NP

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

Volume V
Integrated Resource Analysis (4 CSR 240-22.060)
Risk Analysis and Strategy Selection (4 CSR 240-22.070)

September 2007

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ES. Executive Summary

ES.1 Objectives

Integrated resource planning for electric utilities has evolved considerably over the past twenty years and can no longer solely identify the least cost resources; such a plan must explicitly consider risks and uncertainties. Empire's objectives in preparing its 2007 IRP reflect its commitment to provide cost-effective, safe, and reliable electric service to its customers:

- to generate and provide reliable electricity service while complying with all environmental requirements
- to minimize rate impacts for customers
- to achieve and/or maintain investment grade ratings on its debt; thus providing for corporate financial stability and minimizing the financing costs included in the rates paid by Empire's customers
- to accommodate and manage cost, environmental, and load growth uncertainties.

ES.2 Base Plan Assumptions

Both DSM and supply-side resources were considered as available resources in this IRP. Empire chose not to eliminate from consideration any of the potential future DSM programs, conventional resources or renewable resources before they were modeled in the Capacity Expansion Model (CEM) of Global Energy Decisions (GED). However, no nuclear units were allowed as a resource choice in the base case. In addition, no scrubber was installed on Asbury Unit 1 in the base case.

A number of scenarios and contingency scenarios were examined in developing the preferred plan. Resource assumptions made for the base case (and which are common to all cases) include:

1) The Westar contract for 162 MW of purchased power from the Jeffrey coal units terminates in 2010, prior to the summer peak.
2) An ownership share of 50 MW in the coal-fired Plum Point generating unit and a 50 MW PPA (with the option to convert to ownership in 2015). Plum Point is assumed to begin operation in 2010, prior to the summer peak. Although the IRP assumes that the PPA is converted to ownership in 2015, the decision to convert has yet to be made.
3) A 100 MW ownership share in Iatan 2 which will begin operation in 2010, prior to the summer peak.
4) A PPA for 105 MW of wind from the Meridian Way Wind Farm, scheduled to begin operation in 2009.
5) **_____.**
6) Five percent of installed wind capacity counts towards the capacity reserve margin.

7) **_____
_____**

With these supply-side resource decisions and implementation of the slate of DSM programs, Empire's planning reserve margins appear to be satisfied until the **____** timeframe using the base load forecast in this IRP.

ES.3 Alternative Resource Plans

Although eleven plans were developed in addition to the base case, four of those plans were deemed to be contingency scenarios and the full stochastic analysis was not conducted for them. The primary scenarios are:

- High fuel, market, and wind prices (Plan 2)
- Low fuel and market prices (Plan 3)
- High load (Plan 4)
- Low load (Plan 5)
- **_____**
- Base assumptions, nuclear available after 2020 (Plan 11)
- Base assumptions, no coal units after 2010 (Plan 12)

The contingency scenarios are:

- Medium environmental costs (Plan 6)
- High environmental costs (Plan 7)
- No Riverton CC conversion (Plan 8)
- **_____**

The present value of revenue requirements (PVRR) for each of the primary scenarios are shown in Figure ES-1. These PVRRs are shown to be in a very narrow range.

Figure ES-1
****Highly Confidential in its Entirety****
Primary Scenarios – 20 Year Deterministic PVRR (2007 – 2026)

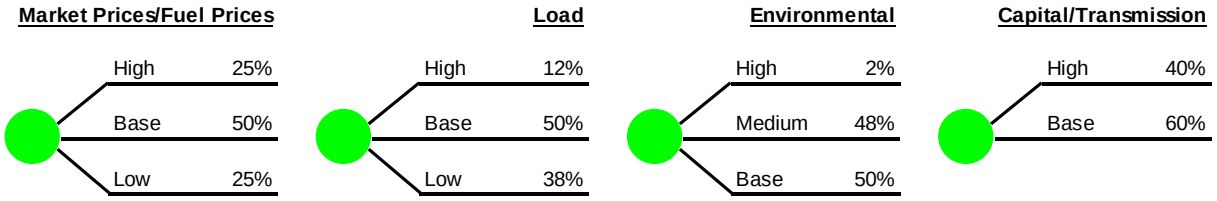
Source: GED

A specific alternative deterministic analysis was conducted to examine the timing for the installation of a potential scrubber at Asbury. The base case did not include any Asbury scrubber. Alternative cases included the Asbury scrubber installed in 2013 and the Asbury scrubber installed in 2018

ES.4 Uncertainty Analysis and Risk Profiles

Risk profiles were prepared in order to quantify the risks associated with the preferred plan and the alternate scenarios. These risk profiles are cumulative probability distributions of the present value of revenue requirements (PVRR) developed across a range of uncertainties that reflect the key uncertainties or risks associated with the future. The decision tree developed for the uncertainty analysis examined four uncertain variables for each of the eight primary plans. The uncertainties examined included: 1) market and fuel prices, 2) load forecast, 3) environmental costs, and 4) capital and transmission costs. For the market prices/fuel prices and load, the uncertainties reflect a high and low around a base. For capital and transmission costs, only a higher level was examined. For environmental costs, the base served as the lowest expected future and both medium and high environmental costs were examined. The decision tree is shown in Figure ES-2.

Figure ES-2
Decision Tree Uncertainties



(Source: GED)

The range of risks associated with each of the plans examined is seen to be fairly similar in Figure ES-3. The PVRRs for the scenarios with the risk values plotted in a different manner are provided on Figure ES-4. The risk values (the dotted areas) represent the difference between the expected value of the PVRRs in a deterministic simulation and the expected value of the PVRRs once all of the risks are considered through the uncertainty analysis. Figure ES-4 again demonstrates the similarity among all of the scenarios examined in terms of both expected value and risk profile.

Figure ES-3
Primary Scenarios – Risk Profiles (2007 – 2026)

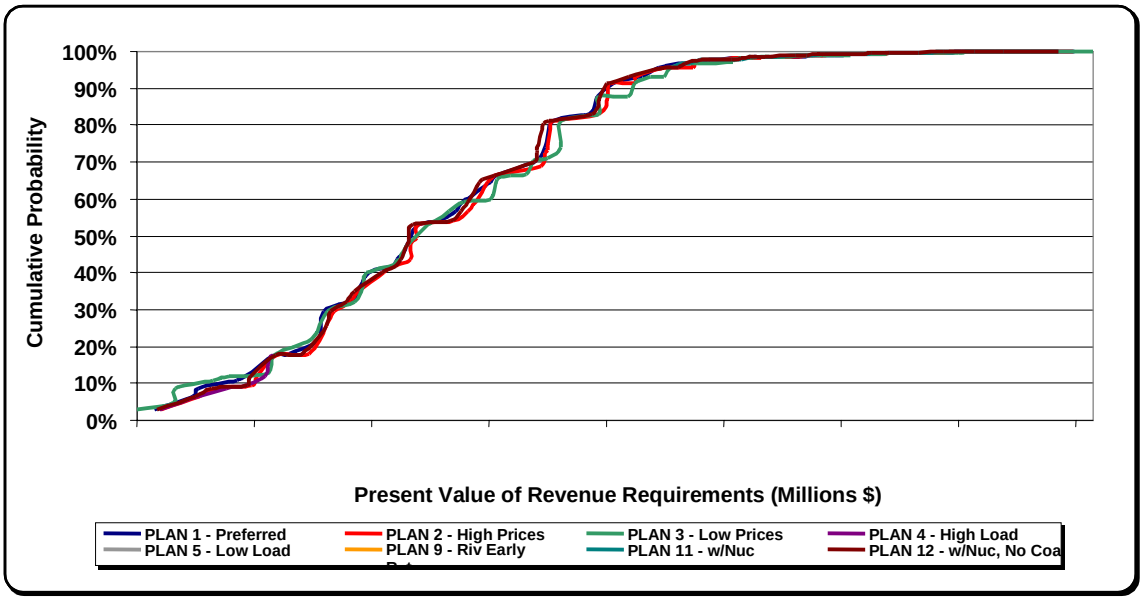


Figure ES-4
****Highly Confidential in its Entirety****
Primary Scenarios – PVRR With Risk Values (2007-2026)

PVRR With Risk Values (2007 – 2026)

ES.5 Preferred Plan

The examination of the scenarios as well as the contingency scenarios led to a set of DSM and supply-side resource additions over the planning horizon that constitute Empire's preferred plan. Figure ES-5 shows the supply-side additions in the preferred plan. Figure ES-6 shows the DSM programs selected in the preferred plan.

Table ES-1 details the supply-side and DSM resources that in total constitute the resources in the preferred plan. With the current assumptions for the cost of new nuclear units, it appears that ownership participation in a jointly-owned unit might be a cost effective alternative for Empire if capacity were available from such a unit. However, the plans associated with such a unit in the area have not advanced to such a point that it could be realistically considered by Empire in the preferred plan over the twenty-year planning horizon in this IRP.

The results of the IRP analysis documented in this report reflect only current and projected conditions as they are known today. Empire will reexamine its decisions for future system expansions as the need for additional resources, driven by load growth, and the influence of external factors, primarily environmental, become more evident. Specifically, the need for additional supply-side capacity around the **____** timeframe will be reexamined annually and in the next IRP, currently scheduled for filing in 2010, before a firm decision is made as to the exact timing and type of resource that might be added.

Figure ES-5
****Highly Confidential in its Entirety****
Preferred Plan Resource Additions (Excludes Committed Additions)

(Source: GED)

Figure ES-6
****Highly Confidential in its Entirety****

Preferred Plan – DSM Programs

Table ES-1
Empire's Preferred Plan – DSM and Supply-Side Resource Additions

Year	New Resources	Committed Resources in this IRP
2007		
2008	**_____**	
2009	**_____**	Meridian Way Wind Farm (105 MW)
2010		Iatan 2 (100 MW), Plum Point (100 MW)
2011		**_____**
2012		
2013		
2014	**_____**	
2015		
2016		
2017	**_____**	
2018	**_____**	
2019	**_____**	
2020	**_____**	
2021	**_____**	
2022	**_____**	
2023	**_____**	
2024	**_____**	
2025	**_____**	
2026	**_____**	
_____		

ES.6 Implementation Plan

Currently, construction is progressing on 200 MW (Empire's approximate share) of new jointly-owned coal-fired capacity (100 MW at Iatan 2 and 100 MW at Plum Point). Each of these units is scheduled to come on line in 2010. In addition, a power purchase agreement (PPA) has been signed for 105 MW of new wind energy (Meridian Way Wind Farm) scheduled to begin operation in 2009. **_____.**

The demand-side management (DSM) programs currently being implemented include:

- Low Income Efficiency Program
- Low Income – New Home Program
- Home Performance with ENERGY STAR® Program
- ENERGY STAR® Change a Light

- Residential High Efficiency Central Air Conditioning (CAC)
- ENERGY STAR® Homes
- Commercial and Industrial (C&I) Rebate
- Building Operator Certification Program.

Due to the filing requirements associated with an IRP in Missouri, Empire is scheduled to complete another IRP filing (in 2010 – based on a three-year cycle) prior to the initiation of substantive expenditures related to any uncommitted future capacity additions **_____ _____** contemplated in this IRP. As a result of its current resource commitments in conjunction with the analysis results from this IRP, Empire will:

- **_____ _____ _____**
- **_____ _____**
- Track and evaluate results of the implementation of DSM programs and keep the Customer Programs Collaborative (CPC) informed as to the results.[1]
- Monitor federal efforts with regard to imposition of a carbon tax.
- Monitor state and federal legislative and regulatory requirements for renewable portfolio standards.
- Monitor plans for future baseload generation in the region.

ES.7 Resource Acquisition Strategy

The preferred plan and the implementation plan have been accepted and reviewed by Empire's senior management and constitute its Resource Acquisition Strategy. **_____ _____** all actions contemplated in this IRP for new supply-side resources will occur after the time at which Empire's next IRP is due for filing (2010). Empire will implement DSM programs after approval by the CPC within the window between the 2007 IRP filing and the 2010 IRP filing. Otherwise, no major resource decisions will be made until after the 2010 IRP is filed.

The critical uncertain factor is the potential enactment of a carbon tax or carbon cap and trade legislation by the U.S. Congress. Empire personnel and senior management are staying informed of these developments through review of trade press and other normal communication channels.

