



Rules of
Department of Economic
Development
Division 240—Public Service Commission
Chapter 22—Electric Utility Resource
Planning

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**Title 4—DEPARTMENT OF
ECONOMIC DEVELOPMENT
Division 240—Public Service
Commission
Chapter 22—Electric Utility
Resource Planning**

4 CSR 240-22.010 Policy Objectives

PURPOSE: This rule states the public policy goal that this chapter is designed to achieve and identifies the objectives that the electric utility resource planning process must serve.

(1) The commission's policy goal in promulgating this chapter is to set minimum standards to govern the scope and objectives of the resource planning process that is required of electric utilities subject to its jurisdiction in order to ensure that the public interest is adequately served. Compliance with these rules shall not be construed to result in commission approval of the utility's resource plans, resource acquisition strategies, or investment decisions.

(2) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. The fundamental objective requires that the utility shall—

(A) Consider and analyze demand-side resources, renewable energy, and supply-side resources on an equivalent basis, subject to compliance with all legal mandates that may affect the selection of utility electric energy resources, in the resource planning process;

(B) Use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan, subject to the constraints in subsection (2)(C); and

(C) Explicitly identify and, where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs. The utility shall describe and document the process and rationale used by decision-makers to assess the tradeoffs and determine the appropriate balance between minimization of expected utility costs and these other considerations in selecting the preferred resource plan and developing the resource acquisition strategy. These consider-

ations shall include, but are not necessarily limited to, mitigation of:

1. Risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans;

2. Risks associated with new or more stringent legal mandates that may be imposed at some point within the planning horizon; and

3. Rate increases associated with alternative resource plans.

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.020 Definitions

PURPOSE: This rule defines terms used in the rules comprising 4 CSR 240-22—Electric Utility Resource Planning.

(1) Acknowledgment is an action the commission may take with respect to the officially adopted resource acquisition strategy or any element of the resource acquisition strategy including the preferred resource plan. Acknowledgement means that the commission finds the preferred resource plan, resource acquisition strategy, or the specified element of the resource acquisition strategy to be reasonable at a specific date, typically the date of the filing of the utility's Chapter 22 compliance filing or the date that acknowledgment is given. Acknowledgment may be given in whole, in part, or not at all. Acknowledgment shall not be construed to mean or constitute a finding as to the prudence, pre-approval, or prior commission authorization of any specific project or group of projects.

(2) Annual update filing means the annual update report prepared by the utility in advance of the annual update workshop and the summary report prepared by the utility following the workshop as referenced in 4 CSR 240-22.080(3).

(3) Candidate resource options are the potential demand-side resource options pursuant to 4 CSR 240-22.050(6) and the potential supply-side resource options pursuant to 4 CSR 240-22.040(4) that advance to be included in one (1) or more alternative resource plans.

(4) Capacity means the maximum capability to continuously produce and deliver electric power via supply-side resources or the avoidance of the need for this capability by demand-side resources.

(5) Coincident demand means the hourly demand of a component of system load at the hour of system peak demand within a specified interval of time.

(6) Concern means concerns with the electric utility's compliance with the provisions of this chapter, any major concerns with the methodologies or analyses required to be performed by this chapter, and anything that, while not rising to the level of a deficiency, may prevent the electric utility's resource acquisition strategy from effectively fulfilling the objectives of Chapter 22.

(7) Contingency resource plan means an alternative resource plan designed to enhance the utility's ability to respond quickly and appropriately to events or circumstances that would render the preferred resource plan obsolete.

(8) Critical uncertain factor is any uncertain factor that is likely to materially affect the outcome of the resource planning decision.

(9) Deficiency means deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and anything that would cause the electric utility's resource acquisition strategy to fail to meet the requirements identified in Chapter 22.

(10) Demand means the rate of electric power use measured in kilowatts (kW).

(11) Demand-side program means an organized process for packaging and delivering to a particular market segment a portfolio of end-use measures that is broad enough to include at least some measures that are appropriate for most members of the target market segment.

(12) Demand-side rate means a rate structure for retail electric service designed to reduce the net consumption or modify the time of consumption of a customer rate class.

(13) Demand-side resource is a demand-side program or a demand-side rate conducted by the utility to modify the net consumption of electricity on the retail customer's side of the meter. A load-building program or rate is not a demand-side resource.



(14) Describe and document refers to the demonstration of compliance with each provision of this chapter. Describe means the provision of information in the technical volume(s) of the triennial compliance filing, in sufficient detail to inform the stakeholders how the utility complied with each applicable requirement of Chapter 22, why that approach was chosen, and the results of its approach. The description in the technical volume(s), including narrative text, graphs, tables, and other pertinent information, shall be written in a manner that would allow a stakeholder to thoroughly assess the utility's resource acquisition strategy and each of its components. Document means the provision of all of the supporting information relating to the filed resource acquisition strategy pursuant to 4 CSR 240-22.080(11).

(15) Distributed generation means a grid-connected electric generation system that is sized based on local load requirements and distributed primarily to the local load.

(16) Electric utility or utility means any electrical corporation as defined in section 386.020, RSMo, which is subject to the jurisdiction of the commission.

(17) End-use energy service or energy service means the specific need that is served by the final use of energy, such as lighting, cooking, space heating, air conditioning, refrigeration, water heating, or motive power.

(18) End-use measure means an energy-efficiency measure or an energy-management measure.

(19) Energy means the total amount of electric power that is generated or used over a specified interval of time measured in kilowatt-hours (kWh).

(20) Energy-efficiency measure means any device, technology, or operating procedure that makes it possible to deliver an adequate level and quality of end-use energy service while using less energy than would otherwise be required.

(21) Energy-management measure means any device, technology, or operating procedure that makes it possible to alter the time pattern of electricity usage so as to require less generating capacity or to allow the electric power to be supplied from more fuel-efficient generating units. Energy-management measures are sometimes referred to as demand-response measures.

(22) Expected cost of an alternative resource plan is the statistical expectation of the cost of implementing that plan, contingent upon the uncertain factors and associated probabilities. The utility shall consider probable environmental costs as well as direct utility costs in its assessment of alternative resource plans.

(23) Expected unserved hours means the statistical expectation of the number of hours per year that a utility will be unable to supply its native load without importing emergency power.

(24) Historical period shall be the ten (10) most recent years or the period of time used as the basis of the utility's forecast, whichever is longer.

(25) Implementation period means the time interval between the triennial compliance filings required of each utility pursuant to 4 CSR 240-22.080.

(26) Implementation plan means descriptions and schedules for the major tasks necessary to implement the preferred resource plan over the implementation period.

(27) Information means any fact, relationship, insight, estimate, or expert judgment that narrows the range of uncertainty surrounding key decision variables or has the potential to substantially influence or alter resource-planning decisions.

(28) Legal mandates include applicable state and federal executive orders, legislation, court decisions, and applicable state and federal administrative agency orders, rules, and regulations affecting electric utility cost recovery mechanisms, loads, resources, or resource plans.

(29) Levelized cost means the dollar amount of a fixed annual payment for which a stream of those payments over a specified period of time is equal to a specified present value based on a specified rate of interest.

(30) Life-cycle cost means the present worth of costs over the lifetime of any device or means for delivering end-use energy service.

(31) Load-building program means an organized promotional effort by the utility to persuade energy-related decision-makers to choose electricity instead of other forms of energy for the provision of energy service or to persuade existing customers to increase their use of electricity, either by substituting electricity for other forms of energy or by

increasing the level or variety of energy services used. This term is not intended to include the provision of technical or engineering assistance, information about filed rates and tariffs, or other forms of routine customer service.

(32) Load impact means the change in energy usage and the change in diversified demand during a specified interval of time due to the implementation of a demand-side resource.

(33) Load profile means a plot of hourly demand versus chronological hour of the day from the hour ending 1:00 a.m. to the hour ending 12:00 midnight.

(34) Load-research data means major class level average hourly demands (kWhs per hour) derived from the metered instantaneous demand for each customer in the load-research sample.

(35) Long run means an analytical framework within which all factors of production are variable.

(36) Lost revenues means the reduction between rate cases in billed demand (kW) and energy (kWh) due to installed end-use measures, multiplied by the fixed-cost margin of the appropriate rate component.

(37) Major class is a cost-of-service class of the utility.

(38) Market imperfection means any factor or situation that contributes to inefficient energy-related choices by decision-makers, including at least:

(A) Inadequate information about costs, performance, and benefits of end-use measures;

(B) Inadequate marketing infrastructure or delivery channels for end-use measures;

(C) Inadequate financing options for end-use measures;

(D) Mismatched economic incentives resulting from situations where the person who pays the initial cost of an efficiency investment is different from the person who pays the operating costs associated with the chosen efficiency level;

(E) Ineffective economic incentives when decision-makers give low priority to energy-related choices because they have a short-term ownership perspective or because energy costs are a relatively small share of the total cost structure (for businesses) or of the total budget (for households); or

(F) Inefficient pricing of energy supplies.



(39) Market segment means any subgroup of utility customers (or other energy-related decision-makers) which has some or all of the following characteristics in common: they have a similar mix of end-use energy service needs, they are subject to a similar array of market imperfections that tend to inhibit efficient energy-related choices, they have similar values and priorities concerning energy-related choices, or the utility has access to them through similar channels or modes of communication.

(40) Maximum achievable potential means energy savings and demand savings relative to a utility's baseline energy forecast and baseline demand forecast, respectively, resulting from expected program participation and ideal implementation conditions. Maximum achievable potential establishes a maximum target for demand-side savings that a utility can expect to achieve through its demand-side programs and involves incentives that represent a very high portion of total program costs and very short customer payback periods. Maximum achievable potential is considered the hypothetical upper-boundary of achievable demand-side savings potential, because it presumes conditions that are ideal and are not typically observed.

(41) Nominal dollars means future or then-current dollar values that are not adjusted to remove the effects of anticipated inflation.

(42) Participant means an energy-related decision-maker who implements one (1) or more end-use measures as a direct result of a demand-side program.

(43) Planning horizon means a future time period of at least twenty (20) years' duration over which the costs and benefits of alternative resource plans are evaluated.

(44) Plot means a graphical representation to present data. Each plot shall be labeled as a stand-alone figure, whose axes shall be labeled with units. The data presented in each plot also shall be provided in tabular form in the technical volumes and in workpapers. Data tables will be labeled, including the identification of the corresponding plot. The plots and data tables shall be numbered, referenced, and explained in the text of the technical volumes and in workpapers.

(45) Potential resource options are all of the resources in the comprehensive set of demand-side resources that shall be considered pursuant to 4 CSR 240-22.050(1) and in the comprehensive set of supply-side

resources that shall be considered pursuant to 4 CSR 240-22.040(1).

(46) Preferred resource plan means the resource plan that is contained in the resource acquisition strategy that has most recently been adopted by the utility decision-maker(s) for implementation by the electric utility.

