the Midwest ISO on tariff issues. It is believed that continued active involvement in the various planning processes would maintain a reliable transmission system.

Ameren continues to plan its transmission systems following the Ameren Transmission Planning Criteria and Guidelines, MAIN Guides, and NERC Reliability Standards to meet the various needs of the customers and to minimize the opportunities for significant constraints that would impact reliability.

Ameren routinely performs rigorous analyses of the Ameren system throughout a five- to 10-year planning horizon. These studies consider the effects of system load growth, the adequacy of the supply to new and existing substations to meet local load growth, the siting of new generation resources and changing regional use of the BES and the resulting impact on the reliability of the Ameren transmission system. In the event that these studies forecast reduced reliability, additional studies evaluating all practical alternatives are performed to determine what, where and when system upgrades are required. These proposed solutions include applicable new technologies, e.g. Flexible AC Transmission System (FACTS) devices, high-temperature operation conductor, etc., as well as more traditional planning solutions. Distributed resources and demand-side management solutions are also considered, if practical. The total cost for maintaining system reliability is considered for the expansion options.

Ameren participates in regional reliability and planning activities through the NERC and MAIN organizations, and through the Midwest ISO. Ameren provides leadership through active participation in NERC and MAIN committees responsible for developing reliability standards and coordinating and pursuing activities associated with the planning and maintenance of a reliable transmission system. These committees include the NERC Transmission Subcommittee, the NERC Transmission Issues Subcommittee, the MAIN Planning Committee, and the MAIN Transmission Task Force. Similarly, Ameren provides leadership through actively participating in Midwest ISO planning activities, including the Planning Subcommittee and the Expansion Planning Working Group. Participation in these regional planning efforts is the method by which Ameren's local plans are "rolled-up" on a regional basis. This regional roll-up provides the opportunity to evaluate regional solutions that may resolve multiple local issues. Through these efforts, Ameren works to provide a reliable system throughout the Midwest region and to ensure that opportunities for system expansion make sense and would provide the required system benefits while seeking a balance between regional and Ameren goals.

Ameren also participates in regional generation interconnection studies for proposed generation interconnections inside and outside of the Ameren footprint. Ameren responds to requests for proposals from the Midwest to perform studies of proposed generation interconnections to the Ameren system. This activity ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the Ameren system so as to maintain system reliability. As discussed above, all applicable Ameren transmission planning criteria, MAIN guides, and NERC Reliability Standards are used in evaluating the proposed generation connections. Powerflow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If there are system deficiencies, facility studies, if requested, are performed to refine the limitations and develop alternative solutions.

Ameren also participates in ad hoc committees for interconnection requests in areas outside of Ameren which may affect the reliability of the Ameren system. In addition, Ameren is working with the Midwest ISO to increase participation in studies along RTO seams. Participation in these interconnection study activities influences the planning process and leads to a more reliable regional BES.

Ameren continues to work to improve the overall effectiveness of regional operations within the Midwest ISO footprint. The Midwest ISO methodologies, processes, and business practices for a variety of activities have been evolving since Ameren joined the organization. Many of the processes were borrowed from PJM and modified to fit Midwest ISO. Opportunities for improvement exist.

The implementation of energy markets has changed traditional generation dispatch, control area net scheduled interchange, and transmission flows. Ameren has modified and updated its practices to deal with this evolution and is working with the Midwest ISO to optimize local and regional interaction. Areas in which changes continue to occur are outage scheduling, the calculation of available transmission capacity (ATC), market and non-market congestion issues, and balancing authority issues in a regional market.

Tariff issues can also impact transmission system expansion and development. Ameren continues to work with the Midwest ISO to ensure that tariffs affecting transmission are reasonable, fair, and equitable. Recently, the Midwest ISO made a FERC filing which proposed a revenue allocation sharing method for network upgrades associated with major reliability and generation projects developed through the stakeholder process (refer to the Midwest ISO Regional Expansion Criteria & Benefits Task Force information on the Midwest ISO web site http://www.midwestiso.org/plan_inter/expansion.shtml).

Ameren has also initiated an internal program to understand what factors impact all the Midwest ISO charges and credits, and to determine if the Midwest ISO is developing these charges and credits correctly. A number of issues are being investigated in this regard, including reviews of marginal losses and marginal loss rebates, sufficiency to meet Ameren revenue requirements, impacts of real-time negative congestion, and appropriate use of Ameren generation assets.

6.9.3 AMEREN TRANSMISSION PLANS

As discussed above, the Ameren transmission system needs to be flexible and robust to serve the needs of all users, including AmerenUE bundled native retail load, for a wide variety of operating conditions. A flexible and robust transmission system is necessary to enable AmerenUE to pursue cost effective capacity and energy alternatives.

Updates to Ameren's transmission plans are provided to the Midwest ISO twice a year for model-building and other planning and reporting activities. The more significant projects are included in the Appendix A of the Midwest ISO transmission expansion plan (refer to the MTEP05 Appendix A information on the Midwest ISO web site http://www.midwestiso.org /plan_inter/expansion.shtml). The update that will be provided to the Midwest ISO for their next expansion plan (MTEP06) will include the completion of the following AmerenUE projects:

1. Callaway-Loose Creek-Franks 345 kV line in 2006
2. Apache Flats-Mariosa Delta-Moreau 161 kV line in 2006
3. Loose Creek-Mariosa Delta 345 kV line and Mariosa Delta 345/161 kV substation in 2008
4. Joachim 345/138 kV substation in 2008

Note the one-year advancement for the Apache Flats-Moreau 161 kV line and the one-year deferral for the Mariosa Delta 345/161 kV and Joachim 345/138 kV substations compared to the MTEP05 publication.

Other Ameren projects that have been included in Appendix A are those from the 2002 Missouri stipulated agreement that would provide for increased import capability into AmerenUE. Most of these projects would be completed in 2006, including the:

1. Rebuilding of the Cahokia-Lemay Tap-1&2 138 kV lines
2. Reconductoring of the Campbell-Maline-1&2 138 kV lines
3. Reconductoring of the Roxford-Mississippi Tap-1&2 138 kV lines

A project to increase ground clearances on the Cahokia-North Coulterville 230 kV line should be completed in 2007. The Cahokia 345/138 kV 560 MVA transformer #9 was replaced with a 700 MVA unit in 2003. Note that the Dupo 345/138kV substation, its 345 kV supply line and associated 138 kV line upgrades that were included in the stipulated settlement project list have been deferred. Network upgrades associated with the proposed Prairie State generation interconnection, including a new 345 kV transmission line across the Mississippi River south of St. Louis, have affected the need and timing of these upgrades. The original network upgrades, all on the Illinois-Missouri interface, were selected to address known transmission limitations to imports into AmerenUE from the east, which is where the majority of external generation is located, including the generation that participates in the Midwest ISO and PJM markets

Appendix A of the Midwest ISO transmission expansion plan (MTEP) also includes the major transmission connections and upgrades planned for the Ameren system to support large generation interconnections. Some of these are associated with the proposed 1,650 MW Prairie State Energy Campus, located in Washington County, Illinois, approximately 35 miles southeast of St. Louis. The Prairie State project, including a 28-mile Baldwin-Rush Island 345 kV transmission line, is a significant enhancement to the Ameren system in the St. Louis metropolitan area. In addition, several large wind development projects have been proposed for Illinois, mostly in the north-central portion of the state and outside of the Midwest ISO footprint. Some Illinois wind projects have been proposed for the Ameren footprint, but these are still under study. Very little generation interconnection activity is proposed for the AmerenUE area or eastern Missouri at this time.

The Midwest ISO has been coordinating the planning activities of its members since the first Midwest ISO expansion planning effort in 2003. To date the Midwest ISO has had very little impact on the network upgrades identified in the Ameren planning processes. Local transmission plans continue to be rolled-up to the regional level, but no Ameren projects have been modified and no additional Ameren network upgrades have been proposed to meet regional goals. The Midwest ISO planning process continues to evolve with a long term goal to develop a robust transmission system to provide for regional reliability and to support a regional market.

The Midwest ISO has developed a method to assess the deliverability of generation within the Midwest ISO market. While this test is more typically associated with unregulated generation, it is the default test which the Midwest ISO uses to evaluate all generation within its footprint. Generation which passes this test can be designated as a network resource by any load in the Midwest ISO footprint (or in the case of AmerenUE, designated to serve the native AmerenUE bundled load). Generation that fails this test can either participate in the Midwest ISO market as an energy resource, which cannot be designated for capacity resource purposes, or the generation could alternately seek to establish limited deliverability to a specific load, such as to the AmerenUE bundled load. All AmerenUE generation in service prior to the summer of 2005 has been determined to have regional deliverability and therefore can be designated as a network resource for AmerenUE bundled load.

The most recent Midwest ISO generation deliverability studies have identified constraints which may block the addition of new network resources in the Ameren footprint. Ameren has questioned the Midwest ISO study methodology as it goes beyond any NERC standards or Ameren planning criteria. Ameren has been working with the Midwest ISO planning staff to address the deliverability issues and possibly revise its deliverability methodology.

6.9.4 AmerenUE Distribution Planning

Ongoing assessments of the age, condition, and efficiency level of AmerenUE distribution facilities require daily decisions regarding implementation of cost-effective measures to ensure reliable service. These assessments include the benefits of DSM and distributed generation targeted for specific areas.

The following are examples of loss reduction programs and procedures impacting energy and demand that are typically reviewed outside the context of the integrated resource planning process.

Distribution Transformer Loss Evaluation – All new transformer purchases since the late 1970's have been initiated on the basis of the total evaluated life-cycle cost of ownership. This ownership cost includes both the energy and demand costs of transformer core and winding losses over the expected economic life of the transformer, in addition to the transformer purchase price and reliability. The loss evaluation procedure was developed using the economic and system parameters contained in the EVA procedure and is updated as changes are made to those parameters. This evaluation procedure is used to compare the relative merits of alternative transformer designs for the approximately 6,500 transformers that are purchased each year.

Distribution Transformer Replacement – In early 1992 Union Electric implemented a distribution transformer replacement program aimed at identifying and removing those transformers containing PCB oil from the system. Subsequently, in March 1993 the company began a strategic program of distribution transformer modernization directed towards replacing the older, high-loss/high-failure distribution transformers on the system with the much lower loss silicon-steel transformers purchased under the loss evaluation procedure. This program is still in effect today, and the population of potentially PCB-contaminated units continues to decrease.

Transformer Load Management – This program forms the basis for the company's circuit analysis and trouble analysis systems. By assigning customers to individual transformers the Transformer Load Management program allows AmerenUE to predict transformer peak demand from total energy usage. This information is used by the company to reduce distribution losses through more efficient loading of fewer transformers. The company also uses the automated meter reading system to take load readings during peak load periods to more accurately measure transformer demand.

Distribution Engineering Workstation (DEW) – This power engineering software allows the company to examine the line losses associated with alternative circuit configurations, determine appropriate economic conductor sizing and determine the optimal capacitor placement to reduce distribution losses.

6.10 QUANTITATIVE SCREENING

6.10.1 OVERVIEW

A list of 28 potential supply-side resource options, which include traditional and relatively new technologies, was developed as a starting point for this screening process. The first-level screening started with independent reports covering various technologies. Reports were submitted by Burns & McDonnell, Navigant Consulting, Montgomery Watson Harza (MWH), and Sargent & Lundy. All of these reports are included in the *Generation Technology Reports* documents of the AmerenUE Integrated Resource Planning filing.

The first-level screening uses the details supplied by these various reports as the main source for the inputs. The first-level analysis is a one-on-one comparison of levelized annual costs evaluated for a range of capacity factors for each supply option by type: base, combustion turbines, renewables and storage. This first-level screening includes only emission costs associated with sulfur dioxide (SO_2) and nitrogen oxides (NO_X). This first-level screening process is discussed in more detail in section 6.10.2.

The original group of supply-side options considered in the first-level screening was evaluated again using the added costs associated with greenhouse gases (GHG) in 2013. This second level screening or "scenario evaluation" was used to determine the most favorable, currently available, supply-side options. The most favorable supply side-options are those that exhibit the lowest cost per MWh at various capacity factors. The supply-side resource options that did not appear to be competitive with the other options over a range of capacity factors and after considering other factors were not given further consideration. The scenario evaluation is discussed in more detail in section 6.10.3.

6.10.2 First-level Screening

The first-level screening provides an economic comparison of the potential supply-side resource options. The results give insight into which technologies are most economic at various capacity factors. The technologies with higher costs were identified for elimination from further evaluations.

Fixed costs were calculated using each option's unit rating, capital costs, fixed-operation and maintenance costs and a fixed charge rate. The levelized annual fixed-charge rate was calculated based on each option's expected tax and plant life. The fixed-charge rate includes cost of debt and equity, property tax, income tax and depreciation. Table 6.9 contains the fixed costs for new additions in 2013.

Variable costs were calculated using each option's fuel costs, net plant heat rate, variable operation and maintenance costs, emission costs and production tax credits (for renewable projects - except solar). The fixed and variable costs were then combined and expressed on a $/MWh basis over a range of capacity factors to determine the cost to generate electricity for each option. Table 6.9 contains the variable costs for new additions in 2013.

New Additions

The potential supply-side options considered in the first-level screening only include "New Additions." A new addition is any resource that could be installed at a greenfield location or at an existing facility. The amount of capacity from this type of facility is not limited by existing equipment on the system. Supply-side options considered as "Improvements," which is additional capacity or energy that would result from a modification or efficiency improvement to an existing facility on the system, were not considered in either the first-level screening or the scenario evaluation. The 30-year levelized costs for new additions without GHG in 2013 is shown on Table 6.10 and with GHG in 2013 on Table 6.11.

The "Generation Technology Assessment" report completed by Burns & McDonnell, issued in November 2004, includes the following types of supply-side generation:

- Coal units: Subcritical and Supercritical Pulverized Coal, Circulating Fluidized Bed (CFB), and Integrated Gasification Combined Cycle (IGCC)
- Natural Gas units: Simple Cycle Gas Turbine (SCGT), Combined Cycle Gas Turbine (CCGT), Cogeneration, Diesel Engines, and Compressed Air Energy Storage (CAES)
- Renewables: Biomass, Landfill Gas, Agriculture Methane Gas, Solar, and Wind
- Nuclear: Advanced Pressurized Water Reactor (APWR) and Advanced Boiling Water Reactor (ABWR)

The "Nuclear Industry Overview & IRP Analysis Parameters" report by Navigant Consulting, issued in June 2005, includes the following types of supply-side generation:

- AP1000 PWR
- Economic Simplified Boiling Water Reactor (ESBWR)

The "Missouri Pumped Storage Project Concept Study" by Montgomery Watson Harza, issued in September 2004, includes Pumped Storage units in various configurations.

The "IGCC Technology Assessment Report" by Sargent & Lundy, issued in September 2005, includes the following types of supply-side generation:

- Integrated Gasification Combined Cycle (IGCC) unit using PRB coal
- Integrated Gasification Combined Cycle (IGCC) unit using Illinois coal

All of the independent reports listed above are included in the *Generation Technology Reports* document of the AmerenUE Integrated Resource Plan filing.

The supply-side resources considered as new additions can be further categorized as base, intermediate and peaking technologies. Although renewable energy and storage technologies may also be categorized as base, intermediate or peaking, they have unique characteristics such as limited availability, tax advantages or other attributes that make it more logical to discuss them separately. A brief summary of the supply-side options considered in the screening analysis is shown below. The data used in this analysis are included in Table 6.12.

Base Technologies – Supply-side options normally fueled by low-cost fuels, such as coal and nuclear, are considered as base load technologies. These technologies are typically most economic at higher capacity factors. Several base load technologies were considered for the first-level screening analysis. The list of coal and nuclear technologies considered and supporting details are included in Table 6.12. The 750 MW pulverized coal supercritical unit was the most favorable option. The 750 MW "supercritical" unit was selected over the "subcritical" coal units because the supercritical units have: higher efficiency (3 to 5 percent), lower emissions (3 to 5 percent), comparable reliability, only slightly higher costs (<3 percent), and they have faster ramp rates. Most of the reliability and maintenance concerns for supercritical units have been addressed over the last couple of decades.

The Burns & McDonnell technology assessment included two nuclear units – a 500 MW ABWR and a 500 MW APWR. After reviewing the report it was determined that the data submitted was from old historical data from the Electric Power Research Institute (EPRI) and that neither unit is commercially available today. Based on those findings, an evaluation of nuclear options was requested and supplied by Navigant Consulting (June 2005). Navigant's list included two potential nuclear units – a 1,150 MW AP1000 PWR and a 1,340 MW ESBWR. Both units were included in the first-level screening analysis and the scenario evaluation. Both nuclear units appear to be a low-cost option compared to the other higher cost options used in this analysis. The AP1000 PWR was included in the integrated resource analysis.

The Sargent & Lundy report includes two IGCC plants - a three-unit 750 MW plant using PRB coal and a similar plant using Illinois coal. Both plants were higher in costs when compared to other more economical options; however, these plants have slightly lower emissions when compared to other options and were therefore included in the integrated resource analysis.

Intermediate Technologies – Intermediate load technologies include combined cycle units and fuel cells fueled by natural gas and oil. These technologies are generally most economic in the mid-range of capacity factors and complement base and peaking technologies. The list of gas technologies considered and supporting details are included in Table 6.12. Two combined cycle units were considered in the screening analysis – a 250 MW CCGT (1x1 7FA) and a 500 MW CCGT (2x1 7FA). Of the two, the 500 MW CCGT had the lower cost of generation and was therefore included in the integrated resource analysis. Fuel cells were not included on the initial list of potential supply-side resource options.

Peaking Technologies – In contrast to base load generation, peaking units such as combustion turbines have low construction costs and high fuel costs. These technologies are generally most economic at lower capacity factors. The list of gas technologies considered and supporting details are included in Table 6.12. From the list of potential gas-fired units, all three types of simple-cycle gas turbines had favorable economics and were therefore included in the integrated resource analysis. Diesel engines were included as a supply-side resource option, however, the levelized annual costs associated with this resource option are higher than other lower cost options. Therefore, this option was not included in more detailed analysis beyond the first-level screening.

Renewables – Solar and wind technologies enjoy the benefits of no fuel or environmental costs. However, the amount of energy available from these resources is limited, and their capacity is generally not dispatchable. The list of renewable technologies considered and supporting details are included in Table 6.12. Energy from solar and wind are more abundant in other areas of the country than in the AmerenUE service area. Wind, biomass, landfill gas and agricultural methane gas include a production tax credit based on the recent passage of the 2005 Federal Energy Tax Act while solar does not. Wind had the most favorable economics of the renewable resource options evaluated. The tax credit that was applied to these projects ends after 10 years. However, to simplify the analysis, the tax credit was treated as though it would continue for the economic life of the project. This makes the renewables, especially wind, look more economical than they otherwise would be in a more detailed evaluation like the integrated resource analysis.

Since wind and solar are both intermittent resources for energy and their capacity is not as dependable as other supply-side options, their capacity equivalence is expected to be much less than their rated capacity. The results indicate that solar technologies are several times more expensive than combustion turbine and combined cycle units. Solar was not a favorable resource option when compared to wind and the other renewables.

One biomass project was included in the first-level screening. The results show that the costs for biomass technologies are not competitive with combustion turbines or combined cycle units. The biomass project, which includes a production tax credit, did not have favorable economics when compared to the other resource options.

In this category, a landfill gas and an agriculture methane gas project were considered. Fuel costs for both projects were assumed to be free. This type of technology has a high projected capacity factor; however, they do not generate a large amount of capacity or energy when compared to the other renewables. Neither one of these options looks favorable when compared to wind.

Storage Technologies – Storage technologies include compressed air energy storage (CAES) and pumped storage units. The list of pumped storage technologies considered and supporting details are included in Table 6.12**.** CAES units have capacity limitations due to charging and storage requirements. For a CAES plant, a reasonable estimate for determining the limiting capacity factor can be obtained by assuming that it is charging 50 percent of the time and generating 50 percent of the time. Costs for charging a CAES plant were based on the market costs for off-peak energy. The levelized annual costs in the screening evaluation indicate that a CAES plant is not as favorable as a pumped storage project. Even if the levelized annual costs for a CAES plant had been more favorable when compared to the other resource options, there would be considerably more risk associated with this option as there are only two plants currently operating in the world. Only one of these units is operating in the United States, and that unit is only 110 MW. The larger unit is 290 MW and is operating in Germany.

Pumped storage units also have capacity limitations. Water stored in an upper reservoir is discharged during peak times to provide capacity and then, during the night, the water is pumped from the lower reservoir to the upper reservoir using market costs for off-peak energy. Four pumped storage projects were considered in the first-level screening and the scenario evaluation. Of those, the 800 MW Base pumped storage project showed favorable economics and was included in the integrated resource analysis.

Based on the evaluation supplied by MWH concerning a comparison of the modified schemes, the report indicates that "… the 600 MW modified scheme … provides the least-cost-per-kilowatt installed capacity …". Therefore, based on that analysis and other considerations the 600 MW modified scheme pumped storage unit was also included in the integrated resource analysis.

First-Level Screening Summary

The results for expected conditions with environmental costs for SO_2 and NO_X are shown in Table 6.10 and Figures 6.2 through 6.8.

The most economical peaking technology is the SCGT fueled by natural gas. The most economical intermediate technology is the CCGT fueled by natural gas. The most economical base technology is the 750 MW supercritical pulverized-coal unit. The most economical renewable technology is wind; however, wind is only attractive at a 30 percent capacity factor, which may not be achievable for the area near or in the AmerenUE service territory. The most economical storage technology is pumped storage.