[1] The Customer Programs Collaborative was established as a result of a stipulation and agreement and, in addition to Empire personnel, is comprised of Missouri Public Service Commission staff, Office of Public Counsel, Missouri Department of Natural Resources, and other interested parties. The CPC is charged with making decisions pertaining to the development, implementation, monitoring, and evaluation of Empire's affordability, energy efficiency, and demand response programs.

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 5,330,214 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%.

1.2 Objectives

Integrated resource planning for electric utilities has evolved considerably over the past twenty years and can no longer solely identify the least cost resources; such a plan must explicitly consider risks and uncertainties. Empire's objectives in preparing its 2007 IRP reflect its commitment to provide cost-effective, safe, and reliable electric service to its customers:

- to generate and provide reliable electricity service while complying with all environmental requirements
- to minimize rate impacts for customers
- to achieve and/or maintain investment grade ratings on its debt; thus providing for corporate financial stability and minimizing the financing costs included in the rates paid by Empire's customers
- to accommodate and manage cost, environmental, and load growth uncertainties.

1.3 Regulatory Requirements

4 CSR 240-22.060 Integrated Resource Analysis

PURPOSE: This rule requires the utility to design alternative resource plans to meet the planning objectives identified in 4 CSR 240-22.010(2) and sets minimum standards for

the scope and level of detail required in resource plan analysis, and for the logically consistent and economically equivalent analysis of alternative resource plans.

(1) Resource Planning Objectives. The utility shall design alternative resource plans to satisfy at least the objectives and priorities identified in 4 CSR 240-22.010(2). The utility may identify additional planning objectives that alternative resource plans will be designed to serve.

(2) Specification of Performance Measures. The utility shall specify a set of quantitative measures for assessing the performance of alternative resource plans with respect to identified planning objectives. These measures shall include at least the following: present worth of utility revenue requirements, present worth of probable environmental costs, present worth of out-of-pocket costs to participants in demand-side programs, levelized annual average rates and maximum single-year increase in annual average rates. All present worth and levelization calculations shall use the utility discount rate and all costs and benefits shall be expressed in nominal dollars. Utility decision-makers may also specify other measures that they believe are appropriate for assessing the performance of resource plans relative to the planning objectives identified in 4 CSR 240-22.010(2).

(3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of candidate demand-side and supply-side resources to develop a set of alternative resource plans, each of which is designed to achieve one (1) or more of the planning objectives identified in 4 CSR 240-22.010(2). The alternative resource plans developed at this stage of the analysis shall not include load-building programs, which shall be analyzed as required by section (5) of this rule.

(4) Analysis of Alternative Resource Plans. The utility shall assess the relative performance of the alternative resource plans by calculating for each plan the value of each performance measure specified pursuant to section (2). This calculation shall assume values for uncertain factors that are judged by utility decision-makers to be most likely. The analysis shall cover a planning horizon of at least twenty (20) years and shall be carried out with computer models that are capable of simulating the total operation of the system on a year-by-year basis in order to assess the cumulative impacts of alternative resource plans. These models shall be sufficiently detailed to accomplish the following tasks and objectives:

(A) The financial impact of alternative resource plans shall be modeled in sufficient detail to provide comparative estimates of at least the following measures of the utility's financial condition for each year of the planning horizon: pretax interest coverage, ratio of total debt to total capital and ratio of net cash flow to capital expenditures;

(B) The modeling procedure shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law. This provision does not imply any requirement for the utility to file actual rate cases or for the commission to accord any particular ratemaking treatment to actual costs incurred by the utility;

(C) The modeling procedure shall include a method to ensure that the impact of changes in electric rates on future levels of demand for electric service is accounted for in the analysis; and

(D) The modeling procedure shall treat supply-side and demand-side resources on a logically consistent and economically equivalent basis. This means that the same types or categories of costs, benefits and risks shall be considered, and that these factors shall be quantified at a similar level of detail and precision for all resource types.

(5) Analysis of Load-Building Programs. If the utility intends to continue existing load-building programs or implement new ones, it shall analyze these programs in the context of one (1) or more of the alternative plans developed pursuant to section (3) of this rule, including the preferred resource plan selected pursuant to 4 CSR 240-22.070(6). This analysis shall use the same modeling procedure and assumptions described in section (4) and shall include the following elements:

(A) Estimation of the impact of load-building programs on the electric utility's summer and winter peak demands and energy usage;

(B) A comparison of annual average rates in each year of the planning horizon for the resource plan with and without the load-building program;

(C) A comparison of the probable environmental costs of the resource plan in each year of the planning horizon with and without the proposed load-building program; and

(D) An assessment of any other aspects of the proposed load-building programs that affect the public interest.

(6) 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 prepare a report that contains at least the following information:

(A) A description of each alternative resource plan including the type and size of each resource addition and a listing of the sequence and schedule for retiring existing resources and acquiring each new resource addition;

(B) A summary tabulation that shows the performance of each alternative resource plan as measured by each of the measures specified in section (2) of this rule;

(C) For each alternative resource plan, a plot of each of the following over the planning horizon:

1. The combined impact of all demand-side resources on the base-case forecast of summer and winter peak demands;
2. The composition, by program, of the capacity provided by demand-side resources;
3. The composition, by supply resource, of the capacity (including reserve margin) provided by supply resources. Existing supply-side resources may be shown as a single resource;
4. The combined impact of all demand-side resources on the base-case forecast of annual energy requirements;
5. The composition, by program, of the annual energy provided by demand-side resources;
6. The composition, by supply resource, of the annual energy (including losses) provided by supply resources. Existing supply-side resources may be shown as a single resource;
7. The values of the three (3) measures of financial condition identified in subsection (4)(A);

8. Annual average rates;
9. Annual emissions of each environmental pollutant identified pursuant to 4 CSR 240-22.040(2)(B)1; and
10. Annual probable environmental costs.

(D) A discussion of how the impacts of rate changes on future electric loads were modeled and how the appropriate estimates of price elasticity were obtained;

(E) A description of the computer models used in the analysis of alternative resource plans; and

(F) A description of any proposed load-building programs, a discussion of why these programs are judged to be in the public interest and, for all resource plans that include these programs, plots of the following over the planning horizon:
1. Annual average rates with and without the load-building programs; and
2. Annual utility costs and probable environmental costs with and without the load-building programs.

Table 1
Summary of Compliance with Reporting Requirements for IRP Rule for Integrated Resource Analysis (4 CSR 240-22.060 (6))

Rule	Description	Location in Report
22.060 (6) (A)	Each alternative resource plan	Table 12, Table 13, Appendix B
22.060 (6) (B)	Summary tabulation	Table 15, Figures 2-8
22.060 (6) (C)	Plots required	Appendix B, C, D, E, Figure 18
22.060 (6) (D)	Impact of rate changes on future loads	See Volume II. Empire used economic drivers to forecast its future peak and energy demand.
22.060 (6) (E)	Description of computer models	Appendix A
22.060 (6) (F)	Load-building program description	None planned

4 CSR 240-22.070 Risk Analysis and Strategy Selection

PURPOSE: This rule requires the utility to identify the critical uncertain factors that affect the performance of resource plans, establishes minimum standards for the methods used to assess the risks associated with these uncertainties and requires the utility to specify and officially adopt a resource acquisition strategy.

(1) The utility shall use the methods of formal decision analysis to assess the impacts of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240- 22.060(3), to analyze the risks associated with alternative resource plans, to quantify the value of better information concerning the critical uncertain factors and to explicitly state and document the subjective probabilities that utility decision-makers assign to each of these uncertain factors. This assessment shall include a decision-tree representation of the key decisions and uncertainties associated with each alternative resource plan.

(2) Before developing a detailed decision-tree representation of each resource plan, the utility shall conduct a preliminary sensitivity analysis to identify the uncertain factors that are critical to the performance of the resource plan. This analysis shall assess at least the following uncertain factors:
  (A) The range of future load growth represented by the low-case and high-case load forecasts;
  (B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital;
  (C) Future changes in environmental laws, regulations or standards;
  (D) Relative real fuel prices;
  (E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities;
  (F) Construction costs and schedules for new generation and transmission facilities;
  (G) Purchased power availability, terms and cost;
  (H) Sulfur dioxide emission allowance prices;
  (I) Fixed operation and maintenance costs for existing generation facilities;
  (J) Equivalent or full- and partial-forced outage rates for new and existing generation facilities;
  (K) Future load impacts of demand-side programs; and
  (L) Utility marketing and delivery costs for demand-side programs.

(3) For each alternative resource plan, the utility shall construct a decision-tree diagram that appropriately represents the key resource decisions and critical uncertain factors that affect the performance of the resource plan.

(4) The decision-tree diagram for all alternative resource plans shall include at least two (2) chance nodes for load growth uncertainty over consecutive subintervals of the planning horizon. The first of these subintervals shall be not more than ten (10) years long.

(5) The utility shall use the decision-tree formulation to compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2), contingent upon the identified uncertain factors and associated subjective probabilities assigned by utility decision makers pursuant to section (1) of this rule. Both the expected performance and the risks of each alternative resource plan shall be quantified.
  (A) The expected performance of each resource plan shall be measured by the statistical expectation of the value of each performance measure.
  (B) The risk associated with each resource plan shall be characterized by some measure of the dispersion of the probability distribution for each performance measure, such as the standard deviation or the values associated with specified percentiles of the distribution.

(6) The utility shall select a preferred resource plan from among the alternative plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060 and sections (1)–(5) of this rule. The preferred resource plan shall satisfy at least the following conditions:
  (A) In the judgment of utility decision makers, the preferred plan shall strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2); and

(B) The trend of expected unserved hours for the preferred resource plan must not indicate a consistent increase in the need for emergency imported power over the planning horizon.

(7) The impact of the preferred resource plan on future requirements for emergency imported power shall be explicitly modeled and quantified. The requirement for emergency imported power shall be measured by expected unserved hours under normal-weather load conditions.

(A) The daily normal-weather series used to develop normal-weather loads shall contain a representative amount of day-to-day temperature variation. Both the high and low extreme values of daily normal-weather variables shall be consistent with the historical average of annual extreme temperatures.

(B) The supply-system simulation software used to calculate expected unserved hours shall be capable of accurately representing at least the following aspects of system operations:

1. Chronological dispatch, including unit commitment decisions that are consistent with the operational characteristics and constraints of all system resources;
2. Heat rates, fuel costs, variable operation and maintenance costs, and sulfur dioxide emission allowance costs for each generating unit;
3. Scheduled maintenance outages for each generating unit;
4. Partial- and full-forced-outage rates for each generating unit; and
5. Capacity and energy purchases and sales, including the full spectrum of possibilities, from long-term firm contracts or unit participation agreements to hourly economy transactions.
    A. The utility shall maintain the capability to model purchases and sales of energy both with and without the inclusion of sulfur dioxide emission allowances.
    B. The level of energy sales and purchases shall be consistent with forecasts of the utility's own production costs as compared to the forecasted production costs of other likely participants in the bulk power market; and

(C) The utility may use an alternative method of calculating expected unserved hours per year if it can demonstrate that the alternative method produces results that are equivalent to those obtained by a method that meets the requirements of subsection (7)(B).

(8) The utility shall quantify the expected value of better information concerning at least the critical uncertain factors that affect the performance of the preferred resource plan, as measured by the present value of utility revenue requirements.

(9) The utility shall develop an implementation plan that specifies the major tasks and schedules necessary to implement the preferred resource plan over the implementation period. The implementation plan shall contain:

(A) A schedule and description of ongoing and planned research activities to update and improve the quality of data used in load analysis and forecasting;

(B) A schedule and description of ongoing and planned demand-side programs, program evaluations and research activities;

(C) A schedule and description of all supply-side resource acquisition and construction activities; and

(D) Identification of critical paths and major milestones for each resource acquisition project, including decision points for committing to major expenditures.