(47) Probable environmental cost means the expected cost to the utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the utility decision-makers, 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.

(48) Public counsel means the public counsel of the state of Missouri or their designated representative.

(49) Realistic achievable potential means energy savings and demand savings relative to a utility's baseline energy forecast and baseline demand forecast, respectively, resulting from expected program participation and realistic implementation conditions. Realistic achievable potential establishes a realistic target for demand-side savings that a utility can expect to achieve through its demand-side programs and involves incentives that represent a moderate portion of total program costs and longer customer payback periods when compared to those associated with maximum achievable potential.

(50) Renewable energy means electricity generated from a source that is classified as a renewable energy source under a state or federal renewable energy standard to which the utility is subject.

(51) Resource acquisition strategy means a preferred resource plan, an implementation plan, a set of contingency resource plans, and the events or circumstances that would result in the utility moving to each contingency resource plan. It includes the type, estimated size, and timing of resources that the utility plans to achieve in its preferred resource plan.

(52) Resource plan means a particular combination of demand-side and supply-side resources to be acquired according to a specified schedule over the planning horizon.

(53) Resource planning means the process by which an electric utility evaluates and chooses the appropriate mix and schedule of sup-

ply-side, demand-side, and distribution and transmission resource additions and retirements to provide the public with an adequate level, quality, and variety of end-use energy services.

(54) RTO/ISO means Regional Transmission Organization or independent transmission system operator as defined in the Federal Energy Regulatory Commission (FERC) Order 200 and subsequent FERC orders.

(55) Special contemporary issues means a written list of issues contained in a commission order with input from staff, public counsel, and intervenors that are evolving new issues, which may not otherwise have been addressed by the utility or are continuations of unresolved issues from the preceding triennial compliance filing or annual update filing. Each utility shall evaluate and incorporate special contemporary issues in its next triennial compliance filing or annual update filing.

(56) Stakeholder group means—

(A) Staff, public counsel, and any person or entity granted intervention in a prior Chapter 22 proceeding of the electric utility. Such persons or entities shall be a party to any subsequent related Chapter 22 proceeding of the electric utility without the necessity of applying to the commission for intervention; and

(B) Any person or entity granted intervention in a current Chapter 22 proceeding of the electric utility.

(57) Subjective probability means the judgmental likelihood that the outcome will actually occur.

(58) Supply-side resource or supply resource means any device or method by which the electric utility can provide to its customers an adequate level and quality of electric power supply.

(59) Technical potential means energy savings and demand savings relative to a utility's baseline energy forecast and baseline demand forecast, respectively, resulting from a theoretical construct that assumes all feasible measures are adopted by customers of the utility regardless of cost or customer preference.

(60) Total resource cost test is a test of the cost-effectiveness of demand-side programs or demand-side rates that compares the sum of avoided utility costs plus avoided probable environmental costs to the sum of all incremental costs related to the end-use measures



that are implemented due to the program or related to the rates (including both utility and participant contributions), plus utility costs to administer, deliver, and evaluate each demand-side program or demand-side rate to quantify the net savings obtained by substituting the demand-side program or demand-side rate for supply-side resources.

(61) Uncertain factor means any event, circumstance, situation, relationship, causal linkage, price, cost, value, response, or other relevant quantity which can materially affect the outcome of resource planning decisions, about which utility planners and decision-makers have incomplete or inadequate information at the time a decision must be made.

(62) Utility costs are the costs of operating the utility system and developing and implementing a resource plan that are incurred and paid by the utility. On an annual basis, utility cost is synonymous with utility revenue requirement.

(63) The utility cost test is a test of the cost-effectiveness of demand-side programs or demand-side rates that compares the avoided utility costs to the sum of all utility incentive payments, plus utility costs to administer, deliver, and evaluate each demand-side program or demand-side rate to quantify the net savings obtained by substituting the demand-side program or demand-side rate for supply-side resources.

(64) Utility discount rate means the post-tax rate of return on net investment used to calculate the utility's annual revenue requirements.

(65) Weather measure means a function of daily temperature data that reflects the observed relationship between electric load and temperature.

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.030 Load Analysis and Load Forecasting

PURPOSE: This rule sets minimum standards for the maintenance and updating of historical data, the level of detail required in ana-

lyzing loads, and the purposes to be accomplished by load analysis and by load forecast models. The load analysis discussed in this rule is intended to support both demand-side management efforts of 4 CSR 240-22.050 and the load forecast models of this rule. This rule also sets the minimum standards for the documentation of the inputs, components, and methods used to derive the load forecasts.

(1) **Selecting Load Analysis Methods.** The utility may choose multiple methods of load analysis if it deems doing so is necessary to achieve all of the purposes of load analysis and if the methods are consistent with, and calibrated to, one another. The utility shall describe and document its intended purposes for load analysis methods, why the selected load analysis methods best fulfill those purposes, and how the load analysis methods are consistent with one another and with the end-use consumption data used in the demand-side analysis as described in 4 CSR 240-22.050. At a minimum, the load analysis methods shall be selected to achieve the following purposes:

(A) To identify end-use measures that may be potential demand-side resources, generally, those end-use measures with an opportunity for energy and/or demand savings;

(B) To derive a data set of historical values from load research data that can be used as dependent and independent variables in the load forecasts;

(C) To facilitate the analysis of impacts of implemented demand-side programs and demand-side rates on the load forecasts and to augment measurement of the effectiveness of demand-side resources necessary for 4 CSR 240-22.070(8) in the evaluation of the performance of the demand-side programs or rates after they are implemented; and

(D) To preserve, in a historical database, the results of the load analysis used to perform the demand-side analysis as described in 4 CSR 240-22.050, and the load forecast- ing described in 4 CSR 240-22.030.

(2) **Historical Database for Load Analysis.** 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 and described and documented in the triennial compliance filings:

(A) **Customer Class Detail.** At a minimum, the historical database shall be maintained for each of the major classes;

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

1. For each jurisdiction for which it prepares customer and energy and demand forecasts, for each major class, to the actual monthly energy usage and number of customers and weather-normalized monthly energy usage;

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

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

(C) **Load Component Detail.** The historical database 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-per-unit component, for both actual and weather-normalized loads.

1. The number-of-units component shall be the number of customers, square feet, devices, or other units as appropriate to the customer class and the load analysis method selected by the utility. The utility shall select the units component with the intent of providing meaningful load analysis for demand-side analysis and maintaining the integrity of the database over time.

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. The estimates of the effect of weather on historical major class and system loads shall incorporate the non-linear response of loads to daily weather and seasonal variations in loads.

3. The utility shall describe and 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; and the relevant statistical results of the models, including parameter estimates and tests of statistical significance. The data used to estimate the models, including the development of model input data from basic data, shall be included in the workpapers supplied at the time the compliance report is filed;

(D) For each major class specified pursuant to subsection (2)(A), the utility shall provide, on a seasonal and annual basis for each year of the historical period—

1. Its assessment of the historical end-use drivers of energy usage and peak demand, including trends in numbers of units and energy consumption per unit;

2. Its assessment of the weather sensitivity of energy and peak demand; and



3. Plots illustrating trends materially affecting electricity consumption over the historical period;

(E) The utility shall describe and document any adjustments that it made to historical data prior to using it in its development or interpretation of the forecasting models; and

(F) Length of Historical Database. The utility shall develop and retain the historical database over the historical period.

(3) Analysis of Number of Units. For each major class, the utility shall describe and document its analysis of the historical relationship between the number of units and the economic and/or demographic factors (explanatory variables) that affect the number of units for that major class. The analysis may incorporate or substitute the results of secondary analyses, with the proviso that the utility analyze and verify the applicability of those results to its service territory. If the utility develops primary analyses, or to the extent they are available from secondary analyses, these relationships shall be specified as statistical or mathematical models that relate the number of units to the explanatory variables.

(A) Choice of Explanatory Variables. The utility shall identify appropriate explanatory variables as predictors of the number of units for each major class. The critical assumptions that influence the explanatory variables shall also be identified and documented.

(B) Documentation of statistical models shall include the elements specified in subsection (2)(C) of this rule. Documentation of mathematical models shall include a specification of the functional form of the equations if the utility develops primary analyses, or to the extent they are available if the utility incorporates secondary analyses.

(4) Analysis of Use Per Unit. For each major class, the utility shall describe and document its analysis of historical use per unit by end use.

(A) End-Use Load Detail. For each major class, use per unit shall be disaggregated, where information permits, by end-uses that contribute significantly to energy use or peak demand.

1. The utility shall consider developing information on at least the following end-use loads:

A. For the residential sector: lighting, space cooling, space heating, ventilation, water heating, refrigerators, freezers, cooking, clothes washers, clothes dryers, television, personal computers, furnace fans, plug loads, and other uses;

B. For the commercial sector: space heat, space cooling, ventilation, water heat, refrigeration, lighting, office equipment, cooking equipment, and other uses; and

C. For the industrial sector: machine drives, space heat, space cooling, ventilation, lighting, process heating, and other uses.

2. The utility may modify the end-use loads specified in paragraph (4)(A)1.

A. The utility may remove or consolidate the specified end-use loads if it determines that a specified end-use load is not contributing, and is not likely to contribute in the future, significantly to energy use or peak demand in a major class.

B. The utility shall add to the specified end-use loads if it determines that an end-use load currently not specified is likely to contribute significantly to energy use or peak demand in a major class.

C. The utility shall provide documentation of its decision to modify the specified end-use loads for which information is developed, as well as an assessment of how the modifications can be made to best preserve the continuity and integrity of the end-use load database.

3. For each major class and each end-use load, including those listed in paragraph (4)(A)1., if information is not available, the utility shall provide a schedule for acquiring this end-use load 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 load information has proven to be infeasible.

4. The utility shall determine the effect that weather has on the total load of each major class by disaggregating the load into its cooling, heating, and non-weather-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.

(B) The database and historical analysis required for each end use shall be developed from a utility-specific survey or other primary data. The database and analysis may incorporate or substitute the results of secondary data, with the proviso that the utility analyze and verify the applicability of those results to its service territory. The database 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 load identified in subsection (4)(A), the utility shall implement a procedure to develop and maintain adequate data on the energy-related characteristics of the building, appli-

ance, and equipment stock including saturation levels, efficiency levels, and sizes, where applicable. The utility shall update the data before each triennial compliance filing; and

2. Estimates of end-use energy and demand. For the end-use loads identified in subsection (4)(A), the utility shall estimate monthly energies and demands at the time of monthly system peaks and shall calibrate these energies and demands to equal the weather-normalized monthly energies and demands at the time of monthly peaks for each major class for the most recently available data.

