Document No. 2

Integrated Resource Plan

Filing Requirements

PUBLIC VERSION

Corporate Planning Department

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SUMMARY INFORMATION AND NARRATIVE DESCRIPTION

This document Addresses the requirements of 4 CSR 240-22.080 (1):

Each electric utility which sold more than one (1) million megawatt-hours to Missouri retail electric customers in calendar year 1991 shall make a filing with the commission every three (3) years that demonstrates compliance with the provisions of this chapter of rules. The utility's filing shall include at least the following items:

(A) Letter of transmittal;

Included in filing.

(B) Summary information and any press release related to the filing;

A summary of AmerenUE's resource plan compliance filing is set forth in the Executive Summary and Section 1 of the Integrated Resource Analysis. These sections describe the Company's resource planning objective and summarize its preferred resource plan. It also discusses plan development and the planning environment. Finally, it explains that the IRP is supported by six main components with associated appendices and references:

1. **Filing Requirements** - In this document, AmerenUE cites each provision of Chapter 22 of the Electric Utility Resource Planning rules and states how it either responded directly to the rule or indirectly to the rule in those circumstances where the rule requirements no longer represents standard resource planning practices.
2. **Integrated Resource Analysis** - This is a summary document that condenses the information contained in all volumes of documentation filed. The document starts with a flowchart of the IRP process and proceeds to discuss every aspect of the flowchart.
3. **Load Forecast Data And Methodology** - This is a summary document of the AmerenUE sales and peak demand forecasts including a detailed discussions of AmerenUE's forecast models and techniques.
4. **Demand-Side Management Briefing** - This document contains AmerenUE's analysis of best practices for demand response and energy efficiency programs across the nation. It also includes a listing of both past and present pilot programs offered by AmerenUE.
5. **Risk & Uncertainty Briefing** - This document contains detailed descriptions of the process and parameters used by AmerenUE to assess risk and uncertainty in its resource planning.
6. **Generation Technology Assessment** - This set of documents contains detailed descriptions of the capital and operating cost assumptions and design parameters underlying the supply side resources analyzed by AmerenUE.

The remaining sections of the Integrated Resource Analysis describe in more detail the Company's planning process. Section 2 summarizes the planning and analysis process. Section 3 discusses the forecasting effort and results. Section 4 outlines the assumptions. Section 5 describes the demand-side planning process. Section 6 reviews the supply-side resource options and screening analysis. Section 7 delineates the integration process. Section 8 summarizes the scenario analysis and results. Section 9 summarizes the preferred resource plan and describes the implementation plan associated with the results.

(C) Reports and information required by 4 CSR 240-22.030(8), 4 CSR 240-22.040(9), 4 CSR 240-22.050(11), 4 CSR 240-22.060(6) and 4 CSR 240-22.070(11);

The present document - the Missouri Filing Requirements - includes the Company's response to each section of Chapter 22 of the Commission's resource planning rules, where a response was necessary. This document lists each section in numerical order followed by the Company's response. It either includes the reports and information required by the sections cited above or refers the reader to other documents which contain them.

(D) A narrative description and summary of the reports and information referred to in subsection (1)(C). The narrative shall specifically show that the resource acquisition strategy contained in the filing has been officially approved by the utility, and that the methods used and the procedures followed by the utility in formulating the resource acquisition strategy comply with the provisions of this chapter of rules;

The Company's resource acquisition strategy, consisting of its preferred resource plan and implementation plan, was approved by its Board of Directors and reviewed by its Executive Council. As evidenced by the documents included with this filing, the Company has developed its resource acquisition strategy using methods and procedures that comply with Chapter 22.

(E) A request for a protective order from the commission if the utility seeks to protect anything contained in the filing as trade secrets, or as confidential or private technical, financial or business information; and

The Company is requesting in a separate document that the Commission issue a protective order regarding this filing.

(F) Tariff sheets as required by 4 CSR 240-14.040(2) for demand-side programs that are promotional practices as defined by 4 CSR 240-14.010(6)(L).

Where required, all current demand-side programs have approved tariff sheets. Additional tariffs will be submitted as programs are developed.

PURPOSE: This rule sets minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing and forecasting loads, and for the documentation of the inputs, components and methods used to derive the load forecasts.

(1) Historical Data Base. The utility shall develop and maintain data on the actual historical patterns of energy usage within its service territory. The following information shall be maintained and updated on an ongoing basis:

(A) Customer Class Detail. The historical data base shall be maintained for each of the following major classes: residential, commercial, industrial, interruptible and other classes that may be required for forecasting (for example, large power, wholesale, outdoor lighting and public authorities).

1. Taking into account the requirement for an unbiased forecast as well as the cost of developing data at the subclass level, the utility shall determine what level of subclass detail is required for forecasting and what methods to use in gathering subclass information for each major class.

The following class and subclass detail are used for forecasting:

Major Class	Subclass
Residential	none
Commercial	Small General, Large General, Primary
Industrial	none
Wholesale	Individual Customer
Street Lighting	none

Class and subclass data is acquired from AmerenUE's CSS bill data. For the complete description of the documentation of class and subclass statistical forecast models refer to the Model Specification sections, 2005 Load Forecast Data and Methodology, pages 25-42.

2. The utility shall consider the following categories of subclasses: for residential, dwelling type; for commercial, building or business type; and for industrial, product type. If the utility uses subclasses which do not fit into these categories, it must explain the reasons for its choice of subclasses;

The class and subclass divisions were chosen based on data availability and format in AmerenUE's CSS bill data. The subclasses used in the historical database are described in the previous response in (1)(A)1. The dwelling type information for the residential class was not available for the AmerenUE service territory and the SAE modeling approach effectively accounts for inherent residential usage patterns. Small General, Large General, and Primary were chosen as subclasses for commercial usage, in addition to the SAE approach, because it implies a similar usage pattern within the subclasses. Industrial and Street Lighting are not currently forecast by subclass; although, the Industrial class is broken into the following subclasses based on an exponential extrapolation of their respective share of total Industrial sales: Small General Service, Large General Service, Small Primary Service, and Large primary Service.

(B) Load Data Detail. The historical load data base shall contain the following data:

1. ***For each jurisdiction under which the utility has rates established and for which it prepares customer and energy forecasts, each major class, and to the extent data is required to support the detail specified in paragraph (1)(A)1., for each subclass, actual monthly energy usage and number of customers and weather-normalized monthly energy usage;***

The data used to support the detail specified in (1)(A)1. is located in a Microsoft Access application ("Forecast Manager") designed to store historical sales, customers, and weather normalized sales for each major class and corresponding subclass.

2. ***For each major class, estimated actual and weather-normalized demands at the time of monthly system peaks; and***

Actual class monthly demand is available. Major class hourly weather normalization is being investigated and should be available in future analyses.

3. ***For the system, actual and weather-normalized hourly net system load;***

Actual hourly net system loads are available. Hourly net system load weather normalization is being investigated and should be available in future analyses.

(C) Load Component Detail. The historical data base for major class monthly energy usage and demands at time of monthly peaks shall be disaggregated into a number of units component and a use (kWh) per unit component, for both actual and weather-normalized loads.

1. ***Typical units for the major classes are - residential, number of customers; commercial, square feet of floor space or commercial employment level; and industrial, production output or employment level. If the utility uses a different unit measure, it must explain the reason for choosing different units.***

The Itron toolset has the ability to model dependent sales data against many independent variables, concurrently, as well as indicate the statistical significance of such modeling. AmerenUE uses the Itron toolset in this manner, and does not model energy as demand per unit components. Customer count information is inconsistent within the AmerenUE databases, and is modeled independent of the energy components.

Major Class	Independent variables	(Units) Reference
Residential	XHEAT, XCOOL, XOTHER	Residential Sales Model Specification, 2005 Load Forecast Data and Methodology, pages 24-28
Commercial	XHEAT, XCOOL, XOTHER, GDP	Commercial Sales Model Specification, 2005 Load Forecast Data and Methodology, pages 29-37
Industrial	Cooling Variable (Price & CDD)	Industrial Sales Model Specification, 2005 Load Forecast Data and Methodology, pages 40-42
Wholesale	Weather (HDD, CDD),	Wholesale Sales Model Specification,

	Non-Manuf. Employment	2005 Load Forecast Data and Methodology, page 40
Street Light	GDP	Dusk to Dawn Sales Model Specification & Street Lighting and Public Authority Sales Model Specification, 2005 Load Forecast Data and Methodology, pages 36-39

2. ***The utility shall develop and implement a procedure to routinely measure and regularly update estimates of the effect of departures from normal weather on class and system electric loads.***
   A. ***The estimates of the effect of weather on class and system loads shall incorporate the nonlinear response of loads to daily weather and seasonal variations in loads.***

For a description of this process refer to the Historical Weather Normalization Methodology and Update to Weather Normalization Process sections, 2005 Load Forecast Data and Methodology, pages 11-17.

B. ***For at least the base year of the forecast, the utility shall estimate the cooling, heating, and nonweather-sensitive components of the weather-normalized major class loads.***

Weather-sensitive classes include the residential, commercial, and wholesale classes. Nonweather-sensitive classes include the industrial and street lighting classes. System limitations prohibit the disaggregation of loads into heating, cooling, and other components; however, AmerenUE does make use of the SAE approach to estimate the components for the residential class based on SAE information provided by Itron. AmerenUE's sales forecast is combined with the provided load profiles to estimate the heating, cooling, and nonweather-sensitive components for the residential class.