(10) The utility shall develop, document and officially adopt a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by the board of directors, a committee of senior management, an officer of the company or other responsible party who has been duly delegated the authority to commit the utility to the course of action described in the resource acquisition strategy. The officially adopted resource acquisition strategy shall consist of the following components:

(A) A preferred resource plan selected pursuant to the requirements of section (6) of this rule;

(B) An implementation plan developed pursuant to the requirements of section (9) of this rule;

(C) A specification of the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the preferred resource plan is judged to be appropriate and an explanation of how these limits were determined;

(D) A set of contingency options that are judged to be appropriate responses to extreme outcomes of the critical uncertain factors and an explanation of why these options are judged to be appropriate responses to the specified outcomes; and

(E) A process for monitoring the critical uncertain factors on a continuous basis and reporting significant changes in a timely fashion to those managers or officers who have the authority to direct the implementation of contingency options when the specified limits for uncertain factors are exceeded.

(11) 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 decision-tree diagram for each of the alternative resource plans along with narrative discussions of the following aspects of the decision analysis:

1. A discussion of the sequence and timing of the decisions represented by decision nodes in the decision tree and a description of the specific decision alternatives considered at each decision point; and
2. An explanation of how the critical uncertain factors were identified, how the ranges of potential outcomes for each uncertain factor were determined and how the subjective probabilities for each outcome were derived;

(B) Plots of the cumulative probability distribution of each performance measure for each alternative resource plan;

(C) For each performance measure, a table that shows the expected value and the risk of each resource plan;

(D) A plot of the expected level of annual unserved hours for the preferred resource plan over the planning horizon;

(E) A discussion of the analysis of the value of better information required by section (8), a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities;

(F) A discussion of the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale

used by utility decision-makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk; and

(G) The fully documented resource acquisition strategy that has been developed and officially adopted pursuant to the requirements of section (10) of this rule.

Table 2
Summary of Compliance with Reporting Requirements for IRP Rule for Risk Analysis and Strategy Selection (4 CSR 240-22.070 (11))

Rule	Description	Location in Report
22.070 (11) (A)	Decision –tree diagram	Figure 11, Section 3.1
22.070 (11) (B)	Cumulative probability distribution plots	Figures 14-21
22.070 (11) (C)	Table of expected value and risk	Table 15
22.070 (11) (D)	Annual unserved hours	Figure 45
22.070 (11) (E)	Value of better information	Section 3.3
22.070 (11) (F)	Process to develop preferred plan	Section 4.0
22.070 (11) (G)	Fully documented resource acquisition strategy	Section 6.0

2.0 Alternative Resource Plans

Empire undertook detailed analysis in the performance of this integrated resource plan. A total of 12 alternative resource plans were developed. Detailed risk analysis was undertaken for eight of the twelve plans developed. Analysis began with a base case. The assumptions for the various plans and the results for those plans are described in this section of the IRP report.

2.1 Base Plan Assumptions

Resource assumptions made for the base plan (also referred to as Plan 1) and which are common to all cases include:

1) The Riverton 12 combustion turbine enters commercial operation in 2007.
2) The Westar contract for 162 MW of purchased power from the Jeffrey coal units terminates in 2010, prior to the summer peak.
3) An ownership share of 50 MW in the coal-fired Plum Point generating unit and a 50 MW PPA (with the option to convert to ownership in 2015). Plum Point is assumed to begin operation in 2010, prior to the summer peak. Although the IRP assumes that the PPA is converted to ownership in 2015, the decision to convert has yet to be made.
4) A 100 MW ownership share in Iatan 2 which will begin operation in 2010, prior to the summer peak.
5) **_____ _____**105 MW Meridian Way Wind Farm which begins operation in 2009.
6) Five percent of installed wind capacity counts towards the capacity reserve margin.
7) **_____ _____**
8) Asbury 2 is assumed to be in operation throughout the study period at its current rating of 17 MW. **_____ _____ _____**
9) A selective catalytic reduction (SCR) system is installed at Asbury in 2007. A baghouse is installed in 2010. No scrubber is installed at Asbury.
10) A scrubber and SCR are installed at Iatan 1 in 2008.

An additional assumption for the base plan is that the purchase power price for a new generic wind energy resource is $45/MWh (2006 $), escalated at 3%.

Empire assumed that for each 100 MW of wind energy installed, for operational stability a 50 MW combustion turbine needs to be added as well.

Both demand-side management (DSM) and supply-side resources were considered as available resources in this IRP. Empire chose not to eliminate from consideration any of

the potential future DSM programs, viable conventional resources or renewable resources before they were modeled in the Capacity Expansion Model (CEM) of Global Energy Decisions (GED). A number of scenarios and contingency scenarios were examined in developing the preferred plan.

The demand-side options available for selection during the optimization modeling for all scenarios were:

- Low Income Efficiency
- Low Income New Homes
- Home Performance with ENERGY STAR®
- ENERGY STAR® Change A Light
- Residential High Efficiency CAC Program
- ENERGY STAR® Homes
- C&I Rebate
- Building Operator Certification Program
- C&I Peak Load Reduction Program
- Air Conditioning Cycling Program

The conventional and renewable supply-side resources available for selection during the optimization modeling were:

- Pulverized Coal
- Combustion Turbine (CT)
- Combined Cycle (CC)
- Riverton 12 conversion to CC (Riv CC)
- Nuclear
- Distributed Generation (DG)
- Integrated Gasification Combined Cycle (IGCC)
- Atmospheric Circulating Fluidized Bed (ACFB)
- Wind
- Biomass

2.2 Alternative Resource Plans Examined

The alternative resource plan scenarios examined were:

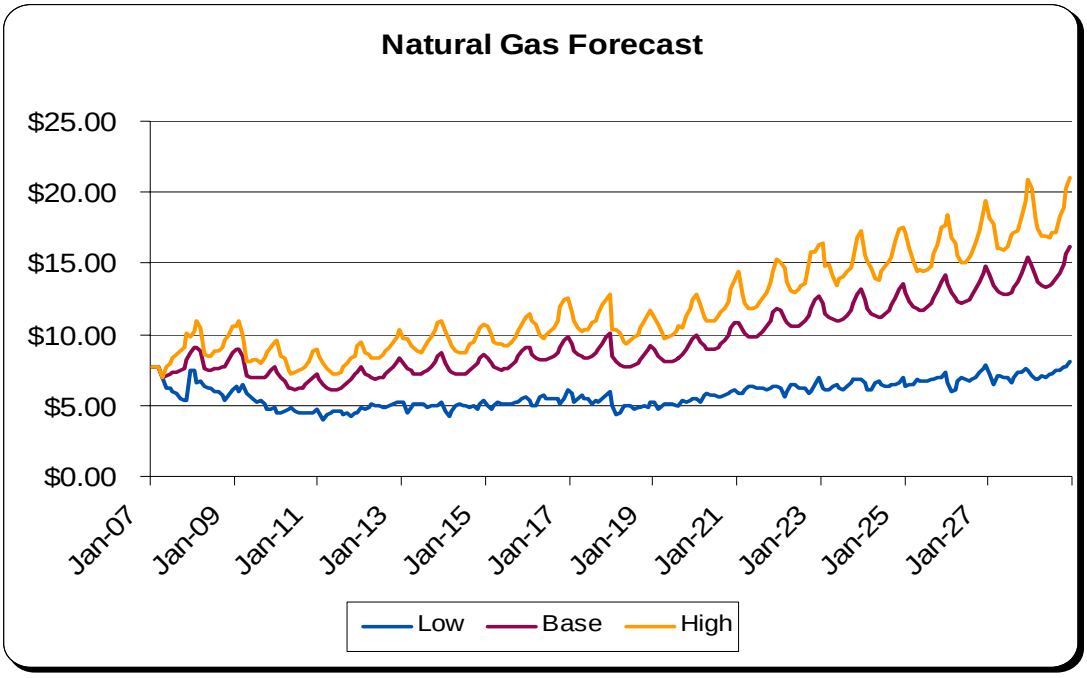
Plan 1 – Base Plan
Plan 2 – High Fuel, Market and Wind Price Scenario
Plan 3 – Low Fuel and Market Price Scenario
Plan 4 – High Load Scenario
Plan 5 – Low Load Scenario
Plan 6 – Medium Environmental Scenario
Plan 7 – High Environmental Scenario
Plan 8 – No Riverton CC Scenario

** _____ **
** _____ **
Plan 11 – Base Scenario with Nuclear Option
Plan 12 – Base Scenario with Nuclear Option and No Coal Option

2.2.1 High Fuel, Market and Wind Price Scenario – Plan 2

Higher natural gas, market, and wind energy prices were assumed for this scenario and correlated with higher coal and oil prices. Wind was assumed to experience a $25/MWh price increase in 2015. The wind resource energy price continued to escalate at 3% from 2016 through the end of the study period. The natural gas price levels which drive the base, low, and high fuel price scenarios are shown in Figure 1.

Figure 1



Source: GED

2.2.2 Low Fuel and Market Price Scenario – Plan 3

Lower natural gas and market prices were assumed for this scenario and correlated with lower coal and oil prices. The natural gas price levels which drive the base, low, and high fuel price scenarios are shown in Figure 1.

2.2.3 High Load Scenario – Plan 4

The high load scenario used the high load forecast developed and described in Volume II. Table 3 shows the annual peak demands for each of the base, low and high load growth forecasts. Table 4 shows the annual energy consumption for each of the base, low and high load forecasts.

Table 3
****Highly Confidential in its Entirety****
Peak Demand Forecast Comparison

Table 4
****Highly Confidential in its Entirety****
Annual Energy Forecast Comparison

2.2.4 Low Load Scenario – Plan 5

The low load scenario used the low load forecast developed and described in Volume II. Table 3 shows the annual peak demands for each of the base, low and high load growth forecasts. Table 4 shows the annual energy consumption for each of the base, low and high load forecasts.

2.2.5 Medium Environmental Scenario – Plan 6

The medium environmental scenario used the medium environmental assumption costs. For this scenario, 100 MW of CT capacity was required for operational stability for each 100 MW of wind energy added. Table 5 shows the carbon dioxide (CO_2) tax assumptions for each of the base, medium and high environmental scenarios.

Table 5
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 sulfur dioxide (SO_2), nitrous oxides (NO_x) and mercury emission allowances prices were correlated with the CO_2 prices. In addition, natural gas, oil, and coal prices were changed to reflect the differing market conditions. Tables 6-11 show the projected prices for these variables for each of the environmental scenarios.

Table 6
****Highly Confidential in its Entirety****
Projected Coal Prices – Carbon Scenarios ($/MMBtu)

Source: GED

Table 7
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 8
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 9
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 10
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 11
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

2.2.6 High Environmental Scenario – Plan 7

The high environmental scenario used the high environmental assumption costs. For this scenario, 100 MW of CT capacity was required for operational stability for each 100 MW of wind energy added. Table 5 shows the CO_2 tax assumptions for each of the base, medium and high environmental scenarios. For the medium and high CO_2 scenarios, changes in SO_2, NO_x and mercury emission allowances prices were correlated with the CO_2 prices. In addition, natural gas, oil, and coal prices were changed to reflect the differing market conditions. Tables 6-11 show the projected prices for these variables for each of the environmental scenarios.

2.2.7 No Riverton CC Scenario – Plan 8

Although it appears that converting the Riverton 12 CT to a combined cycle unit might be a desirable supply-side option for Empire to consider in the future, water constraints at the Riverton plant site may preclude this option. This alternative plan optimized future resources assuming that the combined cycle conversion was not a capacity expansion option.

****_____****

**_____
_____
_____**

****_____****

**_____
_____
_____
_____**

2.2.10 Base Scenario with Nuclear Option – Plan 11

In response to concerns about global climate change, it is possible that one or more of Empire's neighboring utilities might decide to proceed with the licensing and

construction of a nuclear unit. In this alternative resource plan, one capacity expansion option was Empire's participation as a joint owner in a small slice of a larger nuclear unit being built in the region.

2.2.11 Base Scenario with Nuclear Option and No Coal Option – Plan 12

In this alternative resource plan, one capacity expansion option was Empire's participation as a joint owner in a small slice of a larger nuclear unit being built in the region. In addition, coal was no longer considered as a future capacity expansion option in the optimization.