(5) Selecting Load Forecasting Models. The utility shall select load forecast models and develop the historical database needed to support the selected models. The selected load forecast models will include a method of end-use load analysis for at least the residential and small commercial classes, unless the utility demonstrates that end-use load methods are not practicable and provides documentation that other methods are at a minimum comparable to end-use methods. The utility may choose multiple models and methods if it deems doing so is necessary to achieve all of the purposes of load forecasting and if the methods and models are consistent with, and calibrated to, one another. The utility shall describe and document its intended purposes for load forecast models, why the selected load forecast models best fulfill those purposes, and how the load forecast models are consistent with one another and with the end-use usage data used in the demand-side analysis as described in 4 CSR 240-22.050. As a minimum, the load forecast models shall be selected to achieve the following purposes:

(A) Assessment of consumption drivers and customer usage patterns—to better understand customer preferences and their impacts on future energy and demand requirements, including weather sensitivity of load;

(B) Long-term load forecasts—to serve as a basis for planning capacity and energy service needs. This can be served by any forecasting method or methods that produce reasonable projections (based on comparing model projections of loads to actual loads) of future demand and energy loads;

(C) Policy analysis—to assess the impact of legal mandates, economic policies, and rate designs on future energy and demand requirements. The utility may use any load forecasting method or methods that it demonstrates can adequately analyze the impacts of legal mandates, economic policies, and rate designs.



(6) Load Forecasting Model Specifications.

(A) For each load forecasting model selected by the utility pursuant to section 4 CSR 240-22.030(5), the utility shall describe and document its—

1. Determination of appropriate independent variables as predictors of energy and peak demand for each major class. The critical assumptions that influence the independent variables shall also be identified.

A. The utility shall assess the applicability of the historical explanatory variables pursuant to subsection (3)(A) to its selected forecast model.

B. To the extent that the independent variables selected by the utility differ from the historical explanatory variables, the utility shall describe and document those differences;

2. Development of any mathematical or statistical equations comprising the load forecast models, including a specification of the functional form of the equations; and

3. Assessment of the applicability of any load forecast models or portions of models that were utilized by the utility but developed by others, including a specification of the functional forms of any equations or models, to the extent they are available.

(B) If the utility selects load forecast models that include end-use load methods, the utility shall describe and document any deviations in the independent variables or functional forms of the equations from those derived from load analysis in sections (3) and (4).

(C) Historical Database for Load Forecasting. In addition to the load analysis database, the utility shall develop and maintain a database consistent with and as needed to run each forecast model utilized by the utility. The utility shall describe and document its load forecasting historical database in the triennial compliance filings. As a minimum, the utility shall—

1. Develop and maintain a data set of historical values for each independent variable of each forecast model. The historical values for each independent variable shall be collected for a period of ten (10) years, or such period deemed sufficient to allow the independent variables to be accurately forecasted over the entire planning horizon;

2. Explain any adjustments that it made to historical data prior to using it in its development of the forecasting models;

3. Archive previous projections of all independent variables used in the energy usage and peak load forecasts made in at least the past ten (10) years and provide a comparison of the historical projected values in prior plan filings to actual historical values and to

projected values in the current compliance filing; and

4. Archive all previous forecasts of energy and peak demand, including the final data sets used to develop the forecasts, made in at least the past ten (10) years. Provide a comparison of the historical final forecasts to the actual historical energy and peak demands and to the current forecasts in the current triennial compliance filing.

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

(A) Major 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, and shall describe and document those forecasts in its triennial compliance filings. Where applicable, these major class forecasts shall be separated into their jurisdictional components.

1. The utility shall describe and document how the base-case forecasts of energy usage and demands have 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. If the methodology does not incorporate economic and demographic factors, the utility shall explain how it accounted for the effects of these factors.

2. The utility shall describe and document how the forecasts of energy usage and demands have taken into account the effects of legal mandates affecting the consumption of electricity.

3. The utility shall describe and document how the forecasts of energy usage and demands are consistent with trends in historical consumption patterns, end uses, and end-use efficiency in the utility's service area as identified pursuant to sections 4 CSR 240-22.030(2), (3), and (4).

4. For at least the base year of the forecast, the utility shall describe and document its estimates of the monthly cooling, heating, and non-weather-sensitive components of the weather-normalized major class loads.

5. Where judgment has been applied to modify the results of its energy and peak

forecast models, the utility shall describe and document the factors which caused the modification and how those factors were quantified.

6. For each major class specified pursuant to subsection (2)(A), the utility shall provide plots of class monthly energy and coincident peak demand at the time of summer and winter system peaks. The plots shall cover the historical database period and the forecast period of at least twenty (20) years. The plots of coincident peak demands for the historical period shall include both actual and weather-normalized peak demands at the time of summer and winter system peaks. The plots of coincident peak demand for the forecast period shall show the class coincident demands for the base-case forecast at the time of summer and winter system peaks.

7. The utility shall provide plots of the net system load profiles for the summer peak day and the winter peak day showing the contribution of each major class. The plots shall be provided in the triennial filing for the base year of the forecast and for the fifth, tenth, and twentieth years of the forecast. Plots for all years shall be included in the workpapers supplied at the time of the triennial filing.

(B) Forecasts of Independent Variables. The forecasts of independent variables shall be specified, described, and documented.

1. Documentation of mathematical models developed by the utility to forecast the independent variables shall include the reasons the utility selected the models as well as specification of the functional form of the equations.

2. If the utility adopted forecasts of independent variables developed by another entity, documentation shall include the reasons the utility selected those forecasts, an analysis showing that the forecasts are applicable to the utility's service territory, and, if available, a specification of the functional form of the equations used to forecast the independent variables.

3. These forecasts of independent variables shall be compared to historical trends in the variables, and significant differences between the forecasts and long-term and recent trends shall be analyzed and explained.

4. 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.

(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 peak demands at time of summer and winter system peaks for each major class.

(8) Load Forecast Sensitivity Analysis. The utility shall describe and document its analysis of the sensitivity of the dependent variables of the base-case forecast for each major class to variations in the independent variables identified in subsection 4 CSR 240-22.030(6)(A).

(A) The utility shall produce at least two (2) additional normal weather 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 risk analysis required by 4 CSR 240-22.060.

(B) The utility shall estimate the sensitivity of system peak load forecasts to extreme weather conditions. This information shall be considered by utility decision-makers to assess the ability of alternative resource plans to serve load under extreme weather conditions when selecting the preferred resource plan pursuant to 4 CSR 240-22.070(1).

(C) The utility shall provide plots of energy usage and peak demand covering the historical database period and the forecast period of at least twenty (20) years.

1. The energy plots shall include the summer, non-summer, and total energy usage for each calendar year. The peak demand plots shall include the summer and winter peak demands.

2. 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.

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

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 utility shall evaluate all existing supply-side resources and identify a variety of potential supply-side resource options which the utility can reasonably expect to use, devel-

op, implement, or acquire, and, for purposes of integrated resource planning, all such supply-side resources shall be considered as potential supply-side resource options. These potential supply-side resource options include full or partial ownership of new plants using existing generation technologies; full or partial ownership of new plants using new generation technologies, including technologies expected to become commercially available within the twenty (20)-year planning horizon; renewable energy resources on the utility-side of the meter, including a wide variety of renewable generation technologies; technologies for distributed generation; life extension and refurbishment at existing generating plants; enhancement of the emission controls at existing or new generating plants; purchased power from bi-lateral transactions and from organized capacity and energy markets; generating plant 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 sufficient to fairly analyze and compare each of these potential supply-side resource options, including at least those attributes needed to assess capital cost, fixed and variable operation and maintenance costs, probable environmental costs, and operating characteristics.

(2) The utility shall describe and document its analysis of each potential supply-side resource option referred to in section (1). The utility may conduct a preliminary screening analysis to determine a short list of preliminary supply-side candidate resource options, or it may consider all of the potential supply-side resource options to be preliminary supply-side candidate resource options pursuant to subsection (2)(C). All costs shall be expressed in nominal dollars.

(A) Cost rankings of each potential supply-side resource option 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 potential supply-side resource option using the utility discount rate. The utility shall include the costs of ancillary and/or back-up sources of supply required to achieve necessary reliability levels in connection with intermittent and/or uncontrollable sources of generation (i.e., wind and solar).

(B) The probable environmental costs of each potential supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental legal mandates that may be imposed at

some point within the planning horizon. The utility shall identify a list of environmental pollutants for which, in the judgment of the utility decision-makers, legal mandates may be imposed during the planning horizon which would result in compliance costs that could significantly impact utility rates. The utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that legal mandates requiring additional levels of mitigation will be imposed at some point within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation cost for each identified pollutant.

(C) The utility shall indicate which potential supply-side resource options it considers to be preliminary supply-side candidate resource options. Any utility using the preliminary screening analysis to identify preliminary supply-side candidate resource options shall rank all preliminary supply-side candidate resource options based on estimates of the utility costs and also on utility costs plus probable environmental costs. The utility shall—

1. Provide a summary table showing each potential supply-side resource option and the utility cost and the probable environmental cost for each potential supply-side resource option and an assessment of whether each potential supply-side resource option qualifies as a utility renewable energy resource; and

2. Explain which potential supply-side resource options are eliminated from further consideration and the reasons for their elimination.

(3) The utility shall describe and document its analysis of the interconnection and any other transmission requirements associated with the preliminary supply-side candidate resource options identified in subsection (2)(C).

(A) The analysis shall include the identification of transmission constraints, as estimated pursuant to 4 CSR 240-22.045(3), whether within the Regional Transmission Organization's (RTO's) footprint, on an interconnected RTO, or a transmission system that is not part of an RTO. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the preliminary supply-side candidate resource options under consideration, that the costs of the transmission system investments associated with preliminary supply-side candidate resource options, as estimated pursuant to 4 CSR 240-22.045(3), are properly considered and to provide an adequate foundation of basic information for decisions to



include, but not be limited to, the following:

1. Joint ownership or participation in generation construction projects;
2. Construction of wholly-owned generation facilities;
3. Participation in major refurbishment, life extension, upgrading, or retrofitting of existing generation facilities;
4. Improvements on its transmission and distribution system to increase efficiency and reduce power losses;
5. Acquisition of existing generating facilities; and
6. Opportunities for new long-term power purchases and sales, and short-term power purchases that may be required for bridging the gap between other supply options, both firm and nonfirm, that are likely to be available over all or part of the planning horizon.

(B) This analysis shall include the identification of any output limitations imposed on existing or new supply-side resources due to transmission and/or distribution system capacity constraints, in order to ensure that supply-side candidate resource options are evaluated in accordance with any such constraints.

(4) All preliminary supply-side candidate resource options which are not eliminated shall be identified as supply-side candidate resource options. The supply-side candidate resource options that the utility passes on for further evaluation in the integration process shall represent a wide variety of supply-side resource options with diverse fuel and generation technologies, including a wide range of renewable technologies and technologies suitable for distributed generation.

(A) The utility shall describe and document its process for identifying and analyzing potential supply-side resource options and preliminary supply-side candidate resource options and for choosing its supply-side candidate resource options to advance to the integration analysis.