C. ***The utility shall document the methods used to develop weather measures and the methods used to estimate the effect of weather on electric loads. If statistical models are used, the documentation shall include at least: the functional form of the models; the estimation techniques employed; the data used to estimate the models, including the development of model input data from basic data; and the relevant statistical results of the models, including parameter estimates and tests of statistical significance; and***

For the components of the weather normalization process, refer to the Historical Weather Normalization Methodology and Update to Weather Normalization Process sections, 2005 Load Forecast Data and Methodology, pages 11-17.

(D) Length of Data Base. Once the utility has developed the historical data base, it shall retain that data base for the ten (10) most recent years or for the period of time used as the basis of the utility's forecast, whichever is longer.

1. ***The development of actual and weather-normalized monthly class and system energy usage and actual hourly net system loads shall start from January 1982 or for the period of time used as the basis of the utility's forecast of these loads, whichever is longer.***

The data source listed in (1)(B)(2) contains monthly data consistent with our subclasses and begins in 1995. For the purposes of building a monthly forecast model, there are sufficient degrees of freedom for accurate statistical modeling.

2. ***Estimated actual and weather-normalized class and system monthly demands at the time of the system peak and weather-normalized hourly system loads shall start from January 1990 or for the period of time used as the basis of the utility's forecast of these loads, whichever is longer.***

The forecasting data source containing monthly demands at system peak begins January, 1998, which is sufficient for developing the peak forecasts as described in the Peak Demand Forecast section, 2005 Load Forecast Data and Methodology, pages 10-11.

(2) Analysis of Number of Units. For each major class or subclass, the utility shall analyze the historical relationship between the number of units and the economic or demographic factors (driver variables) that affect the number of units for that major class or subclass. These relationships shall be specified as statistical or mathematical models that relate the number of units to the driver variables.

(A) Choice of Driver Variables. The utility shall identify appropriate driver variables as predictors of the number of units for each major class or subclass. The critical assumptions that influence the driver variables shall also be identified.

(B) Documentation of statistical models shall include the elements specified in subparagraph (1)(C)2.C. Documentation of mathematical models shall include a specification of the functional form of the equations.

(C) Where the utility has modeled the relationship between the number of units and the driver variables for a major class but not for subclasses within that major class, it shall consider how a change in subclass shares of major class units could affect the major class forecast.

The Itron toolset has the ability to model dependent sales data against many independent variables, concurrently, as well as indicate the statistical significance of such modeling. AmerenUE uses the Itron toolset in this manner, and does not model energy as demand per unit components. For the complete description of the choice of driver variables and documentation of statistical models refer to the Model Specification sections, 2005 Load Forecast Data and Methodology, pages 25-42.

(3) Analysis of Use Per Unit. For each major class, the utility shall analyze historical use per unit by end use.

(A) End-Use Detail. For each major class, use per unit shall be disaggregated by end use where information permits.

1. ***Where applicable for each major class, end-use information shall be developed for at least lighting, process equipment, space cooling, space heating, water heating and refrigeration.***

The residential and commercial classes are modeled using a Statistically Adjusted End-use (SAE) modeling approach. This approach captures the usage patterns for heating, cooling, and other components as well as efficiency and saturation trends. For the complete description of the SAE approach refer to the Residential SAE Model and Commercial SAE Model sections, 2005 Load Forecast Data and Methodology, pages 25-28 for residential details and pages 29-31 for commercial details.

2. ***For each major class and each end use, including those listed in paragraph (3)(A)1., if information is not available, the utility shall provide a schedule for acquiring this end-use information or demonstrate that either the expected costs of acquisition were found to outweigh the expected benefits over the planning horizon or that gathering the end-use information has proven to be infeasible.***

The data used to develop the residential and commercial SAE models is procured from the EIA and is updated annually. No reliable information is available to construct end-use detail for other major classes. In addition, the remaining subclasses are more sensitive to production and demand related drivers. The statistical models give the ability to select the driver variables whose impact explain variation and trends; ultimately minimizing forecast error.

3. ***If the utility has not yet acquired end-use information on space cooling or space heating for a major class, the utility shall determine the effect that weather has on the total load of that major class by disaggregating the load into its cooling, heating and nonweather-sensitive components. If the cooling or heating components are a significant portion of the total load of the major class, then the cooling or heating components of that load shall be designated as end uses for that major class.***

The entire load in the industrial and street lighting classes is largely nonweather-sensitive. Where weather is a factor for usage patterns, as with the residential and commercial, the forecast models reflect that relationship. For a description major class independent variables refer to Response (1)(C)1. or for a complete description of the model specifications refer to the Model Specification sections, <u>2005 Load Forecast Data and Methodology</u>, pages 25-42.

4. ***The difference between the total load of a major class and all end uses for which the utility has acquired end-use information shall be designated as an end use for that major class.***

The SAE modeling approach consists of three end-use components; heating, cooling, and other. The "other" end-use component encompasses the end-use components other than heating and cooling.

(B) The data base and historical analysis required for each end use shall include at least the following:

1. ***Measures of the stock of energy-using capital goods. For each major class and end use, the utility shall implement a procedure to develop and maintain survey data on the energy-related characteristics of the building, appliance and equipment stock including saturation levels, efficiency levels and sizes where applicable. The utility shall update these surveys before each scheduled filing pursuant to 4 CSR 240-22.080; and***

The end-use and efficiency data used for the residential and commercial SAE modeling approach is updated on an annual basis. There are no intentions of acquiring end-use information for the remaining major classes as the cost of obtaining such information would outweigh its impact on forecast accuracy improvement.

2. ***Estimates of end-use energy and demand. For each end use, the utility shall estimate end-use monthly energies and demands at time of monthly system peaks, and shall calibrate these energies and demands to equal the weather-normalized monthly energies and demands at time of monthly peaks for each major class for the most recently available data.***

For a complete description of the monthly peak and energy demand forecasting process refer to the Peak Demand Forecast and Summer and Winter Peak Demand Forecasts, <u>2005 Load Forecast Data and Methodology</u>, pages 10-11 and pages 17-24.

(4) Analysis of Load Profiles. The utility shall develop a consistent set of daily load profiles for the most recent year for which data is available. For each month, load profiles shall be developed for a peak weekday, a representative of at least one (1) weekday and a representative of at least one (1) weekend day.

(A) Load profiles for each day type shall be developed for each end use, for each major class and for the net system load.

(B) For each day type, the estimated end-use load profiles shall be calibrated to sum to the estimated major class load profiles, and the estimated major class load profiles shall be calibrated to sum to the net system load profiles.

Load profiles consist of 8760 hour load shapes by major class that sum to the net system load profile at the time of the monthly system peak only. The remaining hours (other than the hour of the monthly system peak) are not calibrated, but AmerenUE is investigating the possibility of hour-by-hour calibration in the conversion to MetrixLT for peak forecasting. Load profiles for major classes at the time of summer and nonsummer coincident peak are available in the 2005 Load Forecast Data and Methodology: Residential, pages 88-94; Commercial total, pages 106-112; Commercial SLPA, pages 180-186; Commercial Wholesale, pages 193-197; Industrial total, pages 207-213.

(5) Base-Case Load Forecast. The utility's base-case load forecast shall be based on projections of the major economic and demographic driver variables that utility decision makers believe to be most likely. All components of the base-case forecast shall be based on the assumption of normal weather conditions. The load impacts of implemented demand-side programs shall be incorporated in the base-case load forecast but the load impacts of proposed demand-side programs shall not be included in the base-case forecast.

(A) Customer Class and Total Load Detail. The utility shall produce forecasts of monthly energy usage and demands at the time of the summer and winter system peaks by major class for each year of the planning horizon. Where the utility anticipates that jurisdictional levels of forecasts will be required to meet the requirements of a specific state, then the utility shall determine a procedure by which the major class forecasts can be separated by jurisdictional component.

Monthly demands for summer and winter by major class through the forecast horizon can be found in the document, 2005 Load Forecast Data and Methodology: Total System, pages 67-68; Residential, pages 86-87; Commercial total, pages 104-106; Commercial SLPA, pages 178-179; Commercial Wholesale, pages 191-192; Industrial total, pages 205-206.

(B) Load Component Detail. For each major class, the utility shall produce separate forecasts of the number of units and use per unit components based on the analysis described in sections (2) and (3) of this rule.

1. Number of units forecast. The utility's forecast of number of units for each major class shall be based on the analysis of the relationship between number of units and driver variables described in section (2). Where judgment has been applied to modify the results of a statistical or mathematical model, the utility shall specify the factors which caused the modification and shall explain how those factors were quantified.

A. The forecasts of the driver variables shall be specified and clearly documented. These forecasts shall be compared to historical trends, and significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

B. The forecasts of the number of units for each major class shall be compared to historical trends. Significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

Forecasts of the driver variables were supplied by Economy.com, a forecasting service used by AmerenUE. There were no significant differences between the forecasts and long-term and recent trends of driver variables and units for any major class. For details about driver variables used in model specifications, refer to the Model Specification sections, 2005 Load Forecast Data and Methodology, pages 25-42.