6.10.3 SCENARIO EVALUATION

A scenario evaluation was completed by using the data from the first-level screening for each supply-side option, along with the costs anticipated for future GHG emissions, to develop another one-on-one comparison of levelized annual costs for each supply option. The results were again evaluated against a range of capacity factors. This scenario evaluation includes emission costs associated with SO_2 and NO_X as well as GHGs at a date in the future - 2013. The results are also included in Table 6.11 and Figures 6.10 through 6.16. The GHG tax had the greatest impact on a $/MWh basis for the technologies that are the largest emitters of GHG, like coal, while the technologies that emitted either little or no GHGs, like nuclear and wind, had little to no change over the results determined in the first-level screening analysis.

6.10.4 SUMMARY

The purpose of this analysis is to help narrow down the field of potential supply-side options to a more manageable list for further consideration. The first-level screening analysis considered all readily available supply-side resource options and their associated costs with the exception of greenhouse gases. The scenario evaluation has taken the list of supply-side resource options considered in the first-level screening analysis and included the costs associated with the greenhouse gas tax to determine their impact on each of these options. And finally, from the analyses described above, a list of economically viable supply-side options was developed. Economically viable supply-side options are those that exhibit the lowest cost per MWh at various capacity factors and taking into account a few other considerations. Figures 6.9 and 6.17 show all of the most viable supply-side options on a one-on-one basis with and without the greenhouse gas tax.

The following list of viable supply-side options, as determined from the analysis described above, were included in the integrated resource analysis:

- 750 MW PC Supercritical
- 750 MW IGCC using PRB coal
- 750 MW IGCC using Illinois coal

- 500 MW CCGT (3) (2x1 7FA)
- 180 MW SCGT (3) (4xLM6000 PC Sprint)
- 320 MW SCGT (1) (4x 7EA)
- 340 MW SCGT (3) (2x 7FA)
- Nuclear AP 1000 1150 MW APWR
- 50 MW Wind
- PS 800 MW Base
- PS 600 MW Modified

When comparing all viable supply-side options listed above on either Figure 6.9 or Figure 6.17, it is easy to jump to the conclusion that wind is the lowest cost option, which is true if you are only considering projects that have a capacity factor in the range of 30 to 50 percent. However, as mentioned in the First-Level Summary above, wind is attractive only at a 30 percent capacity factor, which may not be achievable for the area near or in the AmerenUE service territory. And, as discussed in section 6.10.2, base technologies "… are typically most economic at higher capacity factors.", intermediate technologies "… are generally most economic in the mid-range of capacity factors …", and peaking technologies "… are most economic at the lower capacity factors.". Therefore, the same caution must be used when making other comparisons at other capacity factors. For example, a base unit will not be favorable on an economic basis when compared to a peaking unit in the range of 10 to 30 percent. And, conversely a peaking unit will not be favorable on an economic basis when compared to a base unit when considering a capacity factor from 70 to 100 percent.

The integrated resource analysis provides a more detailed evaluation of the viable supply-side options by taking into consideration the operational needs of the system and at the same time taking into account the associated operating costs for each option.

Table 6.9
Fixed and Variable Costs For New Additions In 2013

[redacted]

Tables 6.10 and 6.11

30 Year Levelized Costs for New Additions vs Capacity Factor (With and Without GHG)

2013 — Variable + Fixed Costs @ Capacity Factors w/o GHG in 2013

Item #	Technology	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1C	500 MW PC Subcritical	370	196	137	108	91	79	71	65	60	56
2C	750 MW PC Subcritical	323	172	122	96	81	71	64	59	54	51
3C	500 MW PC Supercritical	374	197	138	109	91	79	71	65	60	56
4C	750 MW PC Supercritical	327	174	122	97	82	71	64	59	54	51
5C	500 MW AFBC	391	206	145	114	95	83	74	67	62	58
6C	750 MW AFBC	350	186	131	103	87	76	68	62	57	54
7C	275 MW IGCC	471	246	172	134	112	97	86	78	72	67
8C	750MW IGCC on PRB - S&L (2))	383	202	141	111	93	81	72	65	60	56
9C	750MW IGCC on Illinois Coal - S&L (2))	351	185	129	102	85	74	66	60	56	52
10C	600 MW IGCC GE/Bechtel (1)	411	216	151	118	99	86	76	69	64	60
1G	250 MW CCGT (3) (1x1 7FA)	215	133	106	93	85	79	75	72	70	68
2G	500 MW CCGT (3) (2x1 7FA)	181	117	95	84	78	73	70	68	66	65
3G	180 MW SCGT (3) (4xLM6000 PC Sprint)	198	135	114	103	97	92	89	87	85	84
4G	320 MW SCGT(1) (4x7EA)	191	141	124	116	111	107	105	103	102	101
5G	340 MW SCGT (3) (2x7FA)	164	126	113	107	103	100	98	97	96	95
6G	CAES (4)	302	192	155	137	126					
7G	8 MW Recip (4) Engines (4x2MW)	313	201	163	145	134	126	121	117	114	111
1N	Nuclear AP 1000 1150MW APWR	499	254	173	132	107	91	79	71	64	58
2N	Nuclear ESBWR 1340MW	477	243	165	126	102	87	76	67	61	55
1R	50 MW Biomass	744	431	326	274	243	222	207	196	187	180
2R	Landfill Gas	367	191	132	103	85	73	65	59	54	50
3R	Ag Methane Gas	577	285	188	139	110	91	77	67	58	52
4R	Solar Photovoltaic	754	377	251							
5R	Wind Turbines	286	132	80	54	39					
1PS	PS 800MW Base	207	130	105	92						
2PS	PS 800MW Modified	218	136	109	95						
3PS	PS 600MW Modified	223	139	110	96						
4PS	PS 400MW Modified	235	145	114	99						

2013 — Variable + Fixed Costs @ Capacity Factors w/ GHG in 2013

Item #	Technology	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
1C	500 MW PC Subcritical	387	213	154	125	108	96	88	82	77	73
2C	750 MW PC Subcritical	340	189	139	113	98	88	81	76	71	68
3C	500 MW PC Supercritical	391	214	155	126	108	96	88	81	76	73
4C	750 MW PC Supercritical	343	190	139	113	98	88	81	75	71	67
5C	500 MW AFBC	410	225	163	132	114	101	92	86	81	76
6C	750 MW AFBC	368	204	149	121	105	94	86	80	76	72
7C	275 MW IGCC	486	262	187	150	127	112	102	94	87	82
8C	750MW IGCC on PRB - S&L (2))	400	218	158	128	110	97	89	82	77	73
9C	750MW IGCC on Illinois Coal - S&L (2))	366	200	145	117	100	89	82	76	71	67
10C	600 MW IGCC GE/Bechtel (1)	426	230	165	133	113	100	91	84	78	74
1G	250 MW CCGT (3) (1x1 7FA)	221	140	113	99	91	86	82	79	77	75
2G	500 MW CCGT (3) (2x1 7FA)	188	123	101	91	84	80	77	74	73	71
3G	180 MW SCGT (3) (4xLM6000 PC Sprint)	207	144	123	112	106	102	99	96	95	93
4G	320 MW SCGT(1) (4x7EA)	203	152	136	127	122	119	116	115	113	112
5G	340 MW SCGT (3) (2x7FA)	174	136	123	117	113	110	108	107	106	105
6G	CAES (4)	307	196	159	141	130					
7G	8 MW Recip (4) Engines (4x2MW)	321	210	172	154	143	135	130	126	123	120
1N	Nuclear AP 1000 1150MW APWR	499	254	173	132	107	91	79	71	64	58
2N	Nuclear ESBWR 1340MW	477	243	165	126	102	87	76	67	61	55
1R	50 MW Biomass	767	454	350	298	266	246	231	220	211	204
2R	Landfill Gas	378	201	143	113	96	84	76	69	65	61
3R	Ag Methane Gas	588	296	199	150	121	102	88	77	69	63
4R	Solar Photovoltaic	754	377	251							
5R	Wind Turbines	286	132	80	54	39					
1PS	PS 800MW Base	207	130	105	92						
2PS	PS 800MW Modified	218	136	109	95						
3PS	PS 600MW Modified	223	139	110	96						
4PS	PS 400MW Modified	235	145	114	99						

Table 6.12
Ameren Technology Assessment Summary

[redacted]

