4. A statement that the applicant will offer basic local telecommunications service as a separate and distinct service; and

5. A statement that the applicant will give equitable access to all Missourians, regardless of where they live or their income, to affordable telecommunications services.

AUTHORITY: sections 386.250[,] and 392.455, RSMo 2000 and sections 392.450[,] and 392.451, RSMo Supp. 2010. Original rule filed Aug. 16, 2002, effective April 30, 2003. Amended: Filed March 19, 2004, effective Nov. 30, 2004. Amended: Filed Oct. 28, 2010.

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed amendment with the Missouri Public Service Commission, Steven C. Reed, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before January 3, 2011, and should include a reference to Commission Case No. TX-2010-0099. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/case-filing-information. A public hearing regarding this proposed amendment is scheduled for January 4, 2011, at 10:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Room 305, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment and may be asked to respond to commission questions.

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

PROPOSED AMENDMENT

4 CSR 240-22.010 Policy Objectives. Changes are made throughout this rule to enable it to meet current and future Missouri energy policies.

PURPOSE: This proposed amendment updates the current policy objectives of the resource planning process to reflect current Missouri energy policies.

(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 **with a view to the public welfare, efficient facilities, and substantial justice between patrons and public utilities.** 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. *[This]* **The fundamental** objective requires that the utility shall—

(A) Consider and analyze demand-side *[efficiency and]* resources, **renewable energy** *[management measures]*, **and supply-side resources** on an equivalent basis *[with supply-side alternatives]*, **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 *[contingency options]* **the resource acquisition strategy**. These considerations 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 *[environmental laws or regulations]* **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, [RSMo Supp. 1991] 386.610, and 393.140, RSMo [1986] 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010.

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Editor's Note: The Dissent of Commissioner Jeff Davis to the Proposed Rulemakings Revising the Commission's Chapter 22 Electric Utility Resource Planning Rules follows 4 CSR 240-22.080 on page 1776 of this issue of the Missouri Register.

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

PROPOSED AMENDMENT

4 CSR 240-22.020 Definitions. The commission is adding new sections (5), (11)-(14), (23), (27), (36), (42), (43), (46)-(48), and (52)-(54), deleting sections (4), (10), (12), (24), (25), (30), (31), (35), (36), (45), (50), (52), and (59), amending newly numbered sections (1), (2), (6), (7), (8), (10), (15), (16), (19), (20), (21), (24), (25), (26), (31), (33), (37), (39), (44), (45), (49), (51), (55), (57), (58), (59), (61), and renumbering the remaining sections.

PURPOSE: This proposed amendment reflects the definitions necessary for the proposed revisions to rules 4 CSR 240-22.030 through 4 CSR 240-22.080.

(1) *[Avoided cost means the cost savings obtained by substituting demand-side resources for existing and new supply resources. 4 CSR 240-22.050(2) requires the utility to develop the following measures of avoided cost:*

(A) Avoided utility costs developed pursuant to 4 CSR 240-22.050(2)(D), which include energy cost savings plus demand cost savings associated with generation, transmission and distribution facilities; and

(B) Avoided probable environmental costs developed pursuant to 4 CSR 240-22.050(2)(D) and 4 CSR 240-22.040(2)(B).] **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).**

(2) *[Candidate resource options are demand-side programs that pass the screening test required by 4 CSR 240-22.050(7), or supply-side resources that are not rejected on the basis of the screening analysis required by 4 CSR 240-22.040(2).]* **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) Chance node is a decision-tree fork consisting of two (2) or more branches that represent the range and number of relevant potential outcomes for an uncertain factor.]

[(5)](4) 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.

(5) Concern means 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.

(6) Contingency *[option]* **resource plan** means an alternative *[choice, decision or course of action]* **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.

(7) *[Decision node is a decision-tree fork consisting of two (2) or more branches that represent the set of decision alternatives being considered by utility planners at that stage of the resource planning process.]* **Critical uncertain factor is any uncertain factor that is likely to materially affect the outcome of the resource planning decision.**

(8) *[Decision tree is a diagram that specifies the order in which key resource decisions must be made, enumerates the set of decision alternatives to be considered at each stage, identifies the critical uncertain factors that affect the outcome of each decision and shows how the potential range of values for uncertain factors interact with each decision option to affect the expected cost of providing an adequate level and quality of energy services.]* **Deficiency means anything that would cause the electric utility's resource acquisition strategy to fail to meet the requirements identified in chapter 22.**

[(10) Demand-side measure is synonymous with end-use measure.]

[(11)](10) Demand-side *[resource (or]* 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) Driver variable means an external economic or demographic factor that significantly affects some component of utility loads.]

(11) 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.

(12) 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.

(13) 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).

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

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

[(14)](16) 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.

[(15)](17) End-use measure means an energy-efficiency measure or an energy-management measure.

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

[(17)](19) Energy-efficiency measure means any device, technology, *[rate structure]* 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.

[(18)](20) Energy-management measure means any device, technology, *[rate structure]* 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.**

[(19)](21) 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 *[subjective]* probabilities *[represented by chance nodes in the decision tree. 4 CSR 240-22.060 requires the]*. **The** utility *[to]* **shall** consider probable environmental costs as well as direct utility costs in its assessment of alternative resource plans.

[(20)](22) 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.