2. Use per unit forecast. The utility's forecast of monthly energy usage per unit and seasonal peak demands per unit for each major class shall be based on the analysis described in section (3).

A. The forecasts of the driver variables for the use per unit shall be specified. The utility shall document how the forecast of use per unit has taken into account the effects of real prices of electricity, real prices of competitive energy sources, real incomes and any other relevant economic and demographic factors.

The SAE modeling used for residential and commercial demand forecasting implicitly includes the effect of price on usage. The driver variables for the individual class and subclass statistical models were chosen based on their respective significance level. For details about driver variables used in model specifications, refer to the Model Specification sections, 2005 Load Forecast Data and Methodology, pages 25-42.

> ***B. End-use detail. For each major class and for each end use the utility shall forecast both monthly energy use and demands at time of the summer and winter system peaks.***

AmerenUE is currently working with MetrixLT to produce monthly demand and energy forecasts at the time of summer and winter peaks. Monthly demands for summer and winter by major class through the forecast horizon can be found in the document, 2005 Load Forecast Data and Methodology: Total System, pages 67-68; Residential, pages 86-87; Commercial total, pages 104-106; Commercial SLPA, pages 178-179; Commercial Wholesale, pages 191-192; Industrial total, pages 205-206.

> ***C. The stock of energy using capital goods. For each end use for which the utility has developed measures of the stock of energy using capital goods, and where the utility has determined that forecasting the use of electricity associated with these energy using capital goods is cost-effective and feasible, it shall forecast those measures and document the relationship between the forecasts of the measures to the forecasts of end-use energy and demands at time of the summer and winter system peaks. The values of the driver variables used to generate forecasts of the measures of the stock of energy using capital goods shall be specified and clearly documented.***

The Itron toolset has the ability to model dependent sales data against many independent variables, concurrently, as well as indicate the statistical significance of such modeling. For details about driver variables used in model specifications, refer to the Model Specification sections, 2005 Load Forecast Data and Methodology, pages 25-42.

> ***D. The major class forecasted use per unit shall be compared to historical trends in weather-normalized use per unit. Significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.***

AmerenUE does not currently forecast or analyze major class as demand per unit components. The Itron toolset has the ability to model dependent sales data against many independent variables, concurrently, as well as indicate the statistical significance of such modeling. For details about driver variables used in model specifications, refer to the Model Specification sections, 2005 Load Forecast Data and Methodology, pages 25-42

> ***(C) Net System Load Forecast. The utility shall produce a forecast of net system load profiles for each year of the planning horizon. The net system load forecast shall be consistent with the utility's forecasts of monthly energy and demands at time of summer and winter system peaks for the major rate classes.***

For the methodology used to forecast the net system load profile forecast refer to the Peak Demand Forecast section, 2005 Load Forecast Data and Methodology, pages 10-11. Load profiles for major classes at the time of summer and nonsummer coincident peak are available in the <u>2005 Load Forecast Data and Methodology</u>: Total System, pages 69-75; Residential, pages 88-94; Commercial total, pages 106-112; Commercial SLPA, pages 180-186; Commercial Wholesale, pages 193-197; Industrial total, pages 207-213.

(6) Sensitivity Analysis. The utility shall analyze the sensitivity of the components of the base-case forecast for each major class to variations in the key driver variables, including the real price of electricity, the real price of competing fuels, and economic and demographic factors identified in section (2) and subparagraph (5)(B)2.A.

AmerenUE has conducted an in depth Stochastic Analysis on monthly peak and energy including an analysis of historical data using stochastic simulations. By analyzing the historical variation of peaks and energy, AmerenUE is implicitly measuring the variation of the driver variables. For the details regarding the Stochastic Analysis on historical data refer to the Historical Data Analyses and Simulation Parameter Development subsection of the Simulation Analysis and Variable Development section included in the <u>2005 Risk and Uncertainty Analysis Briefing.</u>

(7) High-Case and Low-Case Load Forecasts. Based on the sensitivity analysis described in section (6), the utility shall produce at least two (2) additional load forecasts (a high-growth case and a low-growth case) that bracket the base-case load forecast. Subjective probabilities shall be assigned to each of the load forecast cases. These forecasts and associated subjective probabilities shall be used as inputs to the strategic risk analysis required by 4 CSR 240-22.070.

AmerenUE has conducted an in depth study regarding peak and energy variability. The Stochastic Analysis provides a defined distribution around the forecast; thus defining the probability of an occurrence varying from the forecast. For the details regarding the Stochastic Analysis refer to the Peak Demand and Energy subsection of the Simulation Analysis and Variable Development, <u>2005 Risk and Uncertainty Analysis Briefing</u>.

(8) 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) For each major class specified in subsection (1)(A), the utility shall provide plots of number of units, energy usage per unit and total class energy usage.***
  - ***1. Plots shall be produced for the summer period (June through September), the remaining nonsummer months and the calendar year.***
  - ***2. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.***
    - ***A. The historical period shall include both actual and weather-normalized energy usage per unit and total class energy usage.***
    - ***B. The plots for the forecast period shall show each end-use component of major class energy usage per unit and total class energy usage for the base-case forecast.***
- ***(B) For each major class specified in subsection (1)(A), the utility shall provide plots of class demand per unit and class total demand at time of summer and winter system peak. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.***
  - ***1. The plots for the historical period shall include both actual and weather-normalized class demands per unit and total demands at the time of summer and winter system peak demands.***
  - ***2. The plots for the forecast period shall show each end-use component of major class coincident demands per unit and total class coincident demands for the base-case forecast.***
- ***(C) For the forecast of class energy and peak demands, the utility shall provide a summary of the sensitivity analysis required by section (6) of this rule that shows how changes in the driver variables affect the forecast.***
- ***(D) For the net system load, the utility shall provide plots of energy usage and peak demand.***
  - ***1. The energy plots shall include the summer, nonsummer and total energy usage for each calendar year.***
  - ***2. The peak demand plots shall include the summer and winter peak demands.***

3. ***The plots shall cover the historical data base period and the forecast period of at least twenty (20) years. The historical period shall include both actual and weather-normalized values. The forecast period shall include the base-case, low-case and high-case forecasts.***
4. ***The utility shall describe how the subjective probabilities assigned to each forecast were determined.***

(E) For each major class, the utility shall provide estimated load profile plots for the summer and winter system peak days.

1. ***The plots shall show each end-use component of the hourly load profile.***
2. ***The plots shall be provided for the base year of the load forecast and for the fifth, tenth and twentieth years of the forecast.***

(F) For the net system load profiles, the utility shall provide plots for the summer peak day and the winter peak day.

1. ***The plots shall show each of the major class components of the net system load profile in a cumulative manner.***
2. ***The plots shall be provided for the base year of the forecast and for the fifth, tenth and twentieth years of the forecast.***

(G) The data presented in all plots shall also be provided in tabular form.

(H) The utility shall provide a description of the methods used to develop all forecasts required by this rule, including an annotated summary that shows how these methods comply with the specific provisions of this rule. If end-use methods have not been used in forecasting, an explanation as to why they have not been used shall be included. Also included shall be the utility's schedule to acquire end-use information and to develop end-use forecasting techniques, or a discussion as to why the acquisition of end-use information and the development of end-use forecasting techniques are either impractical or not cost-effective.

For the complete set of plots, tables, and methods used to develop all forecasts required by this rule refer to the 2005 Load Forecast Data and Methodology. For the specific response to (8)(D)4., refer to the response in (7).

4 CSR 240-22.040 SUPPLY-SIDE RESOURCE 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 gasses, greenhouse gasses, 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;***
  - ***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).***

Section 6 of the Integrated Resource Analysis identifies the potential supply-side resource options that are expected to be developed. Summaries of cost and performance information for each of the options, including fuel, capacity range, lead time, capital cost, fixed and variable operation and maintenance costs, planned and forced outage rates, and emission rates are provided in Tables 6.3 through 6.8 of the Integrated Resource Analysis. Detailed data and discussion of the supply-side technologies are shown in the eight Generation Technology Reports, namely:

1. Venice Combined Cycle Study – Black & Veatch, December 2002
2. Strategic Siting Study – Burns & McDonnell, September 2004
3. Missouri Pumped Storage Project Concept Study – Montgomery Watson Harza, September 2004
4. Rush Island Unit 3 Feasibility Study – Black & Veatch, October 2004

5. Rush Island Unit 3 Conceptual Cost & Performance Study – Sargent & Lundy, October 2004
6. Generation Technology Assessment – Burns & Mc-Donnell, November 2004
7. Nuclear Industry Overview & IRP Analysis Parameters – Navigant Consulting, June 2005
8. IGCC Technology Assessment Report – Sargent & Lundy, September 2005

(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.

Section 6.10 of the Integrated Resource Analysis provides a discussion of the screening analysis. The screening was performed using levelized annual costs.

(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 makers' 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.

Section 6.10 of the Integrated Resource Analysis provides a discussion of the screening analysis. The screening was performed under two scenarios:

1. Clean Air Interstate Rule (CAIR)
2. CAIR plus a carbon tax

The Risk & Uncertainty Analysis Briefing describes the four greenhouse gas levels modeled in the scenario analysis and the stochastic treatment of sulfur dioxide allowance prices.

