NP

2007-2026 Integrated Resource Plan
for
The Empire District Electric Company

Volume III
Supply-Side Resources Analysis (4 CSR 240-22.040)

September 2007

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ES Executive Summary

This supply-side volume of Empire's 2007 Integrated Resource Plan (IRP) contains information on assumptions used for the optimization modeling and risk analysis, the supply-side resources – both conventional and renewable – that were available for the model to consider in the optimization, and a brief description of the screening analysis used prior to resource modeling in the optimization models.

ES.1 Assumptions

A wide variety of data assumptions must be made for IRP modeling. The critical assumptions include fuel price forecasts, market price forecasts, capacity margin requirements, financial parameters, and emission costs. Parameters for generating resources, e.g., heat rates, operating and maintenance (O&M) costs, maintenance schedules, and forced outage rates, must also be specified. The load and energy forecast, an important series of assumptions, is described in Volume II.

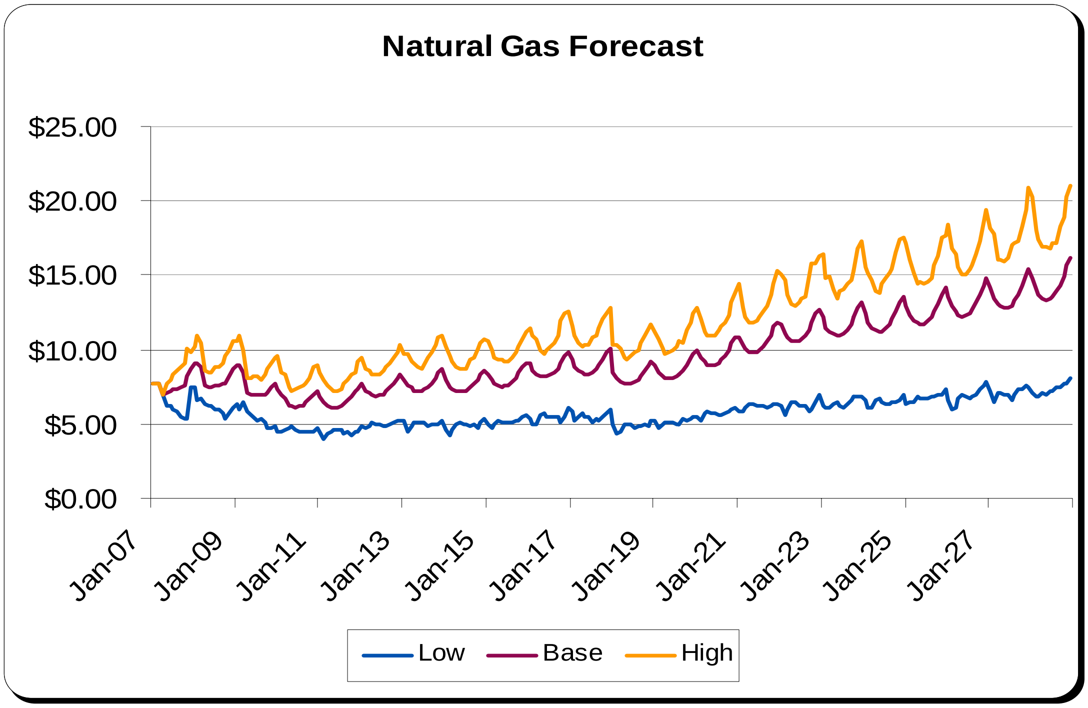
Two of the most significant assumptions underlying this IRP are the natural gas price assumptions and the costs for various forms of air emissions. These assumptions are shown in Table ES-1, Figure ES-1, and Table ES-2.

Table ES-1
Natural Gas Price Forecast ($/MMBtu)

Year	Base Case
2007	7.57
2008	8.07
2009	7.53
2010	6.61
2011	6.53
2012	7.38
2013	7.72
2014	7.64
2015	8.03
2016	8.72
2017	8.94
2018	8.20
2019	8.59
2020	9.53
2021	10.48
2022	11.28
2023	11.68
2024	11.98
2025	12.51
2026	13.07

Source: GED

Figure ES-1



Source: GED

Table ES-2
Emissions Costs

Year	SO_2 ($/ton)	NO_x ($/ton)	Hg ($000/ton)	CO_2 ($/ton)
2007	460	950	-	-
2008	472	1,124	-	-
2009	483	1,540	-	-
2010	495	1,656	13,468	-
2011	508	1,779	13,804	-
2012	520	1,823	14,149	2.3
2013	513	1,870	14,503	3.5
2014	515	1,916	14,866	4.8
2015	507	1,892	15,237	6.1
2016	500	1,904	15,618	7.5
2017	492	1,881	16,009	9.0
2018	484	1,858	16,409	10.5
2019	477	1,822	16,819	12.1
2020	471	1,692	17,240	13.8
2021	465	1,565	17,671	15.5
2022	458	1,454	18,112	17.4
2023	451	1,350	18,565	19.3
2024	446	1,237	19,029	21.3
2025	440	1,185	19,505	23.4
2026	433	1,169	19,993	24.0

Source: GED

ES.2 Supply-Side Resources

In this IRP and prior to any screening of resources, Empire considered a broad range of conventional and renewable resources as options for the future. These included: pulverized coal, combustion turbine (CT), combined cycle (CC), nuclear, distributed generation, integrated gasification combined cycle (IGCC), atmospheric circulating fluidized bed (ACFB), Compressed Air Energy Storage (CAES), wind, and biomass. To take advantage of economies of scale, Empire assumed that the nuclear option involved a small ownership share of a larger unit built by one or more larger utilities in the region. The pulverized coal option was also modeled as a small ownership share of a larger unit built in the region. Combined cycle options included both a new CC unit and the conversion of the Riverton Unit 12 CT to a CC unit.

ES.3 Screening Analysis

All of the technologies described in this supply-side resources volume proceeded into the optimization modeling with the exception of CAES. CAES was not considered in the optimization model due to the economics of such projects being very site specific and, at this time, no project in Empire's region is in the development phase. Because of the methodologies employed in the optimization modeling, there is no need to rank the supply-side technologies at this stage of the evaluation. The technologies are analyzed within the optimization modeling and those that meet the criteria are selected.

1.0 Introduction

1.1 Background

The Empire District Electric Company (Empire) is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. Empire's service territory includes an area of about 10,000 square miles with a population of over 450,000. The service territory is located principally in southwestern Missouri and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal activities of these areas include light industry, agriculture and tourism.

Empire's total 2006 retail electric revenues were derived approximately 87.6% from Missouri customers, 6.1% from Kansas customers, 3.0% from Oklahoma customers and 3.3% from Arkansas customers. Empire supplies electric service at retail to 121 incorporated communities and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 157,000. Empire's 2007 system peak was 1,173 MW which occurred on August 15, 2007, when the temperature was 102°F, surpassing the 2006 peak of 1,159 MW. Empire's 2006 customer load was 5,040,275 MWh. Empire's electric operating revenues in 2006 were derived as follows: residential 41.7%, commercial 30.1%, industrial 16.9%, wholesale on-system 4.6%, wholesale off-system 3.2% and other 3.5%. Empire's 2007 peak was 1,173 MW in August of 2007 and occurred when the temperature was 102°F.

1.2 Regulatory Requirements

4 CSR 240-22.040 Supply-Side Resources Analysis

PURPOSE: This rule establishes minimum standards for the scope and level of detail required in supply-side resource analysis.

(1) The analysis of supply-side resources shall begin with the identification of a variety of potential supply-side resource options which the utility can reasonably expect to develop and implement solely through its own resources or for which it will be a major participant. These options include new plants using existing generation technologies; new plants using new generation technologies; life extension and refurbishment at existing generating plants; enhancement of the emission controls at existing or new generating plants; purchased power from utility sources, cogenerators or independent power producers; efficiency improvements which reduce the utility's own use of energy; and upgrading of the transmission and distribution systems to reduce power and energy losses. The utility shall collect generic cost and performance information for each of these potential resource options which shall include at least the following attributes where applicable:
   (A) Fuel type and feasible variations in fuel type or quality;
   (B) Practical size range;

(C) Maturity of the technology;
(D) Lead time for permitting, design, construction, testing and startup;
(E) Capital cost per kilowatt;
(F) Annual fixed operation and maintenance costs;
(G) Annual variable operation and maintenance costs;
(H) Scheduled routine maintenance outage requirements;
(I) Equivalent forced-outage rates or full and partial-forced-outage rates;
(J) Operational characteristics and constraints of significance in the screening process;
(K) Environmental impacts, including at least the following:
1. Air emissions including at least the primary acid gases, greenhouse gases, ozone precursors, particulates and air toxics;
2. Waste generation including at least the primary forms of solid, liquid, radioactive and hazardous wastes;
3. Water impacts including direct usage and at least the primary pollutant discharges, thermal discharges and groundwater effects; and
4. Siting impacts and constraints of sufficient importance to affect the screening process; and

(L) Other characteristics that may make the technology particularly appropriate as a contingency option under extreme outcomes for the critical uncertain factors identified pursuant to 4 CSR 240-22.070(2).

(2) Each of the supply-side resource options referred to in section (1) shall be subjected to a preliminary screening analysis. The purpose of this step is to provide an initial ranking of these options based on their relative annualized utility costs as well as their probable environmental costs and to eliminate from further consideration those options that have significant disadvantages in terms of utility costs, environmental costs, operational efficiency, risk reduction or planning flexibility, as compared to other available supply-side resource options. All costs shall be expressed in nominal dollars.

(A) Cost rankings shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the resource using the utility discount rate. In lieu of levelized cost, the utility may use an economic carrying charge annualization in which the annual dollar amount increases each year at an assumed inflation rate and for which a stream of these amounts over the life of the resource yields the same present value.

(B) The probable environmental costs of each supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental laws or regulations that may be imposed at some point within the planning horizon.
1. The utility shall identify a list of environmental pollutants for which, in the judgment of utility decision-makers, additional laws or regulations may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.
2. For each pollutant identified pursuant to paragraph (2)(B)1., the utility shall specify at least two (2) levels of mitigation that are more stringent than

existing requirements which are judged to have a nonzero probability of being imposed at some point within the planning horizon.

3. For each mitigation level identified pursuant to paragraph (2)(B)2., the utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that additional laws or regulations requiring that level of mitigation will be imposed at some point within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation level for each identified pollutant.
4. The probable environmental cost for a supply-side resource shall be estimated as the joint cost of simultaneously achieving the expected level of mitigation for all identified pollutants emitted by the resource. The estimated mitigation costs for an environmental pollutant may include or may be entirely comprised of a tax or surcharge imposed on emissions of that pollutant.

(C) The utility shall rank all supply-side resource options identified pursuant to section (1) in terms of both of the following cost estimates: utility costs and utility costs plus probable environmental costs. The utility shall indicate which supply-side options are considered to be candidate resource options for purposes of developing the alternative resource plans required by 4 CSR 240- 22.060(3). The utility shall also indicate which options are eliminated from further consideration on the basis of the screening analysis and shall explain the reasons for their elimination.

(3) The analysis of supply-side resource options shall include a thorough analysis of existing and planned interconnected generation resources. The analysis can be performed by the individual utility or in the context of a joint planning study with other area utilities. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the supply resource options under consideration, that the costs of transmission system investments associated with supply-side resources are properly considered and to provide an adequate foundation of basic information for decisions about the following types of supply-side resource alternatives:

(A) Joint participation in generation construction projects;

(B) Construction of wholly-owned generation or transmission facilities; and

(C) Participation in major refurbishment, upgrading or retrofitting of existing generation or transmission resources.

(4) The utility shall identify and analyze opportunities for life extension and refurbishment of existing generation plants, taking into account their current condition to the extent that it is significant in the planning process.

(5) The utility shall identify and evaluate potential opportunities for new long-term power purchases and sales, both firm and nonfirm, that are likely to be available over all or part of the planning horizon. This evaluation shall be based on an analysis of at least the following attributes of each potential transaction:

(A) Type or nature of the purchase or sale (for example, firm capacity, summer only);

(B) Amount of power to be exchanged;

(C) Estimated contract price;

(D) Timing and duration of the transaction;

(E) Terms and conditions of the transaction, if available;

(F) Required improvements to the utility's generating system, transmission system, or both, and the associated costs; and

(G) Constraints on the utility system caused by wheeling arrangements, whether on the utility's own system, or on an interconnected system, or by the terms and conditions of other contracts or interconnection agreements.

(6) For the utility's preferred resource plan selected pursuant to 4 CSR 240-22.070(7), the utility shall determine if additional future transmission facilities will be required to remedy any new generation-related transmission system inadequacies over the planning horizon. If any such facilities are determined to be required and, in the judgment of utility decision-makers, there is a risk of significant delays or cost increases due to problems in the siting or permitting of any required transmission facilities, this risk shall be analyzed pursuant to the requirements of 4 CSR 240-22.070(2).

(7) The utility shall assess the age, condition and efficiency level of existing transmission and distribution facilities, and shall analyze the feasibility and cost-effectiveness of transmission and distribution system loss-reduction measures as a supply-side resource. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution system, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options.

(8) Before developing alternative resource plans and performing the integrated resource analysis, the utility shall develop ranges of values and probabilities for several important uncertain factors related to supply resources. These values can also be used to refine or verify information developed pursuant to section (2) of this rule. These cost estimates shall include at least the following elements and shall be based on the indicated methods or sources of information:

(A) Fuel price forecasts over the planning horizon for the appropriate type and grade of primary fuel and for any alternative fuel that may be practical as a contingency option.