(B) The utility shall indicate which, if any, of the preliminary supply-side candidate resource options identified in subsection (2)(C) are eliminated from further consideration on the basis of the interconnection and other transmission analysis and shall explain the reasons for their elimination.

(C) The utility shall include the cost of interconnection and any other transmission requirements, in addition to the utility cost and probable environmental cost, in the cost of supply-side candidate resource options advanced for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3).

(5) The utility shall develop, and describe and document, ranges of values and probabilities for several important uncertain factors related to supply-side candidate resource options identified in section (4). These cost estimates shall include at least the following elements, as applicable to the supply-side candidate resource option:

(A) Fuel price forecasts, including fuel delivery costs, 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;

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

(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;

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

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

(F) Estimated costs of interconnection or other transmission requirements associated with each supply-side candidate resource option.

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.045 Transmission and Distribution Analysis

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for transmission and distribution network analysis and reporting.

(1) The electric utility shall describe and document its consideration of the adequacy of the transmission and distribution networks in fulfilling the fundamental planning objective set out in 4 CSR 240-22.010. Each utility shall consider, at a minimum, improvements to the transmission and distribution networks that—

(A) Reduce transmission power and energy

losses. Opportunities to reduce transmission network losses are among the supply-side resources evaluated pursuant to 4 CSR 240-22.040(3). 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 network loss-reduction measures. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution systems, 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;

(B) Interconnect new generation facilities. The utility shall assess the need to construct transmission facilities to interconnect any new generation pursuant to 4 CSR 240-22.040(3) and shall reflect those transmission facilities in the cost benefit analyses of the resource options;

(C) Facilitate power purchases or sales. The utility shall assess the transmission upgrades needed to purchase or sell pursuant to 4 CSR 240-22.040(3). An estimate of the portion of costs of these upgrades that are allocated to the utility shall be reflected in the analysis of preliminary supply-side candidate resource options; and

(D) Incorporate advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources. The utility shall assess transmission and distribution improvements that may become available during the planning horizon that facilitate or expand the availability and cost effectiveness of demand-side resources or supply-side resources. The costs and capabilities of these advanced transmission and distribution technologies shall be reflected in the analyses of each resource option.

(2) Avoided Transmission and Distribution Cost. The utility shall develop, describe, and document an avoided transmission capacity cost and an avoided distribution capacity cost. The avoided transmission and distribution capacity costs are components of the avoided demand cost pursuant to 4 CSR 240-22.050(5)(A).

(3) Transmission Analysis. The utility shall compile information and perform analyses of the transmission networks pertinent to the selection of a resource acquisition strategy. The utility and the Regional Transmission Organization (RTO) to which it belongs both participate in the process for planning transmission upgrades.



(A) The utility shall provide, and describe and document, its—

1. Assessment of the cost and timing of transmission upgrades to reduce congestion and/or losses, to interconnect generation, to facilitate power purchases and sales, and to otherwise maintain a viable transmission network;

2. Assessment of transmission upgrades to incorporate advanced technologies;

3. Estimate of avoided transmission costs;

4. Estimate of the portion and amount of costs of proposed regional transmission upgrades that would be allocated to the utility, and if such costs may differ due to plans for the construction of facilities by an affiliate of the utility instead of the utility itself, then an estimate, by upgrade, of this cost difference;

5. Estimate of any revenue credits the utility will receive in the future for previously built or planned regional transmission upgrades; and

6. Estimate of the timing of needed transmission and distribution resources and any transmission resources being planned by the RTO primarily for economic reasons that may impact the alternative resource plans of the utility.

(B) The utility may use the RTO transmission expansion plan in its consideration of the factors set out in subsection (3)(A) if all of the following conditions are satisfied:

1. The utility actively participates in the development of the RTO transmission plan;

2. The utility reviews the RTO transmission overall expansion plans each year to assess whether the RTO transmission expansion plans, in the judgment of the utility decision-makers, are in the interests of the utility's Missouri customers;

3. The utility reviews the portion of RTO transmission expansion plans each year within its service territory to assess whether the RTO transmission expansion plans pertaining to projects that are partially- or fully-driven by economic considerations (i.e., projects that are not solely or primarily based on reliability considerations), in the judgment of the utility decision-makers, are in the interests of the utility's Missouri customers;

4. The utility documents and describes its review and assessment of the RTO overall and utility-specific transmission expansion plans; and

5. If any affiliate of the utility intends to build transmission within the utility's service territory where the project(s) are partially- or fully-driven by economic considerations, then the utility shall explain why such affiliate-built transmission is in the best interest of the

utility's Missouri customers and describe and document the analysis performed by the utility to determine whether such affiliate-built transmission is in the interest of the utility's Missouri customers.

(C) The utility shall provide copies of the RTO expansion plans, its assessment of the plans, and any supplemental information developed by the utility to fulfill the requirements in subsection (3)(B) of this rule.

(D) The utility shall provide a report for consideration in 4 CSR 240-22.040(3) that identifies the physical transmission upgrades needed to interconnect generation, facilitate power purchases and sales, and otherwise maintain a viable transmission network, including:

1. A list of the transmission upgrades needed to physically interconnect a generation source within the RTO footprint;

2. A list of the transmission upgrades needed to enhance deliverability from a point of delivery within the RTO including requirements for firm transmission service from the point of delivery to the utility's load and requirements for financial transmission rights from a point of delivery within the RTO to the utility's load;

3. A list of transmission upgrades needed to physically interconnect a generation source located outside the RTO footprint;

4. A list of the transmission upgrades needed to enhance deliverability from a generator located outside the RTO including requirements for firm transmission service to a point of delivery within the RTO footprint and requirements for financial transmission rights to a point of delivery within the RTO footprint;

5. The estimated total cost of each transmission upgrade; and

6. The estimated fraction of the total cost and amount of each transmission upgrade allocated to the utility.

(4) Analysis Required for Transmission and Distribution Network Investments to Incorporate Advanced Technologies.

(A) The utility shall develop, and describe and document, plans for transmission upgrades to incorporate advanced transmission technologies as necessary to optimize the investment in the advanced technologies for transmission facilities owned by the utility. The utility may use the RTO transmission expansion plan in its consideration of advanced transmission technologies if all of the conditions in paragraphs (3)(B)1. through (3)(B)3. are satisfied.

(B) The utility shall develop, and describe and document, plans for distribution network

upgrades as necessary to optimize its investment in advanced distribution technologies.

(C) The utility shall describe and document its optimization of investment in advanced transmission and distribution technologies based on an analysis of—

1. Total costs and benefits, including:

A. Costs of the advanced grid investments;

B. Costs of the non-advanced grid investments;

C. Reduced resource costs through enhanced demand response resources and enhanced integration of customer-owned generation resources; and

D. Reduced supply-side production costs;

2. Cost effectiveness, including:

A. The monetary values of all incremental costs of the energy resources and delivery system based on advanced grid technologies relative to the costs of the energy resources and delivery system based on non-advanced grid technologies;

B. The monetary values of all incremental benefits of the energy resources and delivery system based on advanced grid technologies relative to the costs and benefits of the energy resources and delivery system based on non-advanced grid technologies; and

C. Additional non-monetary factors considered by the utility;

3. Societal benefit, including:

A. More consumer power choices;

B. Improved utilization of existing resources;

C. Opportunity to reduce cost in response to price signals;

D. Opportunity to reduce environmental impact in response to environmental signals;

4. Any other factors identified by the utility; and

5. Any other factors identified in the special contemporary issues process pursuant to 4 CSR 240-22.080(4) or the stakeholder group process pursuant to 4 CSR 240-22.080(5).

(D) Before the utility includes non-advanced transmission and distribution grid technologies in its triennial compliance filing or annual update filing, the utility shall—

1. Conduct an analysis which demonstrates that investment in each non-advanced transmission and distribution upgrade is more beneficial to consumers than an investment in the equivalent upgrade incorporating advanced grid technologies. The utility may rely on a generic analysis as long as it verifies its applicability; and

2. Describe and document the analysis.



(E) The utility shall develop, describe, and document the utility's cost benefit analysis and implementation of advanced grid technologies to include:

1. A description of the utility's efforts at incorporating advanced grid technologies into its transmission and distribution networks;

2. A description of the impact of the implementation of distribution advanced grid technologies on the selection of a resource acquisition strategy; and

3. A description of the impact of the implementation of transmission advanced grid technologies on the selection of a resource acquisition strategy.

(5) The electric utility shall identify and describe any affiliate or other relationship with transmission planning, designing, engineering, building, and/or construction management companies that impact or may be impacted by the electric utility. Any description and documentation requirements in sections (1) through (4) also apply to any affiliate transmission planning, designing, engineering, building, and/or construction management company or other transmission planning, designing, engineering, building, and/or construction management company currently participating in transmission works or transmission projects for and/or with the electric utility.

(6) The electric utility shall identify and describe any transmission projects under consideration by an RTO for the electric utility's service territory.

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.050 Demand-Side Resource Analysis

PURPOSE: This rule specifies the principles by which potential demand-side resource options shall be developed and analyzed for cost effectiveness, with the goal of achieving all cost-effective demand-side savings. It also requires the selection of demand-side candidate resource options that are passed on to integrated resource analysis in 4 CSR 240-22.060 and an assessment of their maximum achievable potentials, technical potentials, and realistic achievable potentials.

(1) The utility shall identify a set of potential demand-side resources from which demand-side candidate resource options will be identified for the purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). A potential demand-side resource consists of a demand-side program designed to deliver one (1) or more energy efficiency and energy management measures or a demand-side rate. The utility shall select the set of potential demand-side resources and describe and document its selection—

(A) To provide broad coverage of—

1. Appropriate market segments within each major class;

2. 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; and

3. All major end uses, including at least the end uses which are to be considered in the utility's load analysis as listed in 4 CSR 240-22.030(4)(A)1.;

(B) To fulfill the goal of achieving all cost-effective demand-side savings, the utility shall design highly effective potential demand-side programs consistent with subsection (1)(A) that broadly cover the full spectrum of cost-effective end-use measures for all customer market segments;

(C) To include demand-side rates for all customer market segments;

(D) To consider and assess multiple designs for demand-side programs and demand-side rates, selecting the optimal designs for implementation, and modifying them as necessary to enhance their performance; and

(E) To include the effects of improved technologies expected over the planning horizon to—

1. Reduce or manage energy use; or

2. Improve the delivery of demand-side programs or demand-side rates.

(2) The utility shall conduct, describe, and document market research studies, customer surveys, pilot demand-side programs, pilot demand-side rates, test marketing programs, and other activities as necessary to estimate the maximum achievable potential, technical potential, and realistic achievable potential of potential demand-side resource options for the utility and to develop the information necessary to design and implement cost-effective demand-side programs and demand-side rates. These research activities shall be designed to provide a solid foundation of information applicable to the utility 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 and energy management impacts. The utility may compile existing data or adopt data developed by other entities, including government agencies and other utilities, as long as the utility verifies the applicability of the adopted data to its service territory. The utility shall provide copies of completed market research studies, pilot programs, pilot rates, test marketing programs, and other studies as required by this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates.