(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.

Section 6.10 of the Integrated Resource Analysis provides a discussion of the screening process, including an explanation of the process of choosing candidate resource options for inclusion in alternative resource plans. The data used in the screening analysis and results are included in Tables 6.9 through 6.12 and a comparison or ranking of the various options considered are included in Figures 6.2 through 6.17.

(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.

Section 6.9 of the Integrated Resource Analysis provides a discussion of transmission issues. The Ameren transmission system has always been a key element in AmerenUE integrated resource planning. The original purpose of the transmission system was to cost-effectively deliver network generation resources to native bundled load. Transmission interconnections were later established with neighboring utilities as a means of reducing generation capacity margin requirements and to enhance the overall reliability of the bulk electric system (BES). The resulting interconnected BES provided the ability to exchange power between neighboring utilities during periods of generation deficiencies and also enabled the sale and/or purchase of capacity and energy prior to the establishment of local or regional markets.

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

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

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

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

(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.

Sections 6.2 through 6.5 of the Integrated Resource Analysis provide a discussion of each of the existing units, including current conditions of existing plants and opportunities for efficiency and capacity increases. The vintage of the plants that produce power on the UE system range from 1913 for the Keokuk Hydroelectric Plant to 2005 for CTG-5 at Venice Plant. Sufficient routine maintenance expenditures are planned for all units to provide for continued operation through the study period.

(5) The utility shall identify and evaluate potential opportunities for new long-term power purchases and sales, both firm and non-firm, 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.

Section 6.7 of the Integrated Resource Analysis provides a discussion of power purchases and sales. AmerenUE would use requests for proposals (RFPs) to solicit short-term and intermediate-term power supply agreements. An RFP would primarily be used to solicit capacity to meet AmerenUE's short- and/or intermediate-term needs for reserves. Products like these may be needed during construction periods to build new generation.

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

(6) For the utility's preferred resource plan selected pursuant to 4 CSR 240-22.070(6), 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).

The preferred resource plan involves the purchase of 1,350 MW of low-cost peaking plant, the study and possible implementation of DSM programs and renewable energy resources and the ongoing evaluation of advanced base load technologies and peaking technologies for future resource needs. The planned 1,350 MW of peaking plant has been deemed deliverable by the MISO. For additional new generation, the analysis included generic transmission outlet access costs. The cost of addressing inadequacies caused by new generation on the system will be considered in the selection of the sites for the new units. Combustion turbines and combined cycle units are relatively small and their impact on the system can be minimized through site selection. Prior to installing new generation on the system a more specific study will be undertaken to assess the need for additional transmission facilities. However, AmerenUE does not foresee any problems in siting or permitting any additional transmission facilities required for new generation.

(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.

The assessment of the age, condition and efficiency level of existing transmission and distribution facilities at AmerenUE is an ongoing effort which requires daily decisions regarding implementation of cost-effective measures to provide reliable service to customers.

Studies performed by the Ameren Transmission Planning Department take into account the addition of new facilities and the continued use of existing facilities. In these studies the economic impact of losses are considered in the evaluation of different options, when applicable. The capacity and energy costs associated with losses are included in these evaluations.

Section 6.9 of the Integrated Resource Analysis provides a discussion of T&D loss reduction programs and procedures impacting energy and demand that are typically reviewed outside the context of the integrated resource planning process.

(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.

The Risk & Uncertainty Analysis Briefing and Section 4 of the Integrated Resource Analysis provide a detailed discussion of the various fuel markets, forecasts and factors that may affect these markets.

2. The utility shall consider the accuracy of previous forecasts as an important criterion in selecting providers of fuel price forecasts.

The Risk & Uncertainty Analysis Briefing and Section 4 of the Integrated Resource Analysis provide a detailed discussion of the various fuel markets, forecasts and factors that may affect these markets.

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;

The Risk & Uncertainty Analysis Briefing and Section 4 of the Integrated Resource Analysis provide a detailed discussion of the various fuel markets, forecasts and factors that may affect these markets.

(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.

Section 6.6 of the Integrated Resource Analysis and the eight Generation Technology Reports provide this information.

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;

Section 8.3 of the Risk & Uncertainty Analysis Briefing provides a discussion of the capital costs for the various supply-side options including ranges of estimates and associated subjective probabilities.

(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;

Section 6 of the Integrated Resource Analysis provides a discussion of the fixed and variable O&M costs for the various supply-side options. Section 8.3 of the Risk & Uncertainty Analysis Briefing discusses ranges of estimates and associated subjective probabilities.

(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

Section 4.2 of the Integrated Resource Analysis provides a discussion of the forecast value of SO_2 emission allowances. Section 8 of the Integrated Resource Analysis and the Risk & Uncertainty Analysis Briefing discuss the stochastic treatment of SO_2 emission allowance prices.

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

Section 4 of the Integrated Resource Analysis provides a discussion of the financial parameters used to develop the fixed charges for new construction. Section 6 of the Integrated Resource

Analysis and the eight Generation Technology Reports provide the capital costs of new construction.

(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;

Section 6.10 of the Integrated Resource Analysis provides a discussion of the screening analysis. Tables 6.9 – 6.11 show the costs for each resource option under the two environmental scenarios.

2. Identification of candidate resource options that may be included in alternative resource plans; and

Section 6.10.4 of the Integrated Resource Analysis includes a list of candidate resource options that were included in alternative resource plans.

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;

Section 6.10 of the Integrated Resource Analysis provides a discussion of the criteria used in screening out certain supply-side resources from further analysis. Although these technologies are not included as resource options at this time, the Company will continue to monitor and evaluate them as advancements are made.

(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;

Section 6.10.4 of the Integrated Resource Analysis includes a list of candidate resource options that were included in alternative resource plans. Forecasts, estimates and probability distributions described in section (8) were developed for all resource options in this list.

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

Section 8 of the Integrated Resource Analysis provides a summary of the results of the uncertainty analysis described in section (8) that was completed for candidate resource options.

(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.

Sections 4, 6, 7, 8 and 9 of the Integrated Resource Analysis and the Risk & Uncertainty Analysis Briefing provide a discussion of the probable environmental costs, how they were developed and how they were used in the analysis.

4 CSR 240-22.050 DEMAND-SIDE RESOURCE ANALYSIS

***PURPOSE:** This rule specifies the methods by which end-use measures and demand-side programs shall be developed and screened for cost-effectiveness. It also requires the ongoing evaluation of end-use measures and programs, and the use of program evaluation information to improve program design and cost-effectiveness analysis.*

***(1) Identification of End-Use Measures.** The analysis of demand-side resources shall begin with the development of a menu of energy efficiency and energy management measures that provides broad coverage of -*

(A) All major customer classes, including at least residential, commercial, industrial and interruptible;

AmerenUE used the same menu of energy efficiency measures that it considered in its 1993 IRP plan. See Appendix 2 of the Demand Side Management Briefing (“DSMB”) document. Refer to Section 2 of the DSMB for an explanation why AmerenUE used the results of its 1993 screening analyses of end-use measures as a proxy for its identification of end-use measures that ultimately are rolled up into best-of-class programs.

(B) All significant decision makers, including at least those who choose building design features and thermal integrity levels, equipment and appliance efficiency levels, and utilization levels of the energy-using capital stock;

The menu of energy efficiency measures considered was comprehensive with respect to decision makers in the areas described. For a complete menu of energy efficiency measures considered, see Appendix II of the DSMB document.

(C) All major end uses, including at least lighting, refrigeration, space cooling, space heating, water heating and motive power; and

All major end uses of electricity were included in the development of the menu. For a complete menu of energy efficiency measures considered, see Appendix 2 of the DSMB.

(D) Renewable energy sources and energy technologies that substitute for electricity at the point of use.

These energy sources and technologies were included in the menu of energy efficiency measures. Specifically, the residential and commercial menus included solar space heating and water heating. For a complete menu of energy efficiency measures considered, see Appendix 2 of the DSMB.

***(2) Calculation of Avoided Costs.** The utility shall develop estimates of the cost savings that can be obtained by substituting demand-side resources for existing and new supply-side resources. These avoided cost estimates, expressed in nominal dollars, shall be used for cost-effectiveness screening and ranking of end-use measures and demand-side programs.*

(A) Supply Resource Cost Estimates. The utility shall use the cost estimates developed pursuant to 4 CSR 240-22.040(2) to calculate the following two (2) estimates of avoided cost: avoided utility costs and avoided utility costs plus avoided probable environmental costs.

1. The choice of new generation options used to calculate avoided costs shall be limited to those which will meet the need for capacity under the base-case load forecast at approximately the lowest present value of utility revenue requirements over the planning horizon. The utility shall document the basis on which the timing and choice of the new generation options were determined to be approximately least cost.