[(21) Fixed cost margin means the portion of electric energy and demand rates that is designed to recover all nonvariable costs.]

(23) 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.

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

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

[(24) Inefficient energy-related choice means any decision that causes the life-cycle cost of delivering an adequate level and quality of end-use energy service to be higher than it would be for an available alternative choice.]

[(25) Inefficient price means a price that is not equal to the long-run marginal cost of providing a good or service.]

(26) 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.

(27) 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 loads, resources, or resource plans.

[(27)](28) 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.

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

[(29)](30) 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.

[(30) Load duration curve is a plot of ranked hourly demand versus the number of hours in which demand was greater than or equal to that value over a specified interval of time.]

[(31) Load factor means the average demand over a specified interval of time divided by the maximum demand in the interval.]

[(32)](31) 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 *[measure or program]* **resource**.

[(33)](32) 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)](33) 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) Load-research estimates, or class hourly loads, or class load estimates means the statistical expectation of the average hourly demands for each major class derived from the load-research data for that class.]

[(36) Load-research sample means a subset of utility customers from each major class whose demands are metered to provide statistical estimates of class hourly loads to a specified level of accuracy.]

[(37)](34) Long run means an analytical framework within which all factors of production are variable.

[(38)](35) Lost *[margin or lost]* revenues means the reduction between rate cases in billed demand (kW) and energy (kWh) due to installed demand-side measures, multiplied by the fixed-cost margin of the appropriate rate component.

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

[(39)](37) 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.

[(40)](38) 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.

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

[(42)](40) 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)](41) 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.

(42) 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.

(43) 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).

(44) 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.

[(45) Probable environmental benefits test is a test of the cost-effectiveness of end-use measures that uses the sum of avoided utility costs and avoided probable environmental costs to quantify the savings obtained by substituting the end-use measure for supply resources.]

[(46)](45) Probable environmental cost means the expected cost to the utility of complying with new or additional environmental *[laws, regulations]* **legal mandates**, taxes, or other requirements that, **in the judgment of the** utility decision-makers *[judge]*, 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.

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

(47) Realistic achievable potential of a demand-side candidate resource option or portfolio is an estimate of the load impact that would occur if that resource option or portfolio were implemented in amounts consistent with the most aggressive cost-effective implementation of the resource option or portfolio considered by the utility.

(48) 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.

[(47)](49) Resource acquisition strategy means a preferred resource plan, an implementation plan *[and]*, a set of contingency *[options for responding to]* **resource plans, and the events or circum**stances that would *[render the preferred plan obsolete.]* **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.**

[(48)](50) 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.

[(49)](51) Resource planning means the process by which an electric utility evaluates and chooses the appropriate mix and schedule of supply-side *[and]*, 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.

[(50) Screening test or cost-effectiveness test means the probable environmental benefits test for demand-side measures and the total resource cost test for demand-side programs.]

(52) RTO means Regional Transmission Organization.

(53) Special contemporary issues means a written list of issues prepared by commission staff with input from public counsel and intervenors that are evolving new issues, which may not otherwise have been addressed by the utility or 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.

(54) 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.

[(51)](55) Subjective probability means the judgmental likelihood that the outcome *[represented by each branch of a chance node]* will actually occur. *[The sum of the probabilities associated with the branches of a single chance node must equal one (1). This means that the specified set of potential outcomes must be exhaustive and mutually exclusive.]*

[(52) Sulfur dioxide emission allowance is an authorization to emit, during or after a specified calendar year, one (1) ton of sulfur dioxide, as defined in Title IV of the Clean Air Act Amendments of 1990, 42 USC 7651a(3).]

[(53)](56) 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.

[(54)](57) Technical potential of **a demand-side candidate resource option or portfolio is** an *[end-use measure is an]* estimate of the load impact that would occur if that *[measure]* **resource option or portfolio** were *[installed]* **implemented** at every location in the utility's service territory where the *[measure]* **resource option or portfolio** is technically feasible but has not yet been *[installed]* **implemented.**

[(55)](58) 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 *[of]* **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.

[(56)](59) 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.

[(57)](60) 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.

[(58)](61) 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.

[(59) The utility benefits test is a test of the cost-effectiveness of end-use measures that uses avoided utility costs to quantify the savings obtained by substituting the end-use measure for supply resources.]

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

[(61)](63) 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, [RSMo Supp. 1991] 386.610, and 393.140, RSMo [1986] 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010.

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

PROPOSED AMENDMENT

4 CSR 240-22.030 Load Analysis and *Load* Forecasting. The commission is amending the title, adding new sections (1), (5), (6), and (8), deleting sections (4), (6), and (7), and amending and renumbering the remaining sections.

PURPOSE: This proposed amendment allows the electric utilities more discretion in choosing their load forecasting methodology specifications while retaining the criteria needed for an accurate forecast. It also sets out what data needs to be consistent between the utility's load forecast and the utility's demand-side resource analysis.

*PURPOSE: This rule sets minimum standards for the maintenance and updating of historical data, the level of detail required in analyzing [and forecasting] loads, and 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

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 forecasting described in 4 CSR 240-22.030.