1. Fuel price forecasts shall be obtained from a consulting firm with specific expertise in detailed fuel supply and price analysis or developed by the utility if it has expert knowledge and experience with the fuel under consideration. Each forecast shall consider at least the following factors as applicable to each fuel under consideration:
    A. Present reserves, discovery rates and usage rates of the fuel and forecasts of future trends of these factors;
    B. Profitability and financial condition of producers;
    C. Potential effect of environmental factors, competition and government regulations on producers, including the potential for changes in severance taxes;
    D. Capacity, profitability and expansion potential of present and potential fuel transportation options;
    E. Potential effects of government regulations, competition and environmental legislation on fuel transporters;

F. In the case of uranium fuel, potential effects of competition and government regulations on future costs of enrichment services and cleanup of production facilities; and

G. Potential for governmental restrictions on the use of the fuel for electricity production.

2. The utility shall consider the accuracy of previous forecasts as an important criterion in selecting providers of fuel price forecasts.
3. The provider of each fuel price forecast shall be required to identify the critical uncertain factors that drive the price forecast and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty;

(B) Estimated capital costs including engineering design, construction, testing, startup and certification of new facilities or major upgrades, refurbishment or rehabilitation of existing facilities.

1. Capital cost estimates shall either be obtained from a qualified engineering firm actively engaged in the type of work required or developed by the utility if it has available other sources of expert engineering information applicable to the type of facility under consideration.
2. The provider of the estimate shall be required to identify the critical uncertain factors that may cause the capital cost estimates to change significantly and to provide a range of estimates and an associated subjective probability distribution that reflects this uncertainty;

(C) Estimated annual fixed and variable operation and maintenance costs over the planning horizon for new facilities or for existing facilities that are being upgraded, refurbished or rehabilitated.

1. Fixed and variable operation and maintenance cost estimates shall be obtained from the same source that provides the capital cost estimates.
2. The critical uncertain factors that affect these cost estimates shall be identified and a range of estimates shall be provided, together with an associated subjective probability distribution that reflects this uncertainty;

(D) Forecasts of the annual cost or value of sulfur dioxide emission allowances to be used or produced by each generating facility over the planning horizon.

1. Forecasts of the future value of emission allowances shall be obtained from a qualified consulting firm or other source with expert knowledge of the factors affecting allowance prices.
2. The provider of the forecast shall be required to identify the critical uncertain factors that may cause the value of allowances to change significantly and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty; and

(E) Annual fixed charges for any facility to be included in rate base or annual payment schedule for leased or rented facilities.

(9) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall furnish at least the following information:

(A) A summary table showing each supply resource identified pursuant to section (1) and the results of the screening analysis, including:

1. The calculated values of the utility cost and the probable environmental cost for each resource option and the rankings based on these costs;
2. Identification of candidate resource options that may be included in alternative resource plans; and
3. An explanation of the reasons why each supply-side resource option rejected as a result of the screening analysis was not included as a candidate resource option;

(B) A list of the candidate resource options for which the forecasts, estimates and probability distributions described in section (8) have been developed or are scheduled to be developed by the utility's next scheduled compliance filing pursuant to 4 CSR 240-22.080;

(C) A summary of the results of the uncertainty analysis described in section (8) that has been completed for candidate resource options; and

(D) A summary of the mitigation cost estimates developed by the utility for the candidate resource options identified pursuant to subsection (2)(C). This summary shall include a description of how the alternative mitigation levels and associated subjective probabilities were determined and shall identify the source of the cost estimates for the expected mitigation level.

Table 1 documents how the reporting requirements for 4 CSR 240-22.040, the IRP Rules for Supply-Side Resource Analysis, have been addressed. If a variance was requested or a clarification provided in Empire's July 23, 2007 filing, the notation "App for Variance" is shown for "Location in Report."

Table 1
Summary of Compliance with Reporting Requirements for IRP Rule for Supply-Side Resource Analysis (4 CSR 240-22.040 (9))

Rule	Description	Location in Report
22.040 (9) (A)	Summary table requirements	Section 3.0, Section 4.0. Tables 19-25, 29, and 30. The methodology used in this IRP exceeds the screening and ranking methodology required in the Rule. All supply-side options for which parameters were developed (all options except Compressed Air Energy Storage) were considered as resource options in the optimization modeling.
22.040 (9) (B)	Candidate resource options	Section 3.0. The methodology used in this IRP exceeds the screening and ranking methodology required in the Rule. All supply-side options for which parameters were developed (all options except Compressed Air Energy Storage) were considered as resource options in the optimization modeling.
22.040 (9) (C)	Results of uncertainty analysis	Section 3.0. The methodology used in this IRP exceeds the screening and ranking methodology required in the Rule. All supply-side options for which parameters were developed (all options except Compressed Air Energy Storage) were considered as resource options in the optimization modeling.
22.040 (9) (D)	Summary of mitigation costs	Section 2.8,. Volume V – Section 3.1.3, Figure 8

2.0 Assumptions

A wide variety of data assumptions must be made for IRP modeling. Many of the critical assumptions are described in the following paragraphs and include fuel price forecasts, market price forecasts, capacity margin requirements, financial parameters, and emission costs. Parameters for generating resources, e.g., heat rates, operating and maintenance (O&M) costs, maintenance schedules, and forced outage rates, must also be specified. The load and energy forecast, an important series of assumptions, is described in Volume II.

2.1 Fuel Usage

Table 2 shows a comparison of historical fuel costs, including transportation and other miscellaneous costs, for Empire's facilities:

Table 2
Empire's Historical Delivered Fuel Costs ($/MMBtu)

Fuel Type	2006	2005	2004
Coal - Iatan	0.793	0.786	0.726
Coal - Asbury	1.402	1.309	1.179
Coal – Riverton	1.458	1.391	1.309
Natural Gas	7.276	7.208	4.451
Oil	6.551	5.893	6.842

Empire's weighted cost of fuel burned per kWh generated was 2.6502 cents in 2006, 2.891 cents in 2005, and 1.885 cents in 2004.

The Asbury Plant is fueled primarily by coal with oil being used as the start-up fuel and tire-derived fuel (TDF) being used as a supplemental fuel. In 2006, Asbury burned a coal blend consisting of approximately 80.8% Western coal (Powder River Basin – PRB) and 19.2% local coal (so-called blend coal) on a tonnage basis. Since Empire began burning TDF at Asbury, the equivalent of over 3.7 million passenger tires has been consumed as fuel.

The Riverton Plant fuel requirements are primarily met by coal with the remainder supplied by petroleum coke, natural gas and oil. During 2006, Riverton Units 7 and 8 burned an estimated blend of approximately 81.2% Western coal (PRB) and 19.8% blend fuel (local coal and petroleum coke) on a tonnage basis. Riverton Unit 7 requires a minimum of approximately 25% blend fuel to operate while burning PRB coal. Riverton Unit 8 can burn 100% Western coal or a mix of approximately 80% Western coal and 20% blend fuel.

All of the Western coal for Asbury and Riverton Units 7 and 8 is shipped to the Asbury Plant by rail, a distance of approximately 800 miles. The Western coal is transported from Asbury to Riverton via truck. Both local coal and petroleum coke are transported to Riverton and Asbury via truck.

Unit 1 at the Iatan Plant is a coal-fired generating unit that is jointly-owned by KCP&L (70%), Aquila (18%) and Empire (12%). KCP&L is the operator of this plant and is responsible for arranging its fuel supply. The PRB coal burned in Iatan 1 is transported by rail by the Burlington Northern and Santa Fe (BNSF) Railway Company.

The Energy Center and State Line simple cycle combustion turbine facilities are fueled primarily by natural gas with oil also available for use as needed. During 2006, fuel consumption at the Energy Center, based on kWh generated, was effectively 100% natural gas. State Line fuel consumption during 2005 was 86.7% natural gas with the remainder being oil.

Empire has firm transportation agreements with Southern Star Central Pipeline, Inc. for the transportation of natural gas to the State Line Power Plant for the jointly-owned combined cycle unit. This transportation agreement can also supply natural gas to State Line Unit No. 1, the Energy Center or the Riverton Plant, as elected by Empire on a secondary basis. In 2002, Empire signed a precedent agreement with Williams Natural Gas Company (now Southern Star Central), that provides additional transportation market zone capability for 20 years. This contract provides firm market zone transport to the sites that previously were only served on a secondary basis. The majority of Empire's physical natural gas supply requirements will be met by short-term forward contracts and spot market purchases. Forward natural gas commodity prices and volumes are hedged several years into the future in accordance with Empire's Risk Management Policy in an attempt to lessen the volatility in the Company's fuel expense and gain predictability.

2.2 Coal Price Forecast

The coal price forecasts used for the Asbury, Riverton, Iatan, and Plum Point facilities are based on escalators from the U.S. Department of Energy's Energy Information Administration's (EIA) projections. The EIA reports that since 1999, U.S. coal mining productivity has declined and the average minemouth coal price has increased. EIA projects that average minemouth prices will drop slightly from 2010 to 2019 as mine capacity utilization declines and production shifts away from higher cost mines. After 2019, rising natural gas prices and the need for additional generating capacity result in the construction of many new coal-fired generating plants across the U.S. The associated required investment in new mining capacity, combined with low productivity growth and rising utilization of mining capacity, leads to increasing minemouth prices from 2019 onward.

Coal price projections for Asbury are shown in Table 3, those for Riverton are in Table 4, the coal price projections for Iatan 1 and 2 are shown in Table 5, and Plum Point's coal price projections are found in Table 6.

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Table 3
Asbury Coal Price Forecast ($/MMBtu)

Year	Western Base	Blend Base
2007	**____**	**____**
2008	**____**	**____**
2009	**____**	**____**
2010	**____**	**____**
2011	**____**	**____**
2012	**____**	**____**
2013	**____**	**____**
2014	**____**	**____**
2015	**____**	**____**
2016	**____**	**____**
2017	**____**	**____**
2018	**____**	**____**
2019	**____**	**____**
2020	**____**	**____**
2021	**____**	**____**
2022	**____**	**____**
2023	**____**	**____**
2024	**____**	**____**
2025	**____**	**____**
2026	**____**	**____**

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Table 4
Riverton Coal Price Forecast ($/MMBtu)

Year	Western Base	Pet Coke Base
2007	**____**	**____**
2008	**____**	**____**
2009	**____**	**____**
2010	**____**	**____**
2011	**____**	**____**
2012	**____**	**____**
2013	**____**	**____**
2014	**____**	**____**
2015	**____**	**____**
2016	**____**	**____**
2017	**____**	**____**
2018	**____**	**____**
2019	**____**	**____**
2020	**____**	**____**
2021	**____**	**____**
2022	**____**	**____**
2023	**____**	**____**
2024	**____**	**____**
2025	**____**	**____**
2026	**____**	**____**

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Table 5
Iatan Coal Price Forecast ($/MMBtu)

Year	Base
2007	**____**
2008	**____**
2009	**____**
2010	**____**
2011	**____**
2012	**____**
2013	**____**
2014	**____**
2015	**____**
2016	**____**
2017	**____**
2018	**____**
2019	**____**
2020	**____**
2021	**____**
2022	**____**
2023	**____**
2024	**____**
2025	**____**
2026	**____**

Table 6
Plum Point Coal Price Forecast ($/MMBtu)

Year	Base
2010	**____**
2011	**____**
2012	**____**
2013	**____**
2014	**____**
2015	**____**
2016	**____**
2017	**____**
2018	**____**
2019	**____**
2020	**____**
2021	**____**
2022	**____**
2023	**____**
2024	**____**
2025	**____**
2026	**____**

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2.3 Natural Gas Price Forecast

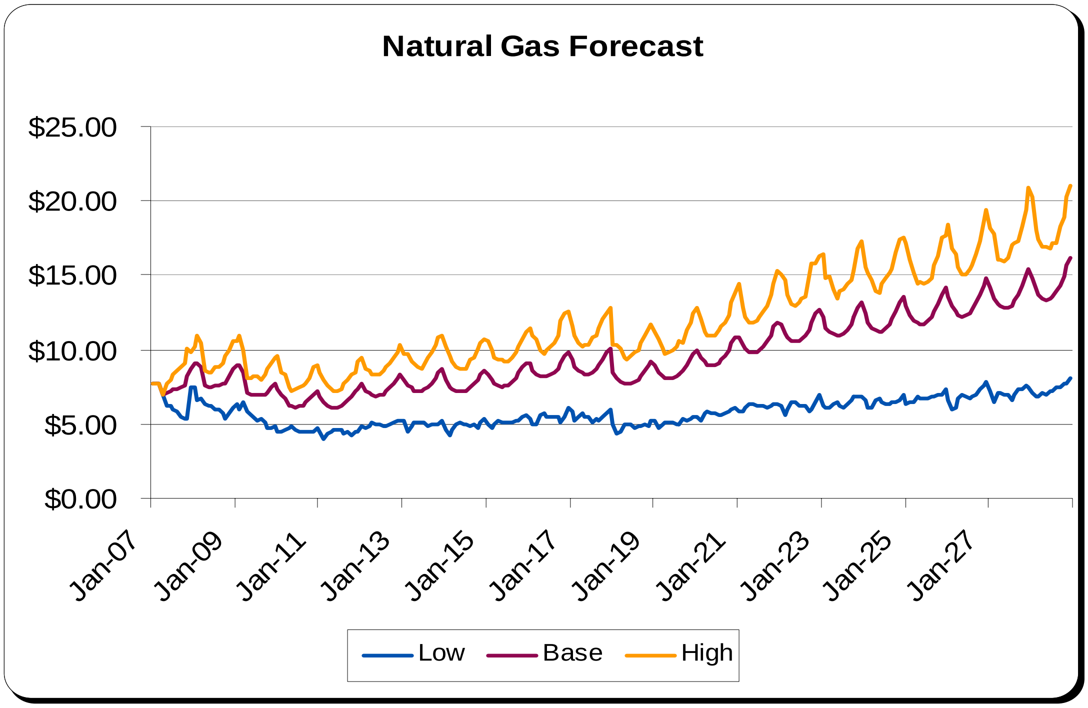
The natural gas price forecast used for this IRP is based on the Global Energy Decisions' (GED) Spring 2007 Power Market Advisory Service Electricity & Fuel Price Outlook which assumes a carbon dioxide (CO_2) tax is effective as of 2012. The natural gas prices are escalated at 3% and are shown on Table 7. The monthly prices used in the modeling based on the annual prices from Table 7 are shown in Figure 1, reflecting the seasonality associated with gas prices, i.e., higher in the winter months and lower in the summer months. Figure 1 shows the low, base, and high natural gas price forecasts.