See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

2. ***The utility shall calculate the annual capacity cost of each new generation option and new transmission and distribution facilities as the sum of the levelized capital cost per kilowatt-year and the fixed operation and maintenance cost per kilowatt-year.***

Market marginal energy costs and regulatory capacity costs were used. See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

3. ***The utility shall calculate the direct running cost of each generation option as the sum of fuel costs, sulfur dioxide emission allowance costs, and variable operation and maintenance costs per kilowatt-hour. The probable environmental costs calculated pursuant to 4 CSR 240-22.040(2)(B) shall also be expressed on a per-kilowatt-hour basis for both existing and new generation resources.***

AmerenUE provided two alternative scenarios of expected hourly marginal energy costs over the next twenty years – one that included anticipated environmental costs (CAIR) and one the included potentially higher costs associated with addressing greenhouse gas emissions. See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

(B) Avoided Cost Periods. The utility shall determine avoided cost periods by grouping hours on a seasonal (for example, summer, winter and transition) and time-of-use basis (for example, on-peak, off-peak, super-peak or shoulder-peak) as required to adequately reflect significant differences in running costs and the type of capacity being utilized to maintain required reserve margins.

See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost periods used.

(C) Calculation of Avoided Capacity and Running Costs. Avoided costs shall be calculated as the difference in costs associated with a specified decrement in load large enough to delay the on-line date of the new capacity additions by at least one (1) year.

1. ***Avoided running cost. For each year of the planning horizon and for each avoided cost period, the utility shall calculate the avoided direct running cost per kilowatt-hour (including sulfur dioxide emission allowance costs) and the avoided probable environmental running cost per kilowatt-hour due to the specified load decrement.***

See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

2. ***Avoided capacity costs. The utility shall calculate and document the avoided capacity costs per kilowatt-year for each year of the planning horizon.***
   - ***A. This calculation shall include the costs of any new generation, transmission and distribution facilities that are delayed or avoided because of the specified load decrement.***

Market marginal energy costs and regulatory capacity costs were used. See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

B. *For each year of the planning horizon, the utility shall determine the avoided cost periods in which the avoided new generation, transmission and distribution capacity was utilized, and shall allocate a nonzero portion of the annualized avoided capacity costs to each of the periods in which that capacity was utilized.*

Market marginal energy costs and regulatory capacity costs were used. See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

(D) Avoided Demand and Energy Costs. The utility shall use the avoided capacity and running costs (appropriately adjusted to reflect reliability reserve margins, demand losses and energy losses) to calculate the avoided demand and energy costs for each avoided cost period. Demand periods shall be defined as the avoided cost periods in which there is a significant probability of a loss of load (for example, periods which require the use of peaking capacity to maintain power pool reserve margins). Nondemand periods are the avoided cost periods in which there is not a significant probability of a loss of load.

1. *Demand period avoided demand costs. Avoided demand costs per kilowatt-year for the demand periods of each season shall include avoided transmission and distribution capacity costs, plus the smaller of the avoided generation capacity cost allocated to the demand period or the avoided capacity cost of peaking capacity.*

Market marginal energy costs and regulatory capacity costs were used. See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

2. *Demand period avoided energy costs. Any capacity cost per kilowatt-year allocated to the demand periods but not included in the avoided demand cost shall be converted to an avoided energy cost by dividing the avoided capacity cost per kilowatt-year by the number of hours in the associated demand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to paragraph (2)(C)1. to calculate the demand period direct energy costs and the probable environmental energy costs.*

The Company identified no capacity costs to which this rule applies.

3. *Nondemand period avoided demand cost. The avoided demand cost for the nondemand periods is zero.*
4. *Nondemand Period Avoided Energy Costs. Avoided capacity cost per kilowatt-year allocated to the nondemand periods within each season shall be converted to a per-kilowatt-hour cost by dividing the avoided capacity cost per kilowatt-year by the number of hours in the associated nondemand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to paragraph (2)(C)1. to calculate the nondemand period direct energy costs and the probable environmental energy costs.*

Market marginal energy costs and regulatory capacity costs were used. See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used..

5. *Annual avoided demand and energy costs. Annual avoided demand costs shall include avoided transmission and distribution capacity costs, plus the smaller of the annual avoided generation capacity costs or the avoided capacity cost of peaking capacity. Annual avoided energy costs shall include annual avoided running costs plus any avoided capacity costs not included in the annual demand cost.*

Market marginal energy costs and regulatory capacity costs were used. See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

(3) Cost-Effectiveness Screening of End-Use Measures. The utility shall evaluate the cost-effectiveness of each end-use measure identified pursuant to section (1) using the probable environmental benefits test. All costs and benefits shall be expressed in nominal dollars.

(A) The utility shall develop estimates of the end-use measure demand reduction for each demand period and energy savings per installation for each avoided cost period on a normal-weather basis. If the utility can show that subannual load impact estimates are not required to capture the potential benefits of an end-use measure, annual estimates of demand and energy savings may be used for cost-effectiveness screening.

See Section 4 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the screening analysis of programs that incorporate cost effective end-use measures.

(B) Benefits per installation of each end-use measure in each avoided cost period shall be calculated as the demand reduction multiplied by the levelized avoided demand cost plus the energy savings multiplied by the levelized avoided energy cost.

1. Avoided costs in each avoided cost period shall be levelized over the planning horizon using the utility discount rate.

Market marginal energy costs and regulatory capacity costs were used. See Section 3.2.1 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of avoided cost data used.

2. Annualized benefits shall be calculated as the sum of the levelized benefits over all avoided cost periods.

Refer to the 1993 analysis. Numerical results are provided in Appendix 2 in the document titled Demand-Side Management Plan-Appendices.

(C) Annualized costs per installation for each end-use measure shall be calculated as the sum of the following components:

1. Incremental costs of implementing the measure (regardless of who pays these costs), levelized over the life of the measure using the utility discount rate;

Assumptions and calculations can be found in Appendix 2 in the document titled Demand-Side Management Plan-Appendices.

2. Incremental annual operation and maintenance costs (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate; and

Where appropriate, these costs were embedded in the incremental cost of each measure and can be found in Appendix 2 in the document titled Demand-Side Management Plan-Appendices.

3. Any probable environmental impact mitigation costs due to implementation of the end-use measure that are borne by either the utility or the customer.

These costs tend to be site specific and are highly uncertain. Therefore, no costs of this type were estimated for end-use measures.

(D) Annualized costs for end-use measures shall not include either utility marketing and delivery costs for demand-side programs or lost revenues due to measure-induced reductions in energy sales or billing demands between rate cases.

Such costs were not included in the measure level screening analysis.

(E) Annualized benefits minus annualized costs per installation must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for an end-use measure to pass the screening test. The utility may relax this criterion for measures that are judged to have potential benefits that are not captured by the estimated load impacts or avoided costs.

In its 1993 analyses, AmerenUE chose to use a ratio of annualized benefits to annualized costs for each measure. Any measure with a ratio greater than 0.95 (including probable environmental costs) was passed to the program level screening analysis. This helped ensure that measures were not prematurely eliminated from the analysis. Full discussions of AmerenUE's approach are provided in Section 2 in Appendix 2 in the document titled Screening Analysis of Demand-Side Management (DSM) Programs.

(F) End-use measures that pass the probable environmental benefits test must be included in at least one (1) potential demand-side program.

AmerenUE developed demand-side programs based on the measure level screening results from its 1993 analysis work and actual pilot program implementation results. See Section 2 of the Screening Analysis of Demand-Side Management (DSM) Programs for a full discussion of program development.

(G) For each end-use measure that passes the probable environmental benefits test, the utility shall also perform the utility benefits test for informational purposes. This calculation shall include the cost components identified in paragraphs (3)(C)1. and 2.

The utility benefits test was provided for all measures, not just those passing the probable environmental benefits test. Full results of these calculations are provided in Appendix 2 in the document DSMP-Appendices.

(4) The utility shall estimate the technical potential of each end-use measure that passes the screening test.

It was not practical in1993 or today to calculate the technical potential of each measure given the number of measures screened. In 1993 AmerenUE requested a waiver to provide technical potential data for all programs included in the Company's program level screening analysis, instead of for individual measures as specified by the rule.

(5) The utility shall conduct market research studies, customer surveys, pilot demand-side programs, test marketing programs and other activities as necessary to estimate the technical potential of end-use measures and to develop the information necessary to design and implement cost-effective demand-side programs. These research activities shall be designed to provide a solid foundation of information about how and by whom

energy-related decisions are made, and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long run energy efficiency.

See Section 2 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the list of viable DSM programs. See Section ES 2 of the Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of viable demand response programs.

(6) The utility shall develop a set of potential demand-side programs that are designed to deliver an appropriate selection of end-use measures to each market segment. The demand-side program planning and design process shall include at least the following activities and elements:

(A) Identify market segments that are numerous and diverse enough to provide relatively complete coverage of the classes and decision makers identified in subsections (1)(A) and (B), and that are specifically defined to reflect the primary market imperfections that are common to the members of the market segment;

See Section 2 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the list of viable DSM programs by class. See Section ES 2 of the Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of viable demand response programs by class.

(B) Analyze the interactions between end-use measures (for example, more efficient lighting reduces the savings related to efficiency gains in cooling equipment because efficient lighting reduces intrinsic heat gain);

This analysis was considered in 1993. However, in order to avoid prematurely eliminating demand-side measures, the economic screening considered each measure by itself, without concern for interactive effects.

(C) Assemble menus of end-use measures that are appropriate to the shared characteristics of each market segment and cost-effective as measured by the screening test; and

See Section 2 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the list of viable DSM programs See Section ES 2 of the Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of viable demand response programs.