*[(1)]***(2)** Historical Data*[B]*base 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. *[The]* **At a minimum, the** historical data*[ ]*base shall be maintained for each of the *[following]* major classes*[: residential, commercial, industrial, interruptible and other classes that may be required for forecasting (for example, large power, wholesale, outdoor lighting and public authorities).*

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

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

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

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

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 data*[ ]*base for major class monthly energy usage and demands at time of monthly peaks shall be disaggregated into a number-of-units component and a *[use kilowatt-hour (kWh) per unit]* **use-per-unit** component, for both actual and weather-normalized loads.

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

*[A.]*The estimates of the effect of weather on historical major class and system loads shall incorporate the nonlinear response of loads to daily weather and seasonal variations in loads.

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

*[C.]***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; *[the data used to estimate the models, including the development of model input data from basic data;]* and the relevant statistical results of the models, including parameter estimates and tests of statistical significance*[; and]***. 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) Length of Data Base. Once the utility has developed the historical data base, it shall retain that data base for the ten (10) most recent years or for the period of time used as the basis of the utility's forecast, whichever is longer.

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

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

*[(2)]***(3)** Analysis of Number of Units. For each major class *[or subclass]*, the utility shall *[analyze]* **describe and document its analysis of** the historical relationship between the number of units and the economic and/or demographic factors (*[driver]* **explanatory** variables) that affect the number of units for that major class *[or subclass. These]*. **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 *[driver]* **explanatory** variables.

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

(B) Documentation of statistical models shall include the elements specified in *[subparagraph (1)(C)2.C.]* **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**.

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

*[(3)]***(4)** Analysis of Use Per Unit. For each major class, the utility shall *[analyze]* **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 *[by end use]*, where information permits*[.*

1. Where applicable for each major class], by end-uses that contribute significantly to energy use *[information shall be developed for at least lighting, process equipment, space cooling, space heating, water heating and refrigeration.]* **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.

*[2.]***3.** For each major class and each end-use load, including those listed in paragraph *[(3)]***(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.

[3. If the utility has not yet acquired end-use information on space cooling or space heating for a major class, the]

4. The utility shall determine the effect that weather has on the total load of *[that]* **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.

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

(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 *[survey]* **adequate** data on the energy-related characteristics of the building, appliance, and equipment stock including saturation levels, efficiency levels, and sizes, where applicable. The utility shall update *[these surveys]* **the data** before each *[scheduled]* **triennial compliance filing** *[pursuant to 4 CSR 240-22.080]*; and

2. Estimates of end-use energy and demand. For *[each]* **the** end-use loads **identified in subsection (4)(A)**, the utility shall estimate *[end-use]* 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.

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

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

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

(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.

[(5)](7) Base-Case Load Forecast. The utility's base-case load forecast shall be based on projections of the *[major economic and demographic driver]* independent variables that utility decision-makers believe to be most likely. All components of the base-case load forecast shall *[be based on the assumption of]* 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) *[Customer]* 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*[. Where the utility anticipates that jurisdictional levels of forecasts will be required to meet the requirements of a specific state, then the utility shall determine a procedure by which the major class forecasts can be separated by jurisdictional component.*

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

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

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

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

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

A. The forecasts of the driver variables for the use per unit shall be specified.], 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 *[forecast of use per unit has]* 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.

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

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.

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

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

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

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

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

[(8) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:]

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.

[(A) For each major class specified in subsection (1)(A), the utility shall provide plots of number of units, energy usage per unit and total class energy usage.

1. Plots shall be produced for the summer period (June through September), the remaining nonsummer months and the calendar year.

2. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

A. The historical period shall include both actual and weather-normalized energy usage per unit and total class energy usage.

B. The plots for the forecast period shall show each end-use component of major class energy usage per unit and total class energy usage for the base-case forecast.

(B) For each major class specified in subsection (1)(A), the utility shall provide plots of class demand per unit and class total demand at time of summer and winter system peak. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

1. The plots for the historical period shall include both actual and weather-normalized class demands per unit and total demands at the time of summer and winter system peak demands.

2. The plots for the forecast period shall show each end-use component of major class coincident demands per unit and total class coincident demands for the base-case forecast.

(C) For the forecast of class energy and peak demands, the utility shall provide a summary of the sensitivity analysis required by section (6) of this rule that shows how changes in the driver variables affect the forecast.

(D) For the net system load, the utility shall provide plots of energy usage and peak demand.

1. The energy plots shall include the summer, nonsummer and total energy usage for each calendar year.

2. The peak demand plots shall include the summer and winter peak demands.]

*[3.]***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** *[values]* **peak demands at the time of summer and winter system peaks.** The plots of **coincident peak demand for** the forecast period shall *[include]* **show the class coincident demands for** the base-case*[, low-case and high-case forecasts]* **forecast at the time of summer and winter system peaks.**

[4. The utility shall describe how the subjective probabilities assigned to each forecast were determined.

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

1. The plots shall show each end-use component of the hourly load profile.

2. The plots shall be provided for the base year of the load forecast and for the fifth, tenth and twentieth years of the forecast.

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

1. The plots shall show each of the major class components of the net system load profile in a cumulative manner.

2. The plots shall be provided for the base year of the forecast and for the fifth, tenth and twentieth years of the forecast.

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

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

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, [RSMo Supp. 1991] 386.610, and 393.140, RSMo [1986] 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010.