Figure 6.2
Base Generation (PC): w/o GHG in 2013

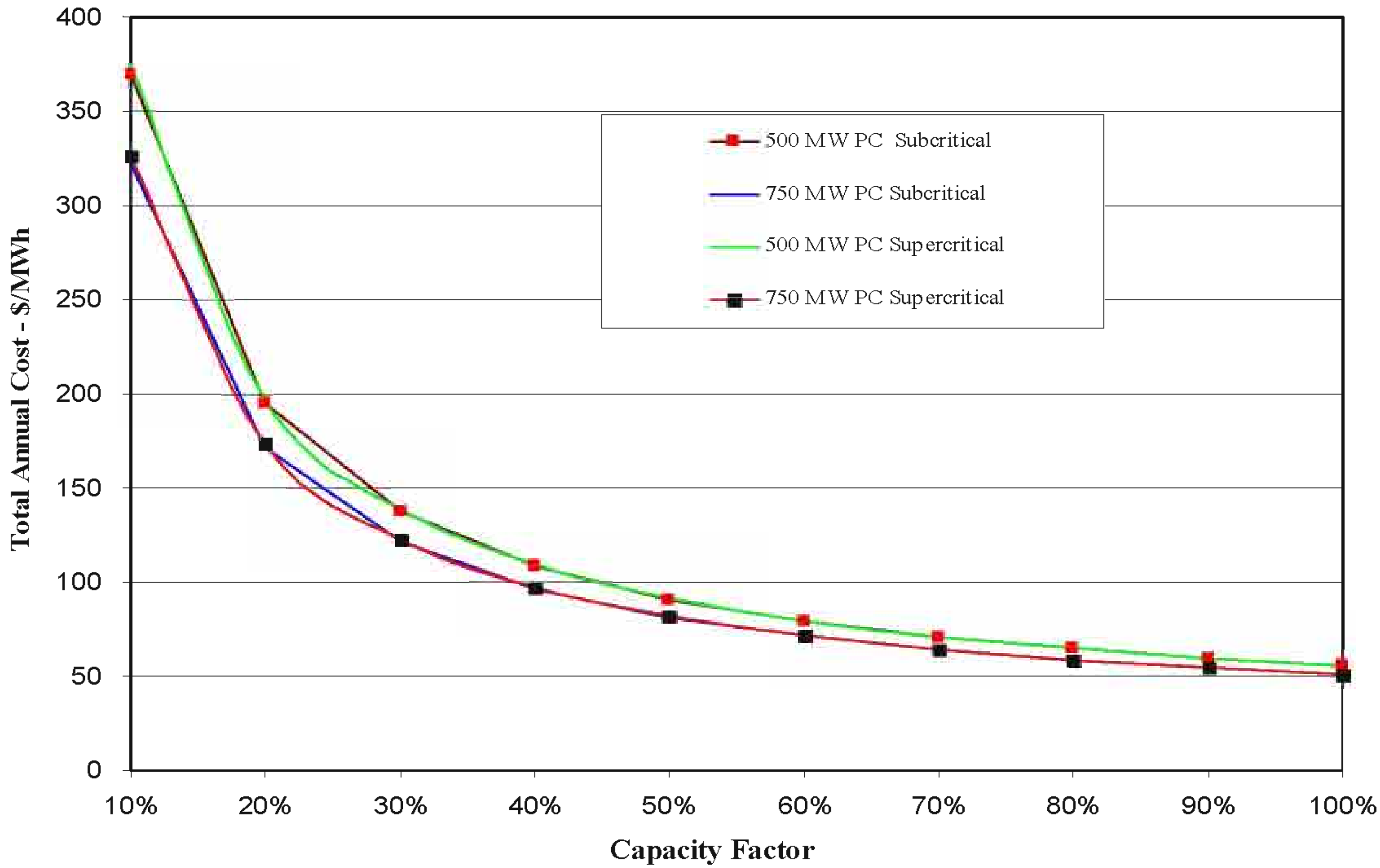


Figure 6.3
Base Generation (AFBC): w/o GHG in 2013

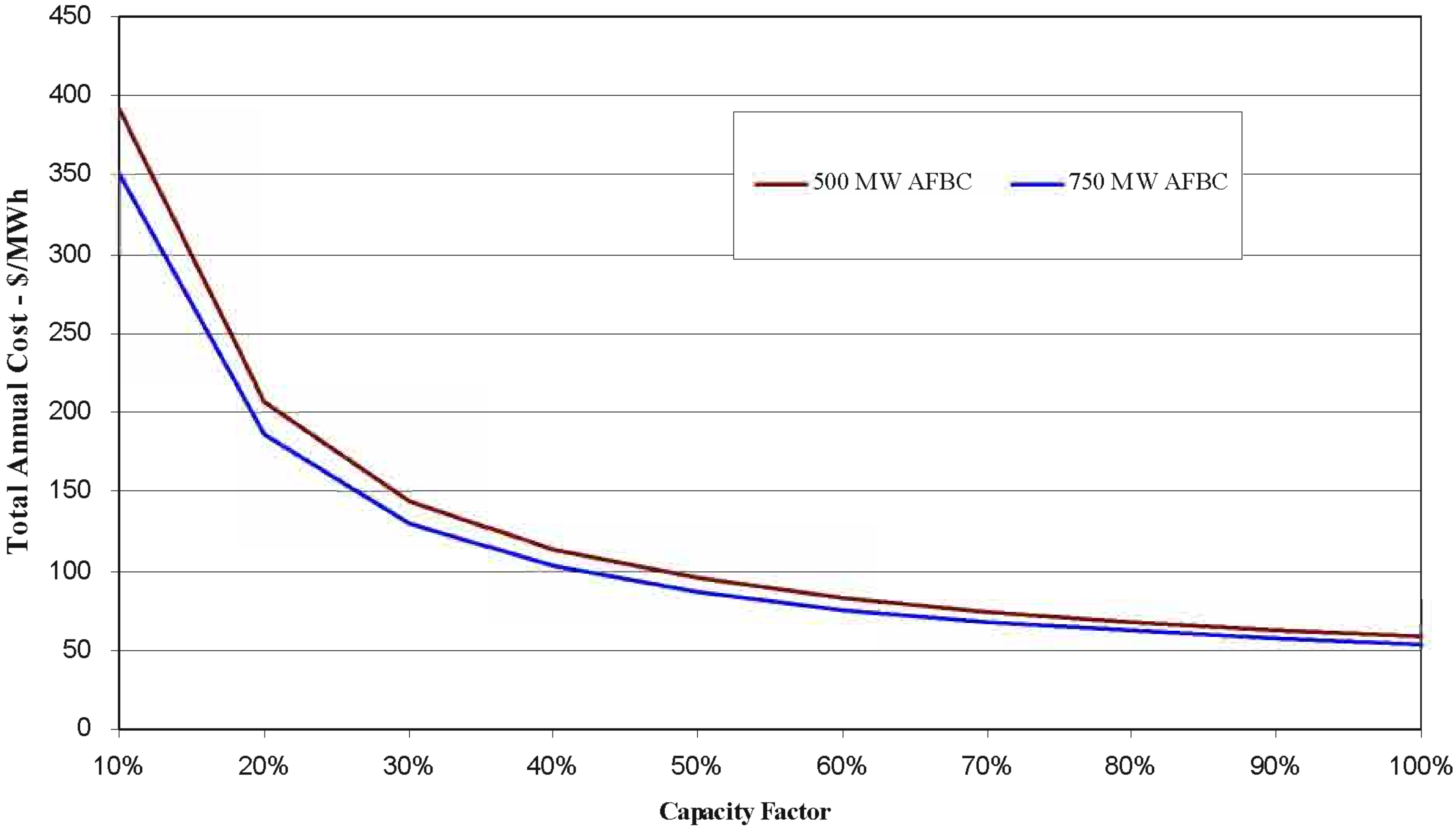


Figure 6.4
Base Generation (IGCC): w/o GHG in 2013

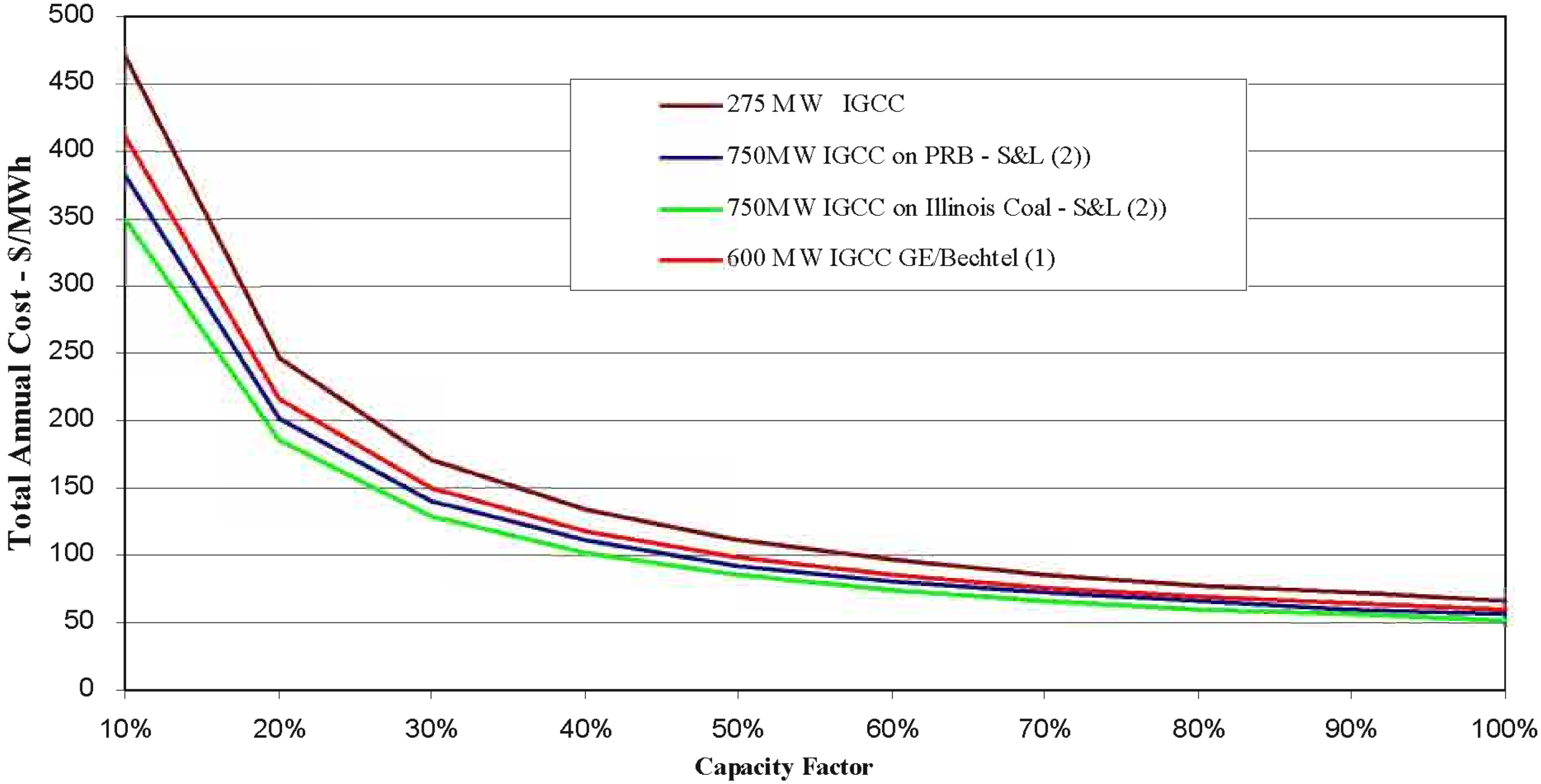


Figure 6.5
Base Generation (Nuclear): w/o GHG in 2013

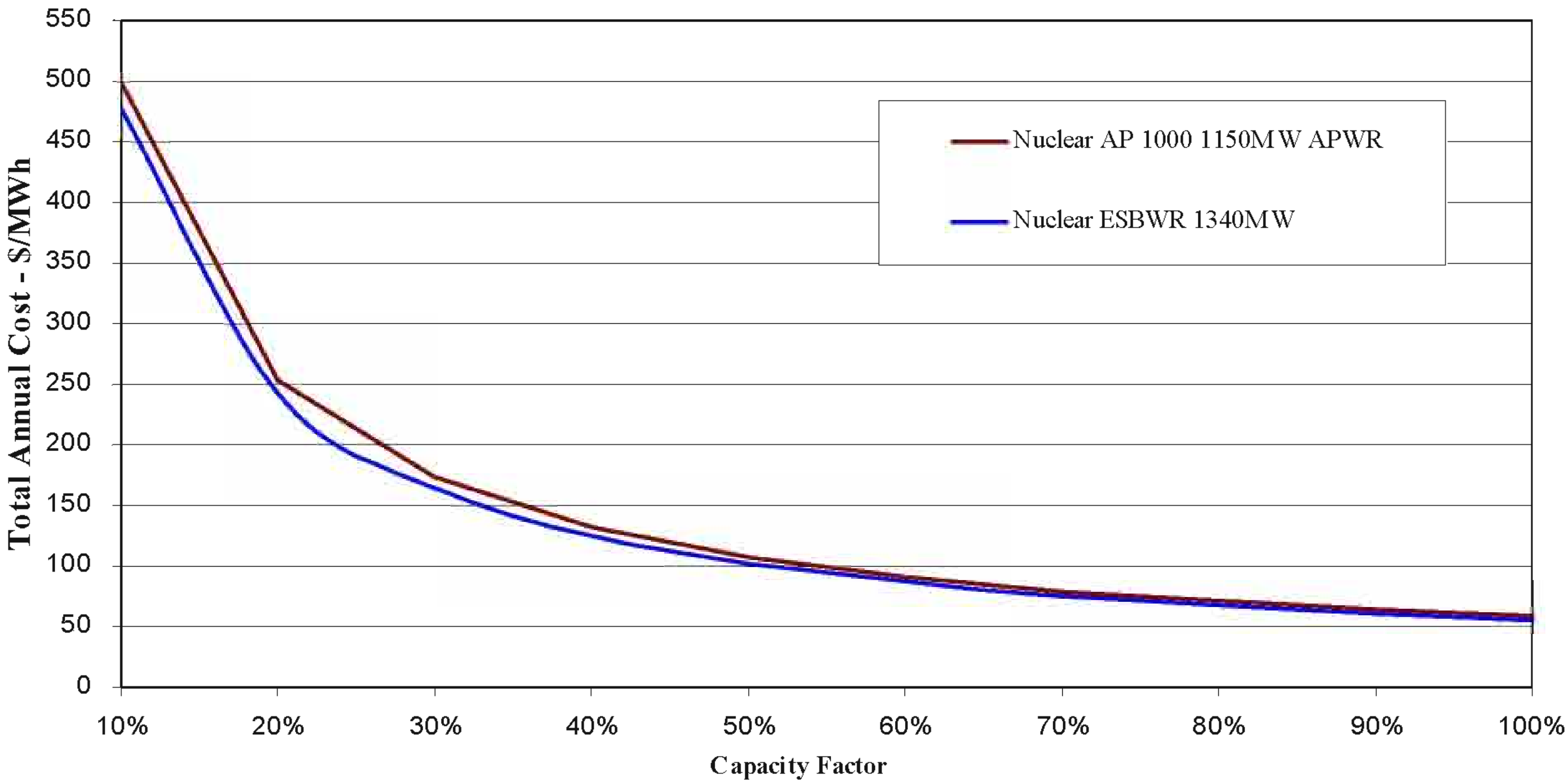


Figure 6.6
Combustion Turbines: w/o GHG in 2013

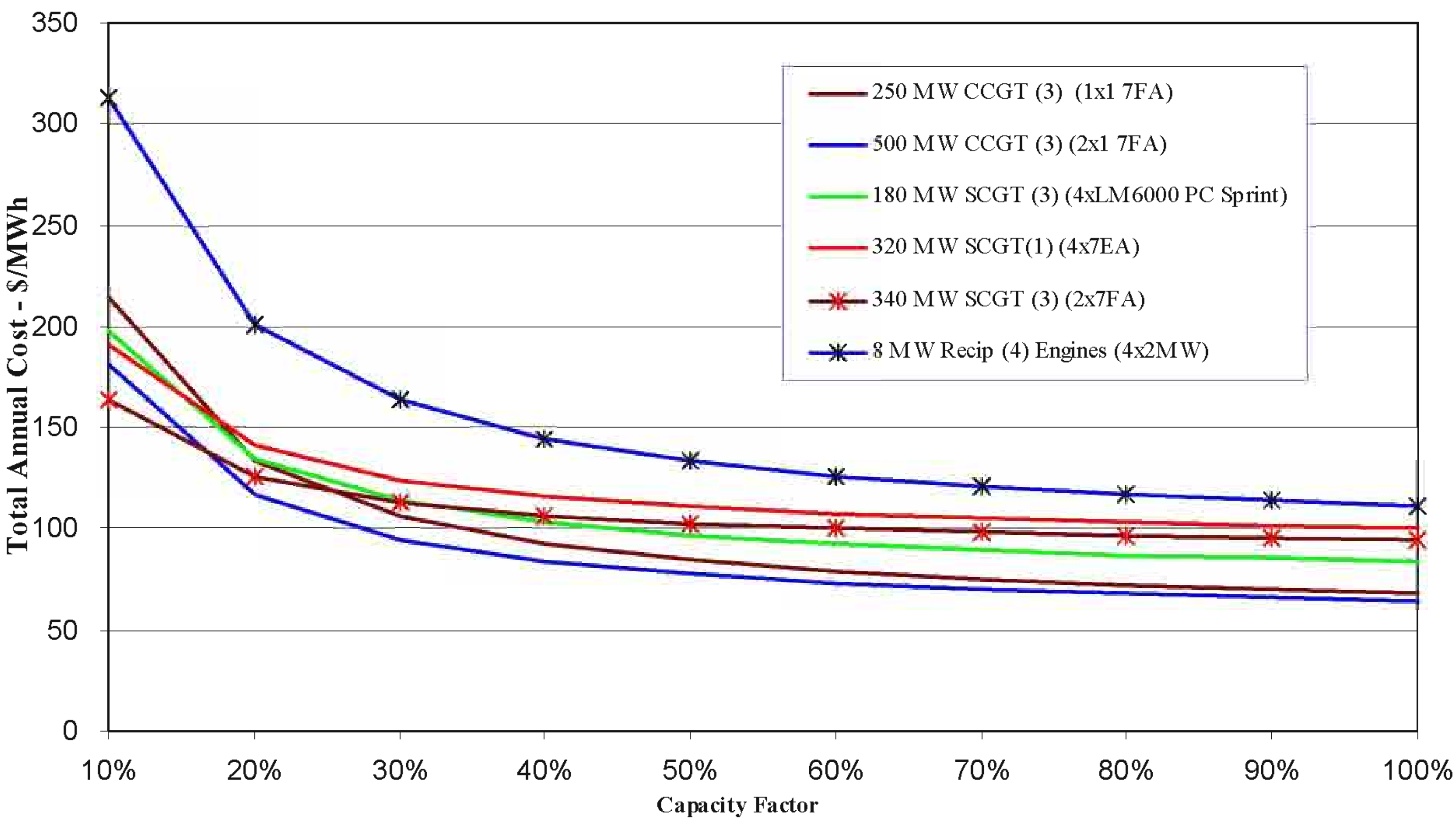


Figure 6.7
Renewables: w/o GHG in 2013

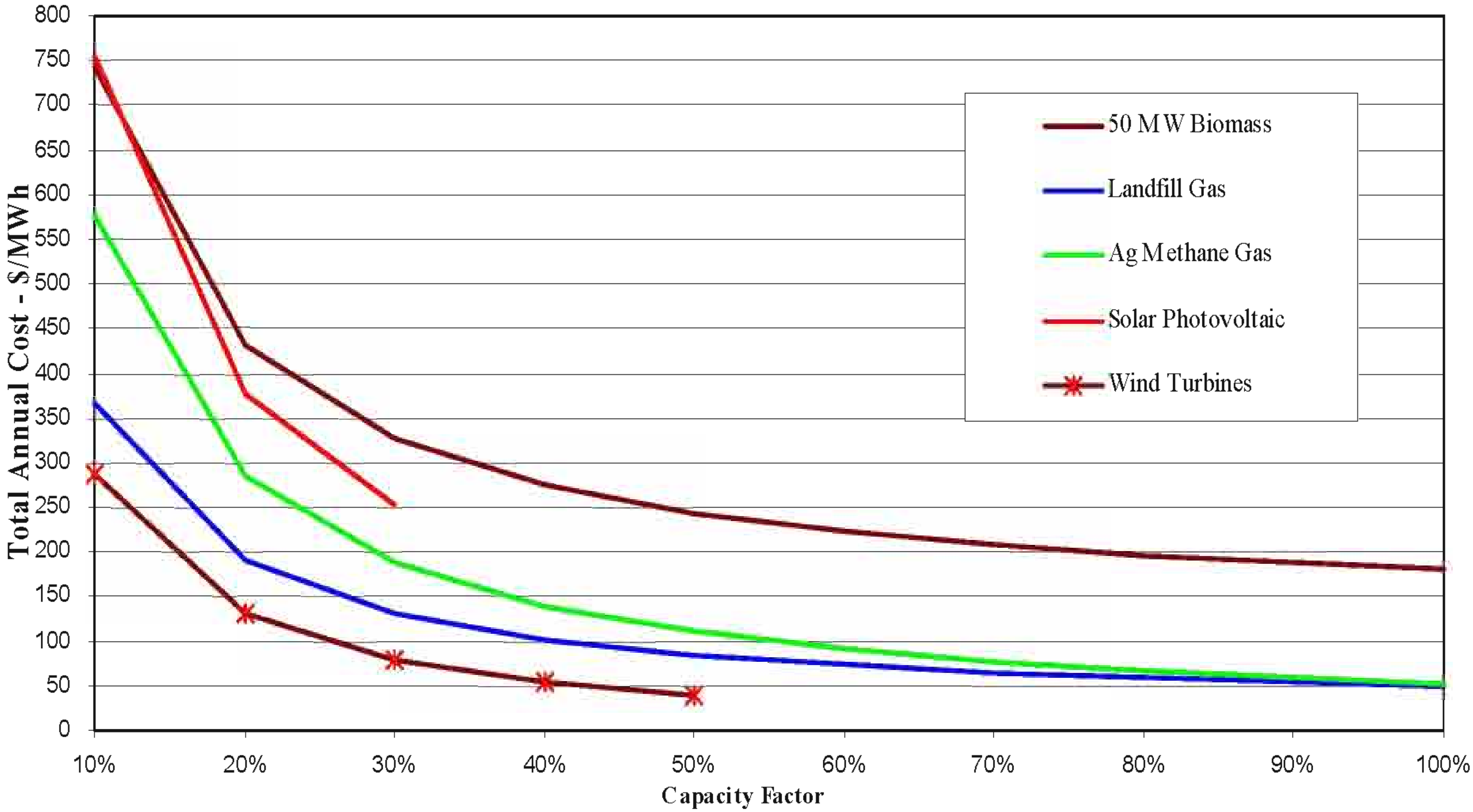


Figure 6.8
Storage: w/o GHG in 2013

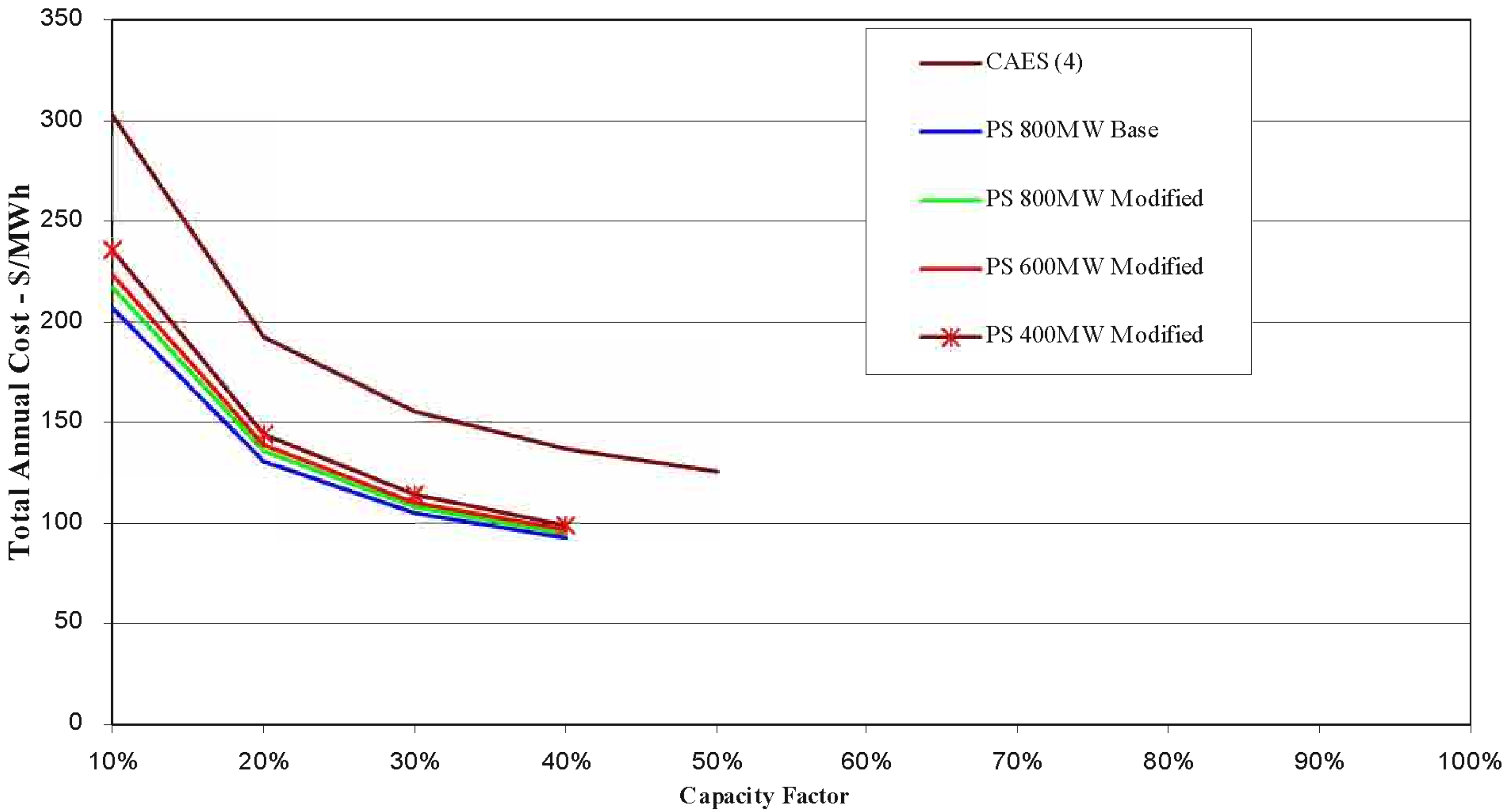


Figure 6.9
Viable Supply-side Options: w/o GHG in 2013

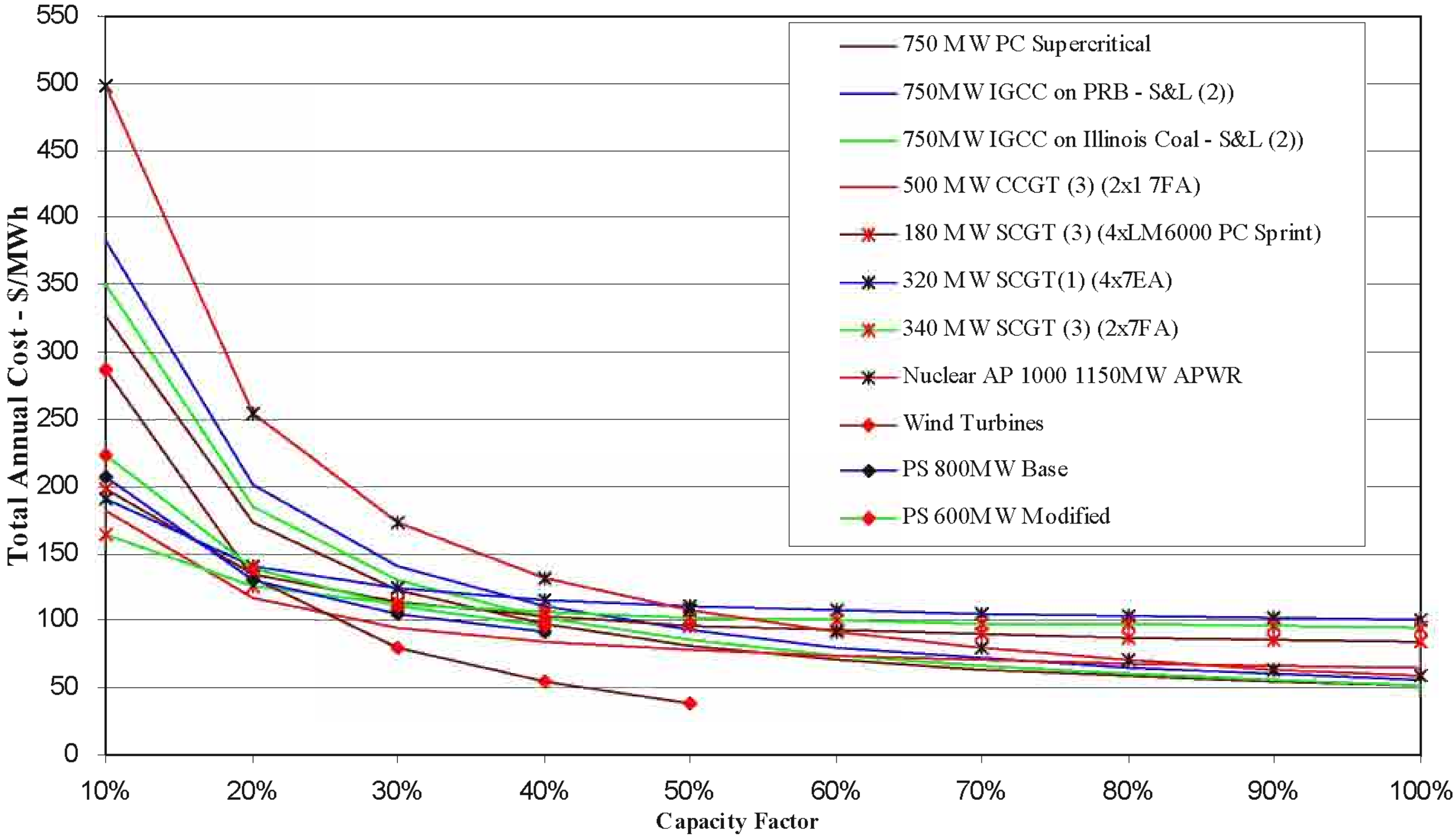


Figure 6.10
Base Generation (PC): w/ GHG in 2013

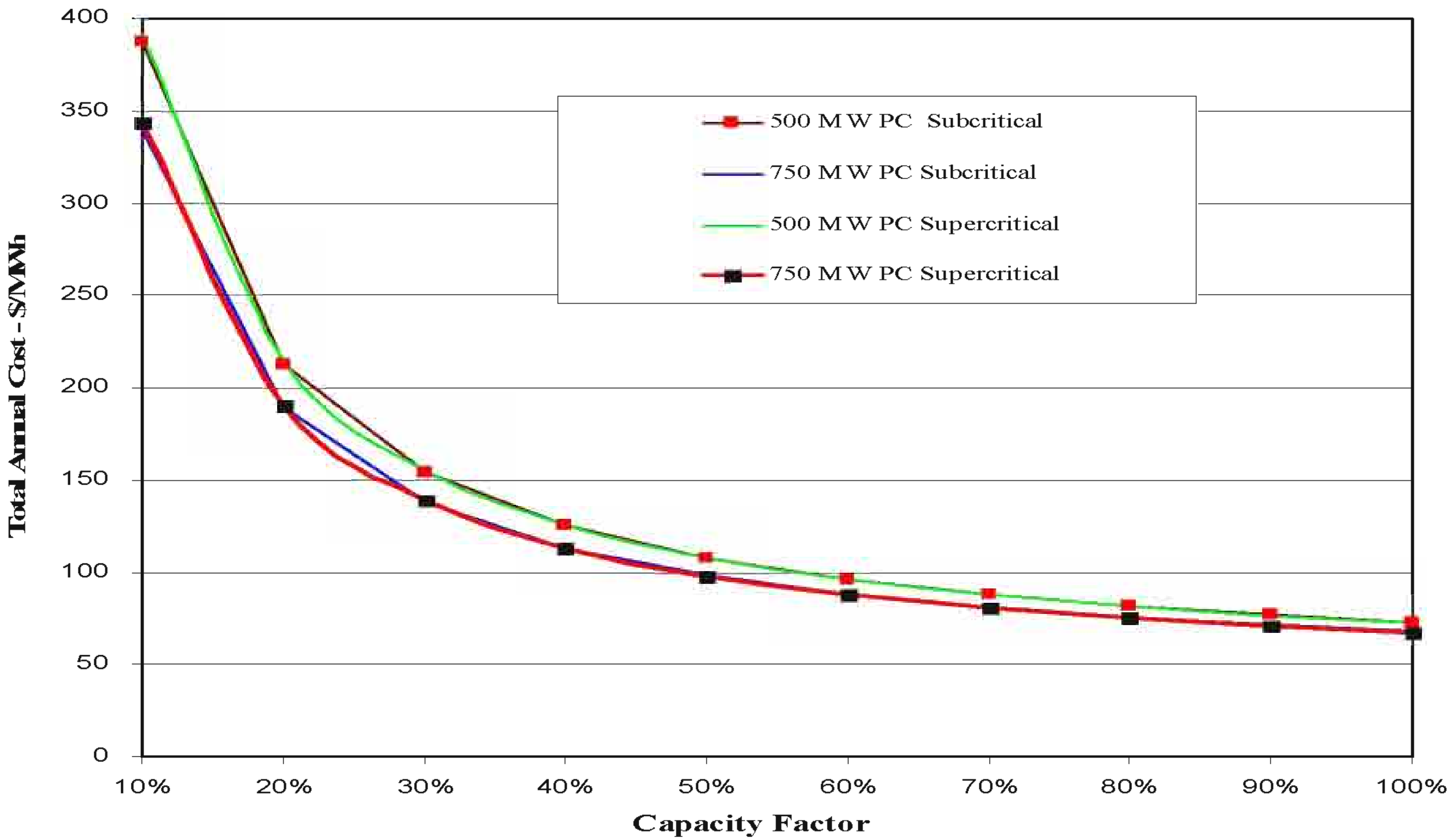


Figure 6.11
Base Generation (AFBC): w/ GHG in 2013

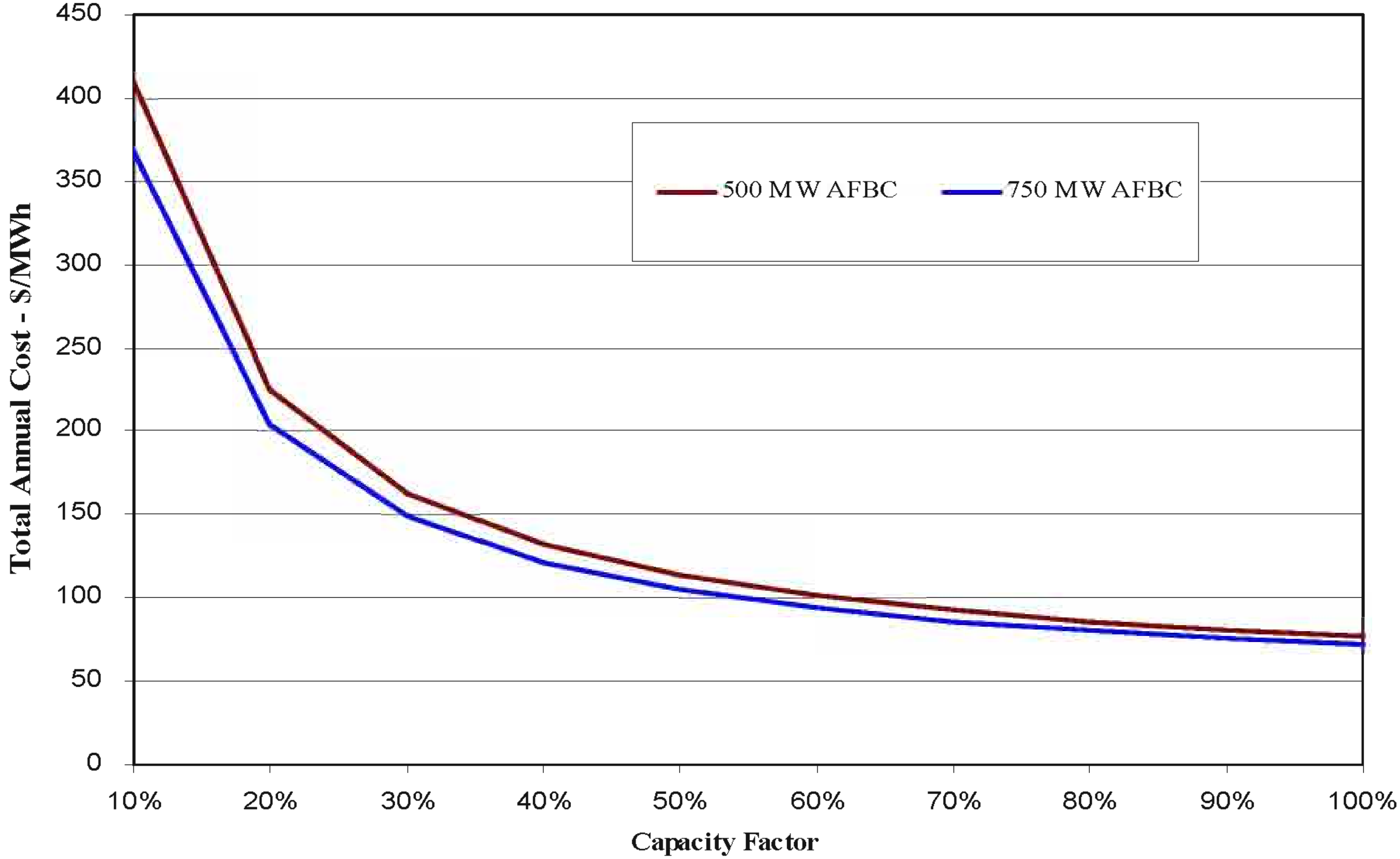


Figure 6.12
Base Generation (IGCC): w/ GHG in 2013

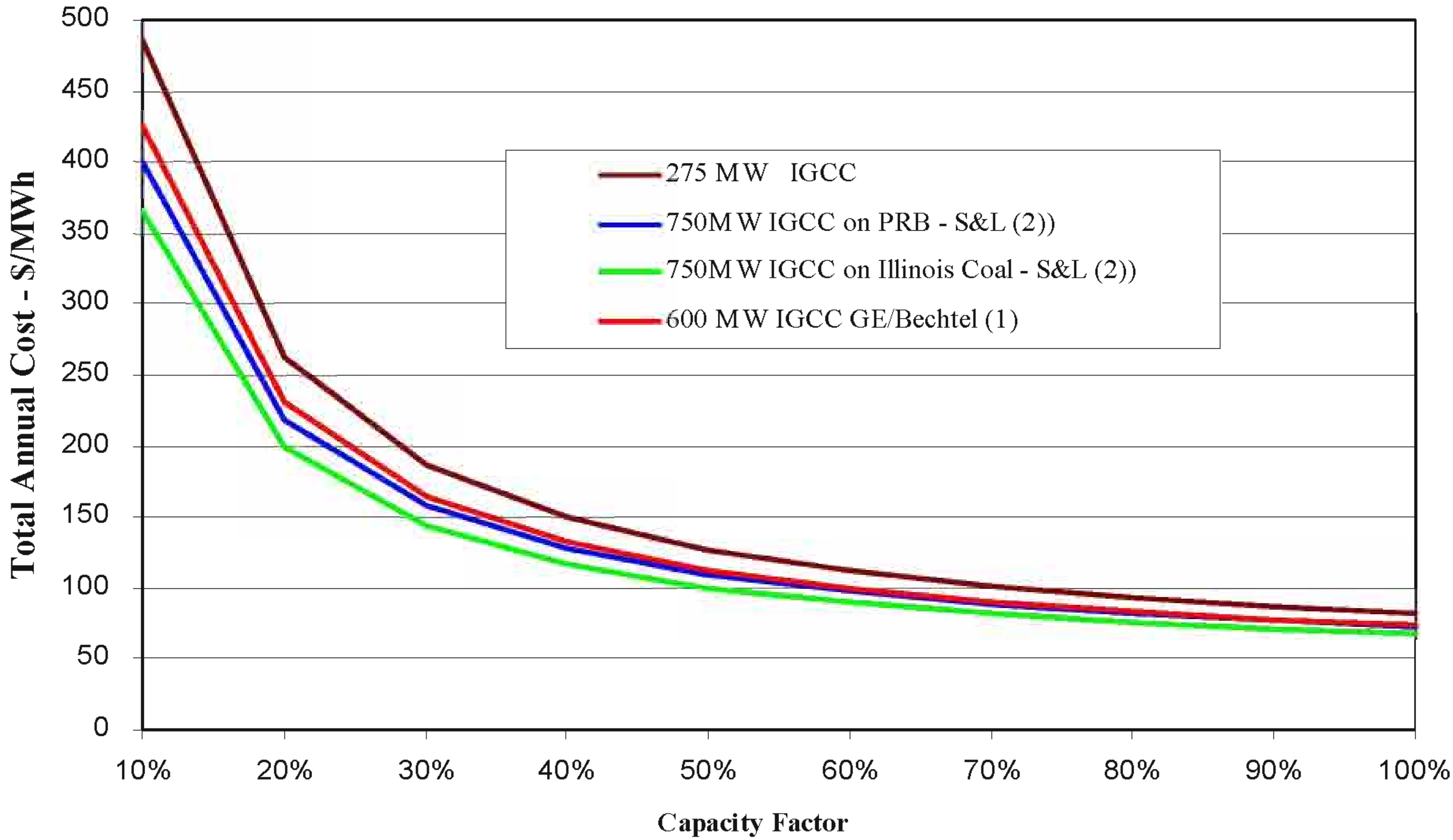


Figure 6.13
Base Generation (Nuclear): w/ GHG in 2013

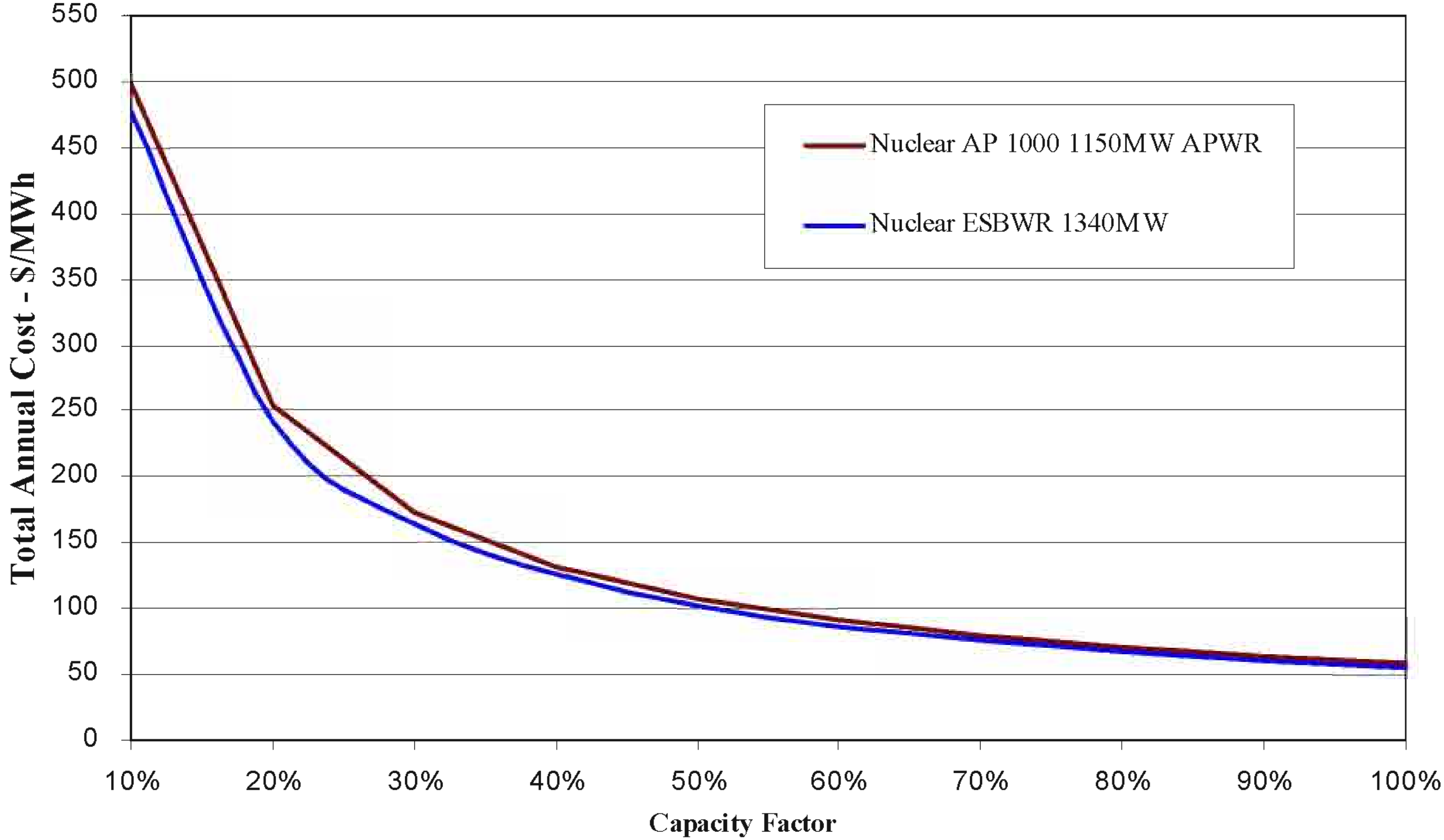


Figure 6.14
Combustion Turbines: w/ GHG in 2013

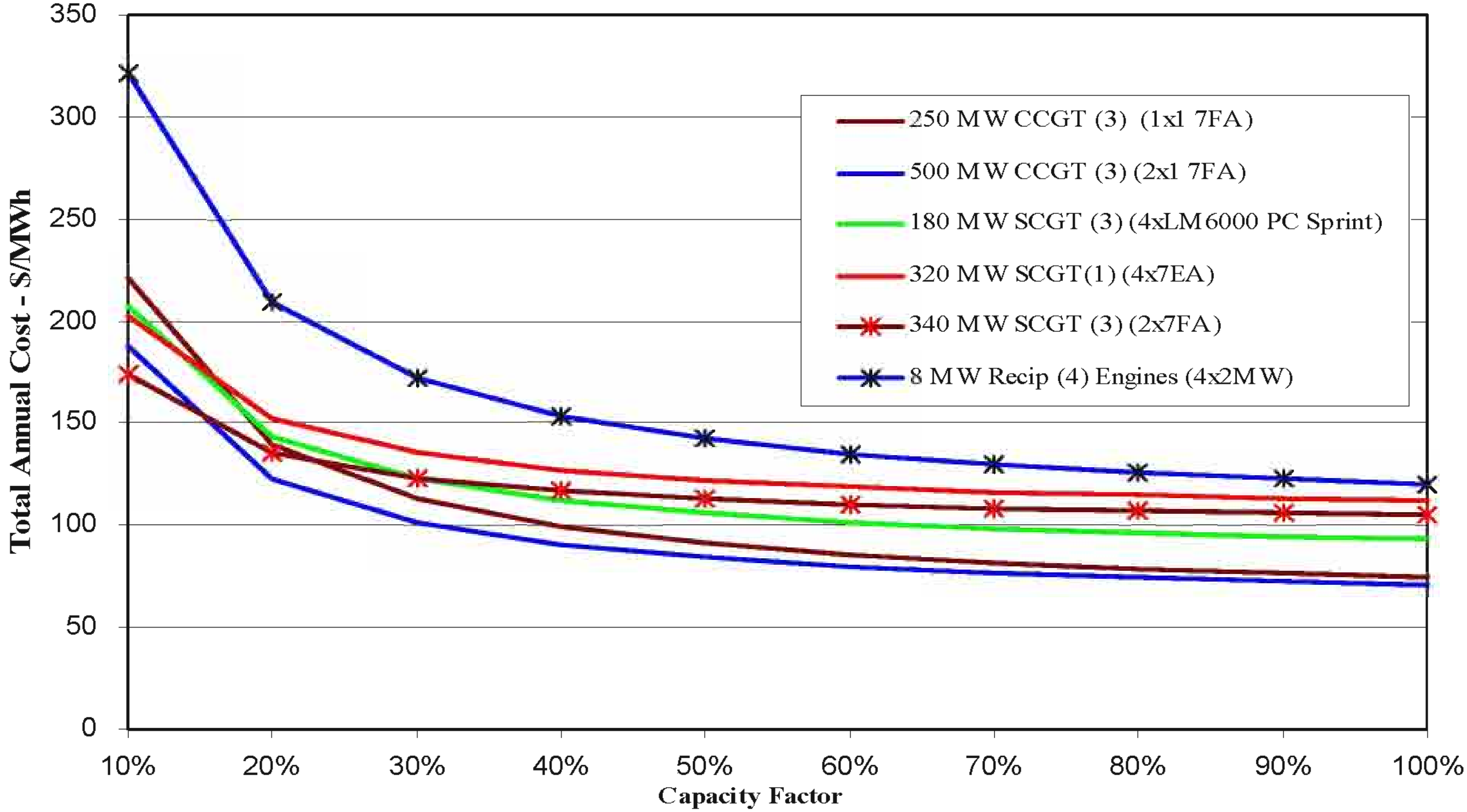


Figure 6.15
Renewables: w/ GHG in 2013

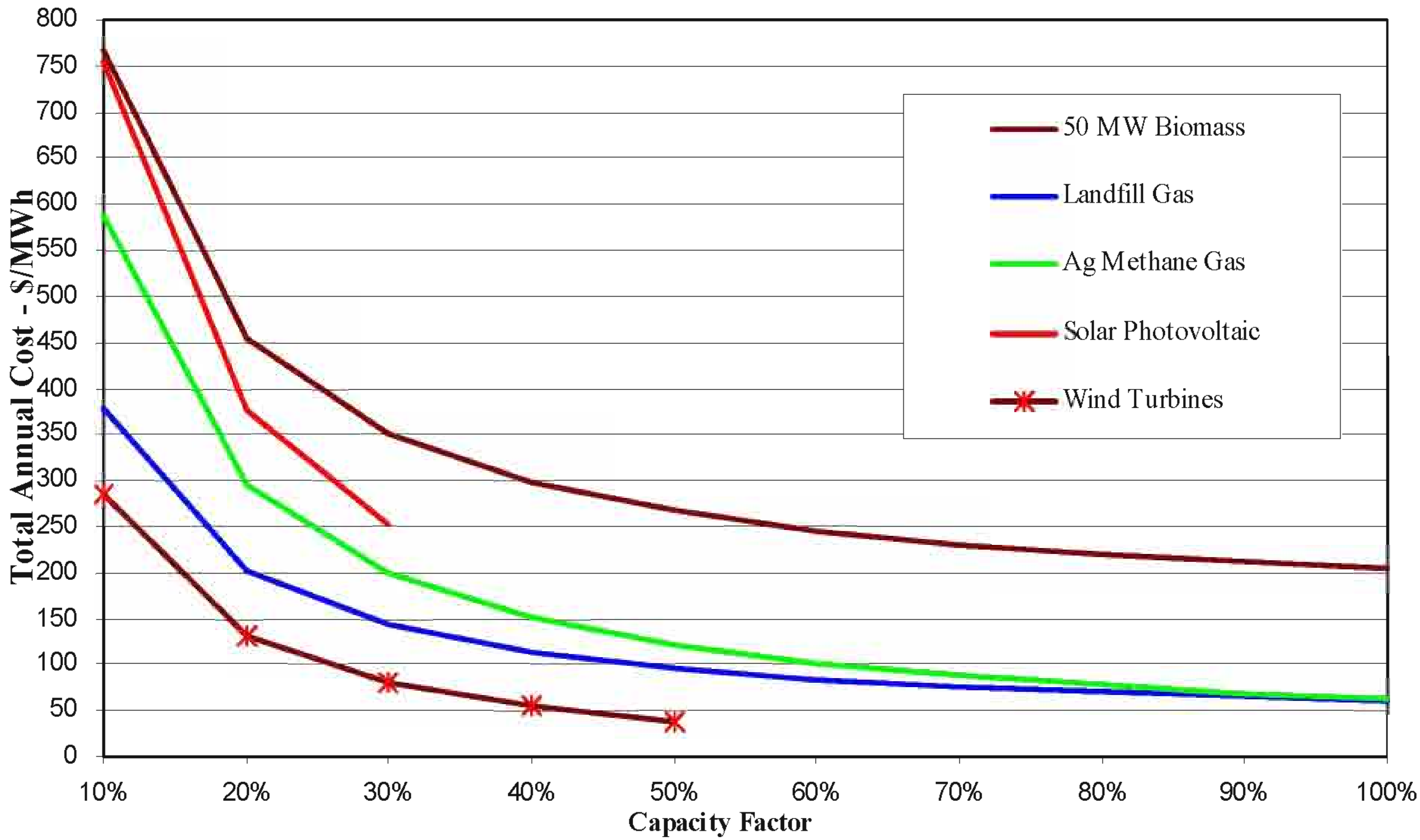


Figure 6.16
Storage: w/ GHG in 2013

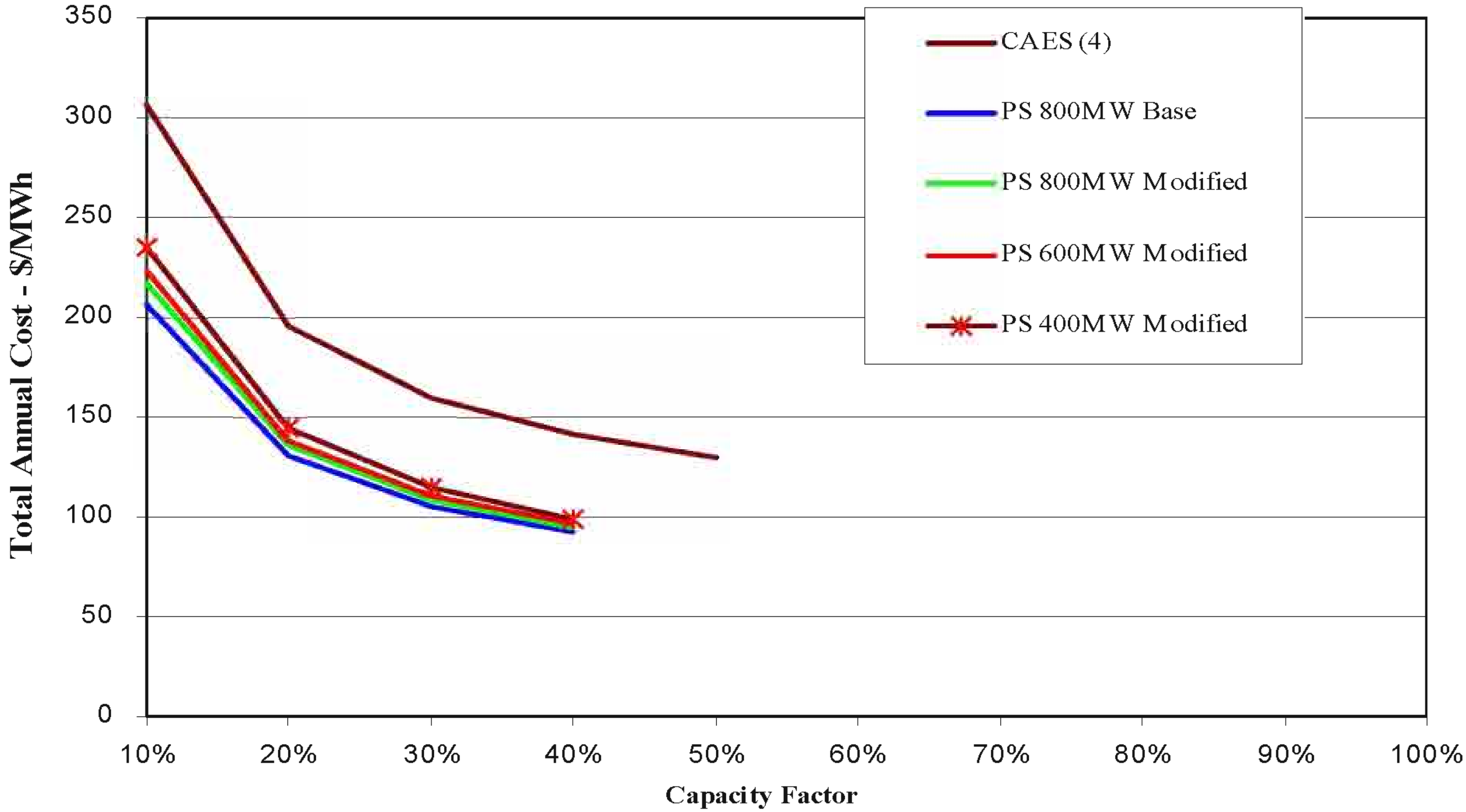
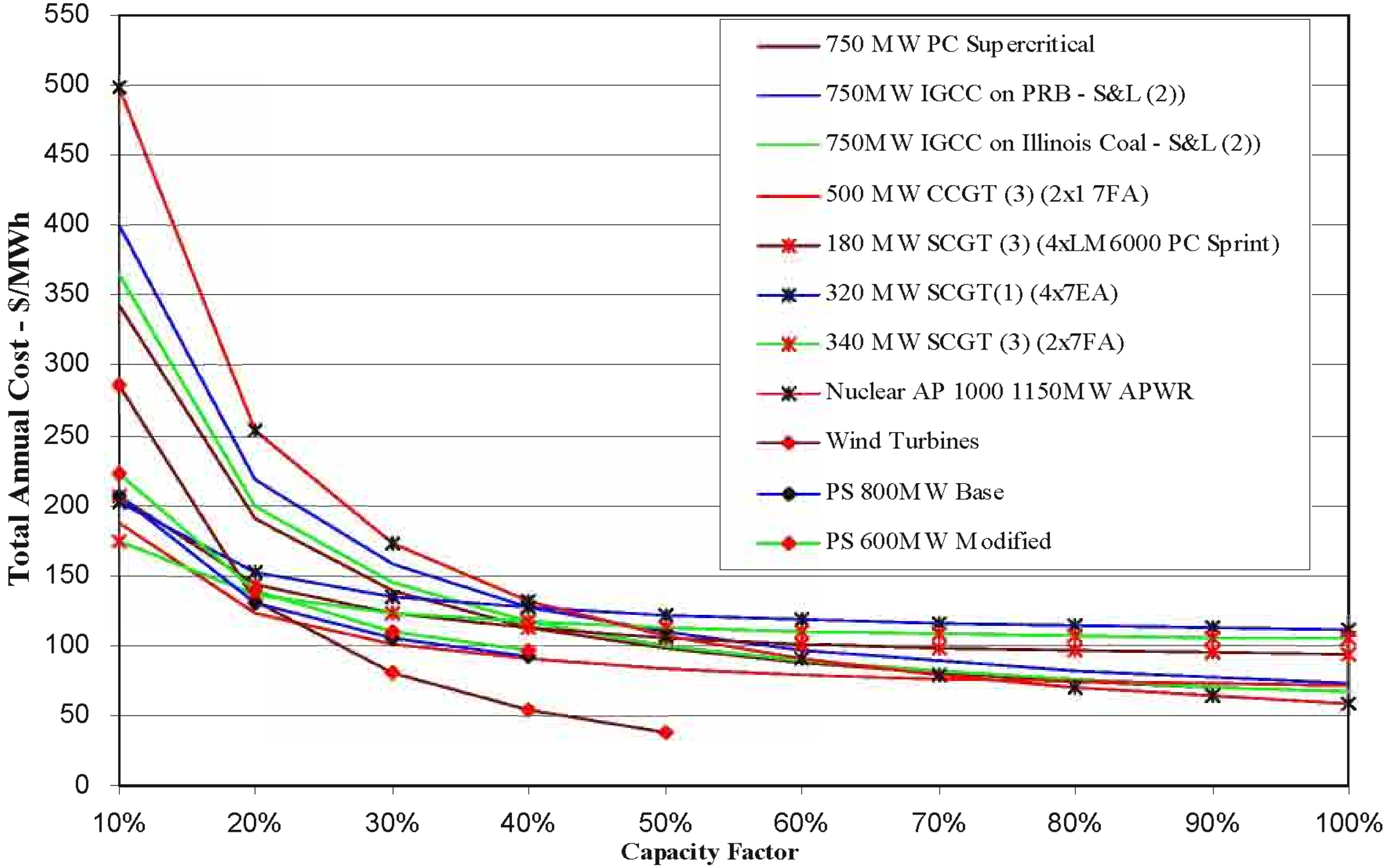


Figure 6.17
Viable Supply-side Options: w/ GHG in 2013



7 PORTFOLIOS

7.1 ALTERNATIVE RESOURCE OPTIONS: SUPPLY-SIDE AND DEMAND-SIDE

The results of the supply-side and demand-side screening analysis show that there are a number of demand-side and supply-side options that could be used in filling the gap between AmerenUE's known resources and prospective load obligations. This Integrated Resource Plan focuses on the candidate options that are known and are considered to be realistic, viable alternatives for balancing resource supply with electricity demand. Key resources that may be economical and could feasibly be developed by AmerenUE to meet its needs include:

- Purchasing existing natural gas – peaking assets
    - Option 1: purchase 600 MWs
    - Option 2: purchase 1,350 MWs
- New generation investment at greenfield sites
    - Wind
    - Supercritical Pulverized Coal
    - Natural gas - peaking
    - Natural gas - combined cycle units
    - Nuclear
    - Integrated Gasification Combined Cycle
- Expanding existing AmerenUE resources
    - Natural gas – combined cycle units at Venice
    - Supercritical Pulverized Coal at Rush Island
    - Integrated Gasification Combined Cycle at Rush Island
- Demand side management programs
    - Real-Time Pricing
    - Occasional Real-Time Pricing
    - Residential Critical- Peak Pricing
    - Residential Air Conditioning Cycling
    - Industrial and Commercial Interruptible
- Renewable fuel generation - Wind

7.2 PORTFOLIO DEVELOPMENT

Constructing portfolios was a process of assembling system and market assumptions, estimating AmerenUE's short position and choosing which portfolio resources are added each year to serve it.

Determining the short position began with the base demand growth forecast and the profile of energy needs. The profile combined with existing resources illustrated

AmerenUE's expected short position.

The resources described above served as the set of building blocks from which each portfolio was constructed. Building a portfolio was not merely a process of randomly adding resources. General guidelines to bound portfolio development are discussed below. For example, a required planning reserve margin was used to determine any additional capacity resource requirements. A [redacted] percent planning reserve margin was used as the primary criterion. Furthermore, resources were added at intervals to limit temporary capacity long or short positions to half the capacity of the resource being added.

AmerenUE had significant discussion around "automatic resource addition logic". There is potential merit of automatic resource addition logic. The lessons learned from this (and past) portfolio building study may allow AmerenUE to include such logic in the next resource plan. Clearly such logic is complex and, for it to be a value-adding exercise, much more than construction of a resource addition stack dependent on dispatch cost is required. AmerenUE is committed to exploring the addition of this logic in the future. In working towards this goal, AmerenUE has purchased the EnerPrise Capacity Expansion Module for automated screening and evaluation of generation capacity expansion, strategic retirement and other resource alternatives. It is a detailed and fast economic optimization model that simultaneously considers resource expansion investments and external market transactions.

7.2.1 Supply-Side Portfolios

In developing supply-side portfolios, several general guidelines were followed. First, we placed more emphasis on the first half of the 20-year analysis period than the second. Thus, different portfolios contained a variety of supply-side generation technologies in the first 10 years (2006-2015), but they tended to have a standardized set of CTGs added in the second 10 years 2016-2025). Note that this does not imply that AmerenUE will build only CTGs after 2015. Rather, to consistently evaluate different supply-side generation technologies, a standardized set of CTGs was added in the out years. AmerenUE will continue to do integrated resource planning studies over the next several years, and we will certainly evaluate portfolios that include a variety of supply-side resources with post 2015 online dates.

Second, the timing of base load resources, such as PC or IGCC, are constrained by the long lead times for permitting and construction. The earliest possible online date for these technologies is 2013. And, in line with the guideline of standardization of out years mentioned above, we built only one base load resource in any portfolio. For example, it was sensible to compare a portfolio consisting of a 2013 PC unit followed by CTGs to one with a 2013 IGCC unit followed by CTGs. It would be less sensible to compare a portfolio consisting of PC units in 2013 and 2018 to one with a 2013 IGCC unit followed by CTGs.