2.3 Alternative Resource Plan Results

The demand-side and supply-side resources selected in each of the alternative plans are shown in Tables 12 and 13. The sizes (MW) of the DSM resources from Plan 1 are shown in Table 14. Capacity and resource balances for all alternative plans are shown in Appendix B. The tables in Appendix B show the DSM resources (in MW) added in each alternative resource plan in each year as well as the supply-side resources added in each alternative plan in each year. The capacity margin achieved in each year is also shown for each alternative plan.

Table 12
****Highly Confidential in its Entirety****
Demand-Side Resources Selected in Alternative Resource Plans

Table 13
****Highly Confidential in its Entirety****
Supply-Side Resources Selected in Alternative Resource Plans

Table 14
****Highly Confidential in its Entirety****
New DSM Resources (Excludes DSM Currently Being Implemented) – Plan 1 (MW)

Of the twelve scenarios examined, four (plans 6, 7, 8, and 10) were deemed to be contingency scenarios and thus were not examined further in the risk analysis. The present value of revenue requirements (PVRR) for the eight primary scenarios are presented on Figure 2. PVRR is the primary financial performance measure considered.

Figure 2
****Highly Confidential in its Entirety****
Primary Scenarios – 20 Year Deterministic PVRR (2007 – 2026)

Source: GED

Other measures of how the primary scenarios compare are presented in Figures 3-9. These include the annual rate increases (Figure 3), the amount of plant in service in the rate base (Figure 4), the annual capacity margin (Figure 5), pre-tax interest coverage (Figure 6), the ratio of total debt to total capital (Figure 7), the ratio of net cash flow to capital expenditures (Figure 8), and the average system rates (Figure 9).

Figure 3
****Highly Confidential in its Entirety****
Primary Scenarios – Annual Rate Increases

Source: GED

Figure 4
****Highly Confidential in its Entirety****
Primary Scenarios – Plant in Service

Source: GED

Figure 5
****Highly Confidential in its Entirety****
Primary Scenarios – Capacity Margin

Source: GED

Figure 6
****Highly Confidential in its Entirety****
Primary Scenarios – PreTax Interest Coverage

Source: GED

Figure 7
****Highly Confidential in its Entirety****
Primary Scenarios – Ratio of Total Debt to Total Capital

Source: GED

Figure 8
****Highly Confidential in its Entirety****
Primary Scenarios – Ratio of Net Cash Flow to Capital Expenditures

Source: GED

Figure 9
****Highly Confidential in its Entirety****
Primary Scenarios – Average System Rates

Source: GED

2.4 Asbury Scrubber Study

In addition to the examination of the appropriate slate of demand-side and supply-side resources that would be part of the preferred plan over the planning horizon, an analysis was performed examining the effects of installing a scrubber on the Asbury plant and the timing associated with any such installation. Three different cases were analyzed: 1) no Asbury scrubber, 2) Asbury scrubber in 2013 and 3) Asbury scrubber in 2018. The key parameters modeled were: base plan assumptions for SO_2 allowances costs and capacity additions, 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. **_____**

Figure 10
****Highly Confidential in its Entirety****
Asbury Scrubber Study

Source: GED

3.0 Risk Analysis

Although many uncertainties face today's electric utility executive, perhaps none is as challenging as global climate change. With the April 2, 2007 U.S. Supreme Court ruling that the Environmental Protection Agency (EPA) can regulate carbon dioxide (CO_2) emissions, global climate change legislation introduced in Congress, and public sentiment showing support for reducing emissions of CO_2 (as long as no individual changes in life style are required and forgetting that more than half of the electricity in the U.S. is produced by coal-fired power plants), future resource decisions face as much or more uncertainty as they have in the past thirty years.

Neither the date of the implementation of any CO_2 limitation nor the form of such legislation (cap and trade or a tax) is known. If a cap and trade system were to be implemented, it is not clear who would get the allowances in market power transactions. And, although electric utilities are a significant contributor to CO_2 emissions, industrial combustion, gasoline, diesel, and jet fuel would need to be regulated as well.[2] Commercially practical and cost-effective carbon capture and carbon sequestration technology does not yet exist. Integrated gasification combined cycle (IGCC) units are not yet deemed to be commercial or economically viable.

Nuclear units do not emit CO_2, but even those new nuclear units currently actively under consideration in parts of the country are not expected to be on line any earlier than 2015. Although one of Empire's neighboring utilities may actively be considering building a nuclear unit, Empire may or may not have opportunities to participate as a joint owner and such may not happen at all over the planning horizon. Concern about global climate change is one of the primary drivers for the implementation of state Renewable Portfolio Standards (RPS) requiring a certain amount of energy to be provided by sources of renewable energy by a date certain. As yet, the U.S. Congress has not coalesced around the idea of a national RPS. Missouri enacted a voluntary RPS in 2007.

Separately, the extreme volatility of natural gas prices over the past three years also contributes to the levels of uncertainty in resource decision making.

3.1 Decision Tree Analysis

Against this backdrop, Empire needed to make choices about the primary types of uncertainty to analyze in this IRP after consideration of its situation, industry best practices, and the key factors that impact its operation.

[2] "Industries Show Uncertainty Over Ruling's Impact," by Jeffrey Ball and Mike Spector, *The Wall Street Journal*, April 3, 2007, p. A10.

The four key uncertainties selected were:

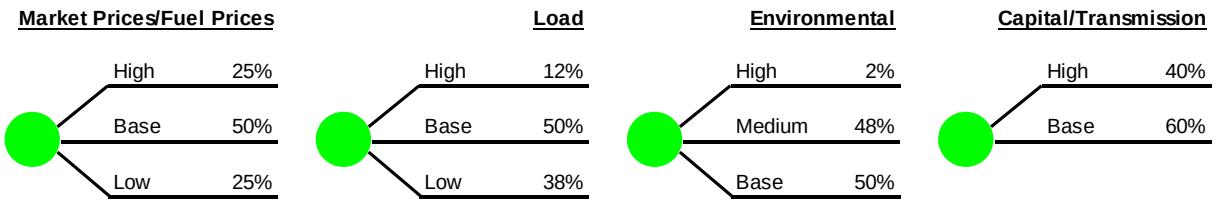
- Market and natural gas prices
- Load forecast
- Environmental costs
- Capital and transmission costs

For this study, GED and Empire used decision analysis techniques to create a decision tree around these four uncertain variables. The analysis was conducted on the eight primary scenarios (all but plans 6, 7, 8, and 10). There are a total of 54 combinations per plan, also known as endpoints, as can be seen on Figure 11. Adding more uncertainties significantly impacts the run time of the model and the costs of completion of this IRP.

3.1.1 Market and Natural Gas Prices

Market prices correlated with the high and low natural gas price forecasts were developed specifically for Empire's market area in the Southwest Power Pool (SPP). Multipliers were used to change coal and oil prices to correspond with the natural gas prices. Probabilities were assigned to each potential future as shown on the decision tree in Figure 11: low market and natural gas prices (25%), base market and natural gas prices (50%), and high market and natural gas prices (25%).

Figure 11
Decision Tree Uncertainties



Source: GED

3.1.2 Load Forecast

Three levels of load forecasts were supplied – high, base, low as shown previously on Tables 3 and 4. Analysis of 34 years of historical data showed customer growth rates of less than 1.8% occurred about 38% of the time, growth in the range of 1.9 to 2.2% occurred 50% of the time, and growth was greater than 2.2% about 12% of the time. These probabilities of occurrence were assigned to the low (38%), base (50%) and high (12%) load forecasts as shown on Figure 11.[3]

[3] Empire's 2006 10-K states: "We expect our annual electric customer growth to range from approximately 1.6% to 1.9% over the next several years, although our electric customer growth for the twelve months ended December 31, 2006 was 2.1%. . . The primary drivers of electric sales growth are customer growth and general economic conditions.

3.1.3 Environmental Costs

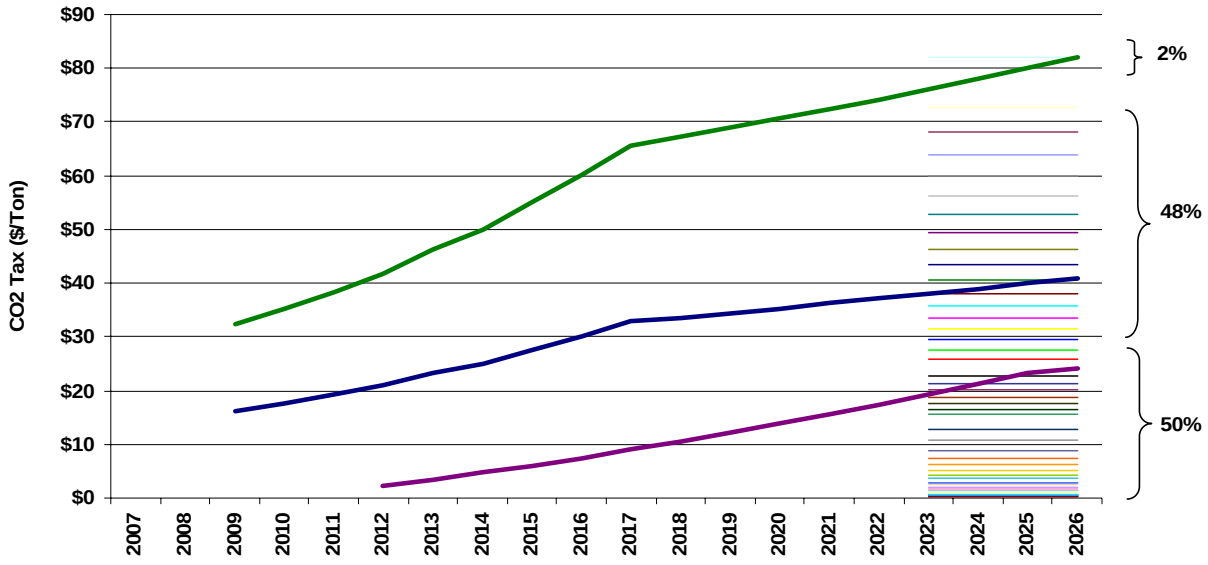
Emissions costs for CO_2, SO_2, and NO_x were developed using the scenarios described earlier for the development of the alternative resource plans and fuel prices were developed that correlated with these emission costs (Tables 5-11). Two alternative cases to the base case were developed: medium and high. Probabilities for the cases are expected to be base 50%, medium 48%, and high 2%. No lower environmental cost case was developed or considered to be probable.

To develop the probabilities for the CO_2 tax cases, GED utilized the 50 stratified Monte Carlo draws developed in Figure 8 and then chose high, medium, and base cases. The three cases are represented as follows:

- High – CO_2 tax level which changes dispatch merit order (i.e., gas displaces coal)
- Medium – Cap and Trade case where CO_2 markets are tempered by the ability to trade CO_2 credits globally
- Base – Represents Global Energy's Spring 2007 Reference case

The intersection of the three cases on Figure 12 was used to develop the probabilities.

Figure 12
CO_2 Tax Cases - Probabilities



Source: Global Energy

3.1.4 Capital and Transmission Costs

Capital and transmission cost uncertainty was conducted for high and base probabilities as shown on Figure 11. No scenarios were examined in which capital and transmission costs were expected to be lower than the base case. Capital and transmission costs for all expansion units were 1.5 times higher in the high case than in the base case except for the

nuclear units which were two times higher. The high case was estimated to have a 40% chance of occurring; the base case 60%. These probability values are subjective based on knowledge of the industry.

3.2 Risk Analysis Results

The Strategic Planning Risk Module was used by GED to develop cumulative probability distributions which are also known as "Risk Profiles". Risk profiles provide the ability to visually assess the risks associated with a decision under uncertainty. The risk profile can be viewed to determine the probability that the PVRR will be any particular value. Figure 13 shows that all of the plans evaluated in this IRP have a very similar risk profile.

Figure 13
****Highly Confidential in its Entirety****
Primary Scenarios – Risk Profiles (2007 – 2026)

Source: GED

Using Plan 1 from Figure 14, there is an 80% probability that PVRR could be as much as **_____** with an expected value ("Probable Utility Cost") of **_____ _____.** From the deterministic simulation, the PVRR value is **_____ _____**(Direct Utility Cost) under "base case" conditions. The **_____** difference between the expected value and the deterministic value is "real option value" or "extrinsic value". This reflects the risk of Plan 1 to future uncertainty.