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed amendment with the Missouri Public Service Commission, Steven C. Reed, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before January 3, 2011, and should include a reference to Commission File No. EX-2010-0254. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/case-filing-information. A public hearing regarding this proposed amendment is scheduled for January 6, 2011, at 9:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Room 305, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 (voice) or Relay Missouri at 711.

Editor's Note: The Dissent of Commissioner Jeff Davis to the Proposed Rulemakings Revising the Commission's Chapter 22 Electric Utility Resource Planning Rules follows 4 CSR 240-22.080 on page 1776 of this issue of the Missouri Register.

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

PROPOSED AMENDMENT

4 CSR 240-22.040 Supply-Side Resource Analysis. The commission is amending section (1), adding a new section (4), deleting sections (4), (6), (7), and (9), and amending and renumbering the remaining sections.

PURPOSE: This proposed amendment reduces the prescriptiveness of the current supply-side analysis rule while making transmission planning a more integral part of the supply-side analysis.

(1) The *[analysis of]* **utility shall evaluate all existing** supply-side resources *[shall begin with the identification of]* **and identify** a variety of potential supply-side resource options which the utility can reasonably expect to use, develop *[and]*, implement *[solely through its own resources or for which it will be a major participant]*, 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 *[utility sources, cogenerators or independent power producers;]* **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 *[for]* **sufficient to fairly analyze and compare** each of these potential *[resource options which shall include at least the following attributes where applicable:*

(A) Fuel type and feasible variations in fuel type or quality;

(B) Practical size range;

(C) Maturity of the technology;

(D) Lead time for permitting, design, construction, testing and startup;

(E) Capital cost per kilowatt;

(F) Annual fixed operation and maintenance costs;

(G) Annual variable operation and maintenance costs;

(H) Scheduled routine maintenance outage requirements;

(I) Equivalent forced-outage rates or full- and partial-forced-outage rates;

(J) Operational characteristics and constraints of significance in the screening process;

(K) Environmental impacts, including at least the following:

1. Air emissions including at least the primary acid gases, greenhouse gases, ozone precursors, particulates and air toxics;

2. Waste generation including at least the primary forms of solid, liquid, radioactive and hazardous wastes;

3. Water impacts including direct usage and at least the primary pollutant discharges, thermal discharges and groundwater effects; and

4. Siting impacts and constraints of sufficient importance to affect the screening process; and

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

[(2) Each of the] supply-side resource options *[referred to in section (1) shall be subjected to a preliminary screening analysis. The purpose of this step is to provide an initial ranking of these options based on their relative annualized utility costs as well as their]*, **including at least those attributes needed to assess capital cost, fixed and variable operation and maintenance costs,** probable environmental costs, and *[to eliminate from further consideration those options that have significant disadvantages in terms of utility costs, environmental costs, operational efficiency, risk reduction or planning flexibility, as compared to other available supply-side resource options]* **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 *[resource]* **potential supply-side resource option** using the utility discount rate. *[In lieu of levelized cost, the utility may use an economic carrying charge annualization in which the annual dollar amount increases each year at an assumed inflation rate and for which a stream of these amounts over the life of the resource yields the same present value.]*

(B) The probable environmental costs of each **potential** supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental *[laws or regulations]* **legal mandates** that may be imposed at some point within the planning horizon.

[1.] The utility shall identify a list of environmental pollutants for which, in the judgment of the utility decision-makers, *[additional laws or regulations]* **legal mandates** may be imposed *[at some point within]* **during** the planning horizon which would result in compliance costs that could *[have a significant]* **significantly** impact *[on]* utility rates.

[2. For each pollutant identified pursuant to paragraph (2)(B)1., the utility shall specify at least two (2) levels of mitigation that are more stringent than existing requirements which are judged to have a nonzero probability of being imposed at some point within the planning horizon.]

[3. For each mitigation level identified pursuant to paragraph (2)(B)2., the] **The** utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that *[additional laws or regulations]* **legal mandates** requiring *[that level]* **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 *[level]* cost for each identified pollutant.

[4. The probable environmental cost for a supply-side resource shall be estimated as the joint cost of simultaneously achieving the expected level of mitigation for all identified pollutants emitted by the resource. The estimated mitigation costs for an environmental pollutant may include or may be entirely comprised of a tax or surcharge imposed on emissions of that pollutant.]

(C) The utility shall *[rank all supply-side resource options identified pursuant to section (1) in terms of both of the following cost estimates: utility costs and utility costs plus probable environmental costs.]* **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 *[indicate which supply-side options are considered to be candidate resource options for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). The utility shall also indicate which options]*—

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 *[on the basis of the screening analysis]* and *[shall explain]* the reasons for their elimination.

(3) *[The analysis of supply-side resource options shall include a thorough analysis of existing and planned interconnected generation resources. The analysis can be performed by the individual utility or in the context of a joint planning study with other area utilities.]* **The 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** *[resources]* **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 about the following *[types of supply-side resource alternatives]*:

*[(A)]***1.** Joint ownership or participation in generation construction projects;

*[(B)]***2.** Construction of wholly-owned generation *[or transmission]* facilities; *[and]*

*[(C)]***3.** Participation in major refurbishment, **life extension,** upgrading, or retrofitting of existing generation *[or transmission resources.]* **facilities;**

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

4. Improvements on its transmission and distribution system to increase efficiency and reduce power losses;

[(5) The utility shall identify and evaluate potential opportunities.]