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

(A) Review demand-side programs that have been implemented by other utilities with similar characteristics and identify programs that would be applicable for the utility;

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

(C) Identify a comprehensive list of end-use measures and demand-side programs considered by the utility and develop menus of end-use measures for each demand-side program. The demand-side programs shall be appropriate to the shared characteristics of each market segment. The end-use measures shall reflect technological changes in end-uses that may be reasonably anticipated to occur during the planning horizon;

(D) Assess how advancements in metering and distribution technologies that may be reasonably anticipated to occur during the planning horizon affect the ability to implement or deliver potential demand-side programs;

(E) 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. When appropriate, consider multiple approaches such as rebates, financing, and direct installations for the same menu of end-use measures;



(F) Evaluate, describe, and document the feasibility, cost-reduction potential, and potential benefits of statewide marketing and outreach programs, joint programs with natural gas utilities, upstream market transformation programs, and other activities. In the event that statewide marketing and outreach programs are preferred, the utilities shall develop joint programs in consultation with the stakeholder group;

(G) Estimate the characteristics needed for the twenty (20)-year planning horizon to assess the cost effectiveness of each potential demand-side program, including:

1. An assessment of the demand and energy reduction impacts of each stand-alone end-use measure contained in each potential demand-side program;

2. An assessment of how the interactions between end-use measures, when bundled with other end-use measures in the potential demand-side program, would affect the stand-alone end-use measure impact estimates;

3. An estimate of the incremental and cumulative number of program participants and end-use measure installations due to the potential demand-side program;

4. For each year of the planning horizon, an estimate of the incremental and cumulative demand reduction and energy savings due to the potential demand-side program; and

5. For each year of the planning horizon, an estimate of the costs, including:

A. The incremental cost of each stand-alone end-use measure;

B. The cost of incentives paid by the utility to customers or utility financing to encourage participation in the potential demand-side program. The utility shall consider multiple levels of incentives paid by the utility for each end-use measure within a potential demand-side program, with corresponding adjustments to the maximum achievable potential and the realistic achievable potential of that potential demand-side program;

C. The cost of incentives to customers to participate in the potential demand-side program paid by the entities other than the utility;

D. The cost to the customer and to the utility of technology to implement a potential demand-side program;

E. The utility's cost to administer the potential demand-side program; and

F. Other costs identified by the utility;

(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 hori-

zon for each potential demand-side program; and

(I) The utility shall describe and document how it performed the assessments and developed the estimates pursuant to subsection (3)(G) and shall provide documentation of its sources and quality of information.

(4) The utility shall develop potential demand-side rates designed for each market segment to reduce the net consumption of electricity or modify the timing of its use. The utility shall describe and document its demand-side rate planning and design process and shall include at least the following activities and elements:

(A) Review demand-side rates that have been implemented by other utilities and identify whether similar demand-side rates would be applicable for the utility taking into account factors such as similarity in electric prices and customer makeup;

(B) Identify demand-side rates applicable to the major classes and decision-makers identified in subsection (1)(A). When appropriate, consider multiple demand-side rate designs for the same major classes;

(C) Assess how technological advancements that may be reasonably anticipated to occur during the planning horizon, including advanced metering and distribution systems, affect the ability to implement demand-side rates;

(D) Estimate the input data and other characteristics needed for the twenty (20)-year planning horizon to assess the cost effectiveness of each potential demand-side rate, including:

1. An assessment of the demand and energy reduction impacts of each potential demand-side rate;

2. An assessment of how the interactions between multiple potential demand-side rates, if offered simultaneously, would affect the impact estimates;

3. An assessment of how the interactions between potential demand-side rates and potential demand-side programs would affect the impact estimates of the potential demand-side programs and potential demand-side rates;

4. For each year of the planning horizon, an estimate of the incremental and cumulative demand reduction and energy savings due to the potential demand-side rate; and

5. For each year of the planning horizon, an estimate of the costs of each potential demand-side rate, including:

A. The cost of incentives to customers to participate in the potential demand-side rate paid by the utility. The utility shall

consider multiple levels of incentives to achieve customer participation in each potential demand-side rate, with corresponding adjustments to the maximum achievable potential and the realistic achievable potentials of that potential demand-side rate;

B. The cost to the customer and to the utility of technology to implement the potential demand-side rate;

C. The utility's cost to administer the potential demand-side rate; and

D. Other costs identified by the utility;

(E) 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 potential demand-side program;

(F) Evaluate how each demand-side rate would be considered by the utility's Regional Transmission Organization (RTO) in resource adequacy determinations, eligibility to participate as a demand response resource in RTO markets for energy, capacity, and ancillary services; and

(G) The utility shall describe and document how it performed the assessments and developed the estimates pursuant to subsection (4)(D) and shall document its sources and quality of information.

(5) The utility shall describe and document its evaluation of the cost effectiveness of each potential demand-side program developed pursuant to section (3) and each potential demand-side rate developed pursuant to section (4). All costs and benefits shall be expressed in nominal dollars.

(A) In each year of the planning horizon, the benefits of each potential demand-side program and each potential demand-side rate 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. These calculations shall be performed both with and without the avoided probable environmental costs. The utility shall describe and document the methods, data, and assumptions it used to develop the avoided costs.

1. The utility avoided demand cost shall include the capacity cost of generation, transmission, and distribution facilities, adjusted to reflect reliability reserve margins and capacity losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs. The utility shall describe and document how it developed its avoided demand cost, and the capacity cost chosen shall be consistent throughout the triennial compliance filing.



2. The utility avoided energy cost shall include the fuel costs, emission allowance costs, and other variable operation and maintenance costs of generation facilities, adjusted to reflect energy losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs. The utility shall describe and document how it developed its avoided energy cost, and the energy costs shall be consistent throughout the triennial compliance filing.

3. The avoided probable environmental costs include the effects of the probable environmental costs calculated pursuant to 4 CSR 240-22.040(2)(B) on the utility avoided demand cost and the utility avoided energy cost. The utility shall describe and document how it developed its avoided probable environmental cost.

(B) The total resource cost test shall be used to evaluate the cost effectiveness of the potential demand-side programs and potential demand-side rates. In each year of the planning horizon—

1. The costs of each potential 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 potential demand-side program;

2. The costs of each potential demand-side rate shall be calculated as the sum of all incremental costs that are due to the rate (including both utility and participant contributions) plus utility costs to administer, deliver, and evaluate each potential demand-side rate; and

3. For purposes of this test, the costs of potential demand-side programs and potential demand-side rates shall not include lost revenues or utility incentive payments to customers.

(C) The utility cost test shall also be performed for purposes of comparison. In each year of the planning horizon—

1. The costs of each potential demand-side program and potential demand-side rate shall be calculated as the sum of all utility incentive payments plus utility costs to administer, deliver, and evaluate each potential demand-side program or potential demand-side rate;

2. For purposes of this test, the costs of potential demand-side programs and potential demand-side rates shall not include lost revenues; and

3. The costs shall include, but separately identify, the costs of any rate of return or incentive included in the utility's recovery of demand-side program costs.

(D) 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 potential demand-side program or potential demand-side rate 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, including programs required to comply with legal mandates.

(E) The utility shall provide results of the total resource cost test and the utility cost test for each potential demand-side program evaluated pursuant to subsection (5)(B) and for each potential demand-side rate evaluated pursuant to subsection (5)(C) of this rule, including a tabulation of the benefits (avoided costs), demand-side resource costs, and net benefits or costs.

(F) If the utility calculates values for other tests to assist in the design of demand-side programs or demand-side rates, the utility shall describe and document the tests and provide the results of those tests.

(G) The utility shall describe and document how it performed the cost effectiveness assessments pursuant to section (5) and shall describe and document its methods and its sources and quality of information.

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

(A) The utility may bundle demand-side candidate resource options into portfolios, as long as the requirements pursuant to section (1) are met and as long as multiple demand-side candidate resource options and portfolios advance for consideration in the integrated resource analysis in 4 CSR 240-22.060. The utility shall describe and document how its demand-side candidate resource options and portfolios satisfy these requirements.

(B) For each demand-side candidate resource option or portfolio, the utility shall describe and document the 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, including a tabulation of the estimated annual change in energy usage and in diversified demand for each year in the planning horizon due to the

implementation of the candidate demand-side resource option or portfolio.

(C) The utility shall describe and document its assessment of the potential uncertainty associated with the load impact estimates of the demand-side candidate resource options or portfolios. The utility shall estimate—

1. The impact of the uncertainty concerning the customer participation levels by estimating and comparing the maximum achievable potential and realistic achievable potential of each demand-side candidate resource option or portfolio; and

2. The impact of uncertainty concerning the cost effectiveness by identifying uncertain factors affecting which end-use resources are cost effective. The utility shall identify how the menu of cost-effective end-use measures changes with these uncertain factors and shall estimate how these changes affect the load impact estimates associated with the demand-side candidate resource options.

(7) For each demand-side candidate resource option identified in section (6), the utility shall describe and document the general principles it will use to develop evaluation plans pursuant to 4 CSR 240-22.070(8). The utility shall verify that the evaluation costs in subsections (5)(B) and (5)(C) are appropriate and commensurate with these evaluation plans and principles.

(8) Demand-side resources and load-building programs shall be separately designed and administered, and all costs shall be separately classified to permit a clear distinction between demand-side resource 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.

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.060 Integrated Resource Plan and Risk 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. This rule also requires the utility to identify the critical uncertain factors that affect the performance of alternative resource plans and establishes minimum standards for the methods used to assess the risks associated with these uncertainties.

(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 meet. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that satisfy all of the planning objectives and priorities.

(2) Specification of Performance Measures. The utility shall specify, describe, and document a set of quantitative measures for assessing the performance of alternative resource plans with respect to resource planning objectives.

(A) These performance measures shall include at least the following:

1. Present worth of utility revenue requirements, with and without any rate of return or financial performance incentives for demand-side resources the utility is planning to request;

2. Present worth of probable environmental costs;

3. Present worth of out-of-pocket costs to participants in demand-side programs and demand-side rates;

4. Levelized annual average rates;

5. Maximum single-year increase in annual average rates;

6. Financial ratios (e.g., pretax interest coverage, ratio of total debt to total capital, ratio of net cash flow to capital expenditures) or other credit metrics indicative of the utility's ability to finance alternative resource plans; and

7. Other measures that utility decision-makers believe are appropriate for assessing the performance of alternative resource plans relative to the planning objectives identified in 4 CSR 240-22.010(2).

(B) All present worth and levelization calculations shall use the utility discount rate and all costs and benefits shall be expressed in nominal dollars.