Table 7
Natural Gas Price Forecast ($/MMBtu)

Year	Base Case
2007	7.57
2008	8.07
2009	7.53
2010	6.61
2011	6.53
2012	7.38
2013	7.72
2014	7.64
2015	8.03
2016	8.72
2017	8.94
2018	8.20
2019	8.59
2020	9.53
2021	10.48
2022	11.28
2023	11.68
2024	11.98
2025	12.51
2026	13.07

Source: GED

Figure 1



Source: GED

2.3.1 Natural Gas Price Forecasting Methodology

GED used three forecasting phases to generate its forecast of natural gas prices. These three phases are shown in Table 8.

Table 8
Reference Case Gas Price Forecasting Phases

Forecast Phase	Period Length	Data Source	Forecast Technique
Futures Driven	First 24 Months	NYMEX Henry Hub futures and market differentials	Calculated Henry Hub and liquid market center differentials
Mean Reversion	Next 24 Months	GED	Linear process to gradually equate near-term to long-term trend
Long-term Trend	Remaining forecast period (to 2030)	Various GED data sources	Fundamental supply and demand analysis modeling

To derive the burner-tip forecasts used, GED first examined regional prices and basis swaps at a number of trading hubs. Using this historical data, for the first 24 months of the forecast, GED developed a differential price between the appropriate market center nearest to the power plant and the Henry Hub. Natural gas prices used for the first 24 months were driven by Henry Hub futures market prices plus a basis differential (if any).

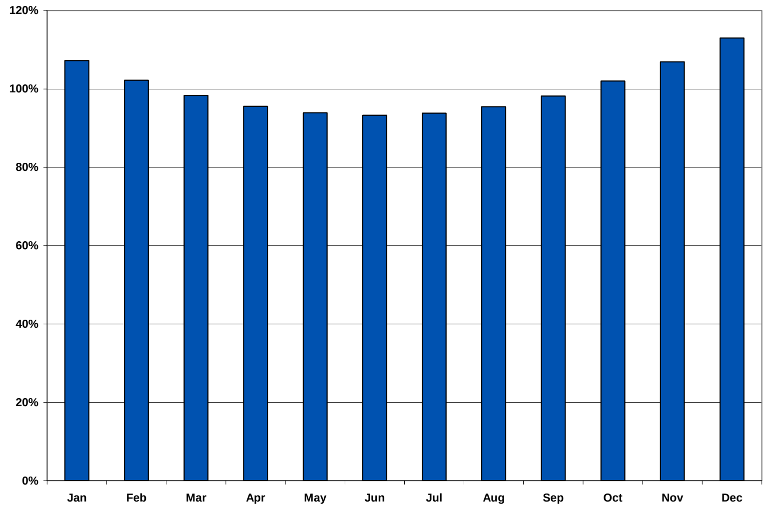
Applying this approach permitted GED's forecast to include the recent shifts in natural gas prices. During the following 24 months of the forecast period, GED imposed a linear mean reversion process on the forecast. This process aligns natural gas prices during the first 24 months back to their long-term, fundamental levels.

To forecast future burner-tip gas prices beyond the initial 48-month period, GED has incorporated the RBAC, Inc.'s GPCM® Natural Gas Market Forecasting System into its modeling methodology for medium- to long-term analysis. The model is a general equilibrium model of natural gas supply and demand in a competitive environment for the North American natural gas industry.

Another important component in GED's gas forecast is the seasonal or monthly variation in price. In general, natural gas prices have been traditionally higher during winter months due to greatly increased core heating demand. To determine the seasonal variation in natural gas prices, data at individual pricing points are utilized. The appropriate observed seasonal pattern is applied to annual natural gas price forecasts to derive monthly price forecasts that are used in GED's market simulations. These seasonal factors represent typical or normalized variation in monthly spot natural gas prices within a region.

The estimated seasonal variation in natural gas prices is shown in Figure 2. This indicates the deviation among monthly natural gas prices as recorded at the Henry Hub. A polynomial curve was then fitted to the monthly average. The figure indicates that prices are highest during periods of increased core heating demand, while they decline during the spring and early summer months. On average, prices tend to begin rising starting in June due to electricity demand increase, coupled with the beginning of the traditional gas storage-filling season.

Figure 2
Natural Gas Price Seasonal Variation



Source: GED

2.3.2 Natural Gas Risk Management Policy

Empire originally enacted a Risk Management Policy (RMP) in 2001 that establishes the approach and internal policy that Empire will use to manage specifically its natural gas commodity risk. The policy is revised approximately each year to reflect increased knowledge and changes in markets and financial instruments. The RMP targets for hedging of natural gas are:

- A minimum of 10% of year four expected gas burn
- A minimum of 20% of year three expected gas burn
- A minimum of 40% of year two expected gas burn
- A minimum of 60% of year one expected gas burn[1]
- Up to 80% of any future year's expected requirement can be hedged if appropriate given the associated volume risk.

The RMP serves to minimize the exposure that Empire has to rising natural gas prices, such as those experienced in late 2005.

2.4 Oil Price Forecast

To forecast No.2 Oil, GED uses a technique similar to natural gas, where representative current NYMEX pricing is blended to its internal forward view. Since crude oil is the raw material used to produce distillate oil, jet kerosene, and heavy fuel oil (e.g., various sulfur grades of #6 residual oil) as well as gasoline, GED derives fuel oil forecasts for generators from its West Texas Intermediate (WTI) Reference Case Forecast.

[1] For example, as of July 2007, Year 1 is 2008, Year 2 is 2009, Year 3 is 2010 and Year 4 is 2011.

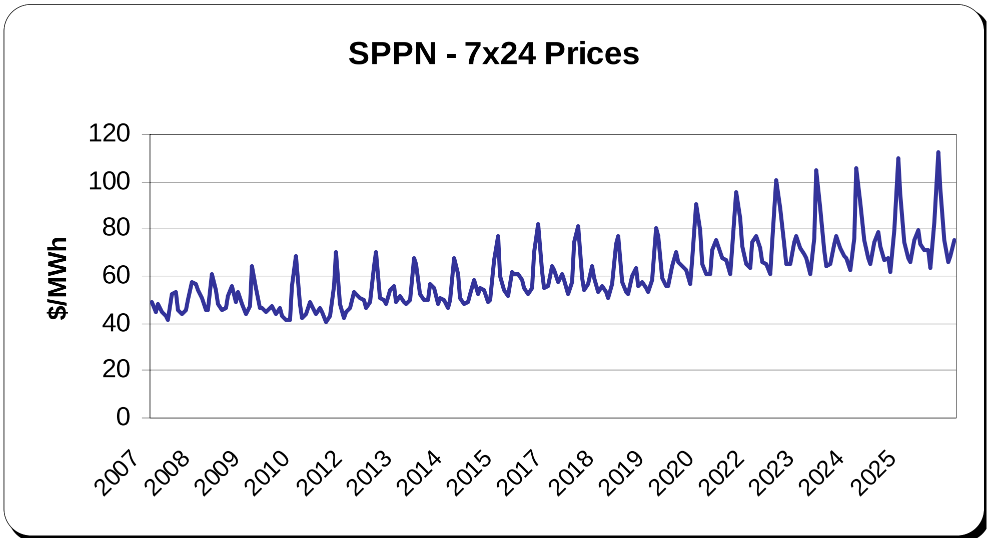
GED produces its WTI Reference Case based on NYMEX future prices for WTI Oil and Fuel Oil #2, product price relationships between fuel oils and long-term supply and demand analysis of the WTI and global crude oil markets. The WTI forecast is based on 72 months of NYMEX Futures prices and on subsequent supply/demand fundamentals for the remainder for the forecast period. The WTI NYMEX prices are incorporated directly for the first 36 months and for the following 36 months by mean regression analysis with the supply/demand analysis.

A similar estimation technique as used to forecast monthly natural gas prices is used to project monthly oil prices.

2.5 Market Price Forecast

Market prices for the Southwest Power Pool (SPP) were projected by GED for use in the modeling, reflecting specifically conditions expected to be experienced by Empire and using the most recent market information available. Market prices were determined for the scenarios as well as for the uncertainty evaluations. The historical and projected on-peak market prices used for the modeling in this IRP are shown in Figure 3.

Figure 3
Market Prices - SPP



Source: GED

2.6 Capacity Margin

As a member of the SPP, Empire is required to maintain a minimum 12% capacity margin which is equivalent to a 13.7% reserve margin. This number has been used as the basis for capacity planning in this IRP.

2.7 Financial Parameters

Empire's discount rate used for planning purposes is 7.68%. The Gross Domestic Product (GDP) Deflator used in all of the model runs is 2.5% per year throughout the forecast period. Levelized fixed charge rates were only applied in the screening portion of the modeling (in the Capacity Expansion Module). The values used were:

- Combustion turbine/combined cycle: 12.15%
- Coal/ACFB/IGCC 11.34%
- Wind and Distributed Generation 11.28%
- Nuclear 11.48%
- Biomass 12.48%

Levelized fixed charge rates were not applied to capital costs for the units in the MIDAS modeling since the model was used to perform a full financial analysis including accelerated depreciation, annual rate base calculations, construction S-curves, and Allowance for Funds Used During Construction (AFUDC). All present value of revenue requirements (PVRR) calculations have been expressed in 2007 dollars.

2.8 Emission Costs

Emission costs were modeled in the IRP analysis including those for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and Mercury (Hg). For the base case, carbon dioxide (CO_2) emission costs were considered beginning in 2012. The Clean Air Interstate rule (CAIR) increases the costs of SO_2 compliance in 2009. The Clean Air Mercury Rule (CAMR) affects mercury emissions nationwide starting in 2010 with second phase restrictions effective 2018. Empire will need to have monitors for Hg in place by 2009. Empire currently believes that Asbury and Riverton are expected to meet Hg requirements until 2018. Hg allowances will need to be obtained for Plum Point and Iatan 2. Empire assumed for purposes of this IRP that no additional Hg allowances will need to be obtained for Iatan 1 through 2018.

NO_x and SO_2, along with many other pollutants, are regulated by a number of state and federal statutes that complicates price projections for the costs of emissions, the limits on the emissions themselves, and the projected future levels of emissions. The emissions costs assumed in the analysis, reflecting a combination of state and federal requirements, are shown in Table 9.

Table 9
Emissions Costs

Year	SO_2 ($/ton)	NO_x ($/ton)	Hg ($000/ton)	CO_2 ($/ton)
2007	460	950	-	-
2008	472	1,124	-	-
2009	483	1,540	-	-
2010	495	1,656	13,468	-
2011	508	1,779	13,804	-
2012	520	1,823	14,149	2.3
2013	513	1,870	14,503	3.5
2014	515	1,916	14,866	4.8
2015	507	1,892	15,237	6.1
2016	500	1,904	15,618	7.5
2017	492	1,881	16,009	9.0
2018	484	1,858	16,409	10.5
2019	477	1,822	16,819	12.1
2020	471	1,692	17,240	13.8
2021	465	1,565	17,671	15.5
2022	458	1,454	18,112	17.4
2023	451	1,350	18,565	19.3
2024	446	1,237	19,029	21.3
2025	440	1,185	19,505	23.4
2026	433	1,169	19,993	24.0

Source: GED

CO_2 regulation was considered in all cases examined. In the base case, regulation started in 2012. For the medium and high CO_2 scenarios, used in the decision tree analysis described in Volume V, regulation began in 2009. Table 10 shows the projected CO_2 taxes ($/ton) for all three scenarios. Because the optimization models are capable of expressly modeling allowance costs and impacts of carbon taxes, no separate environmental mitigation costs needed to be calculated for the supply-side resources enumerated in this Volume of the IRP report.

Table 10
Carbon Dioxide Tax Assumptions

	Base CO_2 Scenario	Medium CO_2 Scenario	High CO_2 Scenario
2009		16.15	32.31
2010		17.66	35.32
2011		19.23	38.47
2012	2.30	20.87	41.75
2013	3.50	23.18	46.36
2014	4.80	24.98	49.95
2015	6.10	27.47	54.95
2016	7.50	30.08	60.16
2017	9.00	32.80	65.60
2018	10.50	33.62	67.24
2019	12.10	34.46	68.93
2020	13.80	35.32	70.65
2021	15.50	36.21	72.41
2022	17.40	37.11	74.23
2023	19.30	38.04	76.08
2024	21.30	38.99	77.98
2025	23.40	39.97	79.93
2026	24.00	40.97	81.93

Source: GED

For the medium and high CO_2 scenarios, changes in SO_2, NO_x and mercury emission allowances prices and gas, oil, and coal prices were correlated with the CO_2 prices. Tables 11-16 show the projected price differences.

Table 11
Projected Coal Prices – Carbon Scenarios ($/MMBtu)

	Base CO_2 Scenario	Medium CO_2 Scenario	High CO_2 Scenario
2010	1.16	1.13	1.09
2015	1.26	1.10	0.95
2020	1.45	1.22	0.99
2025	1.73	1.44	1.16

Source: GED

Table 12
Projected Natural Gas Prices – Carbon Scenarios ($/MMBtu)

	Base CO_2 Scenario	Medium CO_2 Scenario	High CO_2 Scenario
2010	6.53	7.54	8.55
2015	7.74	10.49	13.24
2020	8.97	10.88	12.79
2025	11.48	13.07	14.66

Source: GED

Table 13
Projected Oil Prices – Carbon Scenarios ($/MMBtu)

	Base CO_2 Scenario	Medium CO_2 Scenario	High CO_2 Scenario
2010	5.420	6.260	7.099
2015	6.132	8.021	9.910
2020	6.938	8.282	9.626
2025	7.850	9.096	10.343

Source: GED

Table 14
Projected SO_2 Allowance Prices ($/ton)

	Base CO_2 Scenario	Medium CO_2 Scenario	High CO_2 Scenario
2010	495	467	420
2015	507	478	429
2020	471	331	273
2025	440	328	189

Source: GED

Table 15
Projected NO_x Allowance Prices ($/ton)

	Base CO_2 Scenario	Medium CO_2 Scenario	High CO_2 Scenario
2010	1,656	1,851	2,046
2015	1,892	1,136	286
2020	1,692	1,116	399
2025	1,185	739	294

Source: GED

Table 16
Projected Mercury Allowance Prices ($000/ton)

	Base CO_2 Scenario	Medium CO_2 Scenario	High CO_2 Scenario
2010	13,468	12,510	11,409
2015	15,237	14,154	12,907
2020	17,240	16,014	14,604
2025	19,505	18,118	16,523

Source: GED

3.0 Supply-Side Resources

The supply-side resources described in this IRP include those conventional and renewable resources that are in operation on the Empire system or for which Empire has power purchase agreements (PPA), those conventional and renewable resources for which commitments have already been made (referred to as committed resources), and those potential conventional and renewable resources that are available to Empire over the twenty-year planning horizon. These existing, committed, and future resources are those that have been examined in the modeling process for this IRP.