(D) Design a marketing plan and delivery process to present the menu of end-use measures to the members of each market segment and to persuade decision makers to implement as many of these measures as may be appropriate to their situation.

See Section 2 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the list of viable DSM programs See Section ES 2 of the Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of viable demand response programs.

(7) Cost-Effectiveness Screening of Demand-Side Programs. The utility shall evaluate the cost-effectiveness of each potential demand-side program developed pursuant to section (6) using the total resource cost test. The

utility cost test shall also be performed for purposes of comparison. All costs and benefits shall be expressed in nominal dollars. The following procedure shall be used to perform these tests:

(A) The utility shall estimate the incremental and cumulative number of program participants and end-use measure installations due to the program, and the incremental and cumulative demand reduction and energy savings due to the program in each avoided cost period in each year of the planning horizon.

1. Initial estimates of demand-side program load impacts shall be based on the best available information from in-house research, vendors, consultants, industry research groups, national laboratories or other credible sources.

[redacted] ("[redacted] estimated program participation rates as discussed in Section 2 of the <u>Screening Analysis of Demand-Side Management (DSM) Programs</u> in Appendix 2. [redacted] went beyond the requirements of this rule by analyzing programs using the RIM and Net Economic Benefits ("NEB") tests in addition to the TRC test.

2. As the load-impact measurements required by subsection (9)(B) become available, these results shall be used in the ongoing development and screening of demand-side programs and in the development of alternative resource plans;

Impact evaluation of AmerenUE pilot programs conducted in the 1990s as well as impact evaluations of the best practices programs across the nation were used in the screening analysis of programs.

(B) In each year of the planning horizon, the benefits of each demand-side program shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost, summed over the avoided cost periods within each year. These calculations shall be performed using the avoided probable environmental costs developed pursuant to section (2);

See Section 3 of the <u>Screening Analysis of Demand-Side Management (DSM) Programs</u> in Appendix 2 for a full discussion of the calculation of the benefits of each demand-side program.

(C) Utility Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all utility incentive payments plus utility costs to administer, deliver, and evaluate each demand-side program. For purposes of this test, demand-side program costs shall not include lost revenues or costs paid by participants in demand-side programs;

[redacted] estimated the costs of each demand-side program. See the <u>Screening Analysis of Demand-Side Management (DSM) Programs</u> in Appendix 2 for a full discussion.

(D) Total Resource Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus utility costs to administer, deliver and evaluate each demand-side program. For purposes of this test, demand-side program costs shall not include lost revenues or utility incentive payments to customers;

[redacted] calculated the Total Resource Cost Test for each potential demand-side program. See Section 4 of the <u>Screening Analysis of Demand-Side Management (DSM) Programs</u> in Appendix 2 for a full discussion of viable DSM programs. See Section ES 3 of the

Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of viable demand response programs.

- ***(E)*** ***The present value of program benefits minus the present value of program costs over the planning horizon must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for a demand-side program to pass the utility cost test or the total resource cost test. The utility may relax this criterion for programs that are judged to have potential benefits that are not captured by the estimated load impacts or avoided costs;***

[redacted] calculated a ratio of present valued benefits to present valued costs. Any program with a Total Resource Cost Test ratio greater than or equal to one was considered for integrated resource analysis.

- ***(F)*** ***Potential demand-side programs that pass the total resource cost test shall be considered as candidate resource options and must be included in at least one (1) alternative resource plan developed pursuant to 4 CSR 240-22.060(3).***

The MIDAS model was used to perform a final, more detailed screening of potential demand-side programs. Cost effectiveness was again based on the Total Resource Cost Test, including probable environmental costs. Programs passing this test were considered potential demand-side resources and were included in the development of alternative resource plans. Results of the MIDAS simulations are summarized in Section 8.2 of the Integrated Resource Analysis.

(8) ***For each demand-side program that passes the total resource cost test, the utility shall develop time-differentiated load impact estimates over the planning horizon at the level of detail required by the supply system simulation model that is used in the integrated resource analysis required by 4 CSR 240-22.060(4).***

[redacted] developed the time-differentiated load impacts estimates that were used as inputs for the Midas simulations. See Demand-Side Management Briefing – Appendix 1, Resource Planning Inputs.

(9) ***Evaluation of Demand-Side Programs. The utility shall develop evaluation plans for all demand-side programs that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(6). The purpose of these evaluations shall be to develop the information necessary to improve the design of existing and future demand-side programs, and to gather data on the implementation costs and load impacts of programs for use in cost-effectiveness screening and integrated resource analysis.***

- ***(A)*** ***Process Evaluation. Each demand-side program that is part of the utility's preferred resource plan shall be subjected to an ongoing evaluation process that addresses at least the following questions about program design:***
    1. ***What are the primary market imperfections that are common to the target market segment?***
    2. ***Is the target market segment appropriately defined, or should it be further subdivided or merged with other segments?***
    3. ***Does the mix of end-use measures included in the program appropriately reflect the diversity of end-use energy service needs and existing end-use technologies within the target segment?***
    4. ***Are the communication channels and delivery mechanisms appropriate for the target segment?***
    5. ***What can be done to more effectively overcome the identified market imperfections and to increase the rate of customer acceptance and implementation of each end-use measure included in the program?***
- ***(B)*** ***Impact Evaluation. The utility shall develop methods of estimating the actual load impacts of each demand-side program included in the utility's preferred resource plan to a reasonable degree of accuracy.***

1. ***Impact evaluation methods. Comparisons of one (1) or both of the following types shall be used to measure program impacts in a manner that is based on sound statistical principles:***
   A. ***Comparisons of pre-adoption and post-adoption loads of program participants, corrected for the effects of weather and other intertemporal differences; and***
   B. ***Comparisons between program participants' loads and those of an appropriate control group over the same time period.***

AmerenUE proposes that evaluation plans for all programs included in the preferred resource plan be developed by both energy efficiency and demand response collaborative teams comprised of AmerenUE, Staff, OPC and all interested stakeholders.

2. ***The utility shall develop load-impact measurement protocols that are designed to make the most cost-effective use of the following types of measurements, either individually or in combination: monthly billing data, load-research data, end-use load metered data, building and equipment simulation models, and survey responses or audit data on appliance and equipment type, size and efficiency levels, household or business characteristics, or energy-related building characteristics.***

Such methods will be developed as the Company continues to implement and evaluate pilot energy efficiency programs.

(C) The utility shall develop protocols to collect data regarding demand-side program market potential, participation rates, utility costs, participant costs, and total costs.

Such methods will be developed as the Company continues to implement and evaluate pilot energy efficiency programs.

(10) Demand-side programs and load building programs shall be separately designed and administered, and all costs shall be separately classified so as to permit a clear distinction between demand-side program costs and the costs of load-building programs. The costs of demand-side resource development that also serve other functions shall be allocated between the functions served.

The Company has complied with this requirement. There are no load building components to any of the load impacts estimated for programs included in the screening analyses.

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

(A) A list of the end-use measures developed for initial screening pursuant to the requirements of section (1) of this rule;

See the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the list of viable DSM programs See Section ES 2 of the Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of viable demand response programs..

(B) The estimated load impacts, annualized costs per installation and the results of the probable environmental benefits test for each end-use measure identified pursuant to section (1);

See the 1993 work in Appendix 2 on the DSMP-Appendices.

(C) The technical potential and the results of the utility benefits test for each end-use measure that passes the probable environmental benefits test;

See Sections 1, 2, 3, and 4 of the Demand-Side Management Briefing – Appendix 1, Screening Analysis of Demand-Side Management Programs for a full discussion of technical potential and results of the various tests for the DSM programs. See Sections 2, 3, 4, and 5 of the Demand-Side Management Briefing – Appendix 1, Screening Analysis of Demand Response Programs for the demand response programs.

(D) Documentation of the methods and assumptions used to develop the avoided cost estimates developed pursuant to section (2) including:

1. A description of the type and timing of new supply resources, including transmission and distribution facilities, used to calculate avoided capacity costs;

See the Regulatory Capacity Cost Assumptions in Demand-Side Management Briefing – Appendix 1.

2. A description of the assumptions and procedure used to calculate avoided running costs;

AmerenUE used its fundamentally developed electric price forecast(s) of the wholesale market for the avoided running costs. For a discussion of the development of the electric price forecast, see the Integrated Resource Analysis Section 4, Wholesale Electric Market Price Simulation.

3. A description of the avoided cost periods and how they were determined;

AmerenUE used hourly prices from it's wholesale electric price forecast avoided costs. The energy efficiency and demand response modeling used these hourly prices and did not require a "higher" summarized periods.

4. A tabulation of the direct running costs and the probable environmental running costs for each avoided cost period in each year of the planning horizon; and

5. A tabulation of the avoided demand cost, the avoided direct energy costs and the avoided probable environmental energy costs for each avoided cost period in each year of the planning horizon;

[redacted]

In order to put the hourly data into a readable tabular format, the expected wholesale electric prices for three energy products were calculated.

(E) Copies of completed market research studies, pilot programs, test marketing programs and other studies as required by section (5) of this rule, and descriptions of those studies that are planned or in progress and the scheduled completion dates;

See Section 2 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the list of market research studies. See Section ES 2 of the Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of market research studies.