(3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of demand-side resources 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). Demand-side resources are the demand-side candidate resource options and portfolios developed in 4 CSR 240-22.050(6). Supply-side resources are the supply-side candidate resource options developed in 4 CSR 240-22.040(4). The goal is to develop a set of alternative plans based on substantively different mixes of supply-side resources and demand-side resources and variations in the timing of resource acquisition to assess their relative performance under expected future conditions as well as their robustness under a broad range of future conditions.

(A) The utility shall develop, and describe and document, at least one (1) alternative resource plan, and as many as may be needed to assess the range of options for the choices and timing of resources, for each of the following cases. Each of the alternative resource plans for cases pursuant to paragraphs (3)(A)1.–(3)(A)5. shall provide resources to meet at least the projected load growth and resource retirements over the planning period in a manner specified by the case. The utility shall examine cases that—

1. Minimally comply with legal mandates for demand-side resources, renewable energy resources, and other mandated energy resources. This constitutes the compliance benchmark resource plan for planning purposes;

2. Utilize only renewable energy resources, up to the maximum potential capability of renewable resources in each year of the planning horizon, if that results in more renewable energy resources than the minimally-compliant plan. This constitutes the aggressive renewable energy resource plan for planning purposes;

3. Utilize only demand-side resources, up to the maximum achievable potential of demand-side resources in each year of the planning horizon, if that results in more demand-side resources than the minimally-compliant plan. This constitutes the aggressive demand-side resource plan for planning purposes;

4. In the event that legal mandates identify energy resources other than renewable energy or demand-side resources, utilize only the other energy resources, up to the maximum potential capability of the other energy resources in each year of the planning horizon, if that results in more of the other energy resources than the compliance benchmark resource plan. For planning purposes, this constitutes the aggressive legally-mandated other energy resource plan;

5. Optimally comply with legal mandates for demand-side resources, renewable energy resources, and other targeted energy resources. This constitutes the optimal compliance resource plan, where every legal mandate is at least minimally met, but some resources may be optimally utilized at levels greater than the mandated minimums;

6. Any other plan specified by the commission as a special contemporary issue pursuant to 4 CSR 240-22.080(4);

7. Any other plan specified by commission order; and

8. Any additional alternative resource plans that the utility deems should be analyzed.

(B) The alternative resource plans developed at this stage of the analysis shall not include load-building programs, which shall be analyzed as required by 4 CSR 240-22.070(5).

(C) The utility shall include in its development of alternative resource plans the impact of—

1. The potential retirement or life extension of existing generation plants;

2. The addition of equipment and other retrofits on generation plants to meet environmental requirements; and

3. The conclusion of any currently-implemented demand-side resources.

(D) The utility shall provide a description of each alternative resource plan including the type and size of each demand-side resource and supply-side resource addition and a listing of the sequence and schedule for the end of life of existing resources and for the acquisition of each new resource.

(4) Analysis of Alternative Resource Plans. The utility shall describe and document its assessment of 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 on a year-by-year basis in order to assess the annual and cumulative impacts of alternative resource plans. The analysis shall be based on the assumption that rates will be adjusted annually, in a manner that is consistent with Missouri law. The analysis shall treat supply-side and demand-side resources on a logically-consistent and economically-equivalent basis, such that the same types or categories of costs, benefits, and risks shall be considered and such that these factors shall be quantified at a similar level of detail and precision



for all resource types. The utility shall provide the following information:

(A) 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;

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

1. The combined impact of all demand-side resources on the base-case forecast of summer and winter peak demands;

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

3. The composition, by supply-side resource, of the capacity supplied to the transmission grid provided by supply-side resources. Existing supply-side resources may be shown as a single resource;

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

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

6. The composition, by supply-side resource, of the annual energy supplied to the transmission grid, less losses, provided by supply-side resources. Existing supply-side resources may be shown as a single resource;

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

8. Annual probable environmental costs; and

9. Public and highly-confidential forms of the capacity balance spreadsheets completed in the specified format;

(C) The analysis of economic impact of alternative resource plans, calculated with and without utility financial incentives for demand-side resources, shall provide comparative estimates for each year of the planning horizon—

1. For the following performance measures for each year:

A. Estimated annual revenue requirement;

B. Estimated annual average rates and percentage increase in the average rate from the prior year; and

C. Estimated company financial ratios and credit metrics; and

2. If the estimated company financial ratios in subparagraph (4)(C)1.C. are below investment grade in any year of the planning horizon, a description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating in each year of the planning horizon and the resulting perfor-

mance measures in subparagraphs (4)(C)1.A.–(4)(C)1.C. of the alternative resource plans that are associated with the necessary changes in legal mandates and cost recovery mechanisms.

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

(E) A discussion of the incremental costs of implementing more renewable energy resources than required to comply with renewable energy legal mandates;

(F) A discussion of the incremental costs of implementing more energy efficiency resources than required to comply with energy efficiency legal mandates;

(G) A discussion of the incremental costs of implementing more energy resources than required to comply with any other energy resource legal mandates; and

(H) A description of the computer models used in the analysis of alternative resource plans.

(5) The utility shall describe and document its selection of the uncertain factors that are critical to the performance of the alternative resource plans. The utility shall consider 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 and access to capital;

(C) Future changes in legal mandates;

(D) Relative real fuel prices;

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities for the utility, for a regional transmission organization, and/or other transmission systems;

(F) Construction costs and schedules for new generation and generation-related transmission facilities for the utility, for a regional transmission organization, and/or other transmission systems;

(G) Purchased power availability, terms, cost, optionality, and other benefits;

(H) Price of emission allowances, including at a minimum sulfur dioxide, carbon dioxide, and nitrogen oxides;

(I) Fixed operation and maintenance costs for new and 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 demand-side rates;

(L) Utility marketing and delivery costs for demand-side programs and demand-side rates; and

(M) Any other uncertain factors that the utility determines may be critical to the performance of alternative resource plans.

(6) The utility shall describe and document its assessment of the impacts and interrelationships of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3) and analyze the risks associated with alternative resource plans. This assessment shall explicitly describe and document the probabilities that utility decision-makers assign to each critical uncertain factor.

(7) The utility decision-makers shall assign a probability pursuant to section (5) of this rule to each uncertain factor deemed critical by the utility. The utility shall compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2). Both the expected performance and the risks of each alternative resource plan shall be quantified. The utility shall describe and document its risk assessment of each alternative resource plan.

(A) The expected performance of each resource plan shall be measured by the statistical expectation of the value of each performance measure.

(B) The risk associated with each resource plan shall be characterized by some measure of the dispersion of the probability distribution for each performance measure, such as the standard deviation or the values associated with specified percentiles of the distribution.

(C) The utility shall provide—

1. A discussion of the method the utility used to determine the cumulative probability—

A. 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 probabilities for each outcome were derived; and

B. Analyses supporting the utility's choice of ranges and probabilities for the uncertain factors;

2. Plots of the cumulative probability distribution of each distinct performance measure for each alternative resource plan;

3. For each performance measure, a table that shows the expected value and the risk of each alternative resource plan; and



4. A plot of the expected level of annual unserved hours for each alternative resource plan over the planning horizon.

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.070 Resource Acquisition Strategy Selection

PURPOSE: This rule requires the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans and evaluate the demand-side resources that are included in the resource acquisition strategy.

(1) The utility shall select a preferred resource plan from among the alternative resource plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060. The utility shall describe and document 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. The utility shall provide the names, titles, and roles of the utility decision-makers in the preferred resource plan selection process. The preferred resource plan shall satisfy at least the following conditions:

(A) In the judgment of utility decision-makers, strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2);

(B) Invest in advanced transmission and distribution technologies unless, in the judgment of the utility decision-makers, investing in those technologies to upgrade transmission and/or distribution networks is not in the public interest;

(C) Utilize demand-side resources to the maximum amount that comply with legal mandates and, in the judgment of the utility decision-makers, are consistent with the public interest and achieve state energy policies; and

(D) In the judgment of the utility decision-makers, the preferred plan, in conjunction with the deployment of emergency demand

response measures and access to short-term and emergency power supplies, has sufficient resources to serve load forecasted under extreme weather conditions pursuant to 4 CSR 240-22.030(8)(B) for the implementation period. If the utility cannot affirm the sufficiency of resources, it shall consider an alternative resource plan or modifications to its preferred resource plan that can meet extreme weather conditions.

(2) The utility shall specify 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 explain how these limits were determined. The utility shall also describe and document its assessment of whether, and under what circumstances, other uncertain factors associated with the preferred resource plan could materially affect the performance of the preferred resource plan relative to alternative resource plans.

(3) The utility shall describe and document its quantification of 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 utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities.

(4) The utility shall describe and document its contingency resource plans in preparation for the possibility that the preferred resource plan should cease to be appropriate, whether due to the limits identified pursuant to 4 CSR 240-22.070(2) being exceeded or for any other reason.

(A) The utility shall identify as contingency resource plans those alternative resource plans that become preferred if the critical uncertain factors exceed the limits developed pursuant to section (2).

(B) The utility shall develop a process to pick among alternative resource plans, or to revise the alternative resource plans as necessary, to help ensure reliable and low cost service should the preferred resource plan no longer be appropriate for any reason. The utility may also use this process to confirm the viability of contingency resource plans identified pursuant to subsection (4)(A).

(C) Each contingency resource plan shall satisfy the fundamental objective in 4 CSR 240-22.010(2) and the specific requirements pursuant to 4 CSR 240-22.070(1).

(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 resource plans developed pursuant to 4 CSR 240-22.060(3) of this rule, including the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). This analysis shall use the same modeling procedure and assumptions described in 4 CSR 240-22.060(4). The utility shall describe and document—

(A) Its analysis of load building programs, including the following elements:

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

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

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

4. A calculation of the performance measures and risk by year; and

5. An assessment of any other aspects of the proposed load-building programs that affect the public interest; and

(B) All current and proposed load-building programs, a discussion of why these programs are judged to be in the public interest, and, for all resource plans that include these programs, plots of the following over the planning horizon:

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

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

(6) The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the preferred resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain—

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

(B) A schedule and description of ongoing and planned demand-side programs and demand-side rates, evaluations, and research activities to improve the quality of demand-side resources;

(C) A schedule and description of all supply-side resource research, engineering, retirement, acquisition, and construction



activities, including research to meet expected environmental regulations;

(D) Identification of critical paths and major milestones for implementation of each demand-side resource and each supply-side resource, including decision points for committing to major expenditures;

(E) A description of adequate competitive procurement policies to be used in the acquisition and development of supply-side resources;

(F) 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 resource plans when the specified limits for uncertain factors are exceeded; and

(G) A process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled.