3.1 Existing Resources

Empire's existing resources to meet customer obligations include coal-fired units, natural-gas fired combustion turbines (CT), a hydroelectric unit, an ownership share in a coal-fired unit, an ownership share in a combined cycle (CC) unit, and long-term PPA with Westar (coal) and with PPM Energy (wind). These resources are summarized on Table 17. All unit ratings and environmental retrofit information described in this IRP represent ratings and assumptions in effect at the time the IRP was in the process of being completed. Units are rerated from time to time and all assumptions are subject to change.

In the future, it may be economical for Empire's Asbury station to install additional pollution control equipment for air emissions or it may be otherwise required by regulation to do so. Empire's base case assumptions for the IRP are that a selective catalytic reduction (SCR) system will be installed by late 2007 and a baghouse will be installed in 2010. The base case assumes that no scrubber will be installed at Asbury during the planning horizon but other cases did examine the timing and costs associated with installing a scrubber at Asbury. The financial analysis portions of the planning process captured the capital costs associated with the installation of these pieces of equipment.

Empire's Riverton generating plant located at Riverton, Kansas, has two steam-electric generating units (Riverton 7 and 8) with an aggregate generating capacity of 92 MW and four gas-fired combustion turbine units (Riverton 9, 10, 11 and 12) with an aggregate generating capacity of 192 MW. **____
____**

Empire owns a 12% undivided interest in the nominal 670 MW coal-fired Iatan 1 located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. A new air permit was issued for the Iatan Generating Station on January 31, 2006. The new permit covers the entire Iatan Generating Station and includes the existing Iatan 1 and the to-be-constructed Iatan 2. The new permit limits Iatan 1 to a maximum of 6,600 MMBtu per hour of heat input which reduces Empire's ownership share from 80 MW to 78 MW. The 6,600 MMBtu per hour heat input limit is in effect until the new SCR, scrubber, and baghouse are completed, currently estimated to be late in the fourth quarter of 2008. Empire is entitled to 12% of the unit's available capacity and is obligated to pay for that percentage of the operating costs of the unit.

Empire's State Line Power Plant, located west of Joplin, Missouri, presently consists of State Line Unit 1, a CT with generating capacity of 89 MW and a CC unit (State Line CC) with generating capacity of 500 MW, of which Empire is entitled to 60%, or 300 MW. All units at the State Line Power Plant burn natural gas as a primary fuel, with State Line Unit 1 having the ability to also burn oil as a backup fuel.

Table 17
Empire Supply-Side Resources

Power Plant	Fuel Type	State	Interest (%)	Empire Capacity (MW)	Start Date	Facility Age (Years)
Asbury 1 & 2	Coal	MO	100	210	1970 & 1986	37 & 21
Riverton 7 & 8	Coal	KS	100	92[1]	1950 & 1954	57 & 53
Iatan 1	Coal	MO	12	80[2]	1980	27
Riverton CTs (9-12)	Natural Gas	KS	100	192	1964, 1988, 1988 & 2007	43, 19 & 19, <1
Empire Energy Center CTs	Natural Gas/Oil	MO	100	271	1978 & 1981 2003 & 2003	29 & 26 4 & 4
State Line CT	Natural Gas/Oil	MO	100	89	1995	12
State Line CC	Natural Gas	MO	60	300[3]	2001	6
Ozark Beach	Hydro	MO	100	16	1913	94
Total Empire Installed Capacity				1,250		
Long Term Power Purchases	**Type**				**End Date**	**Term**
Jeffrey Energy Center (Westar)	Coal			162	2010	
Elk River Windfarm	Wind			150[4]	2025[4]	20[4]
Capacity Summary						
Total Coal				382		
Total Gas Turbine				559		
Total Combined Cycle				300		
Total Hydro				16		
Total Purchase				169		
TOTAL				1,419		

Notes:
[1]Riverton 7 is rated at 38 MW, but can only produce 25 MW when burning only coal. The remainder of the capacity is achieved by over-firing natural gas. Riverton 8 is rated at 54 MW, but can produce about 45 MW when burning only coal. The remainder of the capacity is achieved by over-firing natural gas.
[2]Iatan 1 will be derated until 2008 when the installation of additional pollution control equipment is completed. Empire's share will fall to 78 MW for the duration of the deration and will increase to an estimated 85 MW in 2009 once the turbine upgrades are completed.
[3]One of the gas turbines at State Line CC was installed in 1997 and hence is 10 years old. The other gas turbine and steam turbine were installed in 2001.
[4]The Elk River Windfarm consists of 100 1.5 MW turbines for a total of 150 MW. For purposes of the IRP, 5% of installed wind capacity counted toward its reserve margin. Although the term of the PPA is 20 years, the term can be extended once for a period of 5 years at Empire's option.

Empire has four CT peaking units at the Empire Energy Center in Jasper County, Missouri, with an aggregate generating capacity of 271 MW. These peaking units operate on natural gas as well as oil.

Empire's hydroelectric generating plant, located on the White River at Ozark Beach, Missouri, has a generating capacity of 16 MW. In this IRP, the energy available from Ozark Beach was reduced in every year starting in 2009 to reflect the energy lost from the Reallocation of water in the White River by the U.S. Army Corps of Engineers.

In 2006, 63.7% of Empire's total system input (in kWh) was supplied by its steam and thermal generation units, 0.4% was supplied by its hydroelectric generation, and the remaining 35.9% was purchased power, including wind energy. Coal-fired energy purchased from others under contract constituted 21% of Empire's 2006 energy profile and wind energy purchases amounted to 9%.

Figure 4
2006 Energy Provision by Fuel Type

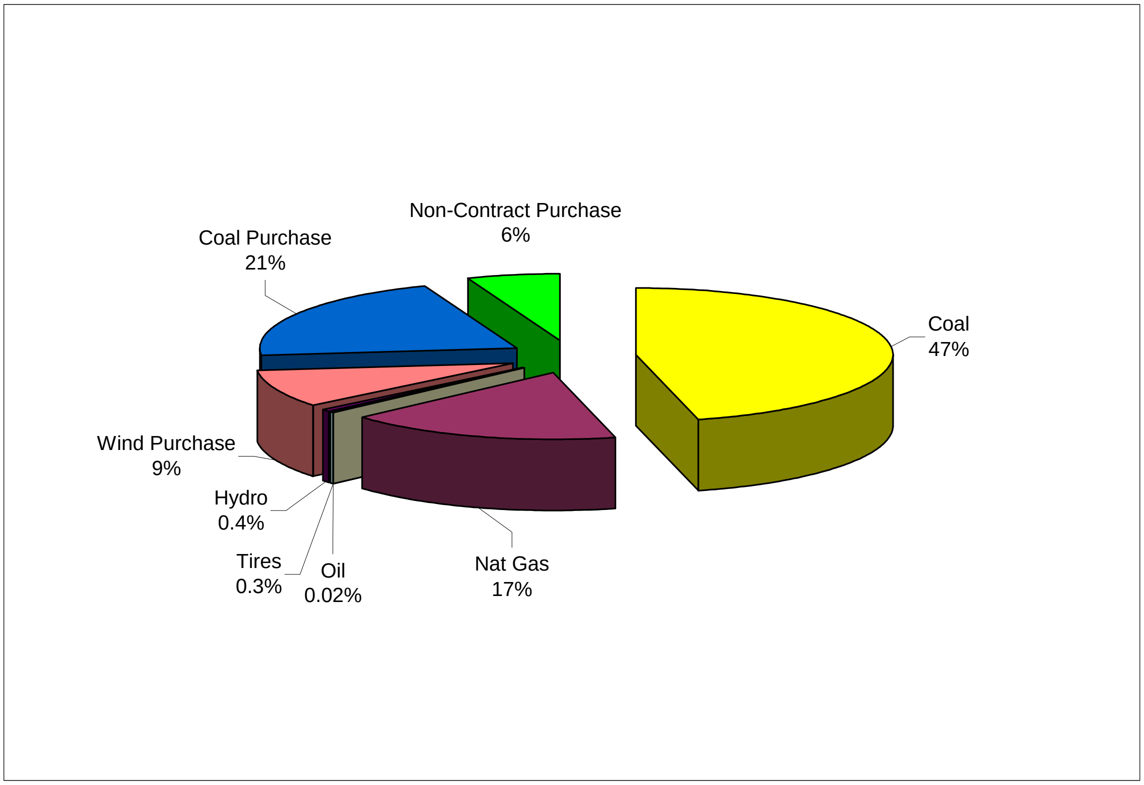


Figure 5 shows the capacity of these existing resources as compared to the projected load forecast over the planning horizon. The difference between the peak forecast line and the blocks of resources is the capacity deficit.

3.1.1 Purchased Power

Empire has existing PPAs for both conventional and renewable resources during the planning horizon.

3.1.1.1 Conventional

Empire currently purchases power under a PPA with Westar Energy. The capacity and energy purchased under this contract are provided from the three coal-fired generating units at Westar's Jeffrey Energy Center. This contract is for 162 MW of capacity and energy. It will expire on May 31, 2010.

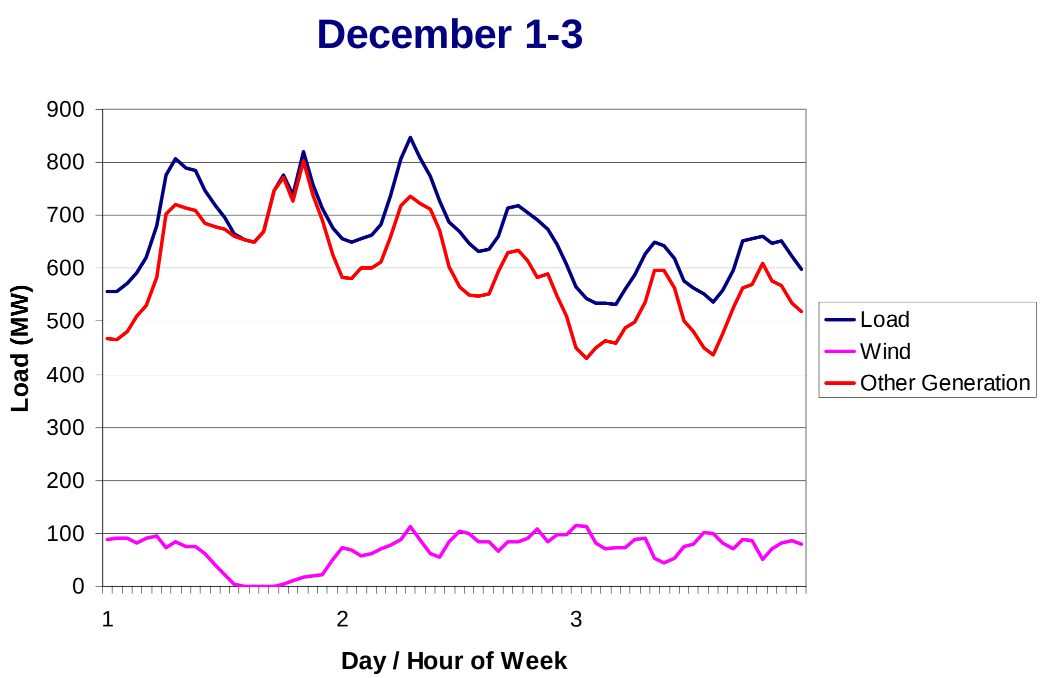
3.1.1.2 Renewables

On December 10, 2004, Empire entered into a 20-year contract with PPM Energy to purchase all of the energy generated at the Elk River Windfarm located in Butler County, Kansas. The Windfarm began commercial operation on December 15, 2005. This facility consists of 100 1.5 MW turbines. Empire also has the ability to extend the contract term for five years after the end of the 20-year contract period. Empire has contracted to purchase all of the output of the project which is estimated to be approximately 550,000 MWh of energy per year.

Figure 5
****Highly Confidential in its Entirety****
Empire Resource Composition (Installed Capacity as of 2007)

Typical output of the windfarm is reflected in Figure 6 which shows Empire's total customer hourly load, the amount of energy produced by the windfarm in each hour, and the amount of generation provided by Empire's other resources for each of the days of December 1-3, 2005. Note that energy production from the windfarm does fall to zero in some hours. In addition, this figure does not reflect the variability in wind generation that occurs on a minute-to-minute basis.

Figure 6
Empire's Customer Load and Elk River Windfarm's Output (2005)



3.1.2 Retirements

Empire's generating resources as shown in Table 17 include units that have been in operation for over 50 years. Last year, during the process of preparing the 2006 IRP, each plant manager and the Director of Environmental Services was interviewed. Topics covered during each interview included the age of the units, the maintenance schedule, known environmental requirements and effects of such on the units, and the possibility of catastrophic events. For the purposes of this IRP, **______________________________ ______________** In the course of preparing this IRP, **_________________________ ___________________________________** was also examined as an alternate plan. Barring significant changes in environmental regulations at the state or federal level, retirements of other units on the Empire system in this IRP's planning horizon would occur only in the case of a catastrophic equipment failure where it would not be economically feasible for the unit to continue operation.