Third, it is not economical to build CTGs one at a time. Rather they would be built in pairs or even three or more at a time. To reflect this economic reality, portfolios contain

at least two CTGs for any given year.

Fourth, as mentioned above, portfolios bring new supply-side capacity online when roughly half of that capacity is needed to satisfy reserve requirements. For example, a 750 MW PC unit is added to a portfolio when AmerenUE is roughly 375 MW short of the required [redacted] percent reserve margin. Short term purchases are required in the few years before the PC unit comes online, and short term sales are made for the few years after it comes online.

Fifth, CTGs were added to maintain the following ratios of CTG types in the fleet:

- Aero-derivatives – 25 percent
- Small Frame – 25 percent
- Large Frame – 50 percent

As discussed in Section 6.6 above, each of these CTG types has different operational characteristics and capital costs. AmerenUE believes that this mixture of CTG types best takes advantages of the of the strengths of the three types while minimizing the weaknesses.

7.2.2 DSM Portfolios

AmerenUE's approach to demand-side resource analysis is to build upon "best practices" demand-side management and energy-efficiency programs both at AmerenUE and at investor-owned electric utilities across the nation. As outlined in the Demand-Side Management Briefing, AmerenUE engaged [redacted] to assist in the preparation of evaluations of various demand-side programs as inputs to the December 2005 integrated resource plan filing.

Two groups of programs – energy-efficiency and demand-response – were developed for inclusion in the DSM Portfolio. Combustion turbine capacity equivalence (CT-CE) analysis was applied to three of the demand response programs: CPP, ACLC, I/C. Both groups were combined with supply-side resources of CTGs, coal, and pumped storage.

Table 7.1
Demand Impacts

	Demand Response						Energy
	RTP	ORTP	CPP	ACLC	I/C	Total	Efficiency
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0.00
2007	-31	0	0	0	-23	-35	-1.52
2008	-31	0	0	0	-23	-35	-3.05
2009	-32	0	0	0	-23	-35	-4.56
2010	-61	-36	-66	-72	-29	-177	-4.56
2011	-61	-37	-66	-73	-29	-179	-4.56
2012	-62	-37	-67	-73	-29	-181	-4.56
2013	-62	-38	-68	-74	-29	-182	-4.56
2014	-63	-38	-68	-75	-29	-184	-4.56
2015	-64	-38	-69	-76	-29	-186	-4.56
2016	-64	-39	-70	-76	-30	-188	-4.56
2017	-65	-39	-71	-77	-30	-190	-3.09
2018	-72	-70	-182	-148	-32	-328	-1.61
2019	-73	-70	-184	-150	-32	-331	-0.15
2020	-73	-71	-186	-151	-32	-335	-0.15
2021	-74	-72	-188	-153	-32	-338	-0.15
2022	-75	-73	-190	-154	-32	-341	-0.15
2023	-76	-73	-192	-156	-32	-345	-0.15
2024	-76	-74	-194	-157	-32	-348	-0.15
2025	-76	-74	-194	-157	-32	-348	-0.15

7.2.3 RENEWABLE PORTFOLIOS

Although the current economic analysis of Missouri wind generation appears marginal, advancements in technology are providing a basis for AmerenUE to continue in its efforts regarding the development of 100 MW of wind generation in its 20-year resource plan. The timing and location of future wind projects depend on the results of current studies and data acquisition efforts as well as potential future Missouri renewable resource portfolio guidelines. For the IRP, AmerenUE analyzed the economics of adding 100 MW of Missouri wind-type projects in combination with CTGs, coal, and pumped storage.

Even with the generous assumption of a 27 percent capacity factor for the wind generators, the addition of 100 MW of wind generation has little impact (27 MW) on the roughly 2,500 MW of coal, pumped storage, and CTG generation included in each of these three portfolios.

7.2.4 CONCLUSION

Table 7.2 contains the details for each portfolio that was tested. While each portfolio differed, groups of portfolios tended to share common characteristics. The following categories evolved:

- DSM and build
    - CTGs
    - Coal
    - Pumped Storage

- Renewable-Wind
    - CTGs
    - Coal
    - Pumped Storage

- Build all natural gas peaking

- Purchase 600MW existing plants, and build
    - CTGs
    - Coal: pulverized or integrated gasification
    - Nuclear
    - Natural gas combined cycle
    - Pumped Storage

- Purchase 1,350MW existing peaking plants and build CT

Table 7.2- Portfolios

All Supply-Side	Renewables	Demand Response & Energy Efficiency
[redacted]		

8 RESULTS

8.1 OVERVIEW

Previous sections described the process of simulating the marketplace and modeling various resource portfolios. This systematic and thorough methodology yielded a large body of results. This section discusses those results and analyzes them to identify their context and meaning. The observations stated in this section are a result of AmerenUE's analysis during the iterative Integrated Resource Planning process. The most important of these create the foundation for the Plan Selection and Implementation detailed in Section 9.

Before discussing the results, it is important to make a distinction between deterministic modeling and stochastic modeling for risk purposes. A deterministic process implicitly reflects perfect information in the modeling process. All variables and world states are fixed and known, providing results that correspond precisely with the expected outcome of steady-state variables and conditions. As such, a deterministic or single-point modeling result reflects the anticipated outcome in light of perfectly executed and implemented assumptions.

A stochastic analysis is one that assesses the exposure of a decision to the randomness of the variables that drive the decision. AmerenUE's stochastic analysis is comprised of three primary components: a simulated risk analysis, a scenario analysis and a sensitivity testing. The *Risk & Uncertainty Analysis Briefing* contains a comprehensive discussion of the stochastic analysis.

Four Categories of Results

- **Deterministic Analysis - Operational & Rate Impacts:** This section presents the expected base-case costs of each portfolio. It summarizes the observations and performance of simulated portfolio operations and customer impacts.