Figure 14
****Highly Confidential in its Entirety****
Plan 1 – Base – Risk Profile (2007 – 2026)

Source: GED

Figures 15 through 21 present the risk profiles for the other primary scenarios.

Figure 15
****Highly Confidential in its Entirety****
Plan 2 – High Prices – Risk Profile (2007 – 2026)

Source: GED

Figure 16
****Highly Confidential in its Entirety****
Plan 3 – Low Prices – Risk Profile (2007 – 2026)

Source: GED

Figure 17
****Highly Confidential in its Entirety****
Plan 4 – High Load – Risk Profile (2007 – 2026)

Source: Global Energy

Figure 18
Highly Confidential in its Entirety**
Plan 5 – Low Load – Risk Profile (2007 – 2026)

Source: GED

Figure 19
****Highly Confidential in its Entirety****
Plan 9 – Riverton 7&8 Early Retirement – Risk Profile (2007 – 2026)

Source: GED

Figure 20
****Highly Confidential in its Entirety****
Plan 11 – With Nuclear – Risk Profile (2007 – 2026)

Source: GED

Figure 21
****Highly Confidential in its Entirety****
Plan 12 – With Nuclear, No Coal – Risk Profile (2007 – 2026)

Source: GED

Figure 22 shows the information from the risk profiles in a different format. The deterministic value (Direct Utility Costs) is shown as the solid bar on this figure. The

difference between the expected value and the deterministic value, the risk value, is shown in the dotted area on top of each plan's bar. Again, note that the risk profiles for all of the scenarios examined in this IRP are quite similar as are the expected values and deterministic values. The values shown graphically in Figure 22 are shown in Table 15.

Figure 22
****Highly Confidential in its Entirety****
Primary Scenarios – PVRR with Risk Value (2007-2026)

Table 15
****Highly Confidential in its Entirety****
Primary Scenarios – PVRR With Risk Values (2007-2026) ($ millions)

3.3 Expected Value of Better Information

If Empire had the opportunity to conduct a research study that would evaluate each of the four critical uncertainties evaluated as part of the risk analysis, such a study could help by improving the probability assessments that were assigned to each of these outcomes. However, if the cost of obtaining the research information exceeds its value, Empire should not conduct the study.

To determine the maximum possible value that Empire could pay for better information, it was assumed Empire could obtain perfect information regarding the states of nature, that is, Empire could determine with certainty which state of nature will occur. To make use of perfect information, a payoff table was developed (Table 15). Table 15 illustrates the optimal resource alternative given perfect knowledge of the future for each level of each uncertainty. For instance, if Empire had perfect knowledge that market/fuel prices will be high or base, then Plan 11 is optimal; however, if Empire had perfect knowledge that market/fuel prices were low, then Plan 3 is optimal.

Table 16
Expected Value of Better Information – States of Nature
****Highly Confidential in its Entirety****

Source: GED

The expected value with perfect information is obtained by taking a weighted average of the optimal plan PVRR for each branch of a state of nature. For market/fuel prices, the expected value with perfect information is obtained as shown in Table 16.

Table 17
Expected Value With Perfect Information – Market and Fuel Prices

Tree Branch	Optimal Plan	Endpoint Value (PVRR $ millions)	Weighting	Weighted Value (PVRR $ millions)	Expected Value With Perfect Information (PVRR$ millions)
High	** **	** **	** **	** **	
Base	** **	** **	** **	** **	
Low	** **	** **	** **	** **	
					** **

The expected value of perfect information (EVPI) is obtained by taking the probabilistic expected value of Plan 11 (shown on Figure 20 as Probable Utility Cost) and subtracting the expected value with perfect information determined in Table 16. EVPI represents the theoretical maximum amount of money Empire could spend to obtain additional information about the states of nature. The EVPI for each of the states of nature – market and fuel prices, load, environmental, and capital and transmission are shown in Table 17.

Table 18
Expected Value of Better Information – Summary ($ millions)

	Fuel Prices	Load	Environmental	Capital and Transmission
Expected Value of Best Decision	**_____**	**_____**	**_____**	**_____**
Expected Value of Decision Strategy Using Perfect Information	**_____**	**_____**	**_____**	**_____**
Expected Value of Better Information	**_____**	**____**	**_____**	**_____**

Source: GED

The calculation process and track along the decision tree to arrive at the bottom row of Table 17 for each state of nature are provided in Figures 23, 24, 25, and 26.

Figure 23
****Highly Confidential in its Entirety****
EVPI – Market and Fuel Prices (2007 – 2026)

Figure 24
****Highly Confidential in its Entirety****
EVPI – Loads (2007 – 2026)

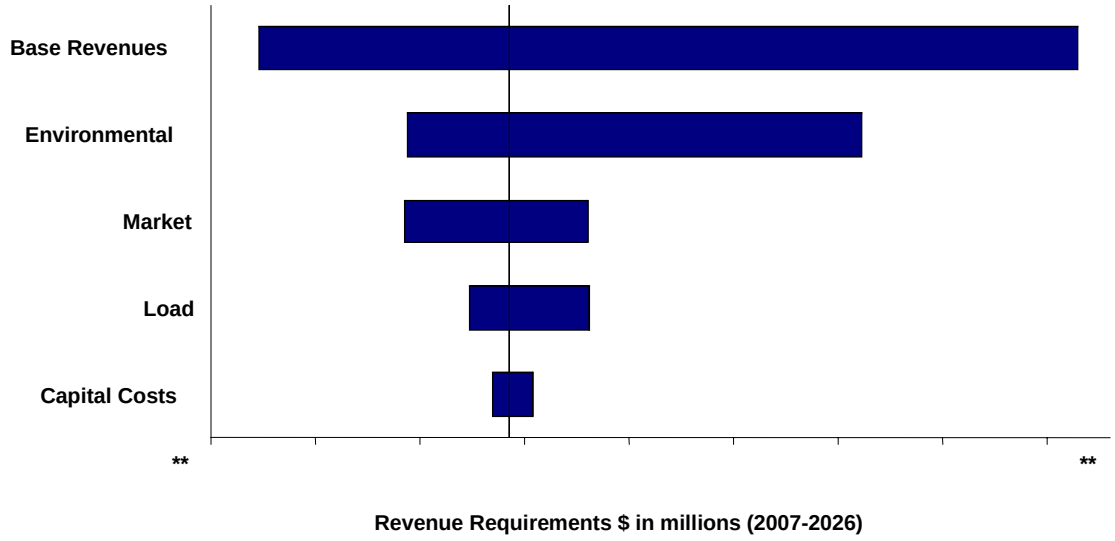
Figure 25
****Highly Confidential in its Entirety****
EVPI – Environmental (2007 – 2026)

Figure 26
****Highly Confidential in its Entirety****
EVPI – Capital and Transmission Costs (2007 – 2026)

3.4 Sensitivity Drivers

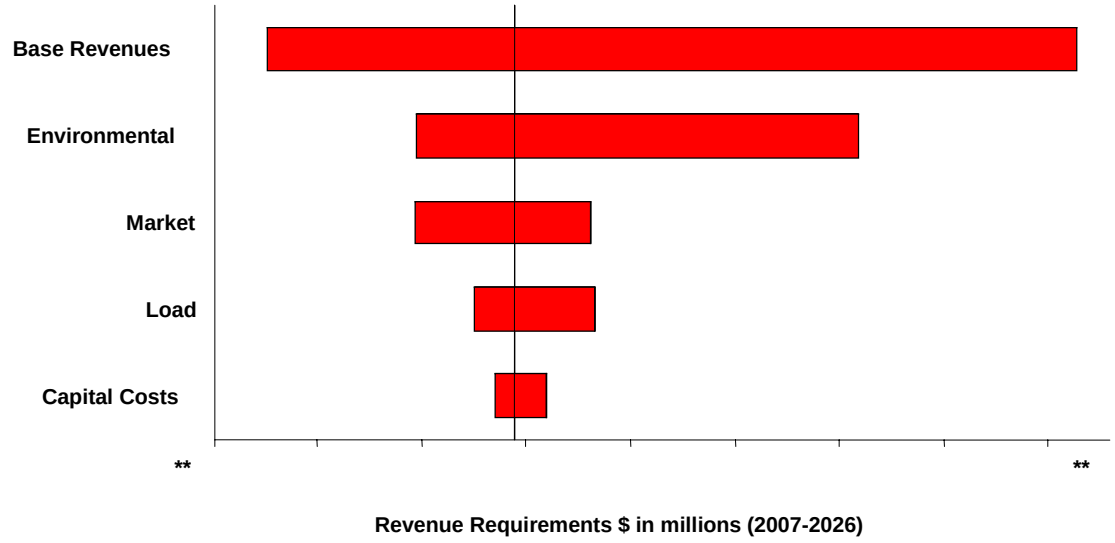
The magnitude of the influence that any specific driving factor has in determining PVRR can be represented in what is called a "tornado chart". The values on this chart are determined through regression analysis and identify the contribution of each variable to the total risk. The effect of environmental concerns, represented primarily by CO_2 regulation, is the primary risk driver in this IRP. Figures 27 through 34 show the tornado charts for each of the primary scenarios.

Figure 27
Plan 1 – Base – Tornado Chart (2007 – 2026)



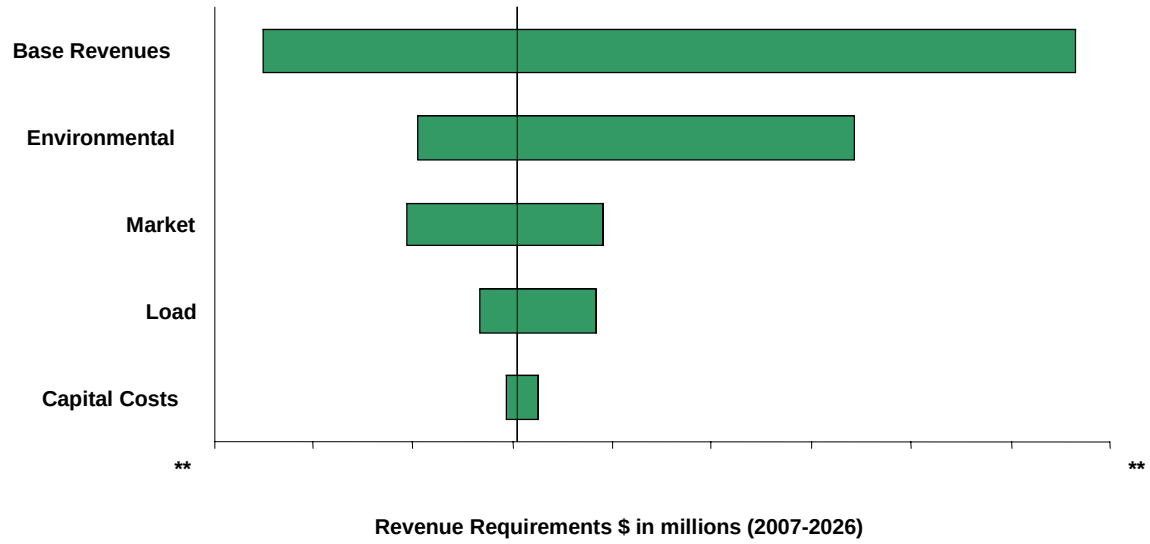
Source: GED

Figure 28
Plan 2 – High Prices – Tornado Chart (2007 – 2026)