3.1.3 Emission Controls on Existing Units

As part of this IRP, Empire examined the cost effectiveness of installing a scrubber on the Asbury plant and the timing associated with any such installation. Parameters associated with installing a scrubber include capital costs of $88.58 million (2013 $) for the scrubber, additional annual O&M costs of $3.075 million (2013 $), and a reduction of 4 MW in the capacity of the unit. Empire is already installing an SCR on Asbury that is expected to be operational by late 2007. For purposes of this IRP, Empire assumed that a baghouse would be installed on Asbury in 2010.

Empire recently examined the blend of local and Western coal at Asbury and the substitution of an alternative coal for the local coal. This analysis examined cost differentials between coals versus the level of SO_2 emission allowances required for each scenario and the impact that fuel switching might have on the need for a scrubber. No immediate change in coal procurement strategy was recommended at this time. Further long-term benefit/cost analysis will be required to determine if the installation of a scrubber can be economically justified.

3.2 Committed Resources

A number of resource commitments have been made by Empire that result in new resources over the planning horizon that are characterized as “committed”, meaning that either construction is underway, contracts have been signed, some level of commitment has been made, e.g., a memorandum of understanding has been signed, or that for purposes of the IRP, it is assumed to be built. Specifically, Empire has signed contracts to own a portion of and to purchase power from the Plum Point unit, has signed a contract to allow for participation as an owner in the Iatan 2 unit, and has signed a contract to purchase wind energy from the Cloud County Windfarm, LLC (which receives power from the Meridian Way Wind Farm). In addition, for purposes of this IRP, **__________
____
_______________________**

Empire has entered into an agreement with Plum Point Energy Associates, LLC to add 100 MW of resources to its system beginning in 2010. This power will come from the Plum Point Power Plant, a new 665-MW, coal-fired generating facility being built near Osceola, Arkansas. Construction has begun and completion is scheduled for 2010. Initially Empire will own 50 MW of the project’s capacity. Empire has made a commitment for a long-term PPA for an additional 50 MW and has the option to convert the 50 MW covered by the PPA into an ownership interest in 2015. In this IRP, Empire is assumed to convert the 50 MW under the PPA to ownership in 2015.

On February 4, 2005, Empire filed an application with the MPSC seeking approval of an Experimental Regulatory Plan (Plan) concerning its possible participation in a new 800-850 MW coal-fired unit (Iatan 2) to be operated by KCP&L and located at the site of the existing Iatan Generating Station (Iatan 1) near Weston, Missouri, or other baseload

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generation options. Empire's application also sought a certificate of convenience and necessity to participate in Iatan 2, if necessary, and in connection therewith, obtain approval that is intended to provide adequate assurance to potential investors to make financial options available to the Company concerning its potential investment in Iatan 2. On July 18, 2005, Empire filed a Stipulation and Agreement (Agreement) regarding its Plan with the MPSC for its consideration and approval conditioned upon its participation in Iatan 2. The Agreement contains conditions related to Empire's infrastructure investments, including Iatan 2, environmental investments in Iatan 1, Riverton 12, and installing an SCR at the Asbury station.

In relation to the above Plan, Empire entered into a letter of intent with KCP&L on June 10, 2005, with respect to Empire's potential purchase of an undivided ownership interest in the proposed 800-850 MW coal-fired Iatan 2. Subsequently, a joint ownership contract was signed. This contract, announced in June 2006, provides for Empire's 12% ownership participation, estimated to be 100 MW of generation capacity, and a proportionate share of the construction, operation, and maintenance costs. At present, Empire expects the Iatan 2 unit to be commercial in 2010.

In June 2007, Empire signed a contract with Horizon Wind Energy to buy wind energy from Cloud County Windfarm, LLC which receives energy from the 100 MW Meridian Way Wind Farm in Cloud County, Kansas near Concordia. The facility is expected to generate 350,000 MWh per year. The facility should be in commercial operation by January 2009.

After accounting for all existing resources (including deratings and retirements) and all planned resources, Empire faces a resource deficit by **____** as shown in Table 18 and Figure 7.

Figure 7
****Highly Confidential in its Entirety****

Load and Capability Summary

Table 18
Load and Capacity Summary 2007-2026 with Existing Resources, Committed Resources and Retirements (MW)

Year	Resources at Beginning of the Year	Planned Additions and Retirements[1]	Total Capacity at End of Year	Peak (net of Base DSM)	Required Capacity (12% Capacity Margin)[2]	Capacity Balance
2007	1270	148 (Riv 12)	1418	**____**	**____**	**___**
2008	1418		1418	**____**	**____**	**___**
2009	1418	5.25 (wind), Capacity adjustments	1430	**____**	**____**	**___**
2010	1430	100 (Iatan 2), 100 (Plum Point), -162 (Westar PPA terminates)	1468	**____**	**____**	**___**
2011	**____**	**________**	**____**	**____**	**____**	**___**
2012	**____**		**____**	**____**	**____**	**___**
2013	**____**		**____**	**____**	**____**	**___**
2014	**____**		**____**	**____**	**____**	**___**
2015	**____**		**____**	**____**	**____**	**___**
2016	**____**		**____**	**____**	**____**	**___**
2017	**____**		**____**	**____**	**____**	**___**
2018	**____**	**_____________**	**____**	**____**	**____**	**___**
2019	**____**		**____**	**____**	**____**	**___**
2020	**____**		**____**	**____**	**____**	**___**
2021	**____**		**____**	**____**	**____**	**___**
2022	**____**		**____**	**____**	**____**	**___**
2023	**____**		**____**	**____**	**____**	**___**
2024	**____**		**____**	**____**	**____**	**___**
2025	**____**		**____**	**____**	**____**	**___**
2026	**____**		**____**	**____**	**____**	**___**

[1]Includes small changes (1 and 2 MW to Asbury and Iatan capacity) during and after environmental retrofits.
[2]12% capacity margin equates to about a 13.7% reserve margin.

3.3 New Resources

Over the planning horizon, in addition to its plan for the implementation of demand-side management, Empire will need to construct or purchase new conventional, purchased power, and/or renewable resources in order to continue to satisfy the SPP capacity margin criteria of 12% and continue to provide safe, economic, and reliable power to its customers. Conventional and renewable technologies available to meet the requirements of Empire's customers in the future that were considered in this IRP and in the optimization modeling are described below. The capital costs modeled for each resource option include only generic costs for new transmission required; not those costs expected at any specific location due to the current methods that the SPP uses to plan and cost out new transmission projects. Costs are included for the switching station at the power plant. Information is provided as to the source of the capital costs for each technology. O&M cost estimates are provided. Empire believes that the uncertainty that surrounds the O&M costs for any future power plant is significantly overshadowed by the uncertainty related to any of natural gas prices, market prices, and the level of carbon taxes. Thus, the uncertainty associated with O&M costs is not considered further in this IRP.

3.3.1 Conventional

A variety of conventional resources were examined in the course of preparing this IRP. These resources included pulverized coal, CT, CC, nuclear, distributed generation, integrated gasification combined cycle (IGCC), atmospheric circulating fluidized bed (ACFB), and the conversion of Riverton 12 from a CT to CC. Compressed air energy storage (CAES) technology was investigated, but was not considered adequately viable to be chosen as a capacity expansion option in the optimization modeling at this time.

3.3.1.1 Pulverized Coal

In a standard pulverized coal unit, chunks of coal are crushed into fine powder in the pulverizers and are fed into a combustion unit (boiler or furnace) where it is burned. Heat from the burning coal is used to generate steam that is used to spin one or more turbines to generate electricity. These types of units currently generate about half of the electricity produced annually in the U.S.

As modeled, the pulverized coal option available to Empire represents its ownership share of a larger unit. As larger units benefit from economies of scale, this modeling choice was made to ensure Empire was able to take advantage of the cost effectiveness represented by the larger units. However, the actual timing and ownership share of units that Empire might be able to participate in will be dependent on plans of other utilities in the region and are expected to be largely out of Empire's control.

Cost and emission data are based on information from a pulverized coal unit currently under construction in the region.

Table 19
Pulverized Coal Performance Parameters

Parameter	Value
Earliest feasible year of installation	2013
Size, MW (net)	50*
Full load heat rate, Btu/kWh	9,300
Capital cost, $/kW (2007 $)	1835.46
Fixed O&M, $/kW-year	26.82
Variable O&M, $/MWh	3.376
Equivalent Forced Outage Rate, %	15.5
Lead time, months	60
SO_2 Emissions, lbs/MMBtu	0.0674
NO_x Emissions, lbs/MMBtu	0.04635
CO_2 Emissions, lbs/MMBtu	210
Mercury Emissions, lbs/MMBtu	0.006
*Ownership share of a larger unit. 1. Based on high level cost estimates recently received by Empire.	

3.3.1.2 Combustion Turbine

Combustion turbines typically burn natural gas and/or No. 2 fuel oil and are available in a wide variety of sizes and configurations. CTs are generally used for peaking and reserve purposes because of their relatively low capital costs, higher full load heat rate, and the higher cost of fuel when compared to conventional coal-fired baseload capacity. CTs, particularly aero-derivatives, have the added benefit of providing quick-start capability in certain configurations. In this IRP, both simple cycle and aero-derivative CTs were options in the optimization modeling. Data for capital costs for the CTs are based on manufacturers' information provided by Siemens, General Electric, and Pratt and Whitney.

Table 20
Combustion Turbine Performance Parameters

Parameter	Aero-derivative CT	Simple Cycle CT
Earliest feasible year of installation	2013	2013
Size, MW (net)	50	115
Full load heat rate, Btu/kWh	12,020	12,020
Capital cost, $/kW (2007 $)	644.97	412.90
Fixed O&M, $/kW-year	10.85	10.85
Variable O&M, $/MWh	3	3
Equivalent Forced Outage Rate, %	5.8	5.8
Lead time, months	24	24
NO_x Emissions, lbs/MMBtu	.02	.02
CO_2 Emissions, lbs/MMBtu	130	130

3.3.1.3 Combined Cycle

In a combined cycle facility, the hot exhaust gases from one or more CTs pass through a heat recovery steam generator (HRSG). The steam generated by the HRSG is expanded through a steam turbine which, in turn, drives an additional generator. Combustion turbine combined cycle systems typically burn natural gas and are available in a wide variety of sizes and configurations. In Empire's IRP, two CC options were available for selection: 1) a new unsited CC facility, and 2) the conversion of the Riverton 12 CT to a CC unit. Riverton 12 achieved commercial operation in 2007. This facility has the potential to be expanded into a CC unit through the addition of a heat recovery steam generator (HRSG). The process of constructing the HRSG and capturing the exhaust steam would mean approximately 100 MW of additional capacity would be deemed to have been installed. The Riverton12 conversion costs are based on an estimate prepared by Black & Veatch. The general combined cycle unit capital costs are based on a cost estimate from a CT manufacturer plus the conversion cost estimates from Black & Veatch.

Table 21
Combined Cycle Performance Parameters

Parameter	General CC	Riverton 12 Conversion
Earliest feasible year of installation	2013	2013
Size, MW (net)	250	100*
Full load heat rate, Btu/kWh	8,550	7,200
Capital cost, $/kW (2007 $)	679.79	1086.03
Fixed O&M, $/kW-year	11.18	(1)
Variable O&M, $/MWh	2.23	2.23
Equivalent Forced Outage Rate, %	14.8	14.8
Lead time, months	48	48
NO_x Emissions, lbs/MMBtu	.02	.01
CO_2 Emissions, lbs/MMBtu	120	119

*Represents the incremental capacity of the CC unit only, not the total including the CT.
1. No additional fixed costs after Riverton 12 is converted to a CT.

3.3.1.4 Nuclear

Nuclear power plants are being seriously examined again after many years of not being an option. Factors driving this interest are the concern over the contributions of fossil fuels to greenhouse gases and global warming as well as the recent significant volatility of natural gas prices. The new Westinghouse AP1000 advanced pressurized reactor received U.S. Nuclear Regulatory Commission (NRC) design approval in December 2005. A design application for General Electric Energy's economic simplified boiling-water reactor (ESBWR) was submitted to the NRC in August 2005.[2]

[2] Brown, Alan S., "Will Changing Times Require a Second Look at Nuclear Power?" *The Bent of Tau Beta Pi*, Spring 2006, pp. 29-33.

Although Empire is not aware of any opportunities for it to become a joint owner of a nuclear unit in the region, Empire did consider a nuclear unit as an option starting in 2020 for cases other than the base case. At some point in the future, possibly within the planning horizon and possibly later than the end of the planning horizon, it is conceivable that nuclear units could be pursued as an additional unit at existing nuclear power plant sites in the region.

The IRP modeling assumes that Empire would purchase a share of a new nuclear unit. However, the actual timing and ownership share of units that Empire might be able to participate in will be dependent on plans of other utilities in the region and are expected to be largely out of Empire's control. This is also the reason that nuclear unit participation is not in either of the base case or the preferred plan.

Empire assumed a capital cost of approximately $2000/kW for nuclear, which is reasonably comparable to the capital cost estimates currently being used and published by the Department of Energy (DOE) EIA.

Table 22
Nuclear Performance Parameters

Parameter	Value
Earliest feasible year of installation	2020
Size, MW (net)	50*
Full load heat rate, Btu/kWh	10,300
Capital cost, $/kW (2007 $)	2140.63
Fixed O&M, $/kW-year	66.03
Variable O&M, $/MWh	3.09
Equivalent Forced Outage Rate, %	3.09
Lead time, months	120
Emissions	None
*Represents share of a larger jointly-owned unit.	

3.3.1.5 Distributed Generation

Distributed generation (DG) refers to small-scale power plants that differ from traditional electricity supply due to their small size, location, and grid connection. DGs are located at or near the point at which the power is used. Such installations relieve congestion in power lines during periods of peak demand, helping to defer investments in additional transmission and distribution capacity. DG facilities are often installed on the distribution system as opposed to on the transmission system, where generation is typically connected. DG facilities may also be used to boost the quality and reliability of local electricity service by providing voltage control and backup power to customers who require such "premium" service.