- **Simulated Risk Analysis:** The simulated risk analysis summarizes portfolio variability due to the quantifiable risks. These parameters can be numerically represented and a known statistical process can be used to represent their variability.

- **Scenario (or Uncertainty) Analysis**: Scenario risks are also parameter driven. However the parameter variability cannot be reasonably represented by a known statistical process. This category is intended to embrace abrupt changes in risk factors, such as introduction of high carbon allowance costs.

- **Sensitivity Testing**: This section presents the findings associated with stressing different parameters such as AmerenUE's Environmental Compliance Strategy, Off-System Market Depth, technology parameters and evaluation of End Effects.

8.2 DETERMINISTIC ANALYSIS – OPERATIONAL & RATE IMPACTS

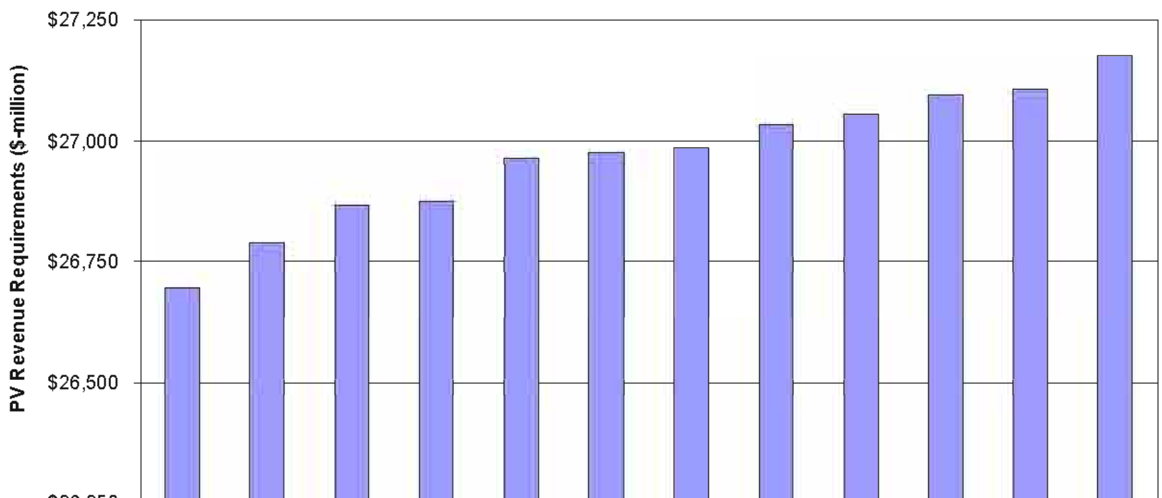
The modeling process simulated expected portfolio operations. The results culminate in total portfolio costs, measured by Present Value Revenue Requirement (PVRR). The PVRR is a central measure of portfolio performance and a critical driver of the resource selection process in the Plan Selection and Implementation.

The modeling also captures a number of other important measures. These include cost sub-categories, which roll up into PVRR. Evaluating the cost components identifies relative strengths and weaknesses of different resource configurations. Explaining why different resources result in different costs, the model finally provides a number of influential operating characteristics.

Determining the portfolio's PVRR was a principal objective of the modeling process. PVRR is the sum of year-by-year revenue requirements of a portfolio, discounted at an after-tax cost of capital to a common date. The cost of capital used was AmerenUE's weighted average cost of capital (WACC) discussed in the assumptions section. PVRR takes into account the time value of money such that different projections of costs due to various timings and magnitudes can be evaluated on a comparable basis. Therefore, comparing PVRR helps identify, on an expected present-value basis, the least-cost portfolio. A PVRR analysis provides an indication of relative rate direction but does not represent a projection of total AmerenUE rates or revenue requirements.

Figure 8.1 illustrates the PVRR for each of the portfolios evaluated. The top portfolio, shown on the left of the graph, represents the best PVRR of the group. The remainder of this section focuses on observations and performances of each portfolio.

Figure 8.1
Deterministic Portfolio Comparison



	CT Buy 1350MW	CT Buy 600MW	RI3 SC PC	Gmfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	PS Base	IGCC Gmfld	IGCC RI3 PRB	Nuclear	CT Bld All
Results	$26,695	$26,789	$26,868	$26,876	$26,964	$26,976	$26,985	$27,032	$27,054	$27,094	$27,104	$27,176

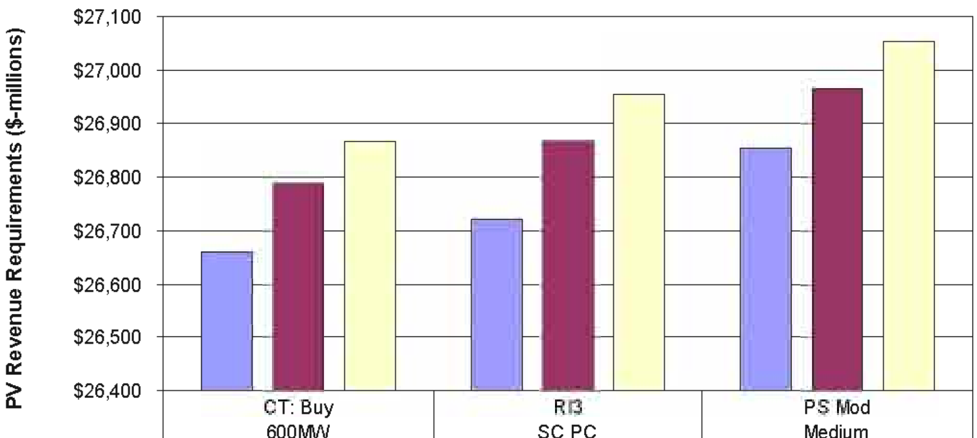
Observations regarding the ranking of the portfolios include:

- The planned acquisition of the 1,350 MW of CTG's has the lowest PVRR.
- CT: Buy 600 MW, RI3 SC PC, and Grnfld SC PC provide similar PVRR with CT: Buy 600 MW being a bit lower.
- PS Mod Medium, IGCC RI3 IL6, and Combined Cycle are in the next tier with PVRR that are $176 to $197 million higher than the purchase of 1,350 MW CTs.

General Observations on all supply-side portfolios:

- Gas-based technologies do not dispatch often enough for their exposure to high gas prices to cause significant harm.
- Portfolios with base load and intermediate plants (i.e. coal, IGCC, nuclear, combined cycle) have a noticeably higher dependence on off-system sales.
- Pumped storage portfolios are negatively impacted by the loss of off-system sales due to "pump back".

Figure 8.2
Demand Response and
Renewable Portfolio Comparison



	CT: Buy 600MW	RI3 SC PC	PS Mod Medium
w/ DR & EE	$26,661	$26,722	$26,855
All Supply-side	$26,789	$26,868	$26,964
w/ Wind	$26,866	$26,954	$27,053

General Observations on all demand response and renewable portfolios:

- Including demand-response or renewable resources does not change the order of portfolios.
- Demand-response placeholder lowers revenue requirements $100 to $150 million.
- Wind increases revenue requirements $80 to $90 million.
- Demand response mixed with new base load (coal) resources results in slightly more benefits than combining it with peaking resources (CTs or pumped storage).
- Adding wind with CTs increases revenue requirements a little less than adding wind with coal under the base scenario.

It is important to note that the results above are a result of the assumption that the real-time pricing program's reductions do not include an adjustment for reliability contribution considerations (i.e. capacity equivalence). AmerenUE does not have experience with calculating capacity equivalence for RTP products. In addition, AmerenUE has existing demand response programs which may further reduce the MW potential for the demand response programs. Both of these issues could significantly reduce the value (or increase revenue requirements) of the demand response portfolios analyzed above. Refer to Section 5 – Demand-Side Resources, Section 7 – Portfolio Development, and the *Demand-Side Briefing* for further discussion of these issues.

Evaluating the components of PVRR provides insight into portfolio performance. These evaluations help explain the results observed and aid in the development of the Implementation Plan.

PVRR is comprised of both fixed and variable cost elements. Variable costs, as traditionally defined, consist of many elements including fuel costs, variable O&M, unit start-up costs, emissions costs or credits and off-system sales and purchases. Variable cost characteristics differ depending on the type and timing of resource installations.

The off-system sales and purchases category includes the PVRR of spot sales and purchases pursuant to the model dispatch logic. Spot-market sale revenues usually increase in the years a large resource is added. At that point, sales rise over portfolios with smaller, more flexible units. For example, coal and nuclear portfolios add a large base load plant in 2013 at which time sales rise significantly.