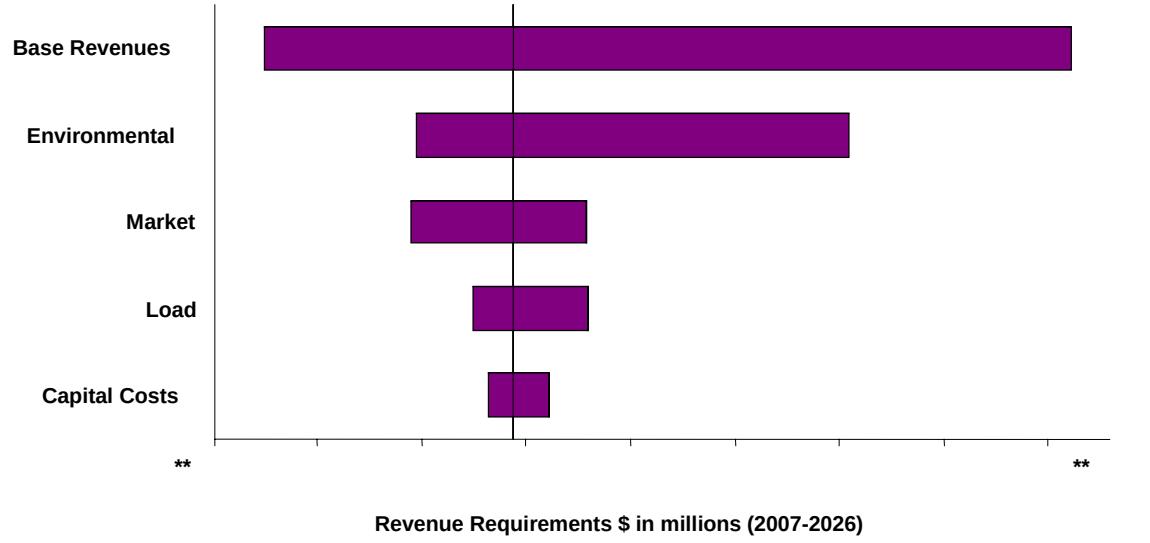
Source: GED

Figure 29
Plan 3 – Low Prices – Tornado Chart (2007 – 2026)



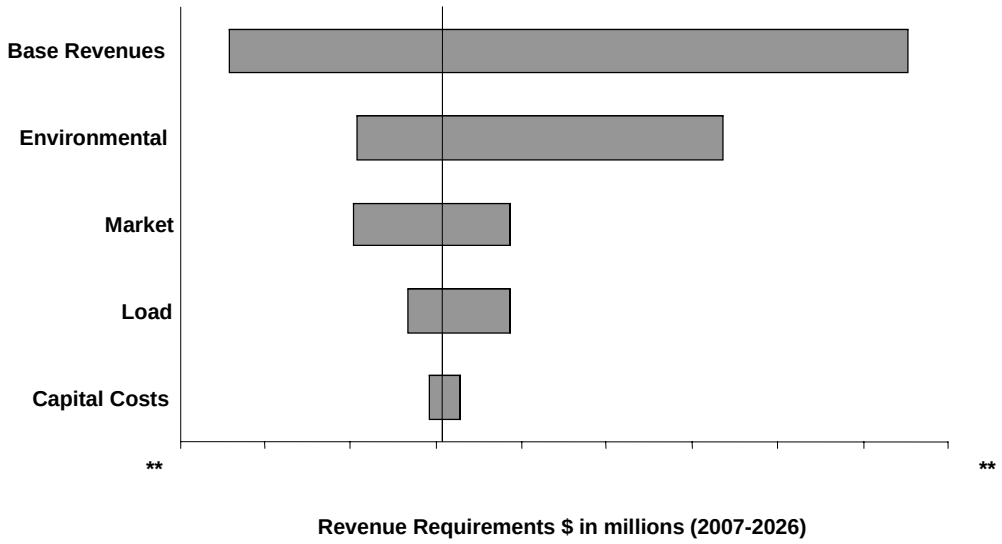
Source: GED

Figure 30
Plan 4 – High Load – Tornado Chart (2007 – 2026)



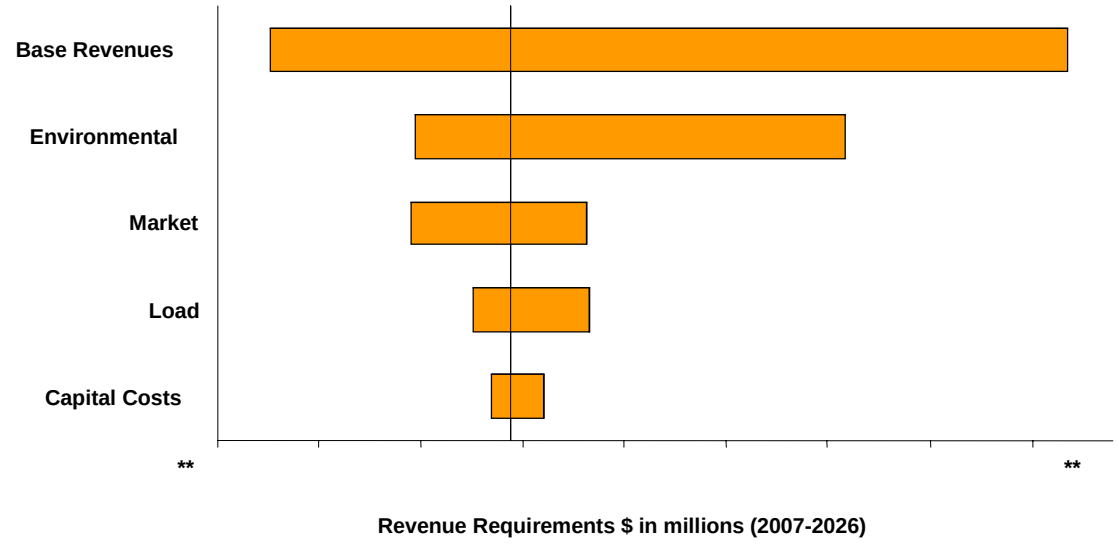
Source: GED

Figure 31
Plan 5 – Low Load – Tornado Chart (2007 – 2026)



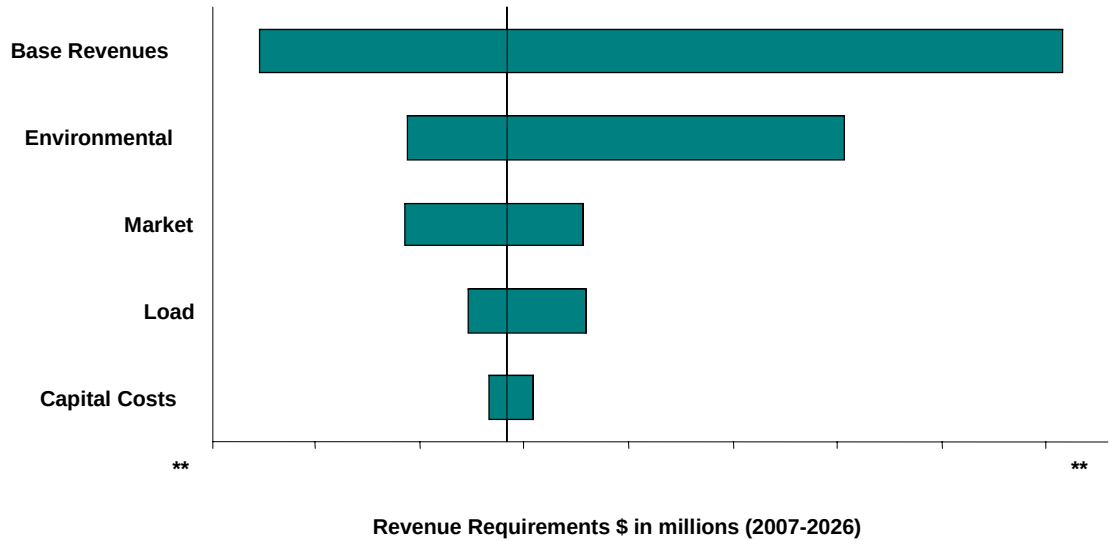
Source: GED

Figure 32
Plan 9 – ** _____ ** – Tornado Chart (2007 – 2026)



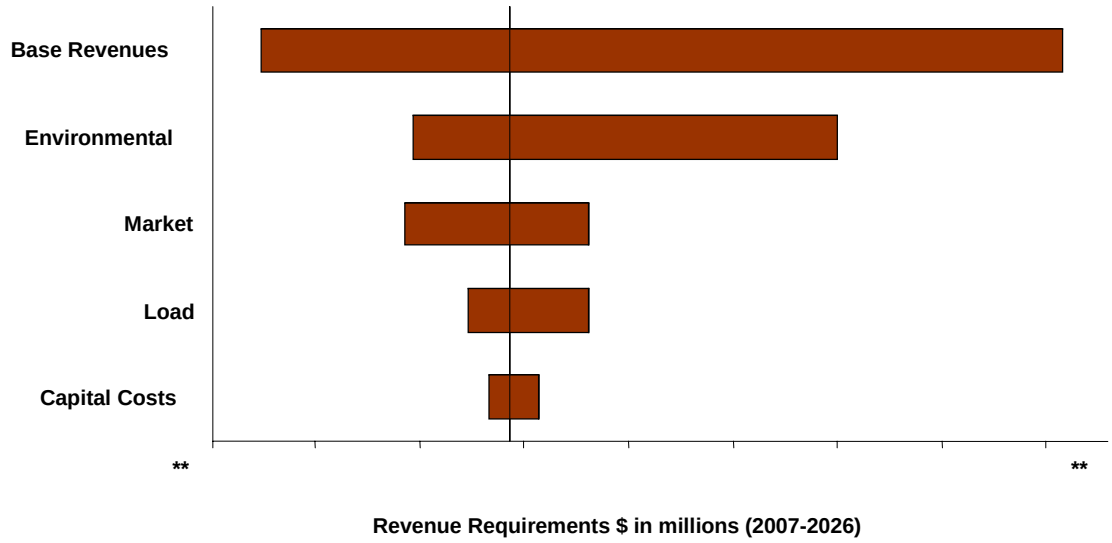
Source: GED

Figure 33
Plan 11 – With Nuclear – Tornado chart (2007 – 2026)



Source: GED

Figure 34
Plan 12 – With Nuclear, No Coal – Tornado Chart (2007 – 2026)



Source: GED

4.0 Preferred Plan

From a deterministic standpoint and after an examination of the risk profiles, all of the primary scenarios evaluated have similar cost and risk results. The selection of Empire's Preferred Plan represents a balancing of the risks and opportunities that are evident as this IRP was prepared and the availability of resources in which Empire could participate as a joint owner. The new DSM and supply-side resources, not including the already committed DSM and supply-side resources, that would be added under the Preferred Plan are shown in Table 18.

Table 19
Empire's Preferred Plan – DSM and Supply-Side Resource Additions

Year	New Resources	Committed Resources in this IRP
2007		
2008	**_____**	
2009	**_____**	Meridian Way Wind Farm (105 MW)
2010		Iatan 2 (100 MW), Plum Point (100 MW)
2011		**_____**
2012		
2013		
2014	**_____**	
2015		
2016		
2017	**_____**	
2018	**_____**	
2019	**_____**	
2020	**_____**	
2021	**_____**	
2022	**_____**	
2023	**_____**	
2024	**_____**	
2025	**_____**	
2026	**_____**	
Note: DSM programs reflected in table only during first year of implementation		

Figures 35 and 36 show the supply-side resources and DSM programs that would be added over the planning horizon in the Preferred Plan.

Figure 35
****Highly Confidential in its Entirety****
Preferred Plan - Resource Additions (Excluded Committed Additions)

Source: GED

Figure 36
****Highly Confidential in its Entirety****

Preferred Plan – DSM Programs

Additional information about the results of the Preferred Plan are provided on Figures 37-46. This information includes: rate increases (Figure 37), average system rates (Figure 38), cumulative rate increases (Figure 39), capital forecast (Figure 40), capitalization

ratios (Figure 41), ratio of total debt to total capital (Figure 42), pretax interest coverage excluding AFUDC (Figure 43), net cash flow to capital expenditures (Figure 44), reliability assessment (Figure 45), risk profile (Figure 46), and a tornado chart (Figure 42). Figure 33 does not represent the future rate increases as Empire would file for rate cases, but instead is the model's view of how rates would change if instantaneous rate recovery was calculated.