Table 23
Distributed Generation Performance Parameters

Parameter	Value
Earliest feasible year of installation	2013
Size, MW (net)	5
Full load heat rate, Btu/kWh	9,500
Capital cost, $/kW (2007 $)	891.69
Fixed O&M, $/kW-year	10.63
Variable O&M, $/MWh	4.2436
Equivalent Forced Outage Rate, %	5
Lead time, months	12
Emissions	None

3.3.1.6 Integrated Gasification Combined Cycle (IGCC)

Coal gasification is a process that converts solid coal into a synthetic gas composed mainly of carbon monoxide and hydrogen. Integrated gasification combined cycle (IGCC) combines both steam and gas turbines ("combined cycle"). The fuel gas leaving the gasifier must be cleaned (to very high levels of removal efficiencies) of sulfur compounds and particulates in order to be a suitable fuel for combustion. After the fuel gas has been cleaned, it is burned and expands in a gas turbine. Steam is generated and superheated in both the gasifier and the heat recovery unit downstream from the gas turbine. The flue gas is then directed through a steam turbine to produce electricity. IGCC plants can achieve up to 45 percent efficiency depending on the level of integration of the various processes, greater than 99 percent SO_2 removal, and NO_x below 50 parts per million.[3] Capital costs are based on values estimated by the Electric Power Research Institute and the DOE's EIA 2007 *Annual Energy Outlook*. The analysis assumes that Empire would participate in a share of a larger jointly-owned unit.

[3] Source: "Clean Coal Technologies for Developing Countries," World Bank Technical Paper No. 286, Energy Series, E. Stratos Tavoulareas and Jean-Pierre Charpentier, July 1995. http://www.worldbank.org/html/fpd/em/power/EA/mitigatn/igccsubs.stm, accessed May 2006.

Table 24
IGCC Performance Parameters

Parameter	Value
Earliest feasible year of installation	2015
Size, MW (net)	50*
Full load heat rate, Btu/kWh	9,300
Capital cost, $/kW (2007 $)	1983.28
Fixed O&M, $/kW-year	24.35
Variable O&M, $/MWh	4.59
Equivalent Forced Outage Rate, %	15.5
Lead time, months	60
SO_2 Emissions, lbs/MMBtu	.03
NO_x Emissions, lbs/MMBtu	.02
CO_2 Emissions, lbs/MMBtu	210
Mercury Emissions, lbs/MMBtu	.003
*Represents a share of a larger jointly-owned unit.	

3.3.1.7 Atmospheric Circulating Fluidized Bed (ACFB)

ACFB technology utilizes the fluidized bed principle in which crushed fuel and limestone are injected into the furnace or combustor. The particles are suspended in a stream of upwardly flowing air that enters the bottom of the furnace through air distribution nozzles. The balance of combustion air is admitted above the bottom of the furnace as secondary air. While combustion takes place, the fine particles are removed from the furnace. The particles are then collected by the solids separators and circulated back into the furnace. The particles' circulation provides efficient heat transfer to the furnace walls and longer residence time for carbon and limestone utilization. ACFB technology brings the capability of designs for a wide range of fuels from low quality to high quality fuels, lower emissions, elimination of high maintenance pulverizers, low auxiliary fuel support, and reduced life cycle costs.

The combustion temperature of an ACFB is much lower than pulverized coal which results in lower NO_x formation and the ability to capture SO_2 with limestone injection in the furnace. Even though the combustion temperature of ACFB is low, the fuel residence time is higher than for pulverized coal, which results in good combustion efficiencies. Maintenance costs are much lower for ACFB as pulverizers for the coal are not required. Even though ACFB boiler equipment is designed for relatively lower flue gas velocities, the heat transfer coefficient of the ACFB furnace is nearly double that of pulverized coal which makes the furnace compact. ACFB boilers release very low levels of SO_2 and NO_x pollutants as compared to pulverized coal.[4] Capital costs were derived from GED's Spring Reference Case.

[4]Kavidass, S., Anderson, G.L., Norton, G.S., Jr., "Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power," POWER-GEN Asia 2000, BR-1708, September 20-22, 2000.

Table 25
ACFB Performance Parameters

Parameter	Value
Earliest feasible year of installation	2013
Size, MW (net)	50
Full load heat rate, Btu/kWh	9,300
Capital cost, $/kW (2007 $)	2307.64
Fixed O&M, $/kW-year	27.7
Variable O&M, $/MWh	2.911
Equivalent Forced Outage Rate, %	15.5
Construction time, months	60
SO_2 Emissions, lbs/MMBtu	0.0674
NO_x Emissions, lbs/MMBtu	0.04635
CO_2 Emissions, lbs/MMBtu	210
Mercury Emissions, lbs/MMBtu	0.006

3.3.1.8 Compressed Air Energy Storage (CAES)

Compressed Air Energy Storage (CAES) technology combines a CT with the use of off-peak electricity to compress air and store it underground in airtight caverns or mines. When the CT needs the air to generate electricity during on-peak hours, the process is reversed and the air is used along with natural gas to power the CT. Such a process consumes less than 40% of the natural gas used in a conventional CT because the natural gas is not being used to drive the machine's compressor. CAES technology is about 30 years old. Two plants using CAES technology are currently in operation: 290-MW unit in Germany built in 1978 and a 110-MW unit in McIntosh, Alabama. Both of these operating plants use caverns created by salt deposits.[5]

3.3.2 Renewable Resources

Renewable resources are appearing in more electric utilities' resource portfolios due to two primary drivers: 1) renewable energy portfolio standards have been enacted in some states requiring or strongly encouraging utilities to install a minimum percentage of renewables by a date certain, and 2) the costs for many renewable technologies have become more cost competitive. Renewable portfolio standards (RPS) are statutes enacted by state legislatures or through voter referenda that mandate a minimum amount of renewable energy (usually as a function of total system energy) be included in utility resource portfolios by a date certain often with the required percentage increasing over time. RPS have primarily, but not exclusively, been enacted as a result of state-based electric restructuring efforts. As of mid 2007, twenty-five states plus the District of Columbia have set renewable standards (see Figure 8).[6] Some of the states allow or

[5] "Compressed Air Energy Storage," U.S. Department of Energy, Distributed Energy Program, www.eere.energy.gov/de/compressed_air.html. "Technologies: CAES," Electricity Storage Association, www.electricitystorage.org/tech/technologies_technologies_caes.htm.
[6]"”States with Renewables Portfolio Standards," www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm.

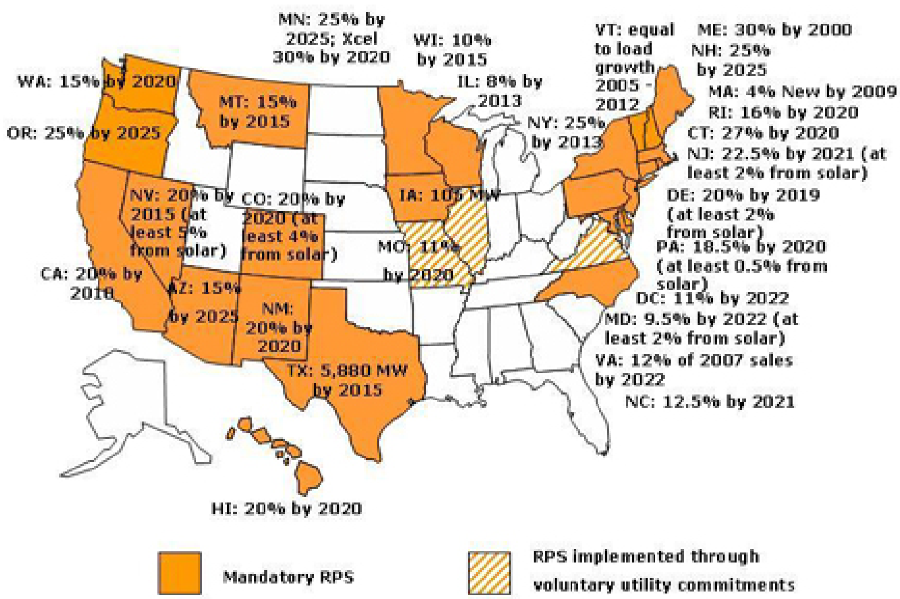
encourage a trading mechanism for the exchange of renewable energy credits among the state's utilities to facilitate compliance with the RPS.[7]

In June 2007, Missouri Governor Matt Blunt signed Senate Bill 54 (see Appendix A) that creates renewable energy targets for the utilities in Missouri. The targets include: four percent renewable energy by 2012, eight percent by 2015, and 11 percent by 2020. Eligible renewable energy technology is defined by the Bill as including, but not limited to:

- Solar, including photovoltaic cells, concentrating solar power technologies, and low temperature solar collectors
- Wind
- Hydroelectric, not included pump-storage
- Hydrogen from renewable sources
- Biomass, any organic matter available on a renewable basis, including dedicated energy crops and trees, agricultural food and feed crops, agricultural crops wastes and residues, wood wastes and residues, animal waste, aquatic plants, biogas from landfills or wastewater treatment plants
- Other renewable energy defined by rule by the MPSC.

Generation provide by any existing eligible renewable energy technology, owned, controlled, or purchased by an electric utility that is operational prior to August 28, 2007, will count toward meeting the renewable energy target as long as it continues to generate electricity.

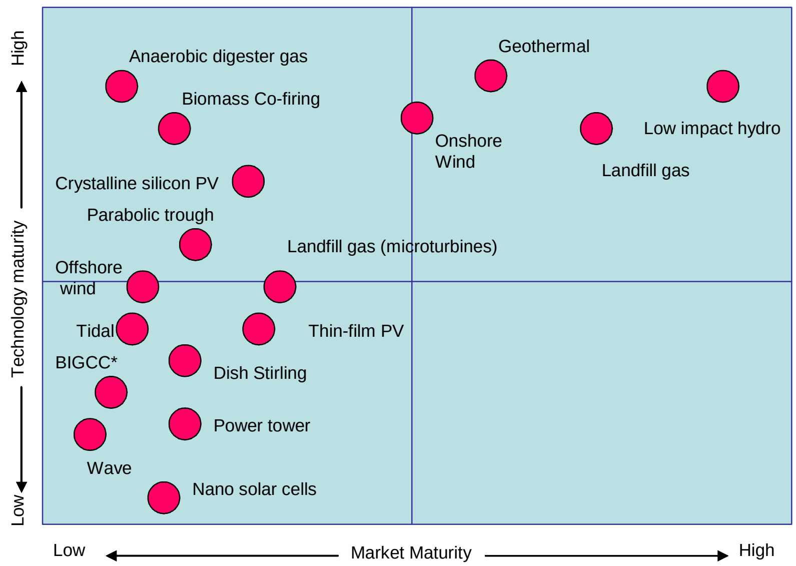
Figure 8
States with Renewable Portfolio Standards



[7] "Renewable Portfolio Standards," www.newrules.org/electricity/rps.html.

Some of the renewable technologies have reached a commercial state as demonstrated in Figure 9 and some have reached market maturity. Figure 9 shows that both biomass and wind are technologically mature although the primary drivers for wind technology development remain the federal production tax credits and RPS enacted by states.

Figure 9[8]
Renewable Energy Technology Status



*Biomass integrated gasification combined cycle
Source: Navigant Consulting

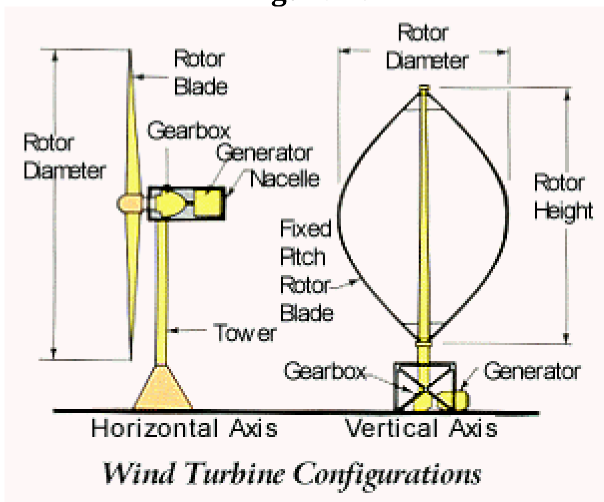
Three categories of renewable resources have the most significant potential to meet the needs of Empire's customers during the planning period – wind, chicken/turkey waste (a form of biomass), and tires. Empire currently burns fuel derived from tires at its Asbury station and is purchasing wind from PPM Energy, whose wind generation facility (Elk River Windfarm) is near Beaumont, Kansas. Empire has also made commitments to purchase wind energy from Cloud County Windfarm, LLC (the Meridian Way Wind Farm) in Cloud County, Kansas with operation scheduled by January 2009.

3.3.2.1 Wind

Wind energy systems for utility applications transform the kinetic energy of the wind into electrical energy. Wind electric turbines are either vertical-axis (egg-beater-style) or horizontal-axis (propeller-style) machines. Horizontal-axis turbines are the most common today, constituting almost all of the utility-scale (greater than 100 kW) applications. Figure 10 shows these two wind turbine configurations.

[8] Schimmoller, Brian K., "Renewables Get Into the Mix," *Power Engineering*, January 2004, pp. 22-30.

Figure 10



Turbine subsystems include:

- A rotor, or blades, that convert the wind's energy into rotational shaft energy
- A nacelle (enclosure) containing a drive train, usually including a gearbox (not all turbines require a gearbox) and a generator
- A tower to support the rotor and drive train
- Electronic equipment such as controls, electrical cables, ground support equipment, and interconnection equipment.[9]

The American Wind Energy Association (AWEA) reported at the end of 2006 that the U.S. had11,603 MW of installed wind energy capacity. The top ten states as reported by AWEA are shown in Table 26.