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. *[This evaluation shall be based on an analysis of at least the following attributes of each potential transaction:*

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

(B) Amount of power to be exchanged;

(C) Estimated contract price;

(D) Timing and duration of the transaction;

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

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

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

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

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

(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).

[(8) Before developing alternative resource plans and performing the integrated resource analysis, the]

(5) The utility shall develop, **and describe and document,** ranges of values and probabilities for several important uncertain factors related to supply *[resources. These values can also be used to refine or verify information developed pursuant to section (2) of this rule]*-**side candidate resource options identified in section (4).** These cost estimates shall include at least the following elements *[and shall be based on the indicated methods or sources of information]*, **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*[.*

1. Fuel price forecasts shall be obtained from a consulting firm with specific expertise in detailed fuel supply and price analysis or developed by the utility if it has expert knowledge and experience with the fuel under consideration. Each forecast shall consider at least the following factors as applicable to each fuel under consideration:

A. Present reserves, discovery rates and usage rates of the fuel and forecasts of future trends of these factors;

B. Profitability and financial condition of producers;

C. Potential effect of environmental factors, competition and government regulations on producers, including the potential for changes in severance taxes;

D. Capacity, profitability and expansion potential of present and potential fuel transportation options;

E Potential effects of government regulations, competition and environmental legislation on fuel transporters;

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

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

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

3. The provider of each fuel price forecast shall be required to identify the critical uncertain factors that drive the price forecast and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty];

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

1. Capital cost estimates shall either be obtained from a qualified engineering firm actively engaged in the type of work required or developed by the utility if it has available other sources of expert engineering information applicable to the type of facility under consideration.

2. The provider of the estimate shall be required to identify the critical uncertain factors that may cause the capital cost estimates to change significantly and to provide a range of estimates and an associated subjective probability distribution that reflects this uncertainty];

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

1. Fixed and variable operation and maintenance cost estimates shall be obtained from the same source that provides the capital cost estimates.

2. The critical uncertain factors that affect these cost estimates shall be identified and a range of estimates shall be provided, together with an associated subjective probability distribution that reflects this uncertainty];

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

1. Forecasts of the future value of emission allowances shall be obtained from a qualified consulting firm or other source with expert knowledge of the factors affecting allowance prices.

2. The provider of the forecast shall be required to identify the critical uncertain factors that may cause the value of allowances to change significantly and to provide a range of forecasts and an associated subjective probability distribution that reflects this uncertainty; and];

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

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

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

1. The calculated values of the utility cost and the probable environmental cost for each resource option and the rankings based on these costs;

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

3. An explanation of the reasons why each supply-side resource option rejected as a result of the screening analysis was not included as a candidate resource option;

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

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

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

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

AUTHORITY: sections 386.040, 386.250, [RSMo Supp. 1991] 386.610, and 393.140, RSMo [1986] 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010.

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed amendment with the Missouri Public Service Commission, Steven C. Reed, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before January 3, 2011, and should include a reference to Commission File No. EX-2010-0254. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/case-filing-information. A public hearing regarding this proposed amendment is scheduled for January 6, 2011, at 9:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Room 305, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 (voice) or Relay Missouri at 711.

Editor's Note: The Dissent of Commissioner Jeff Davis to the Proposed Rulemakings Revising the Commission's Chapter 22 Electric Utility Resource Planning Rules follows 4 CSR 240-22.080 on page 1776 of this issue of the Missouri Register.

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

PROPOSED RULE

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 objectives 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;

(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 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 incremental costs of regional transmission upgrades that would be allocated to the utility;

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 built by the RTO 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 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 customers; and

3. The utility documents and describes its review and assessment of the RTO transmission expansion plans.

(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 estimated congestion costs; 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, 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 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.

AUTHORITY: sections 386.040, 386.250, 386.610, and 393.140, RSMo 2000. Original rule filed Oct. 25, 2010.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule will cost private entities one hundred forty thousand dollars ($140,000) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Steven C. Reed, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before January 3, 2011, and should include a reference to Commission File No. EX-2010-0254. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/case-filing-information. A public hearing regarding this proposed rule is scheduled for January 6 at 9:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Room 305, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 (voice) or Relay Missouri at 711.

FISCAL NOTE
PRIVATE COST

I. Department Title: Missouri Department of Economic Development
Division Title: Missouri Public Service Commission
Chapter Title: Chapter 22 - Electric Utility Resource Planning

Rule Number and Title:	4 CSR 240-22.045 Transmission and Distribution Analysis
Type of Rulemaking:	New Rulemaking

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the first year cost of compliance with the rule by the affected entities:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities (years 2-4):
4	Investor-owned electric utilities	$140,000	$140,000

III. WORKSHEET

1. KCPL estimated the an annual cost of $80,000 to comply with this proposed rule
2. Empire stated that it was difficult to assign any costs at this time to this proposed rule. However, it does estimate a total increase in the cost of report writing (in which it specifically mentions the 4 CSR 240-22.045) of $30,000
3. AmerenUE did not estimate a fiscal impact for this proposed rule.