Operational simulation demonstrates that portfolios with lower PVRR tended to exchange higher fixed costs in return for lower variable costs. For example, the high fixed costs of a coal or nuclear plant can be attributed to a relatively early installation (2013). These fixed costs have greater present values than other portfolios. Offsetting the fixed costs, the variable costs savings of the coal or nuclear (compared to natural gas) have a variable cost advantage over the other portfolios. When the fuel portion of the variable cost is reduced by off-system sales profits, the variable costs for coal and nuclear fare much better. A similar tradeoff occurs with the Renewable portfolio.

Cost measures are important means of evaluating portfolio performance. In addition to costs, the Capacity Utilization factors help explain the operations of each portfolio. Capacity factors provide valuable insight into the utilization of each resource addition. Lower capacity factors imply units needed for reliability but not necessarily for energy. The measure was particularly useful in the portfolio evaluation process in which fuel volatility was tested. Resources that have low capacity factors and use a price volatile fuel, such as natural gas, did not demonstrate enough exposure to high prices to have material detriment to PVRR.

New base load units tended to have high capacity factors that are a result of higher off-system sales and some displacement of existing base load units. Any displacement is indicative of a long market position and adds some risk.

8.3 SIMULATED RISK ANALYSIS

Simulated risks are quantifiable risks. These parameters can be numerically represented and a known statistical process can be used to represent their variability. Risks associated with business-as-usual variability typically falls within this category. AmerenUE's analysis assumes that the simulated risk is driven by uncertainty in the following parameters (risk factors):

[redacted]

Explained by a known statistical process, these risks naturally lend themselves to simulation. As such, their variability is captured in the IRP's modeling. Refer to the *Risk and Uncertainty Analysis Briefing* for detailed information identified above.

8.3.1 RISK MEASURES

Expressing each portfolio in terms of deterministic PVRR conveys just one dimension of portfolio performance. The risk of each portfolio represents another key dimension. This section provides four risk measures for comparison:

- 95^{th} Percentile
- 5^{th} Percentile
- 95^{th} – 5^{th} Percentile
- Coefficient of Variation

Each measure provides a different perspective on the risk profile of the final portfolios. Taken in aggregate, they help establish portfolio rankings.

While it is helpful to evaluate individual portfolio risks, those risk measures alone do not convey the cost effectiveness of investments needed to achieve (or mitigate) them. Therefore, this section also evaluates the tradeoffs between investment and risk.

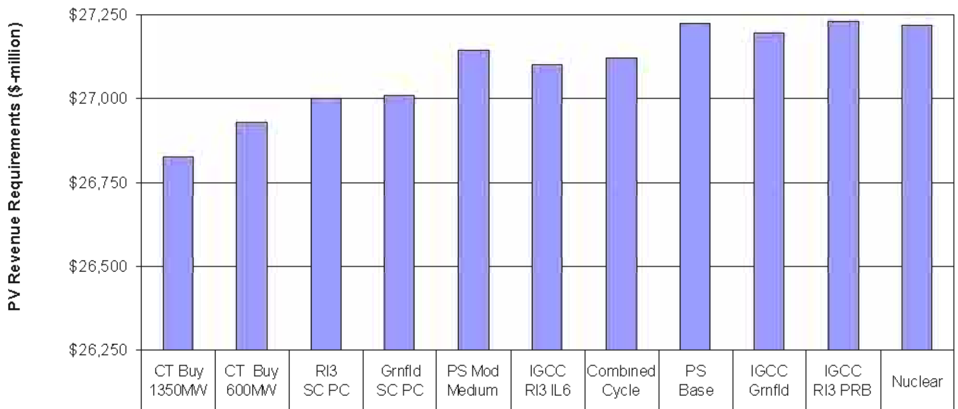
The following risk measures define the risk profile of the final portfolios and allow comparisons between them. In addition to defining the measure and showing the model results, this section details the limitations of each.

95^{th} Percentile

This measure allows for high-risk case comparisons between portfolios. Ninety-five percent of the simulated PVRR observations occurred below this point. Given the asymmetrical distribution of simulated outcomes, the 95^{th} percentile provides an efficient risk representation. The 95^{th} Percentile represents a measure for "***how bad things can***

get." Decisions based on this metric must be made with some caution. While the 95th percentile helps define the high side of potential PVRR outcomes, it doesn't provide insight into the overall variability of the portfolio.

Figure 8.3
95th Percentile PVRR



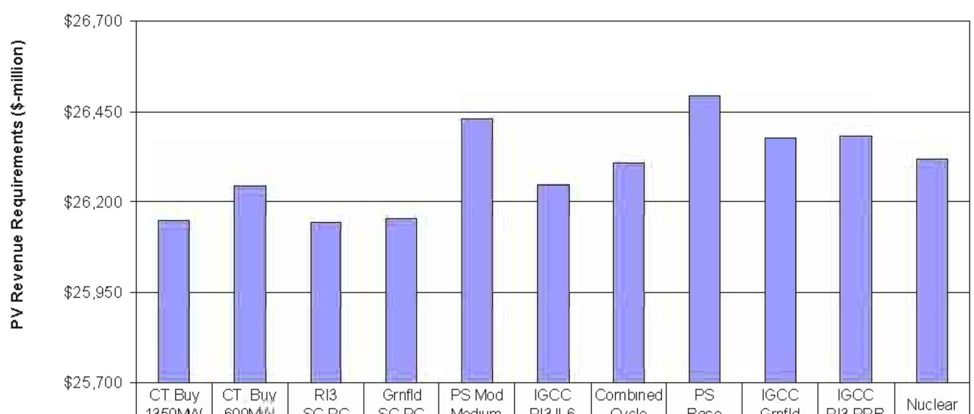
	CT Buy 1350MW	CT Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	PS Base	IGCC Grnfld	IGCC RI3 PRB	Nuclear
95th Percentile	$26,826	$26,928	$27,001	$27,009	$27,145	$27,102	$27,120	$27,224	$27,194	$27,230	$27,217

Those portfolios with lower 95th Percentile PVRR are less likely to have high PVRR outcomes.

5th Percentile

Five percent of the simulated observations occurred below this point. Since low PVRR are generally preferred, this measure of risk helps identify a reasonable approximation of best-case expectations. Like the preceding measures, lower values are generally preferred. They illustrate ***the reasonable extreme of best-case outcomes***. This measure is of particular interest when interpreting the previously discussed risk metrics.

Figure 8.4
5th Percentile PVRR



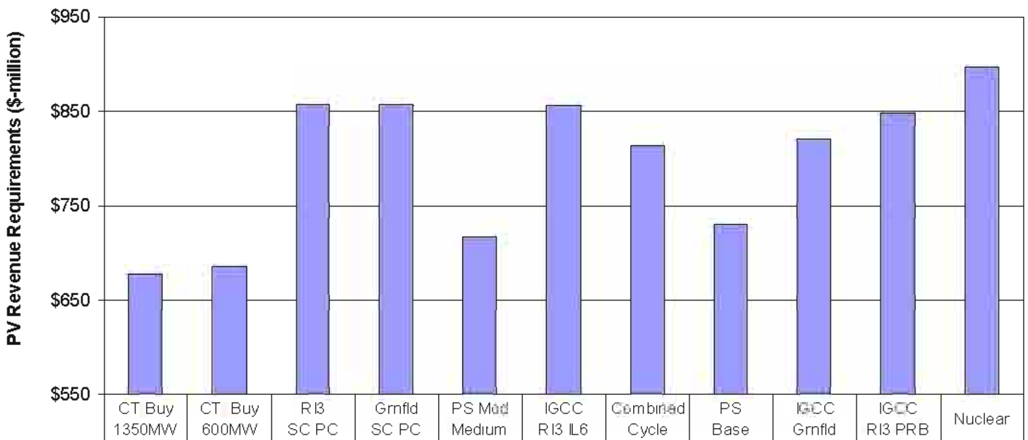
	CT Buy 1350MW	CT Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	PS Base	IGCC Grnfld	IGCC RI3 PRB	Nuclear
5th Percentile	$26,149	$26,243	$26,144	$26,152	$26,428	$26,246	$26,306	$26,494	$26,374	$26,382	$26,319

95^{th} – 5^{th} Percentile

This value is another measure of risk. The measure equals the difference between the 5^{th} percentile and the 95^{th} percentile of PVRR. Forty out of 50 iterations fell within this range. Thus, it represents a reasonable range of expected outcomes for each portfolio. The larger this range, the greater the risk associated with each portfolio.

The 95^{th} – 5^{th} measure defines the *reasonable* range of expected outcomes. However, decisions based on it should be made with some caution. Comparisons based upon this risk measure may be confusing among portfolios with significantly different means and/or 5^{th} percentiles.

Figure 8.5
95^{th}-5^{th} Percentile PVRR



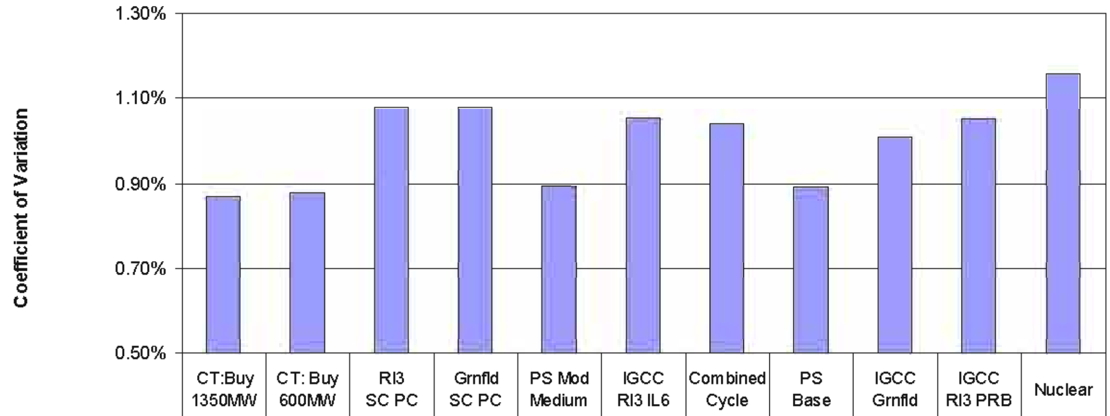
	CT Buy 1350MW	CT Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	PS Base	IGCC Grnfld	IGCC RI3 PRB	Nuclear
95th-5th	$677	$685	$857	$857	$717	$856	$813	$730	$821	$848	$898

Coefficient of Variation

The coefficient of variation is an alternative measure of risk. It equals the standard deviation of the 100 risk iterations divided by their mean. Standard deviation alone is a measure of the relative dispersion (and risk) of iterative outcomes. Dividing by the mean tends to reduce confusion caused when comparing distributions with different means.

While valuable for comparisons, this measure doesn't provide a complete picture of risk within the context of the IRP. Stated as a percentage, the measure doesn't convey the dollar variability associated with each portfolio. The portfolios with lower coefficient of variation have less variability in the probable outcomes.

Figure 8.6
Coefficient of Variation



	CT:Buy 1350MW	CT: Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	PS Base	IGCC Grnfld	IGCC RI3 PRB	Nuclear
Coefficient of Variation	0.87%	0.88%	1.08%	1.08%	0.89%	1.06%	1.04%	0.89%	1.01%	1.05%	1.16%

8.3.2 RISK TRADEOFF

The information above provides valuable comparisons between key portfolio metrics. These comparisons are only the first step in evaluating portfolio risk performance. The next step requires evaluating the tradeoff between investment and risk. Evaluating portfolios in this manner provides useful insight. Superior portfolios should demonstrate a superior tradeoff.

This section details the risk tradeoff associated with two measures. First, this section presents the PVRR relative to the 95th percentile. Second, this section presents the PVRR relative to the 95th–5th percentile.

PVRR vs. 95th Percentile

Figure 8.7 demonstrates the tradeoff between the PVRR and risk. Interpreting the results of this graph is a matter of comparing the investment required by each portfolio (expected or mean PVRR) against the overall risk the portfolio demonstrated in the model (95th percentile PVRR minus mean PVRR).

Stakeholders are assumed to universally prefer lower risk portfolios at any specific investment level. Therefore, portfolios approaching the origin of Figure 8.7 generally dominate those more distant. Under this rule of thumb, CT: Buy 1350MW appears to be the dominant portfolio.

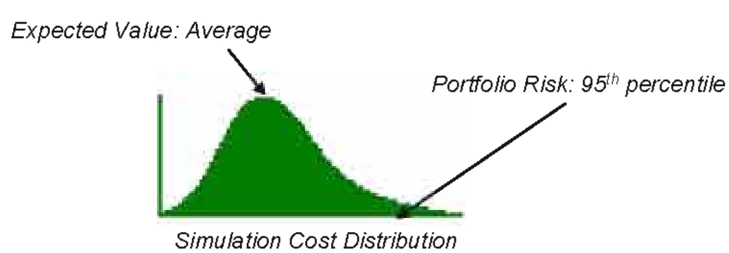
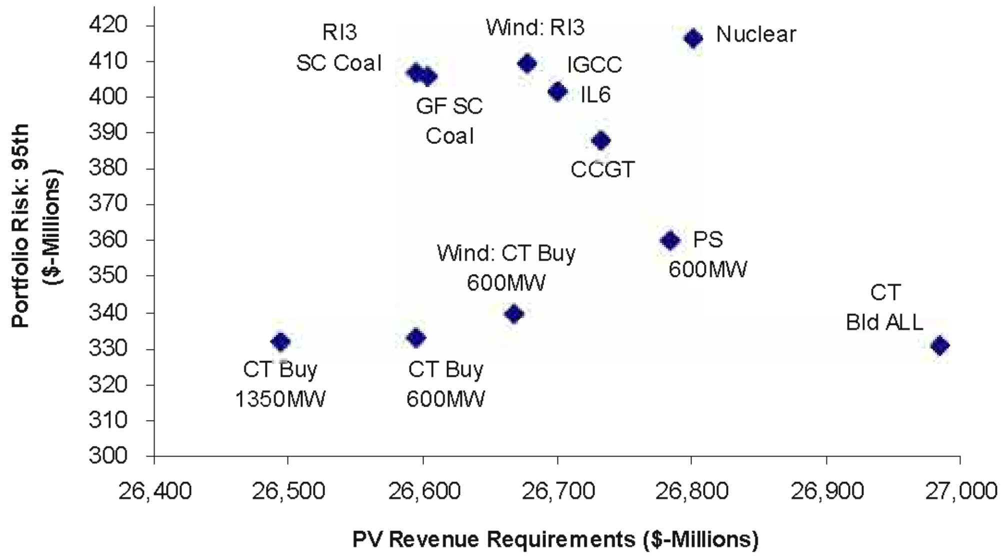


Figure 8.7
PVRR vs. 95th Percentile



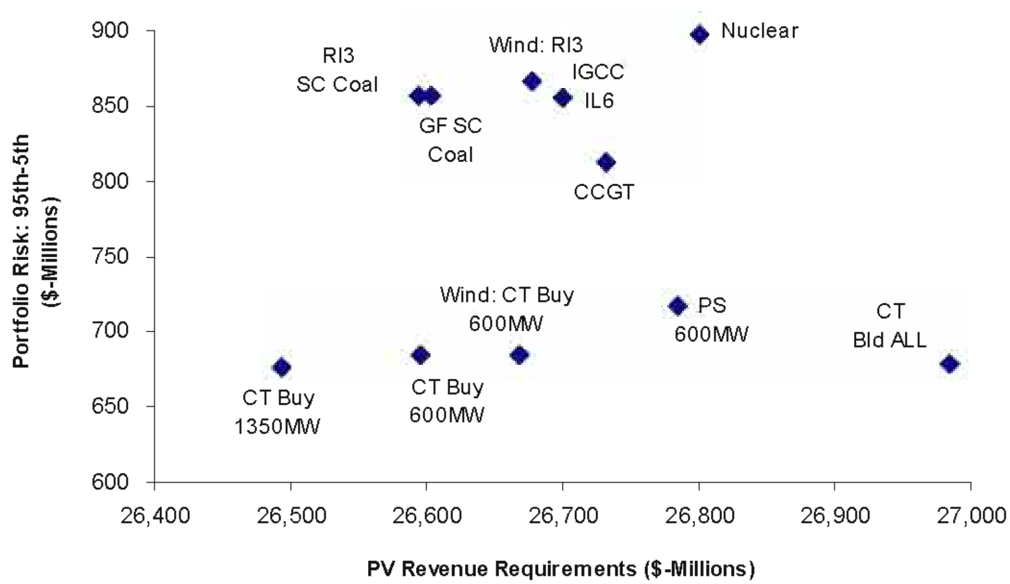
Observations:

- Gas-based technologies do not dispatch often enough for their exposure to gas price volatility to cause significant harm.
- The coal and nuclear portfolios are exposed to off-system sales margin volatility.
- Pumped-storage portfolios are somewhat less exposed to off-system sales, but it is not enough to overcome the gas-based portfolios.

PVRR vs. 95th – 5th Percentile

The 95th percentile alone does not provide a complete picture of risk. Figure 8.8 employs a different risk measure, 95th –5 ^{h} percentile, in order to evaluate the tradeoff between PVRR and risk. Interpretation of this figure is performed in the same manner as before. Results closer to the origin are generally preferred. As such, CT: Buy 1350MW, again, appears as the dominant portfolio. Comparing this graph to the PVRR vs. 95th graph shows that the portfolios virtually stayed in the same relative position. This observation indicates there is as much upside (lower PVRR) as downside (higher PVRR) risk at the 95th and 5th percentile.

Figure 8.8
PVRR vs. 95th-5th Percentile



8.4 SCENARIO RISK ANALYSIS

Similarly to simulated risk, scenario risks are also parameter driven. However the parameter variability cannot be reasonably represented by a known statistical process. This risk category is intended to embrace abrupt changes in the risk factors such as introduction of high carbon allowance costs. The probability of high carbon allowance costs cannot be determined with a reasonable degree of accuracy. Therefore, a scenario of this occurrence is created without applying a probability to it. With assumed values (as opposed to simulated values) portfolios can be tested for their sensitivity to a specific scenario risk.

Simulated risks, by definition, vary randomly given a specific set of core assumptions for the Scenario Risks. The Scenario Risk parameter is manually modified in order to observe the impact on the model. This is a form of stress testing.

In the case of changing scenario risks, the time evolution of PVRR takes a distinctly different path, rather than fluctuating around an expected value as it does in simulated analysis. The measure of scenario risk is the difference between the expected PVRR generated by applying different scenarios.

Greenhouse Gas (CO_2) Scenario

In the US, there is currently no federal CO_2 regulation in place although increasing pressure from the grassroots and state government levels, as well as implementation of CO_2 policies in foreign countries, could result in future federal CO_2 regulation. While the federal government has yet to promulgate national CO_2 emission restrictions, multiple states, legislators and the international community are moving ahead with carbon regulation. At the corporate level, some utility companies have issued reports to address shareholder concerns about climate change and the risks associated with regulatory intervention and compliance.

The future of a carbon tax cost is a federal environmental policy decision beyond AmerenUE's control but it has potential to greatly impact system operations and long-term resource planning. In the absence of certainty around prospective CO_2 emissions regulation, AmerenUE developed a scenario to address the potential impacts of greenhouse gas regulation on its resource portfolio evaluation process. It is clear that the addition of zero emissions resources to the system when there is a CO_2 allowance cost would have a financial and environmental benefit to the company. This scenario tests the impacts of four CO_2scenarios.

In order to determine the impacts of carbon legislation on prospective resource portfolios, AmerenUE consulted ICF Consulting, Inc. to develop a fundamental CO_2 forecast based upon a cap-and-trade regulatory environment post 2010. ICF developed an expected case which is representative of the scope, stringency and timing of an air regulatory structure that is likely to be realized under a regulated or legislated future. High and low sensitivities were provided around the expected case; see Table 8.1 below for the scenario prices. Refer to the *Risk & Uncertainty Analysis Briefing* for further development of this scenario. The results from CO_2 scenario reflect the deterministic outcomes of the four scenarios.