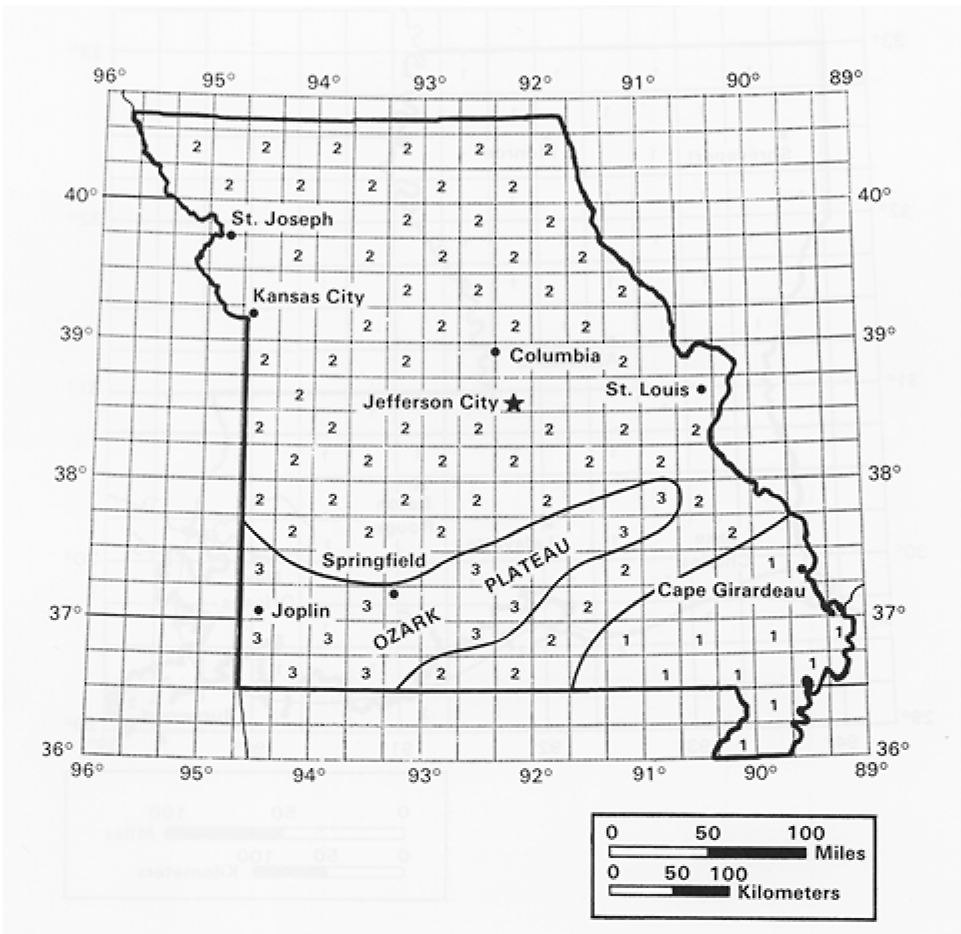
Table 26
Installed Wind Energy Capacity in the U.S. (2006)

State	Installed Capacity (MW)
Texas	2,768
California	2,361
Iowa	936
Minnesota	895
Washington	818
Oklahoma	535
New Mexico	497
Oregon	439
New York	370
Kansas	364

[9] Figure, general information and state project information from web site of the American Wind Energy Association www.awea.org.

The profile of wind resources shown on Figure 11 reveals that Class 3 or lower wind resources exist in Empire's service territory. Generally wind resources need to be at least Class 3 (the highest wind ranking is Class 7) in order to be considered suitable for wind energy development. This map shows some suitable resources in the Ozark Plateau. Wind resource maps from other sources have indicated that the northwest corner of the State has the highest class wind rankings.[10] AWEA reports that there are currently no utility-scale wind projects in Missouri.

Figure 11
Wind Resources in Missouri



The American Wind Energy Association ranks Kansas third in the nation (behind North Dakota and Texas) in potential wind energy production. Oklahoma ranks eighth nationwide in potential wind energy production with most Class 3 and higher wind resources located in the western portion of the state.

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[10] Figure 3-44, "Missouri annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-44m.html.

The resource map in Figure 12 shows the Class 3 and 4 wind resources in Kansas.[11] The resources that AWEA reports to be on-line in Kansas are shown in Table 27.

Figure 12
Kansas Wind Resource Map

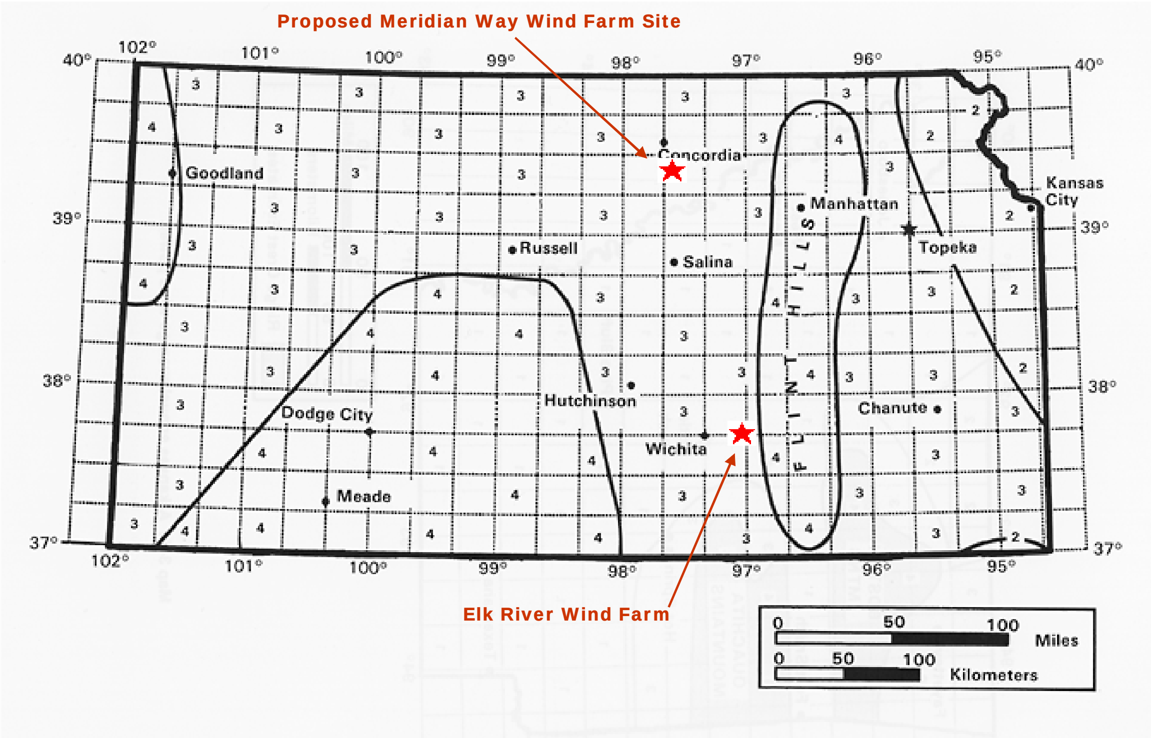


Table 27
Wind Energy Projects in Kansas

Year of Operation	Size (MW)	Name	Developer	Utility Purchaser
1999	1.5	St. Mary's	Western Resources	Western Resources
2001	112.2	Gray County Wind Farm	FPL Energy	Aquila
2005	150	Elk River Wind Farm	PPM Energy	Empire
2006	100.5	Spearville Wind Energy Facility	Kansas City Power & Light	Kansas City Power & Light

The resource map in Figure 13 shows the Class 3 and 4 wind resources in Oklahoma.[12] The resources that AWEA reports to be on-line in Oklahoma are shown in Table 28. AWEA also reports that the Sleeping Bear project of 94.5 MW is under development by Chermac Energy Corporation and Edison Mission Group in Harper County.

[11] Figure 3-42, "Kansas annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-42m.html.
[12] Figure 3-45, "Oklahoma annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-45m.html.

Figure 13
Oklahoma Wind Resource Map

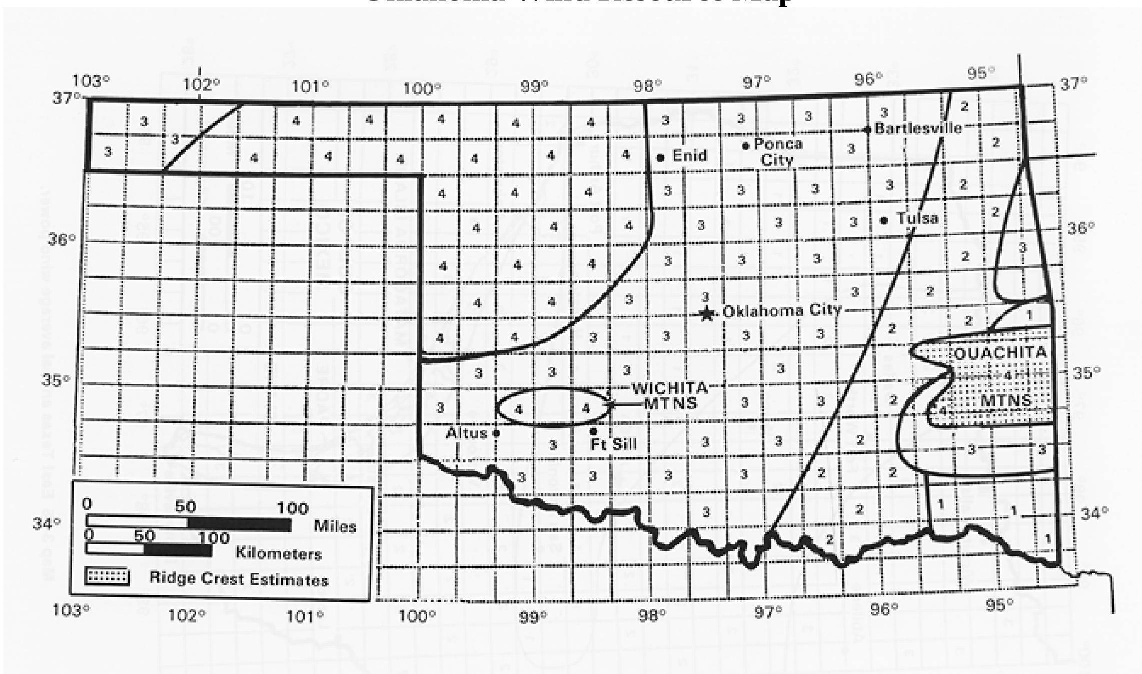
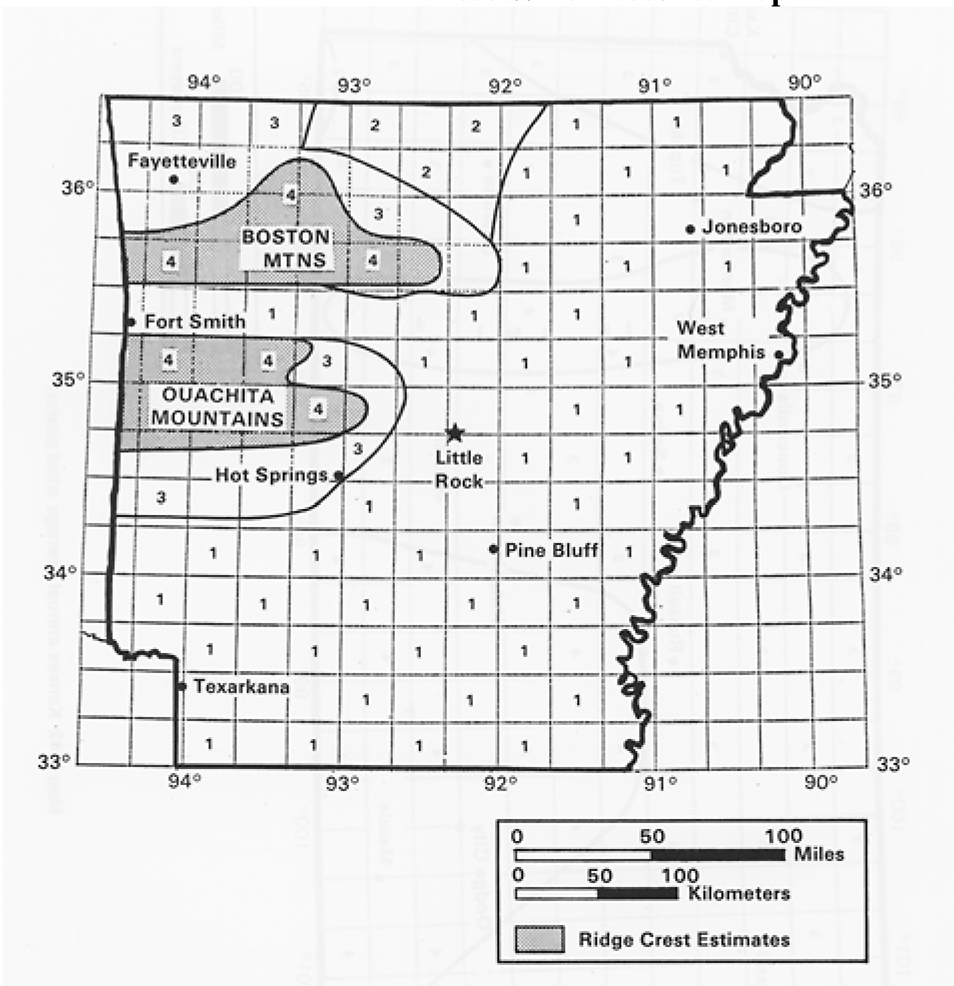


Table 28
Wind Energy Projects in Oklahoma

Year of Operation	Size (MW)	Name	Developer	Utility Purchaser
2003	102	Oklahoma Wind Power Center	FPL Energy	Oklahoma Municipal Power Authority; Oklahoma Gas & Electric
2003	74.25	Blue Canyon Wind Power	Consortium	Western Farmers Electric Coop
2005	147	Weatherford Wind Energy Center	FPL Energy	Public Service Company of Oklahoma (AEP)
2005	0.05	Bergey Windpower Headquarters	Bergey Windpower	Bergey Windpower Headquarters
2005	151.2	Blue Canyon II	Horizon Wind Energy	Public Service Company of Oklahoma (AEP)
2006-2007	120	Centennial Wind Energy Project (2006 Portion)	Invenergy	Oklahoma Gas & Electric

The resource map in Figure 14 shows the Class 3 and 4 wind resources in Arkansas.[13] Only one very small wind resource is reported to be operational by AWEA, 0.1 MW at the Bitworks Prairie Grove Industrial Park. AWEA reports no proposed projects.