IV. ASSUMPTIONS

- The estimates given by KCPL are for both KCP&L and KCP&L Greater Missouri Operations Company. Annual cost for each utility is $40,000.
- There would be some costs to write the reports required by the rule.
- Using the estimate of $40,000 per utility given by KCPL, annual cost for AmerenUE is estimated at $40,000.
- Using the estimate of $40,000 per utility and the changes to filing frequency for Empire which results in Empire having to meet the full rule requirements every six years instead of the current requirement of every 3 years, annual cost for Empire is estimated at $20,000
- *Therefore, the total cost for compliance with this proposed rule is estimated to be $140,000.*

Editor's Note: The Dissent of Commissioner Jeff Davis to the Proposed Rulemakings Revising the Commission's Chapter 22 Electric Utility Resource Planning Rules follows 4 CSR 240-22.080 on page 1776 of this issue of the Missouri Register.

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

PROPOSED AMENDMENT

4 CSR 240-22.050 Demand-Side Resource Analysis. The commission is amending the purpose statement, deleting sections (1) through (11), and adding new sections (1) through (8).

PURPOSE: This proposed amendment allows the utility to determine whether it develops potential demand-side resources using an up/down or down/up analysis. It also allows the utility more latitude in the derivation of avoided costs.

PURPOSE: This rule specifies the ***[methods]*** ***principles*** *by which* ***[****end-use measures and****]*** *potential demand-side* ***[****programs****]*** ***resource options*** *shall be developed and* ***[****screened****]*** ***analyzed*** *for cost-effectiveness****[****. It also requires the ongoing evaluation of end-use measures and programs, and the use of program evaluation information to improve program design and cost-effectiveness analysis****]****,* ***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 technical potentials and realistic achievable potentials.***

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Avoided capacity costs. The utility shall calculate and document the avoided capacity costs per kilowatt-year for each year of the planning horizon.

A. This calculation shall include the costs of any new generation, transmission and distribution facilities that are delayed or avoided because of the specified load decrement.

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

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

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

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

3. Nondemand period avoided demand cost. The avoided demand cost for the nondemand periods is zero (0).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) The utility shall conduct market research studies, customer surveys, pilot demand-side programs, test marketing programs and other activities as necessary to estimate the technical potential of end-use measures and to develop the information necessary to design and implement cost-effective demand-side programs. These research activities shall be designed to provide a solid foundation of information about how and by whom energy-related decisions are made and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long-run energy efficiency.]

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

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

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

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

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

(7) Cost-Effectiveness Screening of Demand-Side Programs. The utility shall evaluate the cost-effectiveness of each potential demand-side program developed pursuant to section (6) using the total resource cost test. The utility cost test shall also be performed for purposes of comparison. All costs and benefits shall be expressed in nominal dollars. The following procedure shall be used to perform these tests:

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

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

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

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

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

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

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

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

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

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

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

3. Does the mix of end-use measures included in the program appropriately reflect the diversity of end-use energy service needs and existing end-use technologies within the target segment?

4. Are the communication channels and delivery mechanisms appropriate for the target segment? and

5. What can be done to more effectively overcome the identified market imperfections and to increase the rate of customer acceptance and implementation of each end-use measure included in the program?

(B) Impact Evaluation. The utility shall develop methods of estimating the actual load impacts of each demand-side program included in the utility's preferred resource plan to a reasonable degree of accuracy.

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

A. Comparisons of preadoption and postadoption loads of program participants, corrected for the effects of weather and other intertemporal differences; and

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

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

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

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

(11) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(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;

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.; and

4. Renewable energy sources, distributed generation resources, and energy technologies on the customer-side of the meter that substitute for electricity at the point of use;

(B) To fulfill the goal of achieving all cost-effective demand-side savings, the utility shall design highly effective potential demand-side programs pursuant to 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 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 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 for the same menu of end-use measures;

(F) Evaluate 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 to participate 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 commensurate adjustments to the technical 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 horizon 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 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 commensurate adjustments to the technical 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); 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 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;

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; and

4. 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.

(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; and

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

(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 technical 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 demand-side resources are cost effective. The utility shall identify how the menu of cost effective demand-side 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, [RSMo Supp. 1991] 386.610, and 393.140, RSMo [1986] 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010.

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will cost private entities four hundred sixty-five thousand dollars ($465,000) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed amendment with the Missouri Public Service Commission, Steven C. Reed, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before January 3, 2011, and should include a reference to Commission File No. EX-2010-0254. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/case-filing-information. A public hearing regarding this proposed amendment is scheduled for January 6, 2011, at 9:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Room 305, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 (voice) or Relay Missouri at 711.

FISCAL NOTE
PRIVATE COST

I. Department Title: Missouri Department of Economic Development
Division Title: Missouri Public Service Commission
Chapter Title: Chapter 22 - Electric Utility Resource Planning

Rule Number and Title:	4 CSR 240-22.050 Demand-Side Resource Analysis
Type of Rulemaking:	Rule Revision

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the first year cost of compliance with the rule by the affected entities:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities (years 2-4):
4	Investor-owned electric utilities	$465,000	$465,000

III. WORKSHEET

1. KCPL estimated $300,000 additional labor (assumed to be annual costs), $350,000 one time consultant cost and $300,000 consultant cost every 6 years. This results in a KCPL estimated $350,000 annual costs and $300,000 costs every 6 years.
2. Empire estimated $170,000 due to analysis related to rate design and smart grid.
3. AmerenUE estimated $100,000 for the analysis of the smart grid, $150,000 for evaluation of the impacts of energy efficiency that occurs outside of its programs and $200,000 for analysis of rate design impacts.