Figure 37
****Highly Confidential in its Entirety****
Preferred Plan - Rate Increases

Source: GED

Figure 38
****Highly Confidential in its Entirety****
Preferred Plan - Average System Rates

Source: GED

Figure 39
****Highly Confidential in its Entirety****
Preferred Plan – Cumulative Rate Increases

Source: GED

Figure 40
****Highly Confidential in its Entirety****
Preferred Plan – Capital Forecast

Source: GED

Figure 41
****Highly Confidential in its Entirety****
Preferred Plan – Capitalization Ratios

Source: GED

Figure 42
****Highly Confidential in its Entirety****
Preferred Plan – Ratio of Total Debt to Total Capital

Source: GED

Figure 43
****Highly Confidential in its Entirety**
Preferred Plan – Pretax Interest Coverage excluding AFUDC

Source: GED

Figure 44
****Highly Confidential in its Entirety****
Preferred Plan – Net Cash Flow to Capital Expenditures

Source: GED

Figure 45
****Highly Confidential in its Entirety****
Preferred Plan – Reliability Assessment (2007 – 2026)

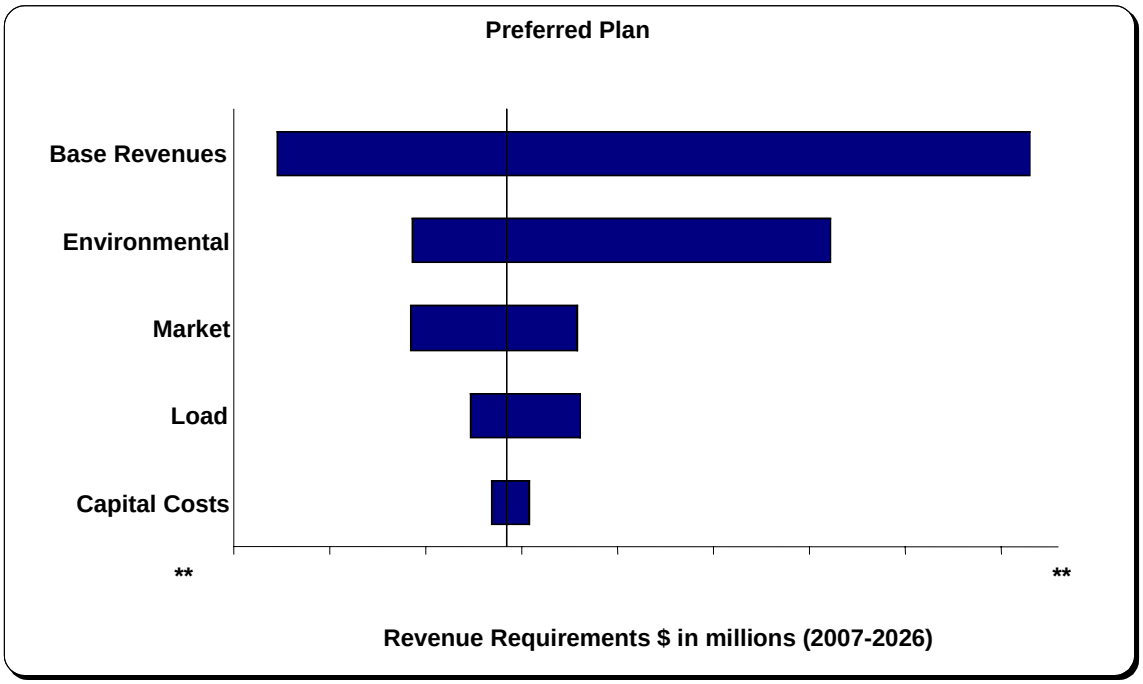
Source: GED

The expected unserved hours in Figure 45 would be experiened only if Empire were not interconnected with neighboring utilities. Because Empire does have access to the market to purchase power when generating units unexpectedly go out of service, the actual unserved energy over the course of any year is actually expected to be 0 MWh.

Figure 46
****Highly Confidential in its Entirety****
Preferred Plan – Risk Profile (2007 – 2026)

Source: GED

Figure 47
Preferred Plan – Tornado Chart



Source: GED

The results of the IRP analysis documented in this report reflect only current and projected conditions as they are known today. Empire will reexamine its decisions for future system expansions as the need for additional resources, driven by load growth, and the influence of external factors, primarily environmental, become more evident. Specifically, the need for additional supply-side capacity around the **____** timeframe will be reexamined annually and in the next IRP, currently scheduled for filing in 2010, before a firm decision is made as to the exact timing and type of resource that might be added.

5.0 Implementation Plan

Currently, construction is progressing on 200 MW (Empire's approximate share) of new jointly-owned coal-fired capacity (100 MW at Iatan 2 and 100 MW at Plum Point). Each of these units is scheduled to come on line in 2010. In addition, a power purchase agreement (PPA) has been signed for 105 MW of new wind energy (Meridian Way Wind Farm) scheduled to begin operation in 2009. **_____ _____**

The demand-side management (DSM) programs currently being implemented include:

- Low Income Efficiency Program
- Low Income – New Home Program
- Home Performance with ENERGY STAR® Program
- ENERGY STAR® Change a Light
- Residential High Efficiency Central Air Conditioning (CAC)
- ENERGY STAR® Homes
- Commercial and Industrial (C&I) Rebate
- Building Operator Certification Program.

Due to the filing requirements associated with an IRP in Missouri, Empire is scheduled to complete another IRP filing (in 2010 – based on a three-year cycle) prior to the initiation of substantive expenditures related to any uncommitted future capacity additions **____ _____** contemplated in this IRP. As a result of its current resource commitments in conjunction with the analysis results from this IRP, Empire will:

- **_____ _____ _____**
- **_____ _____**
- Track and evaluate results of the implementation of DSM programs and keep the Customer Programs Collaborative (CPC) informed as to the results.[4]
- Monitor federal efforts with regard to imposition of a carbon tax.

Empire will also monitor state and federal legislative and regulatory requirements for renewable portfolio standards (RPS) in addition to tracking changes in other environmental regulations. With its current purchase of wind energy from the Elk River Wind Farm and its commitment to purchase wind energy from the Meridian Way Wind Farm, Empire believes that it will be well-positioned to meet the percentages of

[4] The Customer Programs Collaborative was established as a result of a stipulation and agreement and, in addition to Empire personnel, is comprised of Missouri Public Service Commission staff, Office of Public Counsel, Missouri Department of Natural Resources, and other interested parties. The CPC is charged with making decisions pertaining to the development, implementation, monitoring, and evaluation of Empire's affordability, energy efficiency, and demand response programs.

renewable energy that might be required by state or federal RPS over the entire planning horizon.

Empire will also monitor the future of baseload generation in the region over the planning horizon. This could include nuclear, pulverized coal or new technologies as they emerge. For the preferred plan, Empire has assumed that no nuclear units in which it can participate will be built during the planning horizon. However, Empire will keep current on publicly released plans in the region for new nuclear units. Similarly, Empire will monitor and evaluate opportunities for participation in coal-fired units, IGCC units, or other emerging technologies planned in the region. Empire will be cognizant of and striving for resources that incorporate methods for carbon capture and carbon sequestration, as appropriate, in compliance with any global climate change legislation that might be enacted. Environmental risk is a key uncertainty in this IRP.

5.1 Load Forecasting Schedule

Empire will regularly update its load forecast as required for annual budget preparation. Any changes in methodology that result from improved knowledge of the load forecasting modeling package will be incorporated. As conditions change with regard to major industrial customers or on-system wholesale customers, those changes will also be reflected in the load forecasting process and results.

5.2 DSM Schedule

It is Empire's intention to bring the DSM programs selected by the optimization modeling in this IRP to the CPC for review and approval. Subject to such approval, and the agreement of Empire senior management, these DSM programs will be implemented.

5.3 Supply-Side Schedule

The milestones already in place for the procurement of 105 MW from the Meridian Way Wind Farm **_____**

6.0 Resource Acquisition Strategy

The preferred plan documented in Section 4.0 of this report in conjunction with the implementation plan from Section 5.0 have been accepted and reviewed by Empire's senior management and constitute its Resource Acquisition Strategy. **_____ _____** all actions contemplated in this IRP for new supply-side resources will occur after the time at which Empire's next IRP is due for filing (2010). Empire will implement DSM programs after approval by the CPC within the window between the 2007 IRP filing and the 2010 IRP filing. Otherwise, no major resource decisions will be made until after the 2010 IRP is filed.

The critical uncertain factor is the potential enactment of a carbon tax or carbon cap and trade legislation by the U.S. Congress. Empire personnel and senior management are staying informed of these developments through review of trade press and other normal communication channels.

The results of the IRP analysis documented in this report reflect only current and projected conditions as they are known today. Empire will reexamine its decisions for future system expansions as the need for additional resources, driven by load growth, and the influence of external factors, primarily environmental, become more evident. Specifically, the need for additional supply-side capacity around the **____** timeframe will be reexamined annually and in the next IRP, currently scheduled for filing in 2010, before a firm decision is made as to the exact timing and type of resource that might be added.

Appendix A – Supply-Side Model Descriptions

About Global Energy

Global Energy Decisions (Global Energy) provides the energy industry with software solutions, energy markets data, advisory services, and strategic consulting based on a common framework enabling industry professionals to:

- Forecast electricity pricing and demand
- Conduct resource planning
- Perform strategic studies, competitor analyses, and due diligence
- Manage risk
- Trade energy and schedule delivery
- Value assets
- Optimize generation performance
- Make merger and acquisition decisions

Global Energy has worldwide relationships with 400 energy market participants; generators; transmission firms; load serving entities; co-operative enterprises; fuel suppliers; and the firms that finance, analyze and consult to them. With upwards of 175 installed software clients and 100 installed database clients, the company is positioned as a clear leader in market analytics, simulation, planning and risk, and operations management.

Since 1979, Global Energy Advisors has been a trusted advisor performing over 2,500 project assignments worldwide. Since 1997, we have provided independent market opinions for over $15 billion in short- and long-term project financing of more than 70,000 MW of energy projects, including active involvement in some of the largest utility acquisitions and sales during the past decade. Global Energy's personnel are economists; financial analysts; and civil, electrical, mechanical, software and systems engineers—all focused on serving the energy industry. Our staff brings to bear countless years of experience working with almost every major energy industry participant domestically and abroad.

Global Energy utilized its Capacity Expansion and Strategic Planning *powered by MIDAS Gold*® software solution to simulate the regional power markets, screen the resource alternatives, and perform operational and financial analysis of the Empire District Electric portfolio.

Software used for Analysis

Strategic Planning *powered by MIDAS Gold*® was utilized to measure and analyze the consumer value of competition.

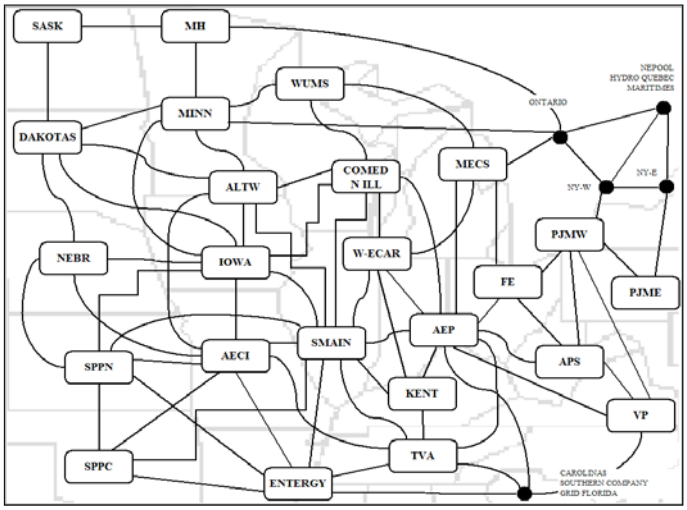
Strategic Planning includes multiple modules for an enterprise-wide strategic solution. These modules are:
Markets
Portfolio
Financial
Risk

Strategic Planning is an integrated, fast, multi-scenario zonal market model capable of capturing many aspects of regional electricity market pricing, resource operation, asset and customer value. The markets and portfolio modules are hourly, multi-market, chronologically correct market production modules used to derive market prices, evaluate power contracts, and develop regional or utility-specific resource plans. The financial and risk modules provide full financial results and statements and decision making tools necessary to value customers, portfolios and business unit profitability.

Markets Module

Generates zonal electric market price forecasts for single and multi-market systems by hour and chronologically correct for 30 years. Prices may be generated for energy only, bid- or ICAP-based bidding processes. Prices generated reflect trading between transaction groups where transaction group may be best defined as an aggregated collection of control areas where congestion is limited and market prices are similar. Trading is limited by transmission paths and constraints quantities.

o **Sample Topology**



SOURCE: Global Energy

The database is populated with Global Energy Intelligence – Market Ops information.