(7) The utility shall develop, describe and document, officially adopt, and implement a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by an officer of the utility 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 (1) of this rule;

(B) An implementation plan developed pursuant to the requirements of section (6) of this rule; and

(C) A set of contingency resource plans developed pursuant to the requirements of section (4) of this rule and identification of the point at which the critical uncertain factors would trigger the utility to move to each contingency resource plan as the preferred resource plan.

(8) Evaluation of Demand-Side Programs and Demand-Side Rates. The utility shall describe and document its evaluation plans for all demand-side programs and demand-side rates that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). Evaluation plans required by this section are for planning purposes and are sep-

arate and distinct from the evaluation, measurement, and verification reports required by 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7); nonetheless, the evaluation plan should, in addition to the requirements of this section, include the proposed evaluation schedule and the proposed approach to achieving the evaluation goals pursuant to 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7). The evaluation plans for each program and rate shall be developed before the program or rate is implemented and shall be filed when the utility files for approval of demand-side programs or demand-side program plans with the tariff application for the program or rate as described in 4 CSR 240-20.094(3). The purpose of these evaluations shall be to develop the information necessary to evaluate the cost-effectiveness and improve the design of existing and future demand-side programs and demand-side rates, to improve the forecasts of customer energy consumption and responsiveness to demand-side programs and demand-side rates, and to gather data on the implementation costs and load impacts of demand-side programs and demand-side rates for use in future cost-effectiveness screening and integrated resource analysis.

(A) Process Evaluation. Each demand-side program and demand-side rate that is part of the utility's preferred resource plan shall be subjected to an ongoing evaluation process which 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 market 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 market segment?

4. Are the communication channels and delivery mechanisms appropriate for the target market 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 and demand-side rate included in the utility's preferred resource plan to a reasonable degree of accuracy.

1. Impact evaluation methods. At a minimum, comparisons of one (1) or both of the following types shall be used to measure program and rate impacts in a manner that is based on sound statistical principles:

A. Comparisons of pre-adoption and post-adoption loads of program or demand-side rate participants, corrected for the effects of weather and other intertemporal differences; and

B. Comparisons between program and demand-side rate participants' loads and those of an appropriate control group over the same time period.

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:

A. Monthly billing data, hourly load data, load research data, end-use load metered data, building and equipment simulation models, and survey responses; or

B. Audit and survey data on appliance and equipment type, size and efficiency levels, household or business characteristics, or energy-related building characteristics.

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

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-22.080 Filing Schedule, Filing Requirements, and Stakeholder Process

PURPOSE: This rule specifies the requirements for electric utility filings to demonstrate compliance with the provisions of this chapter. The purpose of the compliance review required by this chapter is not commission approval of the substantive findings, determinations, or analyses contained in the filing. The purpose of the compliance review required by this chapter is to determine whether the utility's resource acquisition strategy meets the requirements of Chapter 22. However, if the commission determines that the filing substantially meets these requirements, the commission may further acknowledge that the preferred resource plan or resource acquisition strategy is reasonable



in whole or in part at the time of the finding. This rule also establishes a mechanism for the utility to solicit and receive stakeholder input to its resource planning process.

(1) Each electric utility which sold more than one (1) million megawatt-hours to Missouri retail electric customers for calendar year 2009 shall make a filing with the commission every three (3) years on April 1. The electric utilities shall submit their triennial compliance filings on the following schedule:

(A) Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company, or their successors, on April 1, 2012, and every third year thereafter;

(B) The Empire District Electric Company, or its successor, on April 1, 2013, and every third year thereafter; and

(C) Union Electric Company d/b/a Ameren Missouri, or its successor, on April 1, 2014, and every third year thereafter.

(2) The utility's triennial compliance filings shall demonstrate compliance with the provisions of this chapter and shall include at least the following items:

(A) Letter of transmittal expressing commitment to the approved preferred resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to bind and commit the utility to the resource acquisition strategy;

(B) If the preferred resource plan is inconsistent with the utility's business plan, an explanation of the differences and why the differences exist;

(C) Technical volume(s) that fully describe and document the utility's analysis and decisions in selecting its preferred resource plan and resource acquisition strategy.

1. The technical volume(s) shall include all documentation and information specified in 4 CSR 240-22.030–4 CSR 240-22.070 and any other information considered by the utility to analyze and select its resource acquisition strategy.

2. The technical volume(s) shall be organized by chapters corresponding to 4 CSR 240-22.030–4 CSR 240-22.070.

3. A separate chapter shall be designated in the technical volume(s) to address special contemporary issues pursuant to 4 CSR 240-22.080(4) and input from the stakeholder group pursuant to 4 CSR 240-22.080(5). The chapter shall identify the issues raised, how the utility addressed them, and where in the technical volume(s) the reports, analyses, and all resulting actions are presented.

(D) The forecast of capacity balance spreadsheet completed in the specified form, included herein, for the preferred resource

plan and each candidate resource plan considered by the utility.

(E) An executive summary, separately bound and suitable for distribution to the public in paper and electronic formats. The executive summary shall be an informative non-technical description of the preferred resource plan and resource acquisition strategy. This document shall summarize the contents of the technical volume(s) and shall be organized by chapters corresponding to 4 CSR 240-22.030–4 CSR 240-22.070. The executive summary shall include:

1. A brief introduction describing the utility, its existing facilities, existing purchase power arrangements, existing demand-side programs, existing demand-side rates, and the purpose of the resource acquisition strategy;

2. For each major class and for the total of all major classes, the base load forecasts for peak demand and for energy for the planning horizon, with and without utility demand-side resources, and a listing of the economic and demographic assumptions associated with each base load forecast;

3. A summary of the preferred resource plan to meet expected energy service needs for the planning horizon, clearly showing the demand-side resources and supply-side resources (both renewable and non-renewable resources), including additions and retirements for each resource type;

4. Identification of critical uncertain factors affecting the preferred resource plan;

5. For existing legal mandates and approved cost recovery mechanisms, the following performance measures of the preferred resource plan for each year of the planning horizon:

A. Estimated annual revenue requirement;

B. Estimated level of average retail rates and percentage of change from the prior year; and

C. Estimated company financial ratios;

6. If the estimated company financial ratios in subparagraph (2)(E)5.C. of this rule are below investment grade in any year of the planning horizon, a description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating in each year of the planning horizon and the resulting performance measures of the preferred resource plan;

7. Actions and initiatives to implement the resource acquisition strategy prior to the next triennial compliance filing; and

8. A description of the major research projects and programs the utility will continue or commence during the implementation period; and

(F) Such other information or format as the commission may determine.

(3) Beginning in 2012, on or about April 1 of every year in which the utility is not required to submit a triennial compliance filing, each electric utility shall host an annual update workshop with the stakeholder group. The utility at its discretion may host additional update workshops when conditions warrant. Any additional update workshops shall follow the same procedures as the annual update workshop.

(A) The purpose of the annual update workshop is to ensure that members of the stakeholder group have the opportunity to provide input and to stay informed regarding the—

1. Utility's current preferred resource plan;

2. Status of the identified critical uncertain factors;

3. Utility's progress in implementing the resource acquisition strategy;

4. Analyses and conclusions regarding any special contemporary issues that may have been identified pursuant to 4 CSR 240-22.080(4);

5. Resolution of any deficiencies or concerns pursuant to 4 CSR 240-22.080(16); and

6. Changing conditions generally.

(B) The utility shall prepare an annual update report with both a public version and a highly-confidential version to document the information presented at the annual update workshop and shall file the annual update reports with the commission no less than twenty (20) days prior to the annual update workshop. The depth and detail of the annual update report shall generally be commensurate with the magnitude and significance of the changing conditions since the last filed triennial compliance filing or annual update filing. If the current resource acquisition strategy has changed from that contained in the most-recently-filed triennial compliance filing or annual update filing, the annual update report shall describe the changes and provide updated capacity balance spreadsheets required pursuant to 4 CSR 240-22.080(2)(D). If the current resource acquisition strategy has not changed, the annual update report shall explicitly verify that the current resource acquisition strategy is the same as that contained in the most-recently-filed triennial compliance filing or annual update filing.



(C) The utility shall prepare a summary report that shall list and describe any action items resulting from the workshop to be undertaken by the utility prior to next triennial compliance filing or annual update filing. The summary shall be filed within ten (10) days following the workshop. If there are no changes as a result of the workshop, the utility is required to file a notice that it will not be making any changes to its annual update report.

(D) Stakeholders may file comments with the commission concerning the utility's annual update report and summary report within thirty (30) days of the utility's filing of the summary report.

(4) It is the responsibility of each utility to keep abreast of evolving electric resource planning issues and to consider and analyze these issues in a timely manner in the triennial compliance filings and annual update reports. An order containing a list of special contemporary issues shall be issued by the commission for each utility to analyze and document in its next triennial compliance filing or next annual update report. The purpose of the special contemporary issues lists is to ensure that evolving regulatory, economic, financial, environmental, energy, technical, or customer issues are adequately addressed by each utility in its electric resource planning. Each special contemporary issues list will identify new and evolving issues but may also include other issues such as unresolved deficiencies or concerns from the preceding triennial compliance filing. To develop the list of special contemporary issues—

(A) No later than September 15, staff, public counsel, and parties to the last triennial compliance filing of each utility may file suggested special contemporary issues for each utility to consider;

(B) Not later than October 1, the utilities, staff, public counsel, and parties to the last triennial compliance filings may file comments regarding the special contemporary issues filed on September 15; and

(C) No later than November 1, an order containing a list of special contemporary issues shall be issued by the commission for each utility to analyze and document in its next triennial compliance filing or annual update report. The commission shall not be limited to only the filed suggested special contemporary issues. If the commission determines that there are no special contemporary issues for a utility to analyze, an order shall be issued by the commission stating that there are no special contemporary issues.

(5) Each electric utility shall convene a stakeholder group to provide the opportunity for public input into electric utility resource planning in a timely manner that may affect the outcome of the utility resource planning efforts. The utility may choose to not incorporate some, or all, of the stakeholder group input in its analysis and decision-making for the triennial compliance filing.

(A) The utility shall convene at least one (1) meeting of the stakeholder group prior to the triennial compliance plan filing to present a draft of the triennial compliance filing corresponding to 4 CSR 240-22.030–4 CSR 240-22.050 and to present an overview of its proposed alternative resource plans and intended procedures and analyses to meet the requirements of 4 CSR 240-22.060 and 4 CSR 240-22.070. The stakeholders shall make a good faith effort to provide comments on the information provided by the utility, to identify additional alternative resource plans, and to identify where the utility's analyses and intended approaches may not meet the objectives of the rules.

(B) Within thirty (30) days of the last stakeholder group meeting pursuant to subsection (5)(A) of this rule, any stakeholder may provide the utility and other stakeholders with a written statement summarizing any potential deficiencies in or concerns with the utility's proposed compliance with the electric resource planning rules. The utility has the opportunity to address the potential deficiencies or concerns identified by any stakeholder in its preparation of the triennial compliance filing.