IV. ASSUMPTIONS

KCPL

- Costs supplied for KCPL are assumed to be for both KCP&L and KCP&L – Greater Missouri Operations Company (GMO).
- $350,000 of the estimated one time cost was estimated for rate planning and design which is already required by the current rule.
- This results in an annual impact of $300,000 and a every 6 year impact of $300,000 (which divided by 6 to get an annual amount is $50,000)

- *Therefore the fiscal impact estimated for KCP&L and GMO is $350,000 annual costs.*

Empire

- Estimated $170,000 due to smart grid and rate design requirements
- Rate design is required by the current rule
- Changes to filing frequency for Empire results in Empire having to meet the full rule requirements every six years instead of the current requirement of every 3 years.
- *Therefore, the fiscal impact estimated for Empire is a cost of $90,000 every 6 years or $15,000 annually.*

AmerenUE

- In its filings to meet the current requirements, AmerenUE states that it includes an evaluation of the impacts of energy efficiency that occurs outside of its programs in its load forecast. Therefore, AmerenUE is currently incurring this cost.
- Rate design is required by the current rule
- AmerenUE gives costs as cost per filing. Staff assumes that this is an annual cost.
- *Therefore, the fiscal impact estimated for AmerenUE is an annual cost of $100,000*

Editor's Note: The Dissent of Commissioner Jeff Davis to the Proposed Rulemakings Revising the Commission's Chapter 22 Electric Utility Resource Planning Rules follows 4 CSR 240-22.080 on page 1776 of this issue of the Missouri Register.

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

PROPOSED AMENDMENT

4 CSR 240-22.060 Integrated Resource Plan and Risk Analysis. The commission is amending the purpose statement and sections (1)–(3), deleting sections (4)–(6), and adding new sections (4)–(7).

PURPOSE: This proposed amendment moves the risk analysis currently found in 4 CSR 240-22.070 into the integration process. It also sets out definite filing requirements to document the process.

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 *[serve]* **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 *[identified]* resource planning objectives.

(A) These **performance** measures shall include at least the following: *[present]*

1. **Present** worth of utility revenue requirements, *[present]* **with and without any financial performance incentives the utility is planning to request;**

2. **Present** worth of probable environmental costs*[, present]*;

3. **Present** worth of out-of-pocket costs to participants in demand-side programs*[, levelized annual average]* and rates *[and maximum]*;

4. **Levelized annual average rates;**

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

6. **Financial ratios 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. *[Utility decision-makers may also specify other measures that they believe are appropriate for assessing the performance of resource plans relative to the planning objectives identified in 4 CSR 240-22.010(2).]*

(3) Development of Alternative Resource Plans. The utility shall use appropriate combinations of *[candidate]* demand-side 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 to assess their relative performance under expected conditions as well as their robustness under a broad range of 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 resource options, 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 technical 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 staff 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 *[section (5) of this rule]* **4 CSR 240-22.070(5).**

[(4) Analysis of Alternative Resource Plans. The utility shall assess the relative performance of the alternative resource plans by calculating for each plan the value of each performance measure specified pursuant to section (2). This calculation shall assume values for uncertain factors that are judged by utility decision-makers to be most likely. The analysis shall cover a planning horizon of at least twenty (20) years and shall be carried out with computer models

that are capable of simulating the total operation of the system on a year-by-year basis in order to assess the cumulative impacts of alternative resource plans. These models shall be sufficiently detailed to accomplish the following tasks and objectives:

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

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

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

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

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

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

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

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

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

(6) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

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

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

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

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

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

3. The composition, by supply resource, of the capacity (including reserve margin) provided by supply resources. Existing supply-side resources may be shown as a single resource;

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

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

6. The composition, by supply resource, of the annual energy (including losses) provided by supply resources. Existing supply-side resources may be shown as a single resource;

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

8. Annual average rates;

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

10. Annual probable environmental costs.

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

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

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

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

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

(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 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 rate, of the capacity provided by demand-side resources;

3. The composition, by supply-side resource, of the capacity at the customers' meters 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 rate, of the annual energy provided by demand-side resources;

6. The composition, by supply-side resource, of the annual energy at the customer's meters 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, 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 impacts on retail rates; and

C. Estimated company financial ratios; 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 performance measures in subparagraphs (4)(C)1.A.–(4)(C)1.C. of the alternative resource plans;

(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 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, [RSMo Supp. 1991] 386.610, and 393.140, RSMo [1986] 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010.