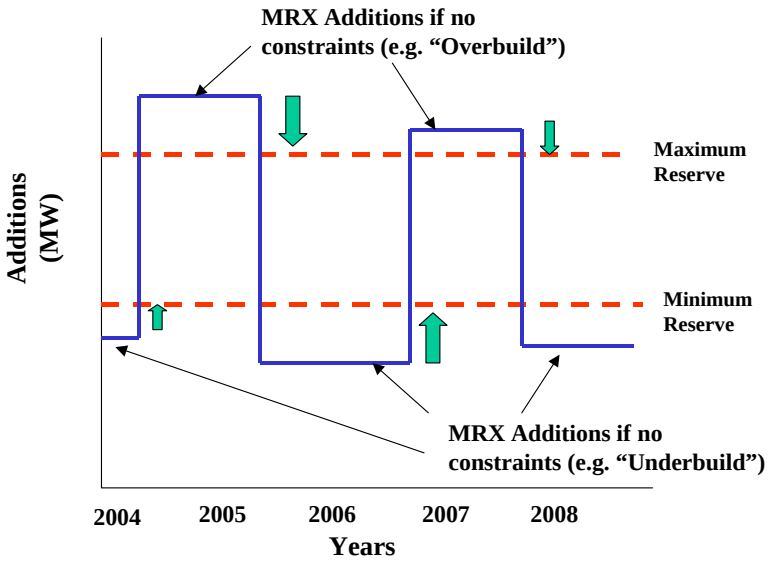
Operational information provided for over 10,000 generating units

- Load forecasts by zone (where zone may be best defined as utility level) and historical hourly load profiles
- Transmission capabilities
- Coal price forecast by plant with delivery adders from basin
- Gas price forecast from Henry Hub with basis and delivery adders

When running the simulation in markets module, the main process of the simulation is to determine hourly market prices. Plant outages are based on a unit derate and maintenance outages may be specified as a number of weeks per year or scheduled.

The market based resource expansion algorithm builds resources by planning region based on user-defined profitability and/or minimum and maximum reserve margin requirements in determining prices. In addition, strategic retirements are made of non-profitable units based on user-defined parameters.

o **MRX Decision Basis**



SOURCE: Global Energy

The markets module simulation process performs the following steps to determine price: Hourly loads are summed for all customers within each Transaction Group.

- For each Transaction Group in each hour, all available hydro power is used to meet firm power sales commitments.
- For each Transaction Group and Day Type, the model calculates production cost data for each dispatchable thermal unit and develops a dispatch order.
- The model calculates a probabilistic supply curve for each Transaction Group considering forced and planned outages.
- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur among Transaction Groups.
- The model records and reports details about the generation, emissions, costs, revenues, etc. associated with these hourly transactions.

Portfolio Module

Once the price trajectories have been completed in the markets module, the portfolio module may be used to perform utility or region specific portfolio analyses. Simulation times are faster and it allows for more detailed operational characteristics for a utility specific fleet. The generation fleet is dispatched competitively against pre-solved market prices from the markets module or other external sources. Native load may also be used for non-merchant/regulated entities with a requirement to serve.

Operates generation fleet based on unit commitment logic which allows for plant specific parameters of:

Ramp rates
Minimum/maximum run times
Start up costs

The decision to commit a unit may be based on one day, three day, seven day and month criteria. Forced outages may be based on monte-carlo or frequency duration with the capability to perform detailed maintenance scheduling. Resources may be de-committed based on transmission export constraints.

Portfolio module has the capability to operate a generation fleet against single or multiple markets to show interface with other zones. In addition, physical, financial and fuel derivatives with pre-defined or user-defined strike periods, unit contingency, replacement policies, or load following for full requirement contracts are active.

Capacity Expansion Module

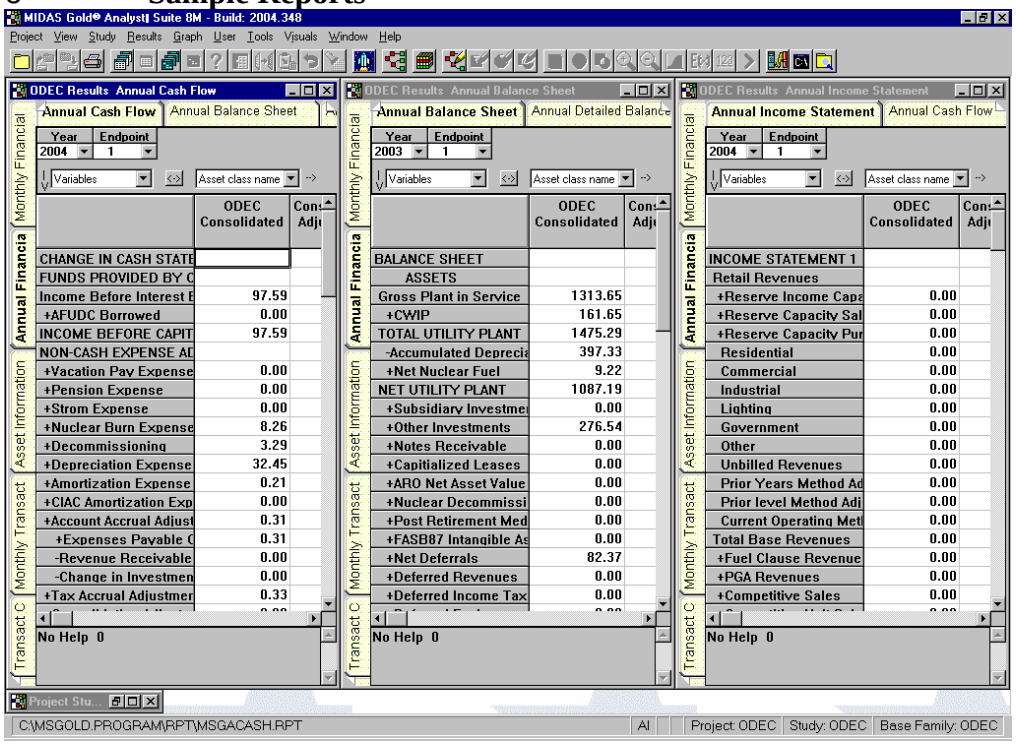
Capacity Expansion automates screening and evaluation of generation capacity expansion, transmission upgrades, strategic retirement, and other resource alternatives. It is a detailed and fast economic optimization model that simultaneously considers resource expansion investments and external market transactions. With Capacity Expansion, the optimal resource expansion strategy is determined based on an objective function subject to a set of constraints. The typical criterion for evaluation is the expected present value of revenue requirements (PVRR) subject to meeting load plus reserves, and various resource planning constraints.

Develop long-term resource expansion plans with type, size, location, and timing of capital projects over a 30-year horizon
Access significant production and costing detail in results
Include a complete range of technologies, including renewables, DSM, retirements, and transmission upgrades, today and in the future
Consider interactions with external markets and between internal regions

Financial Module

The financial module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.

o **Sample Reports**



Source: Global Energy

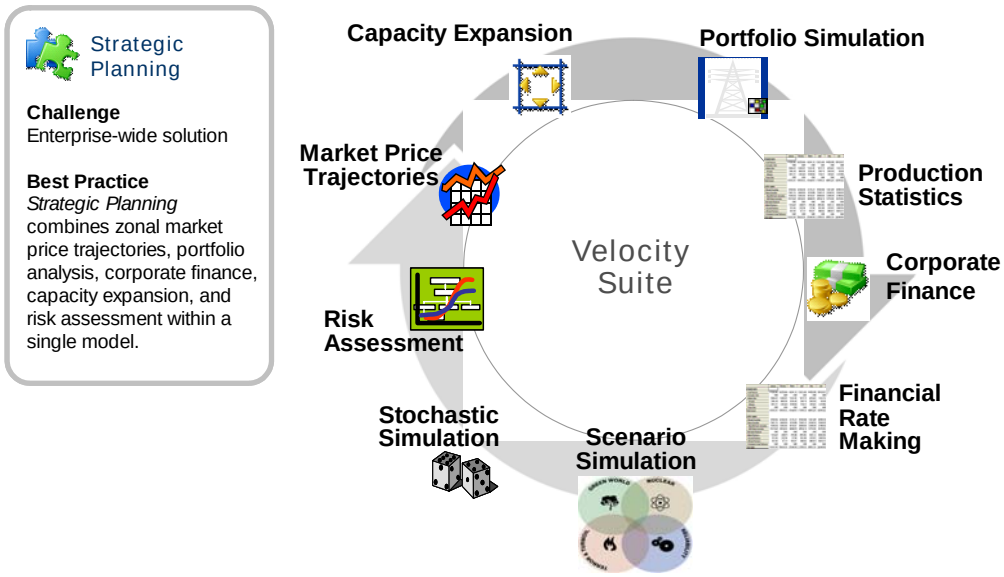
Risk Module

Risk module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables providing flexibility not available in other models.

Strategic Planning has the functionality of developing probabilistic price series by using a four-factor structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission. Using a Latin Hypercube-based stratified sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g. demand, fuel price, availability, hydro year, capital expansion cost, transmission availability, market electricity price, reserve margin, emission price, electricity price and/or weather) and takes into account statistical distributions, correlations, and volatilities for three time periods (i.e. Short-Term hourly, Mid-Term monthly, and Long-Term annual) for each transact group. By allowing these uncertainties to vary over a range of possible values a range or distribution of forecasted prices are developed.

o **Overview of Process**

Strategic Planning
Enterprise-Wide Portfolio Analysis



SOURCE: Global Energy

Appendix B Capacity and Resource Balances – Plans 1 -12

****Highly Confidential in its Entirety****

Table B-1 Plan 1 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-2 Plan 2 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-3 Plan 3 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-4 Plan 4 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-5Plan 5 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-6 Plan 6 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-7 Plan 7 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-8 Plan 8 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-9 Plan 9 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-10 Plan 10 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-11 Plan 11 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table B-12 Plan 12 Capacity and Resource Balance

****Highly Confidential in its Entirety****

Table C-1
Demand-Side Management – Impact on Peak Forecast (MW)

****Highly Confidential in its Entirety****

Table C-1 (continued)

****Highly Confidential in its Entirety****

Table C-2 Demand-Side Management – Impact on Annual Energy (MWh)

****Highly Confidential in its Entirety****

Table D-1

Emissions For All Primary Scenarios

****Highly Confidential in its Entirety****

Table E-1
Annual Generation by Supply-Side Resource – Plan 1 – Base

****Highly Confidential in its Entirety****

Table E-2
Annual Generation by Supply-Side Resource – Plan 2 – High Prices

****Highly Confidential in its Entirety****

Table E-3
Annual Generation by Supply-Side Resource – Plan 3 – Low Prices

****Highly Confidential in its Entirety****

Table E-4
Annual Generation by Supply-Side Resource – Plan 4 – High Load

****Highly Confidential in its Entirety****

Table E-5
Annual Generation by Supply-Side Resource – Plan 5 – Low Load

****Highly Confidential in its Entirety****

Table E-6
Annual Generation by Supply-Side Resource – Plan 9 – Riv Early Ret

****Highly Confidential in its Entirety****

Table E-7
Annual Generation by Supply-Side Resource – Plan 11 – Base with Nuclear

****Highly Confidential in its Entirety****

Table E-8
Annual Generation by Supply-Side Resource – Plan 12 – Base with Nuclear, No Coal

Abbreviations

A/C – Air Conditioning
ACFB – Atmospheric Circulating Fluidized Bed
C&I – Commercial and Industrial
CAC – Central Air Conditioning
CC – Combined Cycle
CEM – Capacity Expansion Model
CO_2 – Carbon dioxide
CPC – Customer Programs Collaborative
CT – Combustion Turbine
DG – Distributed Generation
DSM – Demand-Side Management
EPA – Environmental Protection Agency
EVPI – Expected Value of Perfect Information
GED – Global Energy Decisions
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
PPA – Power Purchase Agreement
PVRR – Present Value of Revenue Requirements
RPS – Renewable Portfolio Standard
SCR – Selective Catalytic Reduction
SO_2 – Sulfur dioxide
SPP – Southwest Power Pool