(F) A description of each market segment identified pursuant to subsection (6)(A);

The market segments identified in this study were primarily related to customer class.

(G) A description of each demand-side program developed for initial screening pursuant to section (6) of this rule;

See Section 2 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the list of viable DSM programs. See Section ES 2 of the Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of viable demand response programs.

(H) A tabulation of the incremental and cumulative number of participants, load impacts, utility costs and program participant costs in each year of the planning horizon for each demand-side program developed pursuant to section (6) of this rule;

See the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2 for a full discussion of the list of assumptions for viable DSM programs. See the Screening Analysis of Demand Response Programs in Appendix 2 for a full discussion of the list of assumptions for viable demand response programs.

(I) The results of the utility cost test and the total resource cost test for each demand-side program developed pursuant to section (6) of this rule; and

See Table 2a through 7 of the Screening Analysis of Demand-Side Management (DSM) Programs in Appendix 2. See Tables 7 through 15 of the Screening Analysis of Demand Response Programs in Appendix 2.

(J) A description of the process and impact evaluation plans for demand-side programs that are included in the preferred resource plan as required by section (9) of this rule and the results of any such evaluations that have been completed since the utility's last scheduled filing pursuant to 4 CSR 240-22.080.

AmerenUE proposes that evaluation plans for all programs included in the preferred resource plan be developed by both energy efficiency and demand response collaborative teams comprised of AmerenUE, Staff, OPC and all interested stakeholders.

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.

See Section 7 of the Integrated Resource Analysis for a description of the alternative resource plans developed.

(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).

The Company incorporated the performance measures specified above in plan development.

(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.

See Section 7 of the Integrated Resource Analysis for a description of the alternative resource plans developed.

(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;

The relative performance of each alternative resource plans was assessed using the performance measures specified in Section (2) of this rule. Section 8 - Results of the Integrated Resource Analysis contains graphs with the measures identified. In addition, see the response to Sections 4CSR 240-22.060.(6).(B) of this rule.

(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;

The Company's modeling procedure assumed that rates would be adjusted annually in a manner that is consistent with current Missouri law.

(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

For a discussion of the role of electricity prices in the various class load forecasts see the <u>2005 Load Forecast Data and Methodology</u>. Estimates of price elasticity were supplied by RER (now Itron) from REEPS and COMMEND models after checking the reasonableness of the price elasticities by running regression models on average use per customer as the dependent variable and prices, weather and trend variables as independent variables.

(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.

The Company utilized consistent and economically equivalent methods in its consideration of supply-side and demand-side resources. See Sections 5, 6, 7 and 8 of the <u>Integrated Resource Analysis</u> and the <u>Demand-Side Management Briefing</u>.

(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;

AmerenUE does not have any load building programs.

(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;

AmerenUE does not have any load building programs.

(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

AmerenUE does not have any load building programs.

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

AmerenUE does not have any load building programs.

(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;

See Section 7 of the <u>Integrated Resource Analysis.</u>

(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;

See Table 60-6.(B) below for present worth of utility revenue requirements, levelized annual average rates and maximum single-year increase in annual average rates.

The probable environmental costs is implicitly included in all modeling and revenue requirement calculations. For a full discussion See Section 4, Emission Allowance & Prices and Wholesale Electric Market Price Simulation, of the Integrated Resource Analysis.

The out-of-pocket costs to participants in demand-side programs is listed in Demand-Side Management Briefing - Appendix 1.

(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;***

See Section 5 of the Integrated Resource Analysis, Demand-Side Management Briefing, and Demand-Side Management Briefing - Appendix 1.

2. ***The composition, by program, of the capacity provided by demand-side resources;***

See Section 7 of the Integrated Resource Analysis-Table 7.1 Demand Impacts, Demand-Side Management Briefing, and Demand-Side Management Briefing - Appendix 1.

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;***

Many portfolios (18) were tested in the detailed System level modeling. The preferred portfolio and two others (RI3 SC PC and PS Mod Medium) were put into graphs to satisfy this rule. See Figures 60-6.(C). 3.a thru 60-6.(C). 3.c below. A table was used for the remaining portfolios, see Section 6, Table 6.1 AmerenUE 2005 Generating Capability – Existing and Section 7, Table 7.2 Portfolios. Graphs of the other portfolios can be made available upon request.

4. ***The combined impact of all demand-side resources on the base-case forecast of annual energy requirements;***

See Section 7 of the Integrated Resource Analysis-Table 7.1 Demand Impacts, Demand-Side Management Briefing, and Demand-Side Management Briefing - Appendix 1.

5. ***The composition, by program, of the annual energy provided by demand-side resources;***

See Section 5 of the Integrated Resource Analysis, Demand-Side Management Briefing, and Demand-Side Management Briefing - Appendix 1.

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;***

Many portfolios (18) were tested in the detailed System level modeling. The preferred portfolio and two others (RI3 SC PC and PS Mod Medium) were put into graphs to satisfy this rule. See Figures 60-6.(C).6.a thru 60-6.(C). 6.c. Graphs of the other portfolios can be made available upon request.

7. The values of the three (3) measures of financial condition identified in subsection (4)(A);

Figures 60-6.(C).7.a thru 60-6.(C). 7.c at the end of this section provide twenty years of data for the following financial ratios as calculated by the MIDAS model:

Interest Coverage with AFUDC	=	(Operating Revenues – Total Operating Expenses – Operating Revenue Tax – Other Taxes)/(Interest on Long-Term Debt + Interest on Short-Term Debt) Note: **This ratio is calculated using after tax data.** Long term debt includes current maturities.
Total Debt to Total Capital	=	(Long-Term Debt + Short-Term Debt)/(Total Capital + Short-Term Debt) Note: Long term debt includes current maturities.
Internal Cash to Capital Expense	=	(Total Cash Provided by Operations – Capital Service Payments)/Construction Expenditures Note: This ratio excludes changes in working capital.

Many portfolios (18) were tested in the detailed System level modeling. The preferred portfolio and two others (RI3 SC PC and PS Mod Medium) were put into graphs to satisfy this rule. See Figures 60-6.(C).7.a thru 60-6.(C). 7.c. Graphs of the other portfolios can be made available upon request.

8. Annual average rates;

The IRP Financial Model includes the total revenue requirement costs associated with investment in new supply-side resources and new transmission as well as costs for existing generation assets' capital revenue requirement, existing generation assets' fixed O&M, and other non-electricity supply costs such as distribution, transmission and general plant capital and operating costs. However, the costs that are deemed common to all IRP portfolios are meant to be representative not absolute. Because the costs common to all portfolios are representative, the impact calculation is only relevant when comparing one IRP portfolio against another. While the impact calculation provides yearly directional implications of rate changes associated with the IRP, it cannot provide a projection of total AmerenUE revenue requirement impacts. Many portfolios (18) were tested in the detailed System level modeling. The preferred portfolio and two others (RI3 SC PC and PS Mod Medium) were put into graphs to satisfy this rule. See Figures 60-6.(C).8. Graphs of the other portfolios will be made available upon request.

9. Annual emissions of each environmental pollutant identified pursuant to 4 CSR 240-22.040(2)(B)1; and

Many portfolios (18) were tested in the detailed System level modeling. The preferred portfolio and two others (RI3 SC PC and PS Mod Medium) were put into graphs to satisfy this rule. See Figures 60-6.(C).9.a thru 0-6.(C).9.c. Graphs of the other portfolios can be made available upon request.

10. Annual probable environmental costs.

See Section 4.2 Emission Allowances and Prices of the Integrated Resource Analysis and Risk & Uncertainity Analysis Briefing, Discussion of Historical Data Analyses and Simulation Parameter Development.

(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;

For a discussion of the role of electricity prices in the various class load forecasts see the 2005 Load Forecast Data and Methodology. Estimates of price elasticity were supplied by RER (now Itron) from REEPS and COMMEND models after checking the reasonableness of the price elasticities by running regression models on average use per customer as the dependent variable and prices, weather and trend variables as independent variables.

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

See Sections 2 and 4, and Appendix D of the Integrated Resource Analysis.

(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:

AmerenUE does not have any load building programs.

1. Annual average rates with and without the load-building programs; and

N/A. See response to 4CSR 240-22.060.(6).(F)

2. Annual utility costs and probable environmental costs with and without the load-building programs.

N/A. See response to 4CSR 240-22.060.(6).(F)

Table 60-6.(B)

	PVRR ($ millions)	Levelized Annual Rate (¢/KWh)	Maxium Single Yr Rate Incr (¢/KWh)
CT: Buy 600MW	$26,789	7.167	0.516
Grnfld SC PC	$26,876	7.190	0.516
RI3 SC PC	$26,868	7.188	0.517
PS Mod Medium	$26,964	7.214	0.517
PS Base	$27,032	7.232	0.517
Combined Cycle	$26,985	7.220	0.516
Nuclear	$27,104	7.252	0.970
Wind: CT Buy 600MW	$26,866	7.188	0.516
Wind: RI3 SC PC	$26,954	7.211	0.517
Wind: PS Mod Medium	$27,053	7.238	0.517
CT: Bld All	$27,176	7.271	0.516
CT:Buy 1350MW	$26,695	7.142	0.503
IGCC 600MW	$27,054	7.238	0.561
IGCC 750MW PRB	$27,094	7.249	0.650
IGCC 750MW IL#6	$26,976	7.217	0.560
DREE: CT Buy 600MW	$26,661	7.133	0.521
DREE: RI3 SC PC	$26,722	7.149	0.522
DREE: PS Mod Medium	$26,855	7.185	0.522

The IRP Financial Model includes the total revenue requirement costs associated with investment in new supply-side resources and new transmission as well as costs for existing generation assets' capital revenue requirement, existing generation assets' fixed O&M, and other non-electricity supply costs such as distribution, transmission and general plant capital and operating costs. However, the costs that are deemed common to all IRP portfolios are meant to be representative not absolute. Because the costs common to all portfolios are representative, the impact calculation is only relevant when comparing one IRP portfolio against another. While the impact calculation provides yearly directional implications of rate changes associated with the IRP, it cannot provide a projection of total AmerenUE revenue requirement impacts.