(C) Any stakeholder input through the process described in section (5) of this rule does not preclude the stakeholder from filing reports in accordance with section (7) or (8) of this rule.

(6) The commission will establish dockets for the purpose of receiving the triennial compliance filings. Unless the commission specifies otherwise, the docket of the triennial compliance filing of each affected utility shall remain open to receive annual update reports including workshop summary reports, notifications of changes to the preferred plan, and other relevant documents submitted between triennial compliance filings. The commission will issue orders that establish an intervention deadline and provide for notice.

(7) The staff shall conduct a limited review of each triennial compliance filing required by this rule and shall file a report not later than one hundred fifty (150) days after each utility's scheduled triennial compliance filing date. The report shall identify any deficiencies

in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies and shall provide at least one (1) suggested remedy for each identified deficiency. Staff may also identify concerns with the utility's triennial compliance filing, may identify concerns related to the substantive reasonableness of the preferred resource plan or resource acquisition strategy, and shall provide at least one (1) suggested remedy for each identified concern. Staff shall provide its workpapers related to each deficiency or concern to all parties within ten (10) days of the date its report is filed. If the staff's limited review finds no deficiencies or no concerns, the staff shall state that in the report. A staff report that finds that an electric utility's filing is in compliance with this chapter shall not be construed as acceptance or agreement with the substantive findings, determinations, or analysis contained in the electric utility's filing.

(8) Also within one hundred fifty (150) days after an electric utility's triennial compliance filing pursuant to this rule, the public counsel and any intervenor may file a report or comments. The report or comments, based on a limited review, may identify any deficiencies in the electric utility's compliance with the provisions of this chapter, any major deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies. The report may also identify concerns with the utility's triennial compliance filing and may identify concerns related to the substantive reasonableness of the preferred resource plan or resource acquisition strategy. Public counsel or intervenors shall make a good faith effort to provide at least one (1) suggested remedy for each identified deficiency or concern. Public counsel or any intervenor shall provide its workpapers, if any, related to each deficiency or concern to all parties within ten (10) days of the date its report is filed.

(9) If the staff, public counsel, or any intervenor finds deficiencies in or concerns with a triennial compliance filing, it shall work with the electric utility and the other parties to reach, within sixty (60) days of the date that the report or comments were submitted, a joint agreement on a plan to remedy the identified deficiencies and concerns. If full agreement cannot be reached, this should be reported to the commission through a joint filing as soon as possible but no later than sixty (60) days after the date on which the report or comments were submitted. The



joint filing should set out in a brief narrative description those areas on which agreement cannot be reached. The resolution of any deficiencies and concerns shall also be noted in the joint filing.

(10) If full agreement on remedying deficiencies or concerns is not reached, then, within sixty (60) days from the date on which the staff, public counsel, or any intervenor submitted a report or comments relating to the electric utility's triennial compliance filing, the electric utility may file a response and the staff, public counsel, and any intervenor may file comments in response to each other. The commission will issue an order which indicates on what items, if any, a hearing will be held and which establishes a procedural schedule.

(11) All workpapers, documents, reports, data, computer model documentation, analysis, letters, memoranda, notes, test results, studies, recordings, transcriptions, and any other supporting information relating to the filed resource acquisition strategy within the electric utility's or its contractors' possession, custody, or control shall be preserved and submitted within two (2) days of its triennial compliance or annual update filings in accordance with any protective order to the staff and public counsel, and to any intervenor within two (2) days of the intervenor signing and filing a confidentiality agreement, for use in its review of the periodic filings required by this rule. All information shall be labeled to reference the sections of the technical volume(s) to which it is related, and all spreadsheets shall have all formulas intact. Each electric utility shall retain at least one (1) readable copy of the officially adopted resource acquisition strategy and all supporting information for at least the prior three (3) triennial compliance filings.

(12) If, between triennial compliance filings, the utility's business plan or acquisition strategy becomes materially inconsistent with the preferred resource plan, or if the utility determines that the preferred resource plan or acquisition strategy is no longer appropriate, either due to the limits identified pursuant to 4 CSR 240-22.070(2) being exceeded or for other reasons, the utility, in writing, shall notify the commission within sixty (60) days of the utility's determination and shall serve notice on all parties to the most recent triennial compliance filing. The notification shall include a description of all changes to the preferred plan and acquisition strategy, the impact of each change on the present value of revenue requirement, and all other perfor-

mance measures specified in the last filing pursuant to 4 CSR 240-22.080 and the rationale for each change.

(A) If the utility decides to implement any of the contingency resource plans identified pursuant to 4 CSR 240-22.070(4), the utility shall file for review a revised resource acquisition strategy. In this filing, the utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the new alternative resource plan remains appropriate.

(B) If the utility decides to implement a resource plan not identified pursuant to 4 CSR 240-22.070(4) or changes its acquisition strategy, it shall give a detailed description of the revised resource plan or acquisition strategy and why none of the contingency resource plans identified in 4 CSR 240-22.070(4) were chosen. In this filing, the utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the new alternative resource plan remains appropriate.

(13) Upon written application made at least twelve (12) months prior to a triennial compliance filing, and after notice and an opportunity for hearing, the commission may waive or grant a variance from a provision of 4 CSR 240-22.030-4 CSR 240-22.080 for good cause shown. The commission may grant an application for waiver or variance filed less than twelve (12) months prior to the triennial compliance filing upon a showing of good cause for the delay in filing the application for waiver or variance.

(A) The granting of a variance to one (1) electric utility which waives or otherwise affects the required compliance with a provision of this chapter does not constitute a waiver respecting, or otherwise affect, the required compliance of any other electric utility with a provision of these rules.

(B) The commission will not waive or grant a variance from this chapter in total.

(14) An electric utility which sells less than seven (7) million megawatt-hours to Missouri retail electric customers for the previous calendar year may apply for a waiver allowing it to conduct an annual update workshop pursuant to section (3) of this rule in place of its scheduled triennial compliance filing pursuant to section (1) of this rule, if the utility has no unresolved deficiencies or concerns from its prior triennial plan filing or annual update filing that materially affect its resource acquisition strategy. Upon written application made at least twelve (12) months prior to a triennial compliance filing, and

after notice and an opportunity for hearing, the commission may allow the utility to conduct the annual update workshop process in lieu of submitting its triennial compliance filing. No more than one (1) such waiver may be granted consecutively between triennial compliance filings.

(15) The commission may extend or reduce any of the time periods specified in this rule for good cause shown.

(16) The commission will issue an order which contains its findings regarding at least one (1) of the following options:

(A) That the electric utility's filing pursuant to this rule either does or does not demonstrate compliance with the requirements of this chapter, and that the utility's resource acquisition strategy either does or does not meet the requirements stated in 4 CSR 240-22.

(B) That the commission approves or disapproves the joint filing on the remedies to the plan deficiencies or concerns developed pursuant to section (9) of this rule;

(C) That the commission understands that full agreement on remedying deficiencies or concerns is not reached and pursuant to section (10) of this rule, the commission will issue an order which indicates on what items, if any, a hearing(s) will be held and which establishes a procedural schedule; and

(D) That the commission establishes a procedural schedule for filings and a hearing(s), if necessary, to remedy deficiencies or concerns as specified by the commission.

(17) If the commission finds that the filing achieves substantial compliance with the requirements outlined in section (16), the commission may acknowledge the utility's preferred resource plan or resource acquisition strategy as reasonable at a specific date. The commission may acknowledge the preferred resource plan or resource acquisition strategy in whole, in part, with exceptions, or not at all. Acknowledgment shall not be construed to mean or constitute a finding as to the prudence, pre-approval, or prior commission authorization of any specific project or group of projects. In proceedings where the reasonableness of resource acquisitions are considered, consistency with an acknowledged preferred resource plan or resource acquisition strategy may be used as supporting evidence but shall not be considered any more or less relevant than any other piece of evidence in the case. Consistency with an acknowledged preferred resource plan or resource acquisition strategy does not create a rebuttable presumption of prudence and



shall not be considered to be dispositive of the issue. Furthermore, in such proceedings, the utility bears the burden of proof that past or proposed actions are consistent with an acknowledged preferred resource plan or resource acquisition strategy and must explain and justify why it took any actions inconsistent with an acknowledged preferred resource plan or resource acquisition strategy.

(A) The utility shall notify the commission pursuant to 4 CSR 240-22.080(12) in the event there is material reason why any plan acknowledged by the commission is no longer viable.

(B) Any interested stakeholder group may file a notice in the utility's most recent Chapter 22 compliance file with the commission if a substantial change in circumstances has occurred that it believes may result in the invalidation of any aspect of a preferred resource plan or portion of a resource acquisition strategy previously acknowledged by the commission.

(C) The utility about which a stakeholder group files a notice described in the previous section may file its response within fifteen (15) working days of the date the notice is filed.

(18) In all future cases before the commission which involve a requested action that is affected by electric utility resources, preferred resource plan, or resource acquisition strategy, the utility must certify that the requested action is substantially consistent with the preferred resource plan specified in the most recent triennial compliance filing or annual update report. If the requested action is not substantially consistent with the preferred resource plan, the utility shall provide a detailed explanation.



Forecast of Capacity Balance (MW) - HIGHLY CONFIDENTIAL

Name of Utility: _____

Year of Electric Utility Resource Planning Filing: _____

	<u>Year 1</u>	<u>Year 2</u>	<u>Year 3</u>	<u>Year 4</u>	<u>Year 5</u>	<u>Year 20</u>
A. System Generation Capacity							
Base Capacity							
Unit 1							
Unit 2							
Unit 3							
Unit 4							
.....							
Unit i							
Total Base Capacity							
Intermediate Capacity							
Unit i+1							
Unit i+2							
Unit i+3							
Unit i+4							
.....							
Unit j							
Total Intermediate Capacity							
Peaking Capacity							
Unit j+1							
Unit j+2							
Unit j+3							
.....							
Unit k							
Total Peaking Capacity							
Intermittent Capacity							
Wind							
Solar							
Total Intermittent Capacity							
Percent Accredited Intermittent Capacity							
Total Accredited Intermittent Capacity							
Total Generation Capacity = TGC							
B. Capacity Transactions							
Purchases							
Source 1							
Source 2							
Source 3							
.....							
Source t							
Total Purchases = P							
Sales							
Party 1							
Party 2							
.....							
Party s							
Total Sales = S							
Net Transactions = NT = P - S							
Total System Capacity = TSC = TGC + NT							
C. System Peaks & Reserves							
Peak Demands							
Forecasted Peak							
less DSM							
Peak Forecast less DSM = PF							
Capacity Reserves = CR = TSC - PF							
D. Capacity Needs							
% Reserve Margin = RM							
% Capacity Margin = CM = RM/(1 + RM)							
Required Capacity = RC = PF/(1-CM)							
Capacity Balance = TSC - RC							



AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010, effective June 30, 2011.*

**Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.*