Figure 14
Arkansas Wind Resource Map



Empire has determined that in order to protect its system from the extreme variability of wind energy resources, for the purposes of this IRP, it will install back up CT capacity in the amount of half of the size of a wind energy facility for any further additions. Thus, for a 100 MW wind energy facility, Empire desires to have 50 MW of CT capacity installed (with quick start capability). Empire is currently not counting any of the capacity of the wind energy facility itself as "dependable capacity", except in the IRP where 5% of the wind energy capacity counted toward planning reserves. The capacity from the associated CT does count toward planning reserves, however. The capacity expansion modeling reflected a 25 MW CT installed for each 50 MW of wind energy capacity installed except in the medium and high environmental cases where 50 MW of

[13] Figure 3-41, "Arkansas annual average wind power," Wind Energy Resource Atlas of the United States, http://rredc.nrel.gov/wind/pubs/atlas/maps/chap3/3-41m.html.

CT capacity was installed for each 50 MW of wind energy capacity. Wind energy can either be owned by Empire or procured through a PPA. The costs of the CT were reflected as part of the total cost of the wind energy alternative. Wind performance parameters are shown in Table 29.

Table 29
Wind Performance Parameters

Parameter	Ownership	PPA
Earliest feasible year of installation	2013	2013
Size, MW (net)	100	50
Full load heat rate, Btu/kWh	NA	NA
Capital cost, $/kW (2007 $)	1242.18	$46.35/MWh*
Fixed O&M, $/kW-year	28.51	-
Variable O&M, $/MWh	-	-
Equivalent Forced Outage Rate, %	-	-
Construction time, months	12	12
Emissions	None	None
*In addition to 3% annual escalation on the capital costs, in the high fuel price case, wind experiences a $25/MWh price increase in 2015, due to assumed termination of any federal production tax credit.		

3.3.2.2 Biomass – Chicken/Turkey Waste

Biomass electric generation is currently the largest source of renewable energy that is not hydroelectric. Biomass means any plant-derived organic matter available on a renewable basis including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, municipal wastes and other waste materials. Waste energy consumption generally falls into categories that include municipal solid waste, landfill gas, other biomass and other. Other biomass includes agriculture byproducts/crops, sludge waste, tires, and other biomass solids, liquids, and gases. Biofuels being developed from biomass resources include ethanol, methanol, biodiesel, Fischer-Tropsch diesel, and gaseous fuels such as hydrogen and methane. [14]

Chicken and/or turkey wastes represent a form of biomass that is prevalent in Empire's service territory. Research on studies conducted for facilities in states outside of Missouri concluded that the cost of power from such a facility would be about 8 cents/kWh and that the heat content of the fuel (chicken or turkey waste mixed with a wood waste product) would be 5,000 to 7,000 Btu/lb.[15] The biomass characteristics modeled in the optimization planning are shown on Table 30.

[14] U.S. Department of Energy, Energy Efficiency and Renewable Energy,"Biomass Topics," http://www.eere.energy.gov/RE/biomass.html.
[15] Missippi_band_choctaw_tep_nov03.pdf.

Table 30
Biomass Performance Parameters

Parameter	Value
Earliest feasible year of installation	2013
Size, MW (net)	5
Full load heat rate, Btu/kWh	12,000
Capital cost, $/kW (2007 $)	2652.65
Fixed O&M, $/kW-year	50.18
Variable O&M, $/MWh	2.96
Equivalent Forced Outage Rate, %	5
Lead time, months	36
SO_2 Emissions, lbs/MMBtu	.027
NO_x Emissions, lbs/MMBtu	0.15
CO_2 Emissions, lbs/MMBtu	195

3.4 Transmission

Empire believes that at least some of the resources that will be required over the planning horizon may have significant transmission costs associated with them. The new process used by the SPP, however, makes it difficult to estimate the transmission costs for any specific resource option. SPP conducts three studies directly associated with transmission planning: Large Generation Interconnect Studies, Aggregate Transmission Service Studies, and the SPP Transmission Expansion Plan (STEP).

The Large Generation Interconnect Study determines all of the modifications needed to connect a new generator into the transmission system. The Aggregate Transmission Service Studies determine system upgrades required to grant transmission service from a generation source to a load. The STEP determines upgrades required for a reliable transmission system and provides a screening of potential economic projects.

As of January 2005, the SPP uses a Federal Energy Regulatory Commission (FERC)-approved process called an Aggregate Transmission Service Study. In this process, SPP combines all long-term point-to-point and all long-term network resource transmission service requests received during a sequential four-month open season into a single aggregate transmission service study. Such an aggregated analysis should result in a more optimal expansion of the SPP transmission system.

For the purposes of Empire’s 2007 IRP, however, it makes the transmission cost adders associated with any specific resource addition difficult to even estimate. In addition, since very few of the supply-side options evaluated in this 2007 IRP are attached to a specific site, this makes evaluation of the associated transmission costs even more difficult. Although transmission costs for specific sites were not possible to estimate given the SPP’s process, Empire did assign transmission costs on a $/kW basis for each candidate resource examined in this IRP.

Empire is providing information in this IRP on future transmission projects within Empire's control area that are planned by the SPP in the STEP (see Appendix B). This information is preliminary, not approved, and subject to change. In addition, since not all of Empire's planned construction projects are accounted for in the SPP Expansion Plan, details from Empire's 2007 Construction Budget for planned transmission and distribution projects are also presented in Appendix B. Plans for transmission projects within the SPP change frequently as conditions on utility systems, including Empire's, change. Empire works to reduce system losses by evaluating losses of power transformers at the time of purchase and by strategically installing capacitor banks on the distribution system.

4.0 Screening Analysis

All of the technologies described in Section 3.0 proceeded into the optimization modeling with the exception of CAES. No sites have yet been identified within Empire's service territory that would be suitable for CAES and cost estimates for construction and operation are not available; thus this technology was categorized as not yet viable.

Because of the methodology employed in the optimization modeling, there is no need to rank the supply-side technologies at this stage of the evaluation. All technologies are analyzed within the optimization modeling and those that meet the criteria are selected. Thus, no ranking was conducted for the supply-side technologies described in this Volume of the IRP.

Appendix A Missouri Senate Bill 54, 2007

393.1020. 1. It is the general assembly's intent to encourage the development and utilization of technically feasible and economical renewable technologies, creating cleaner and more sustainable forms of energy for the residents of the state. It is for this reason that sections 393.1020 to 393.1040 shall be known as the "Green Power Initiative".

2. The definitions provided in section 386.020, RSMo, shall apply to sections 393.1020 to 393.1040. As used in sections 393.1020 to 393.1040, the following terms mean:

393. . "Department", the department of natural resources;

(2) "Eligible renewable energy technology", sources of energy that shall be considered renewable for purposes of this section shall include but not be limited to the following:

393. . Solar, including photovoltaic cells, concentrating solar power technologies, and low temperature solar collectors;

(b) Wind;

© Hydroelectric, not including pump-storage;

(d) Hydrogen from renewable sources;

(e) Biomass, any organic matter available on a renewable basis, including dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, animal waste, aquatic plants, biogas from landfills or wastewater treatment plants; and

(f) Other renewable energy sources defined by rule by the commission after consultation with the department;

(3) "Energy efficiency", verifiable reductions in energy consumption, or verifiable reductions in the rate of energy consumption growth, as defined by rule by the commission after consultation with the department, as a result of measures implemented by electrical corporations and electricity consumers which may include, but not be limited to, pricing signals, electronic controls, education, information, infrastructure improvements, and the use of high efficiency equipment and lighting;

(4) "Total retail electric sales", the kilowatt-hours of electricity delivered in a year by an electrical corporation to its Missouri retail customers.

393.1025. 1. Each electrical corporation shall make a good faith effort to generate or procure sufficient electricity generated by an eligible renewable energy technology, and support energy efficiency measures, so that by 2012, four percent of total retail electric sales in the aggregate by electrical corporations is generated by eligible renewable energy technologies, increasing to eight percent by 2015, and eleven percent generated by eligible renewable energy technologies by 2020. Generation provided by any existing eligible renewable energy technology, owned, controlled, or purchased by electrical corporations, that are operational prior to August 28, 2007, shall be applied towards meeting the objective so long as it continues to generate electricity. Credit towards the objective also may be achieved through energy efficiency that includes electrical corporation and consumer efforts to reduce the consumption of electric energy. After consulting with the department, the commission may establish intermediate goals for the use of renewable energy technologies as part of its rulemaking

process.

2. By July 1, 2008, the commission shall, after consultation with the department, adopt rules that integrate into its resource planning rules the renewable energy objective of subsection 1 of this section and the criteria and standards by which it will measure an electrical corporation's efforts to meet that objective to determine whether it is making the required good faith effort. In this rulemaking, the commission shall include criteria and standards that, at a minimum, shall:

393. . Protect against adverse economic impacts, including the costs of any transmission investments necessary to access eligible renewable energy technologies, on the ratepayers and shareholders;

(2) Protect against undesirable impacts on the reliability of each electrical corporation's system;

(3) Consider environmental compliance costs, present and future, of each source being evaluated; and

(4) Consider technical feasibility, providing for flexibility in meeting the objective in the event electrical corporations are, for good cause shown, unable to meet in aggregate the objective of this section.

3. In its rulemaking under this section, the commission shall provide for a weighted scale of how energy produced by various eligible renewable energy technologies shall count toward an electrical corporation's objective. In establishing this scale, the commission shall consider the attributes of various technologies and fuels and shall establish a system that grants multiple credits toward the objective for those technologies and fuels the commission determines are in the public interest to encourage. The commission may also grant multiple credits toward the objective for generation in the state or procurement of electricity generated in the state that uses an eligible renewable energy technology.

4. The commission shall develop rules as provided in this section in consultation with the department as necessary to implement the requirements of section 393.1025. Any rule or portion of a rule, as that term is defined in section 536.010, RSMo, that is created under the authority delegated in this section and section 393.1020 shall become effective only if it complies with and is subject to all of the provisions of chapter 536, RSMo, and, if applicable, section 536.028, RSMo. This section and chapter 536, RSMo, are nonseverable and if any of the powers vested with the general assembly pursuant to chapter 536, RSMo, to review, to delay the effective date, or to disapprove and annul a rule are subsequently held unconstitutional, then the grant of rulemaking authority and any rule proposed or adopted after August 28, 2007, shall be invalid and void.

393.1030. 1. Each electric corporation shall submit to the commission a biennial report by December thirty-first, beginning in 2009, on its plans, activities, and progress with regard to the objective of section 393.1025, demonstrating to the commission that it is making the required good faith effort. The report must be submitted in a format prescribed by the commission, not to exceed fifty pages, and it shall include the following:

393. . Sufficient data to specify and verify the status of its renewable energy mix relative to the good faith objective;

2) Sufficient data to specify and verify the status of the electric corporation's and its customers' energy efficiency efforts relative to the good faith objective;

(3) Efforts taken to meet the objective;

(4) Any obstacles encountered or anticipated in meeting the objective; and

(5) Potential solutions to the obstacles.

2. The commission shall compile the information provided under subsection 1 of this section and biennially report by July first, beginning in 2010, to the governor, the speaker of the house of representatives, the president pro tempore of the senate, the chairs of the committees in the house of representatives and senate with jurisdiction over energy and environment policy issues, and the department as to the progress of electrical corporations in the state in increasing the amount of renewable energy provided to retail customers and increasing energy efficiency, with any recommendations for regulatory or legislative action. In addition, the Missouri director of the department of economic development shall issue a biennial report by July first, beginning in 2010, on the impact of the renewable portfolio standard on the Missouri economy and the director of the department of natural resources shall issue a biennial report by July first, beginning in 2010, on the environmental impact of sections 393.1020 to 393.1040. The biennial reporting requirements under this subsection shall end after July 1, 2022.

393.1035. 1. Electricity produced by fuel combustion may only count toward an electrical corporation's objectives if the generation facility complies with all federal and state statutes and rules.

2. An electrical corporation may blend or co-fire a fuel listed in subsection 2 of section 393.1020, with other fuels in the generation facility, but only the percentage of electricity that is attributable to a fuel listed in that section can be counted toward an electric corporation's renewable energy objectives.

393.1040. In addition to the renewable energy objectives set forth in sections 393.1025, 393.1030, and 393.1035, it is also the policy of this state to encourage electrical corporations to develop and administer energy efficiency initiatives that reduce the annual growth in energy consumption and the need to build additional electric generation capacity.

Appendix B SPP Transmission Expansion Plan Projects and Empire Construction Budget
****Highly Confidential in its Entirety****
Table B-1 Empire SPP Transmission Expansion Plan (STEP) Projects

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Table B-2
****Highly Confidential in its Entirety****

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Abbreviations

ACFB – Atmospheric Circulating Fluidized Bed
AEP – American Electric Power
AFUDC – Allowance for Funds Used During Construction
AWEA – American Wind Energy Association
Btu – British Thermal Unit
CAES – Compressed Air Energy Storage
CAIR – Clean Air Interstate Rule
CAMR – Clean Air Mercury Rule
CC – Combined Cycle
CFB – Circulating Fluidized Bed
CO_2 – Carbon dioxide
CT – Combustion Turbine
DOE – Department of Energy
EIA – Energy Information Administration
FERC – Federal Energy Regulatory Commission
GDP – Gross Domestic Product
GED – Global Energy Decisions
Hg - Mercury
IGCC – Integrated Gasification Combined Cycle
IRP – Integrated Resource Plan or integrated resource planning
KCP&L – Kansas City Power & Light
kV – kilovolt
kW – kilowatt
kWh – kilowatthour
MMBtu- Millions of British Thermal Units
MPSC – Missouri Public Service Commission
MW – Megawatt
MWh – Megawatthour
NO_x – Nitrous oxides
NRC – U.S. Nuclear Regulatory Commission
NYMEX – New York Mercantile Exchange
O&M – Operating and Maintenance
PPA – Power Purchase Agreement
PVRR – Present Value of Revenue Requirements
RMP – Risk Management Policy
SCR – Selective catalytic reduction
SO_2 – Sulfur dioxide
SPP – Southwest Power Pool
STEP – SPP Transmission Expansion Plan
WTI – West Texas Intermediate