Figure 60-6.(C). 3.a

[redacted]

Figure 60-6.(C). 3.b

[redacted]

Figure 60-6.(C). 3.c

[redacted]

Figure 60-6.(C). 6.a

[redacted]

Figure 60-6.(C). 6.b

[redacted]

Figure 60-6.(C). 6.c

[redacted]

Figure 60-6.(C). 7.a

[redacted]

Figure 60-6.(C). 7.b

[redacted]

Figure 60-6.(C). 7.c

[redacted]

Figure 60-6.(C). 8

[redacted]

Figure 60-6.(C). 9.a

[redacted]

Figure 60-6.(C). 9.b

[redacted]

Figure 60-6.(C). 9.c

[redacted]

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.

For reasons described in Sections 3 and 4 of the Risk & Uncertainty Analysis Briefing, AmerenUE has developed a comprehensive stochastic analysis employing a state-of-the-art simulation analysis, a scenario analysis, and a sensitivity analysis. The decision tree structure underlies all three of these analysis techniques within the MIDAS model framework.

(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.***

See the Sections 4 and 8 Integrated Resource Analysis and Section 5 of the Risk & Uncertainty Analysis Briefing,

(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.

See Sections 4, 7, and 8 Integrated Resource Analysis and Section 5 of the Risk & Uncertainty Analysis Briefing.

(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.

Load growth risk was assessed in the simulation analysis. Load growth was varied on a monthly basis through Latin-Hypercube sampling for the duration of the evaluation period. See Section 8 of the Integrated Resource Analysis for the results of the simulation analysis and Section 5 of the

Risk & Uncertainty Analysis Briefing for the development of the descriptive parameters underlying the peak load and energy probability distributions used in the simulation.

(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.

See Section 8 of the Integrated Resource Analysis.

(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.

See Section 8 of the Integrated Resource Analysis.

(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

See Section 9 of the Integrated Resource Analysis.

(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.

The preferred resource plan does not indicate a consistent increase in the need for emergency imported power over the planning horizon. AmerenUE currently plans to a[redacted]percent short-term and a[redacted]percent long-term planning reserve margin to meet any system contingencies related to either extreme weather or forced outages of generating plants. See Section 4 of the Integrated Resource Analysis for a complete description of the planning standards employed by AmerenUE.

(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.

An hourly, twenty year load dataset was used to calculate the resource plan's reliability. The original forecast used by MIDAS conforms to the rules' requirements as stated in 22.030.

(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).

For this purpose, AmerenUE uses the **EnerPrise Strategic Planning** *powered by* MIDAS Gold®. Midas provides a very precise analysis of resource interactions, such as chronological dispatch based heat rates, fuel costs, variable operation and maintenance costs, emission allowance costs, schedule maintenances outages, EFOR, off-system purchases, and off-system sales. (See the Integrated Resources Analysis Appendix for more detailed information on the Cost Analysis Models). Combined with other financial costs, these factors provide valuable information as to expected operation of an entire electric system.

MIDAS Gold® calculates and reports unserved hours as one of the many reporting variables. Because AmerenUE's system is large, is interconnected to large and liquid markets for electricity, and has a diverse mix of generation technologies, varied sizes of plants, and a robust transmission system, none of the portfolios experienced any unserved hours in the simulations.

(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.

The expected value of perfect information (EVPI) is defined as the expected value if the future uncertain outcomes could be known minus the expected value with no additional information. The EVPI can be developed from the risk simulation analysis and from the CO_2 scenarios. In the risk simulation, [redacted] re uncertain. Since the deterministic portfolio runs assume perfect information for all of these forecasts/assumptions, the EVPI can be developed by subtracting the simulation results for each portfolio from the deterministic results. Table 1 below shows the results of the EVPI analysis of the risk simulation.

	Deterministic	Simulation	EVPI
CT: Buy 1350MW	26,695	26,494	201
CT: Buy 600MW	26,789	26,595	193
RI3 SC PC	26,868	26,594	273
Grnfld SC PC	26,876	26,604	272
PS 600MW	26,964	26,784	180
IGCC 750MW IL#6	26,976	26,700	275
Combined Cycle	26,985	26,732	254
PS 800MW	27,032	26,855	176
IGCC 600MW	27,054	26,804	250
IGCC 750MW PRB	27,094	26,828	266
Nuclear	27,104	26,801	304
CT: Bld All	27,176	26,984	192

Table 1 – Risk Simulation EVPI Results ($ in millions)

In the carbon legislation scenarios, the deterministic results are the results which are uncertain, therefore, the EVPI is calculated as the individual carbon scenario results minus the deterministic results. The EVPI for the carbon scenarios are shown in Table 2.

		Greenhouse Gas Cases							
	Deterministic	Mild	EVPI	Moderate	EVPI	Stringent	EVPI	Nuclear	EVPI
CT: Buy 1350MW	26,695	26,955	260	27,237	542	27,518	823	27,794	1,099
CT: Buy 600MW	26,789	27,048	259	27,324	536	27,600	811	27,885	1,096
RI3 SC PC	26,868	27,203	335	27,441	573	27,680	812	28,302	1,434
Grnfld SC PC	26,876	27,214	338	27,450	575	27,691	815	28,313	1,438
PS 600MW	26,964	27,241	277	27,515	550	27,789	824	28,098	1,134
IGCC 750MW IL#6	26,976	27,280	305	27,481	505	27,686	710	28,289	1,313
Combined Cycle	26,985	27,249	263	27,528	543	27,815	830	28,125	1,140
PS 800MW	27,032	27,309	277	27,581	549	27,854	822	28,166	1,134
IGCC 600MW	27,054	27,348	294	27,560	506	27,774	720	28,321	1,266
IGCC 750MW PRB	27,094	27,417	323	27,642	548	27,871	777	28,474	1,380
Nuclear	27,104	27,168	64	26,983	(122)	26,802	(303)	27,555	451
CT: Bld All	27,176	27,434	258	27,711	535	27,987	811	28,269	1,093

Table 2 – Carbon Scenario EVPI Results ($ in millions)

(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;

See the <u>Load Forecast Data and Methodology</u>.

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

See the <u>Demand Side Management Brief</u>

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

See Sections 6 and 9 of the Integrated Resource Analysis.

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

See Section 9 of the Integrated Resource Analysis.

(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;

The Company has selected a preferred resource plan pursuant to the requirements of Section (6) of this rule. Executive management has reviewed and approved the preferred resource plan contained in Section 9 of the Integrated Resource Analysis.

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

The Company has developed an implementation plan pursuant to the requirements of Section (9) of this rule. Executive management has reviewed and approved the preferred resource plan contained in Section 9 of the Integrated Resource Analysis.

(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;

See Section 8 of the Integrated Resource Analysis and Section 5 of the Risk & Uncertainty Analysis Briefing.

(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

See Section 9 of the Integrated Resource Analysis

(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.

The following groups will be responsible for monitoring and reporting any changes in base case values which would impact the implementation plan. These groups will report any such changes to the Resource Planning Committee for their disposition.

Load Forecast – Corporate Planning will monitor load growth and review projections for future growth on an annual basis.

DSM Program Development – Corporate Planning and Customer Service will be working collaboratively with Staff, OPC, DNR, and all stakeholders to design, implement, evaluate and improve demand response and energy efficiency options to all customer classes.

EFOR – Power Operations will monitor operating availability and identify future trends to determine whether EFOR is deteriorating from current projections.

Commodity prices (coal, natural gas, oil, nuclear fuel) – AFS and Corporate Planning will monitor the fuel commodity and transportation markets to determine if the significant and sustained changes to the forecasts contained in the analysis change.

Environmental legislation/regulation – Environmental Safety and Health and Corporate Planning will monitor current and future environmental initiatives to determine if current cost projections and related assumptions should be modified.

(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

See the Section 9 Integrated Resource Analysis

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;

See Section 4 of the Integrated Resource Analysis and Section 5 of the Risk & Uncertainty Analysis Briefing.

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

See Section 8 of the Integrated Resource Analysis.

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

See Section 8 of the Integrated Resource Analysis.

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

Given the nature of the MISO market evolution there are no unserved hours, see Section 4 of the Integrated Resource Analysis for a more complete discussion.

(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;

See Section 8 of the Integrated Resource Analysis.

(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

See Sections 8 and 9 of the Integrated Resource Analysis.

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

See Section 9 of the Integrated Resource Analysis.