Table 8.1
CO_2 Price Forecasts

Nominal Prices ($/ton CO_2)

Scenario	**2010**	**2015**	**2020**	**2025**
Base - none	$0	$0	$0	$0
Mild	[redacted]			
Moderate				
Stringent				
Stringent-nuclear				

Figure 8.9
CO_2 Scenario Portfolio Comparisons

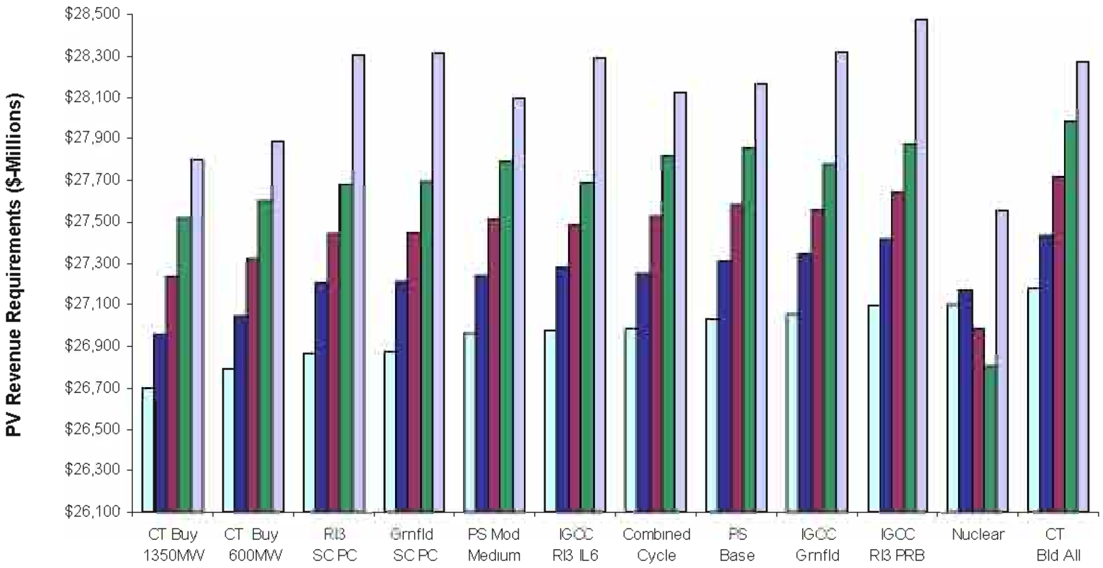


Table 8.2
Relative Ranking of Portfolios with CO_2 Tax

		CT Buy 1350MW	CT Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	PS Base	IGCC Grnfld	IGCC RI3 PRB	Nuclear	CT Bld All
PVRR	CAIR	$26,695	$26,789	$26,868	$26,876	$26,964	$26,976	$26,985	$27,032	$27,054	$27,094	$27,104	$27,176
	GASL	$26,955	$27,048	$27,203	$27,214	$27,241	$27,280	$27,249	$27,309	$27,348	$27,417	$27,168	$27,434
	GASM	$27,237	$27,324	$27,441	$27,450	$27,515	$27,481	$27,528	$27,581	$27,560	$27,642	$26,983	$27,711
	GASH	$27,518	$27,600	$27,680	$27,691	$27,789	$27,686	$27,815	$27,854	$27,774	$27,871	$26,802	$27,987
	GASN	$27,794	$27,885	$28,302	$28,313	$28,098	$28,289	$28,125	$28,166	$28,321	$28,474	$27,555	$28,269
Rankings	CAIR	1	2	3	4	5	6	7	8	9	10	11	12
	GASL	1	2	4	5	6	8	7	9	10	11	3	12
	GASM	2	3	4	5	7	6	8	10	9	11	1	12
	GASH	2	3	4	6	8	5	9	10	7	11	1	12
	GASN	2	3	9	10	4	8	5	6	11	12	1	7
Delta	CAIR	$0	$94	$173	$181	$269	$281	$290	$337	$359	$399	$409	$481
	GASL	$0	$93	$248	$259	$286	$325	$294	$354	$394	$462	$213	$479
	GASM	$0	$88	$204	$214	$278	$244	$292	$344	$324	$405	($254)	$474
	GASH	$0	$82	$162	$173	$271	$168	$297	$336	$257	$353	($716)	$469
	GASN	$0	$90	$508	$519	$304	$494	$330	$372	$526	$680	($239)	$475

Observations:

- PVRR escalates with the increase of the CO_2 Tax for every portfolio.
- Existing thermal unit operation decreases with the increase of CO_2 tax largely due to decreased off-system sales.
- CO_2 testing changes the relative rankings of portfolios measured by PVRR.
- Adding wind to the portfolio produces a relative reduction to PVRR to the same portfolios without a CO_2 Tax.

The probability of any of these CO_2 allowance cost outcomes is unknown. Model results show that zero emission resources, such as nuclear and wind, can displace thermal resources as a hedge against the high CO_2 Tax scenarios.

8.5 SENSITIVITY TESTING

Described in the *Risk & Uncertainty Analysis Briefing* certain inputs or assumptions do not naturally lend themselves to randomized variation within the models. Understanding the nature of these variables and their impact on portfolio performance therefore requires deliberate manipulation of their values. Model assumptions selected for this type of stress testing or scenario analysis include:

- Market Depth (Off-System Sales)
- Environmental Strategy
- Technology parameters
- Capital Life – End Effects

Each sensitivity test was designed to provide insight into the risk associated with each resource plan. The results of the testing are important. They demonstrate that the path ultimately taken by each risk can alter the risk and cost profile of different portfolios. Collectively, they demonstrate the need for planning flexibility. Such flexibility in the development of portfolios is the most practical means of addressing each risk.

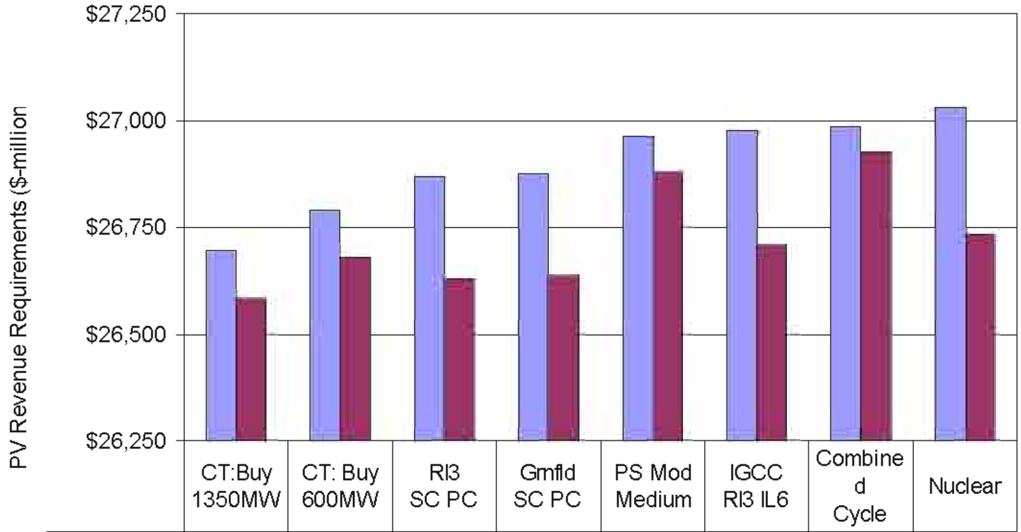
8.5.1 MARKET DEPTH (OFF-SYSTEM SALES)

The depth of the market could have an impact on the optimal resource portfolio in light of value and risk. Assumptions regarding the prospective market depth that can be reasonably anticipated are important in defining value and risk. After the launch of the MISO energy markets in April 2005, a new dynamic was observed relative to off-system transactions. After the launch of the MISO energy markets in April 2005, all resources and loads across the MISO footprint are bidding into a central energy market Essentially, what was once a limited network of counterparties became a more liquid market place.

In order to test the effects of increased market liquidity, market depth sensitivity was performed. Under this sensitivity, the base off-system limitations were removed in the model and the AmerenUE system was integrated into the MISO under the assumption that there would be no congestion impacts resulting from the dispatch of any AmerenUE resource on the system and no transmission limitations were included. Essentially, this sensitivity sought to demonstrate the impact of *unlimited* market depth for the AmerenUE resource portfolios under evaluation.

In light of multiple system and economic dynamics, AmerenUE acknowledges that unlimited market depth is not feasible and did not select this sensitivity to represent an expectation of future market depth. This sensitivity was developed to demonstrate an extreme boundary in the absence of modeling an infinite number of prospective system states, conditions and definitions.

Figure 8.10
Market Depth



	CT:Buy 1350MW	CT: Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combine d Cycle	Nuclear
Current	$26,695	$26,789	$26,868	$26,876	$26,964	$26,976	$26,985	$27,032
Unlimited	$26,582	$26,680	$26,632	$26,639	$26,878	$26,709	$26,927	$26,735

Table 8.3
Market Depth

		CT:Buy 1350MW	CT: Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	Nuclear
PVRR	Current	$26,695	$26,789	$26,868	$26,876	$26,964	$26,976	$26,985	$27,032
	Unlimited	$26,582	$26,680	$26,632	$26,639	$26,878	$26,709	$26,927	$26,735
Rank	Current	1	2	3	4	5	6	7	8
	Unlimited	1	4	2	3	7	5	8	6
Delta	Current	$0	$94	$173	$181	$269	$281	$290	$337
	Unlimited	$0	$98	$50	$57	$296	$127	$345	$153

Observations:

- With unlimited market depth, PVRR decreases for every portfolio.
- Rankings of portfolios change with base load plants benefiting the most from the increase in off-system sales.
- Pumped storage and combined cycle do not capture as much benefit from off-system sales.

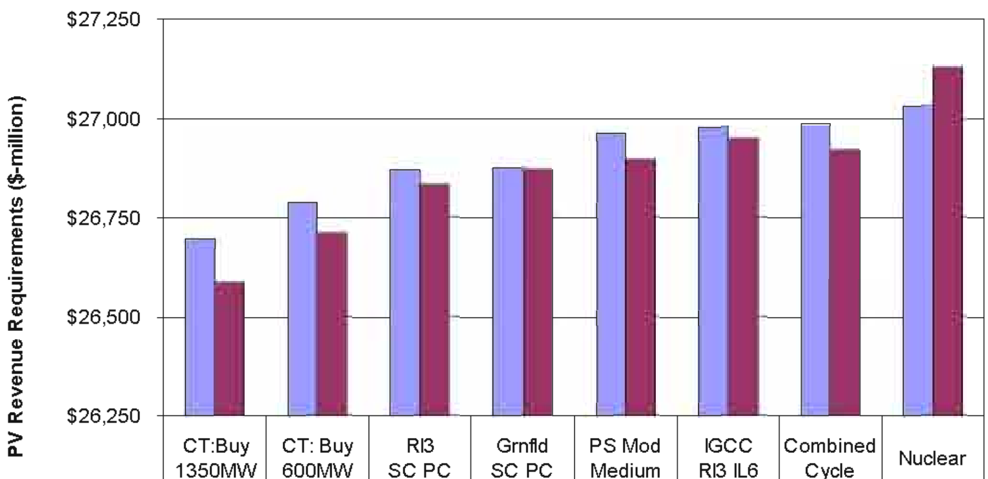
8.5.2 ENVIRONMENTAL COMPLIANCE STRATEGY

In developing an environmental compliance strategy, a company can vary in its method of compliance, from one extreme to the other, or somewhere in between the extremes. At one extreme, the company can choose to not install any new control technology and purchase all required allowances. At the other extreme a company can choose to install new control technology on all uncontrolled units and sell any excess allowances. A more balanced approach lies in between the extremes. In a balanced approach the company may choose to do both: purchase some additional allowances and install some control technology. The compliance strategy should balance the capital and operating and maintenance (O&M) costs of the control technology against the cost of purchasing allowances.

AmerenUE performed an environmental compliance strategy analysis separate from the Integrated Resource Plan (IRP) process. The intent of that analysis was to develop a balanced, least-cost environmental compliance strategy for AmerenUE. That analysis is ongoing; however interim results from it were included in the IRP analysis as an alternative to a "purchase all required emission allowances from market" strategy.

The interim results from this on-going study indicate emission control technology installations that would create an emission strategy which would place AmerenUE in a "near" self-compliant position for SO_2 and NO_X. For this "near" self-compliant environmental control technology scenario, any excess emissions relative to the lower emission caps would be purchased. Any surplus allowances would be sold to maintain the same SO_2 and NO_X position for both alternatives. Refer to the *Risk & Uncertainty Analysis Briefing* for more information on this scenario.

Figure 8.11
Environmental Compliance Strategy



	CT:Buy 1350MW	CT: Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	Nuclear
Market	$26,695	$26,789	$26,868	$26,876	$26,964	$26,976	$26,985	$27,032
Balanced	$26,587	$26,712	$26,831	$26,869	$26,895	$26,946	$26,917	$27,128

Table 8.4
Relative Ranking of Portfolios for
Purchase Allowances versus Balanced Strategy

		CT:Buy 1350MW	CT: Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	Nuclear
PVRR	Market	$26,695	$26,789	$26,868	$26,876	$26,964	$26,976	$26,985	$27,032
	Balanced	$26,587	$26,712	$26,831	$26,869	$26,895	$26,946	$26,917	$27,128
Rank	Market	1	2	3	4	5	6	7	8
	Balanced	1	2	3	4	5	7	6	8
Delta	Market	$0	$94	$173	$181	$269	$281	$290	$337
	Balanced	$0	$125	$244	$282	$308	$359	$330	$541

Observations:

- With the assumptions developed from the interim results, the balanced option slightly lowers PVRR for all portfolios.
- Since the Balanced Environmental Compliance Strategy puts controls on the existing plants, all expansion portfolios benefit from a reduction in emissions.
- Portfolios that consist of all peaking technology (i.e. pumped storage and CTG's) tend to result in higher capacity factors for the existing plants.
- All portfolios have an increase in capital costs due to installation of control technologies.
- All portfolios have a reduction in emission expense.
- Reductions vary by as much 12 percent with the "peaking" portfolios experiencing the largest reductions.
- The Balanced Environmental Compliance Strategy results in only one portfolio changing in ranking.

8.5.3 TECHNOLOGY PARAMETERS

Under this sensitivity, five base operational and capital assumptions were varied independently to determine the impacts on valuation and risk. These sensitivities included deviations to base capital and transmission installed costs, fixed and variable O&M costs, and effective forced outage rate (EFOR) assumptions. The results of these sensitivities are analyzed below with Cumulative Probability Distributions and PVRR vs. $95^{th} – 5^{th}$ Percentile graphs.

Cumulative Probability

The cumulative probability curve represents number of observations for each point that is less than or equal to the current value. Curves that tend to be more vertical represent a narrow band of risk (or less variability in potential outcomes); whereas, curves that tend to be more horizontal represent a wider band of risk (or more variability in potential).

Figure 8.12
Cumulative Probability Distributions
Technology Stress Testing

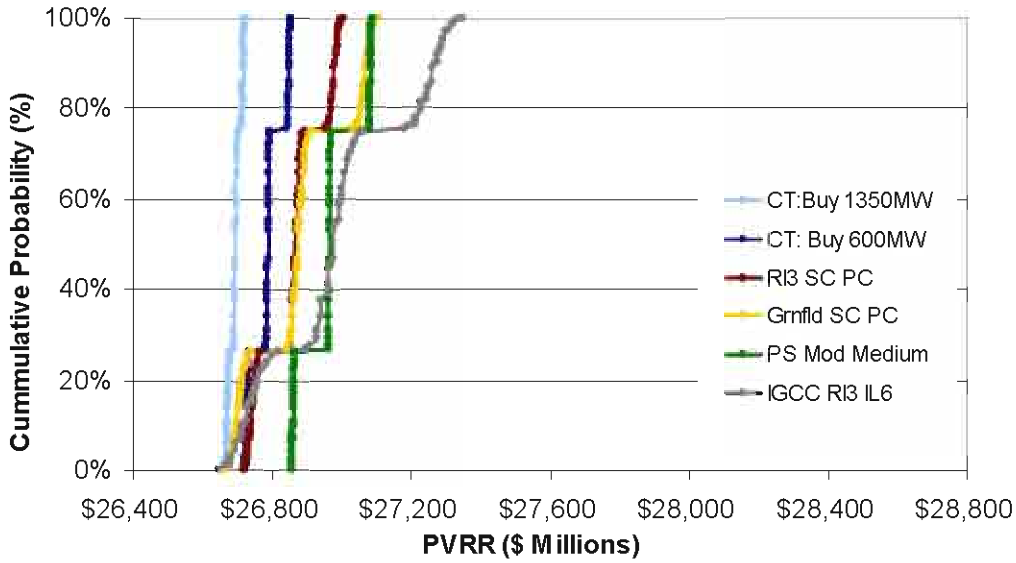
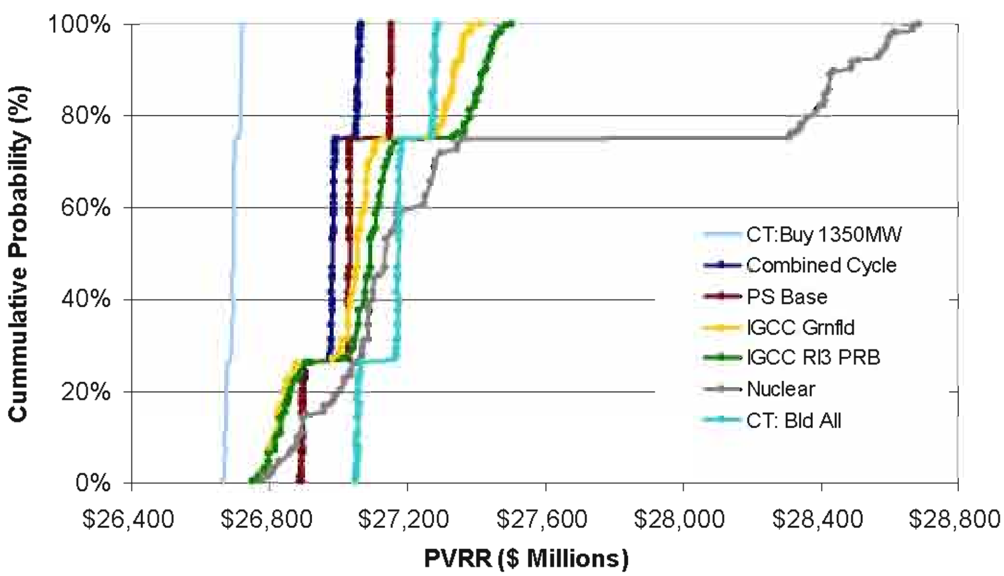


Figure 8.13
Cumulative Probability Distributions
Technology Stress Testing



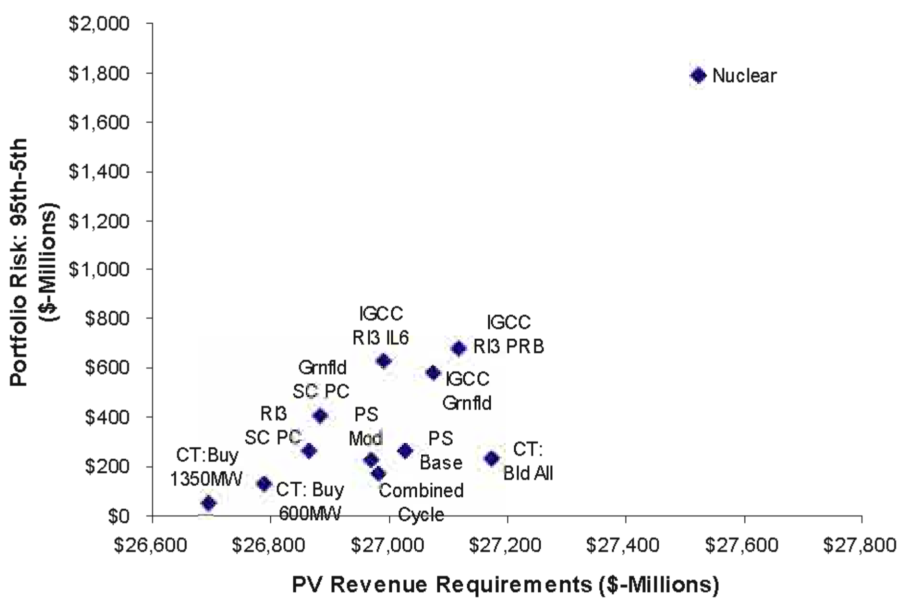
Observations:

- Capital Cost sensitivity had the biggest impact. The three capital sensitivities created a "stair-step" curve for many of the portfolios.
- Nuclear plant had 166 percent high capital bound which resulted in extreme "outliers" for that portfolio.
- Since the CT: Buy 1350MW does not have any cost-of-capital risk associated with building a plant, the curve is close to vertical.
- Portfolios with plants that are less capital intensive tend to have less construction cost risk (more vertical).
- The operating sensitivities (fixed O&M, variable O&M and EFOR) tended to not result in reordering of portfolios.

PVRR vs. 95th – 5th Percentile

The 95th percentile alone does not provide a complete picture of risk. Figure 8.13 employs a different risk measure, 95th–5th percentile, in order to evaluate the tradeoff between PVRR and risk. Interpretation of this figure is performed in the same manner as before. Results closer to the origin are generally preferred.

Figure 8.13
PVRR vs. 95th – 5th Percentile

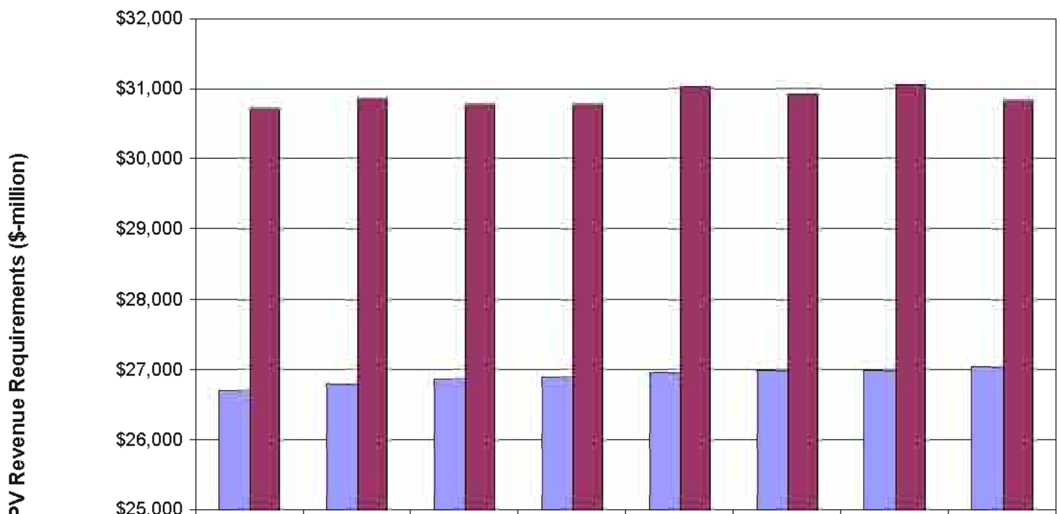


8.5.4 Capital Life – End Effects

It should be noted that the results presented using the revenue requirement calculation do not include an adjustment for capital life end-effects. The analysis period is 20 years, and most of the assets' lives extend beyond the end of the analysis. This results in the higher-cost revenue requirements incurred in the early years of a capital addition's economic life to be included in the PVRR while the lower cost revenue requirements of later years are excluded.

Without some type of end-effects adjustment, the capital-intensive portfolio's PVRR will tend to show a relatively higher revenue requirement. While utilizing revenue requirements is reflective of future ratemaking impacts during the 20-year analysis period, it does not, by itself, provide absolute comparative economics needed to address the relative costs of long-lived assets. To do sensitivity around end effects, the analysis period was extended from 20 year to 28 years. Limitations and assumptions within the model limited the simulation period to 28 years. Refer to the *Risk & Uncertainty Analysis Briefing* for more information on this sensitivity.

Figure 8.14
End-Effects Sensitivity



	CT:Buy 1350MW	CT: Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	Nuclear
20 Yr PVRR	$26,695	$26,789	$26,868	$26,876	$26,964	$26,976	$26,985	$27,032
28 Yr PVRR	$30,727	$30,864	$30,786	$30,789	$31,036	$30,921	$31,066	$30,831

Table 8.5
End Effects Sensitivity

		CT:Buy 1350MW	CT: Buy 600MW	RI3 SC PC	Grnfld SC PC	PS Mod Medium	IGCC RI3 IL6	Combined Cycle	Nuclear
PVRR	20 Yr PVRR	$26,695	$26,789	$26,868	$26,876	$26,964	$26,976	$26,985	$27,032
	28 Yr PVRR	$30,727	$30,864	$30,786	$30,789	$31,036	$30,921	$31,066	$30,831
Rank	20 Yr PVRR	1	2	3	4	5	6	7	8
	28 Yr PVRR	1	5	2	3	7	6	8	4
Delta	20 Yr PVRR	$0	$94	$173	$181	$269	$281	$290	$337
	28 Yr PVRR	$0	$137	$60	$62	$310	$194	$339	$104

Observations:

- End-Effects testing changes the relative rankings of portfolios measured by PVRR.
- As expected, financial performance of portfolios with capital intensive plants improve.

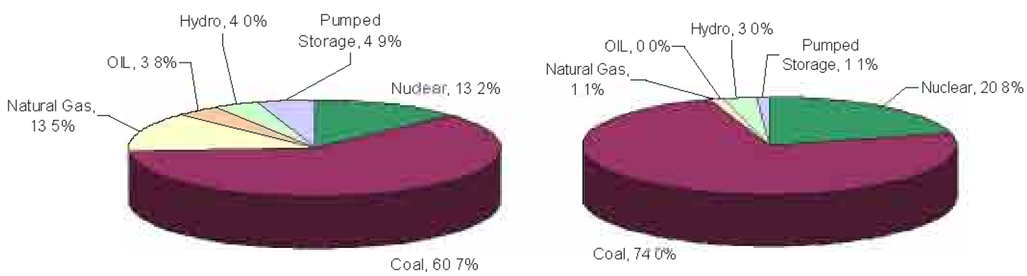
9 PLAN SELECTION AND IMPLEMENTATION

9.1 PLAN SUMMARY – SUPPLY SIDE ANALYSIS

AmerenUE has capacity needs that start at approximately 400 MW in 2006 and grow to approximately 2600 MW by 2025. AmerenUE's base load plants consist of coal, nuclear and hydro units. The base load capacity for 2006 is projected to account for approximately 83 percent of AmerenUE's capacity mix. Whereas, base load capacity is projected to supply approximately 99 percent of the energy produced by AmerenUE. AmerenUE's projected capacity and energy mix for 2006 is shown in Figure 9.1:

Figure 9.1

Capacity Mix 2006[1] **Energy Mix 2006**



[1] 2006 capacity mix w/o CTG's purchases

The projected load duration curves which represent the magnitude and duration of AmerenUE load for each hour of the year for 2006, 2015, and 2025 and are shown in Figure 9.2:

Figure 9.2

AmerenUE Load Duration Curve

[redacted]

The AmerenUE load duration curve indicates that, absent the addition of new base load generation in the 20-year planning period, CTGs will provide a larger portion of AmerenUE's energy requirements in 2025 than in 2006.

Despite the availability of base load generated energy for the majority of the hours of the year, AmerenUE has peaking capacity needs in 2006 that grow by approximately [redacted] MW almost every year in the 20-year resource planning period. Figure 9.3 shows the AmerenUE capacity needs through 2014:

Figure 9.3
AmerenUE Projected Capacity Deficits

[redacted]

<u>AmerenUE RFP To Purchase Existing Peaking Plants</u>

In order to address its immediate capacity needs, AmerenUE issued an RFP to owners of 19 peaking plants in June 2005 to buy existing peaking plant(s) located in the MISO control area. The RFP was sent to bidders representing approximately 10,000 MW of peaking capacity.

Four bidders responded with bids. Of the four bids, two bids were disqualified due to deliverability issues. The two qualifying bids offered approximately 1350 MW of capacity at an average price of approximately $215/kW relative to costs of building at new greenfield sites that range from $371/kW (representing a 42% discount) for a large frame CTG to $608/kW for an aero-derivative CTG (representing a 65% discount). Note that the greenfield site cost estimates reflect overnight construction cost estimates.

The fact that 1350 MWs of capacity was offered at prices that are substantially below the cost to build new CTG capacity has a direct bearing on AmerenUE's preferred resource plan. This unique opportunity allowed AmerenUE to develop a plan to add low cost capacity that minimizes future revenue requirements and allows AmerenUE more time to analyze the impact of emerging generation technologies, emissions regulations and the evolving MISO market. In fact, the addition of 1350 MW of peaking capacity will keep AmerenUE near a [redacted] percent planning reserve margin through [redacted]

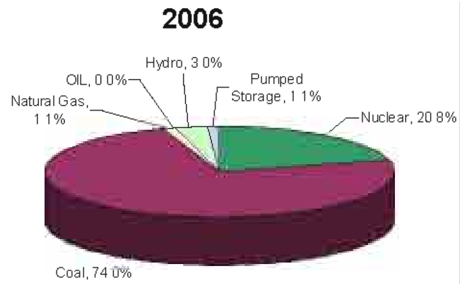
Beyond [redacted] if it is attractive to add base load capacity, an optimally sized supercritical coal unit will likely be approximately 800 MW. AmerenUE would not anticipate installing such a unit immediately in [redacted] but would buy short-term peaking capacity for three years beginning in [redacted] and add the 800 MW block in [redacted] A [redacted] in-service date would require that decisions pertaining to technology, siting and permitting be made no later than [redacted] – assuming a seven-year schedule to permit, site, and build the new coal unit.

There are other factors which could extend the decision date beyond [redacted] One of the factors is the amount of demand response that AmerenUE customers are willing to provide. AmerenUE engaged [redacted] to model the amount of demand response potential in the AmerenUE service territory through the 2025 timeframe. The [redacted] high level screening analysis identified 350 MW of demand response potential. This 350 MW is equivalent to almost [redacted] years of AmerenUE peak demand load growth. The acquisition of 350 MW of demand response from AmerenUE native load customers could defer the need to make a decision to add additional capacity at AmerenUE from [redacted] to almost [redacted] By postponing the decisions associated with developing base load resources, AmerenUE is afforded the opportunity to gain better information related to currently immature but promising resource technologies, emission regimes and market dynamics.

In addition, the preferred plan of adding 1350 MW of CTG capacity reduces risk relative to other plans. Economic and risk analyses of plans that include adding base load capacity depend upon opportunities for off-system sales transactions. The wholesale market price of electricity is a function of many variables including the price of natural gas. To the extent that natural gas prices are volatile, that volatility impacts the market price for electricity and thus the margins associated with off-system sales.

The volatility of natural gas prices has less impact on the preferred plan of adding 1350 MW of CTG capacity. The reason is that the CTGs operate infrequently due to the amount of base load capacity in the AmerenUE portfolio. Figure 9.4 is a comparison of the average annual output of AmerenUE CTGs in 2006 and 2015.

Figure 9.4
Comparison of Average Annual Output



[redacted]

AmerenUE analyzed a variety of capacity expansion plans under three scenarios related to potential greenhouse gas emission regulations. A discussion of the present value of revenue requirements associated with each expansion plan is in Section 8 of the *Integrated Resource Analysis* document. The acquisition of 1350 MW of CTGs is the expansion plan that is least impacted by possible greenhouse gas regulations.

The acquisition is dependent upon successful contract negotiations with two counterparties and the necessary regulatory approvals. Contract negotiations and regulatory approvals are expected to be complete by the end of the 2nd quarter 2006 at a total cost in the $300 million range.

Ameren Energy (AE) serves as the agent to market AmerenUE capacity. With additional capacity resources at AmerenUE, an increased sales presence is required to market AmerenUE's capacity length. AE's current staffing plan calls for the addition of one long-term sales executive in 2006 to focus on AmerenUE capacity sales initiatives.

As the MISO continues to evolve, AmerenUE anticipates access to a much larger market area that can be served by AmerenUE assets. Municipal, wholesale, cooperative and utility load in Missouri, Kansas, Arkansas, Iowa, Illinois, Wisconsin and Indiana would be targeted. While MISO energy markets have undoubtedly increased the competition for such load, AmerenUE is well positioned to compete for increased market share in the region.

Wholesale Bilateral Sales are defined as sales to customers subject only to FERC regulation. Submarkets include municipals, electric cooperatives, utilities and power aggregators. These sales will consist of a broad mix of products, ranging from load-following, block, index and seasonal products. This is the most complex portion of the markets, since some of the opportunity lies outside AmerenUE's traditional control area. AE continues to follow a NERC regional sales approach for this market to concentrate efforts with customers clustered in similar geographies and primarily within the MISO footprint.

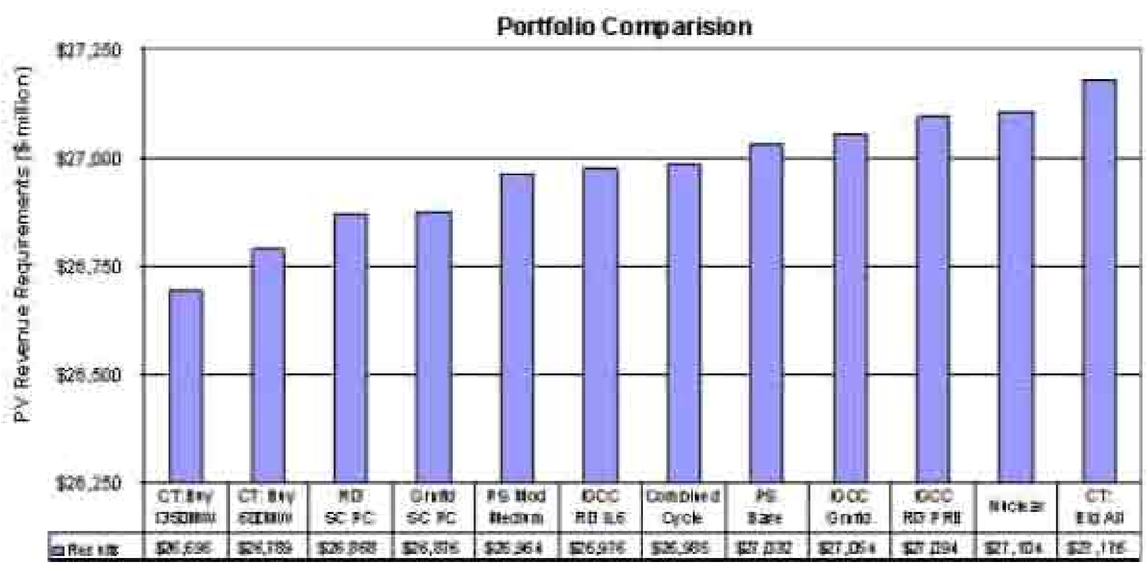
AmerenUE Alternative Plan

If the acquisition of the 1350 MW of existing CTG plants is not successful, AmerenUE's alternative plan of action is to pursue both short-term strategies to acquire peaking capacity and long-term strategies to analyze options including the addition of base load capacity. The immediate objective will be to buy capacity from the market to meet AmerenUE's projected 2006 peak demand. Concurrently, AmerenUE will re-consider options to mitigate deliverability issues associated with the two unsuccessful bidders from its June 2005 RFP to buy an existing peaking plant(s). AmerenUE will also consider building new peaking plants at greenfield sites to meet its capacity needs through at least [redacted] AmerenUE's long-term strategy will be to begin siting, permitting and preliminary engineering work to form the basis to make decisions about building either a coal base load plant or a pumped storage plant as early as [redacted] or [redacted] AmerenUE will continue its efforts to develop cost effective demand response, energy efficiency and renewable energy initiatives to attempt to reduce the rate of growth of electric demand.

All of AmerenUE's capacity expansion plan options include a number of CTG additions – especially in the early years of the 20-year planning period. However, the menu of AmerenUE cost-effective expansion plan options also includes base- and intermediate-capacity options such as supercritical coal, combined cycle, pumped storage, and integrated gasification combined cycle. It is estimated that site acquisition, permitting, engineering and construction of a base load project will take approximately seven years.

Figure 9.5 depicts the ranking of the various capacity expansion plan options on a present value of revenue requirements basis. This particular ranking does not include the economic impact of potential greenhouse gas regulations.

Figure 9.5



The all-CTG expansion plan option, a combined cycle/CTG expansion plan option, a supercritical Rush Island Units 3 coal/CTG option, a supercritical greenfield coal/CTG option and a 600 MW pumped storage/CTG option are relatively close in terms of the present value of revenue requirements and definitely within range of each other – at least within the confines of the modeling assumptions. This is why it is important to understand and consider the characteristics of the AmerenUE system and its capacity needs relative to the AmerenUE native load in making decisions on the optimal capacity expansion plan.

Taking a longer term view, a view that exceeds the 20-year duration of this integrated resource plan, there are factors that may improve the economics of a potential expansion plan that includes a new coal plant. If the market depth in the MISO market for low cost energy generated by coal proves to be deeper than in the past, the economics of the coal-based expansion plan option improves. If greenhouse gas regulation is passed that is less than the stringent greenhouse gas scenario, which is one of the greenhouse gas scenarios modeled in this integrated resource plan filing, the coal based expansion plan option continues to have favorable economics. Finally, the impact of end effects or the economic benefit as the coal plant continues to generate positive economic margin after the 20-year period of this integrated resource plan gives the coal plant expansion plan option more favorable economics on a present value of revenue requirements basis.

A look at the AmerenUE load duration curve in Figure 9.2 provides insight into the potential merits of a pumped storage plant. AmerenUE has base load energy available for most hours of the year. To the extent that the energy is not sold in off-peak periods, the underutilized energy can be used to pump water in low-cost periods so that the pumped hydro plant can generate in high-priced periods. The impact that high Eastern Basin coal has had on off-peak energy prices has eroded the peak to off-peak price spread required to make the economics of a pumped storage work. This may reverse itself over time. Furthermore, the extent to which additional emissions technologies are added to AmerenUE's existing coal fleet and to the extent that the technologies operate more efficiently when the coal fleet operates at a constant load levels, the pumped storage option is a preferable option. Finally, there are potential ancillary service market benefits to a pumped hydro plant that have not been modeled. For example, "new product markets" may be added to the energy markets in MISO – ancillaries and possibly locational capacity. Figure 9.6 is a matrix that compares possible products for MISO relative to product offerings in other RTOs.

Figure 9.6
RTO Products

Product	PJM	NYISO	ISO-NE	MISO	ERCOT	SPP
Energy	DA/RT LMP, Virtuals, Losses	DA/RT Zonal, Losses	DA/RT LMP	DA/RT LMP, Virtuals, Losses	DA/RT Zonal	RT Nodal
Ancillary Services (Regulation, Reserves)	Yes	Yes	Yes	Develop by 2007	Yes	Under Consideration
Capacity	Locational (evolving)	Locational	Locational	To be developed after A/S market	Potential post 2007	
Congestion Management	FTRs/ARRs	TCCs	FTRs/ARRs	FTRs/FGRs	RMR Contracts	TLRs
Demand Response	DA/RT	DA	RT			

9.2 PLAN SUMMARY – DEMAND RESPONSE AND ENERGY EFFICIENCY

Demand Response and Energy Efficiency

The demand-side resource analysis section of the current Missouri electric utility resource planning rules were written in a manner that reflected the status of demand-side planning in 1993 – a minimal knowledge base. The rules required extensive database development, cost-effectiveness screening of end-use measures, technical potential estimation for each cost-effective end-use measure and design and implementation of programs using cost effective measures.

The reality is that in 2005 AmerenUE and many of the investor owned electric utilities in the nation have extensive knowledge databases for demand-side options. It is not necessary to re-invest millions of dollars to re-develop cost-effective end-use measures. Therefore, it is not necessary to double or triple the size of a Resource Planning staff to basically handle research and development associated with building demand-side analysis capabilities from a knowledge base of zero.

AmerenUE proposes that the Missouri Public Service Commission (PSC) establish a statewide policymaking forum to discuss ways to develop demand response (DR) and energy efficiency (EE) as resources to meet capacity and energy needs of Missouri investor owned electric utilities (IOUs), enhance electric system reliability, reduce individual consumer costs and protect the environment. In the long run, a statewide strategic approach to the orderly development of cost effective DR and EE will assist in the development of meaningful long-term, sustainable initiatives as opposed to the short-term, relatively poorly received (by customers) initiatives of the past.

A schematic representation of how the strategic approach would be structured is:

A form of a potential operating model to address a statewide approach to develop and execute DR and EE strategies may be to form three working groups. The first working group is akin to an Executive Steering Team comprised of commissioners, legislators, and officers of stakeholder groups. This group would provide overall policy guidance to other groups involved in the stakeholder collaboration process and focus its efforts on the development of a long-term vision for the development of DR and EE in Missouri by setting a framework, developing goals and focusing on how DR and EE should be integrated with Missouri IOUs' resource planning processes.

The second working group could be comprised of stakeholders who are interested in developing DR and EE initiatives for large customers with the definition of the term "large" to be determined by the group.

The third working group could be comprised of stakeholders who are interested in developing DR and EE initiatives for small commercial/residential customers.

The development of a proposed schedule to initiate the statewide approach may begin with the executive or legislative branch of state government sending the PSC a proposal to develop a Missouri sustainable energy plan by February 1, 2006. The Commission may choose to issue a request for public comment on the proposed sustainable energy plan as early as March 1, 2006. The Commission may then choose to begin public workshops to discuss potential issues and invite Missouri IOUs to make presentations. The workshops may occur during the months of April and May 2006. Beginning as early as June 1, 2006, the policy making working group may begin to meet to develop the overall policy guidance within which the other working groups will develop potential program design parameters. By September 1, 2006, each working group should be in a position to make written recommendations to the PSC Staff concerning their proposals to meet Missouri's sustainable energy goals. Staff may be in a position to make a recommendation to the Commission as early as October 1, 2006. The Commission may be in a position as early as November 1, 2006, to adopt a resolution accepting Staff's recommendations.

Demand Response Coordinating Committee

The United States Demand Response Coordinating Committee (DRCC) is a non-profit organization formed in 2004 to increase the knowledge base in the United States on demand response and facilitate the exchange of information and expertise among demand response practitioners and policy makers. In addition to its U.S. focus, the DRCC has been designated by the U.S. Department of Energy (DOE) as the official Expert Body to represent the United States in the Demand Response Project of the International Energy Agency (IEA). DRCC members include American Electric Power, CEC/LBL PIER Demand Response Research Center, ISO-New England, Midwest ISO, National Grid, NYISO, NYSERDA, Pacific Gas & Electric, PJM Interconnection, San Diego Gas & Electric, Salt River Project, Southern California Edison, and Southern Company. Representatives from DOE, the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA) and the National Association of Regulatory Utility Commissioners (NARUC) serve on the DRCC's Advisory Board.

The Ameren Corporation operating companies, including AmerenUE, joined the DRCC in September 2005 and will leverage benefits from working with national and international experts on the implementation of demand response programs with the AmerenUE demand response and energy efficiency collaborative teams proposed in the preceding paragraphs.

Proposed Rate Treatment For Demand Response and Energy Efficiency Programs

A discussion of both demand response and energy efficiency implementation plans is incomplete without a discussion of proposed rate treatment associated with the cost of implementing such programs.

In the 1990s an argument could have been made that IOUs generally had little incentive to undertake large-scale DSM programs on their own without some type of understanding of ratebase treatment by their state regulatory authorities. Today, the method for allocating funding and administering demand response and energy efficiency programs varies across states. Some states adopt a public benefits charge approach. Other states approved funding on an individual IOU basis.

9.3 PLAN SUMMARY – RENEWABLE ENERGY

AmerenUE will continue its evaluation of renewable energy. The Ameren Corporation operating companies, including AmerenUE, formed a group dedicated to renewable energy options research, development and implementation. In conjunction with the formation of the Renewable Energy Team, Ameren formed several supporting teams consisting of Ameren subject matter experts to support the Renewable Energy Team in the development of recommendations for renewable energy projects.

On-going projects in the renewable energy area include:

- Collaborative with Missouri DNR to assess Missouri wind speed at various heights
- Meetings with wind developers on potential wind development opportunities
- Economic analysis of landfill gas opportunities
- Economic analysis of anaerobic digestor systems
- Grant of $350,000 through June 2007 to study photovoltaic systems
- Turbine upgrades at the Keokuk and Osage hydro-electric facilities

AmerenUE analyzed the economics of adding [redacted] type projects in [redacted] in its capacity expansion plans. Although the current economic analysis of [redacted] appears marginal, advancements in technology are providing a basis for AmerenUE to continue in its efforts regarding the development of [redacted] in its 20-year resource plan. The timing and location of future [redacted] projects depend on the results of current studies and data acquisition efforts as well as potential future Missouri renewable resource portfolio guidelines.

In a manner identical to AmerenUE's proposal to develop demand response and energy efficiency resources, AmerenUE proposes that the Missouri Public Service Commission establish a statewide policymaking forum to develop renewable energy resources to meet the energy needs of Missouri investor owned electric utilities (IOUs), protect the environment and increase diversity in the Missouri fuel mix to produce electricity. A statewide strategic approach to the orderly development of cost effective renewable energy resources, DR, and EE will assist in the development of meaningful long-term, sustainable initiatives.

The systemic approach and the proposed schedule developed in the DR and EE implementation plan section could also apply to renewable energy. In fact, the renewable initiative can be rolled into the demand response and energy efficiency initiative as part of a comprehensive statewide energy policy designed to promote sustainable energy development.