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

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NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to *this proposed amendment with the Missouri Public Service Commission, Steven C. Reed, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before January 3, 2011, and should include a reference to Commission File No. EX-2010-0254. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/case-filing-information. A public hearing regarding this proposed amendment is scheduled for January 6, 2011, at 9:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Room 305, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment and may be asked to respond to commission questions.*

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FISCAL NOTE
PRIVATE COST

I. Department Title: Missouri Department of Economic Development
Division Title: Missouri Public Service Commission
Chapter Title: Chapter 22 - Electric Utility Resource Planning

Rule Number and Title:	4 CSR 240-22.060 Integrated Resource Plan and Risk Analysis
Type of Rulemaking:	Rule Revision

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the first year cost of compliance with the rule by the affected entities:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities (years 2-4):
4	Investor-owned electric utilities	$30,000	$20,000

III. WORKSHEET

1. KCPL estimated a $10,000 one time cost
2. Empire estimated $120,000 for more consultant time
3. AmerenUE did not estimate a cost impact for these changes

II. ASSUMPTIONS

1. Costs supplied for KCPL are assumed to be for both KCP&L and KCP&L – Greater Missouri Operations Company (GMO).
2. Empire currently has consultants do this analysis. An increase in its consulting cost is not unreasonable.
3. Changes to filing frequency for Empire result in Empire having to meet the full rule requirements every six years instead of the current requirement of every 3 years. Therefore annual cost for Empire is estimated at $120,000/6 or $20,000
4. *Therefore, the estimated one time cost for the changes to this rule is $10,000 and an annual cost of $20,000.*

Editor's Note: The Dissent of Commissioner Jeff Davis to the Proposed Rulemakings Revising the Commission's Chapter 22 Electric Utility Resource Planning Rules follows 4 CSR 240-22.080 on page 1776 of this issue of the Missouri Register.

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

PROPOSED AMENDMENT

4 CSR 240-22.070 *[Risk Analysis and]* **Resource Acquisition Strategy Selection.** The commission is amending the title and purpose statement, deleting sections (1)–(11), and adding new sections (1)–(9).

PURPOSE: This proposed amendment requires the utilities 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.

PURPOSE: This rule requires the utility to [identify the critical uncertain factors that affect the performance of resource plans, establishes minimum standards for the methods used to assess the risks associated with these uncertainties and requires the utility to specify] ***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 use the methods of formal decision analysis to assess the impacts of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3), to analyze the risks associated with alternative resource plans, to quantify the value of better information concerning the critical uncertain factors and to explicitly state and document the subjective probabilities that utility decision-makers assign to each of these uncertain factors. This assessment shall include a decision-tree representation of the key decisions and uncertainties associated with each alternative resource plan.

(2) Before developing a detailed decision-tree representation of each resource plan, the utility shall conduct a preliminary sensitivity analysis to identify the uncertain factors that are critical to the performance of the resource plan. This analysis shall assess at least the following uncertain factors:

(A) The range of future load growth represented by the low-case and high-case load forecasts;

(B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital;

(C) Future changes in environmental laws, regulations or standards;

(D) Relative real fuel prices;

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities;

(F) Construction costs and schedules for new generation and transmission facilities;

(G) Purchased power availability, terms and cost;

(H) Sulfur dioxide emission allowance prices;

(I) Fixed operation and maintenance costs for existing generation facilities;

(J) Equivalent or full- and partial-forced-outage rates for new and existing generation facilities;

(K) Future load impacts of demand-side programs; and

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

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

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

(5) The utility shall use the decision-tree formulation to compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2), contingent upon the identified uncertain factors and associated subjective probabilities assigned by utility decision-makers pursuant to section (1) of this rule. Both the expected performance and the risks of each alternative resource plan shall be quantified.

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

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

(6) The utility shall select a preferred resource plan from among the alternative plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060 and sections (1)—(5) of this rule. The preferred resource plan shall satisfy at least the following conditions:

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

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

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

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

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

1. Chronological dispatch, including unit commitment decisions that are consistent with the operational characteristics and constraints of all system resources;

2. Heat rates, fuel costs, variable operation and maintenance costs, and sulfur dioxide emission allowance costs for each generating unit;

3. Scheduled maintenance outages for each generating unit;

4. Partial- and full-forced-outage rates for each generating unit; and

5. Capacity and energy purchases and sales, including the full spectrum of possibilities, from long-term firm contracts or unit participation agreements to hourly economy transactions.

A. The utility shall maintain the capability to model purchases and sales of energy both with and without the inclusion of sulfur dioxide emission allowances.

B. The level of energy sales and purchases shall be consistent with forecasts of the utility's own production costs as compared to the forecasted production costs of other likely participants in the bulk power market; and

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. A discussion of the sequence and timing of the decisions represented by decision nodes in the decision tree and a description of the specific decision alternatives considered at each decision point; and

2. An explanation of how the critical uncertain factors were identified, how the ranges of potential outcomes for each uncertain factor were determined and how the subjective probabilities for each outcome were derived;

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

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

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

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

(F) A discussion of the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision-makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk; and

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

(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 a contingency resource plans identified pursuant to subsection (4)(A).

(C) Each contingency resource plan shall satisfy the fundamental objectives 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 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). The evaluation plans for each program and rate shall be developed before the program or rate is implemented and shall be filed with the tariff application for the program or rate. The purpose of these evaluations shall be to develop the information necessary to 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 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 rate participants, corrected for the effects of weather and other intertemporal differences; and

B. Comparisons between program and 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, load research data, end-use load metered data, building and equipment simulation models, and survey responses; or

B. Audit 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.

(9) If, during the implementation period, a preferred resource plan is replaced by a contingency resource plan as a result of the limits of one (1) or more of the critical uncertain factors being exceeded, or for some other reason, the utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which that contingency resource plan remains appropriate.

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SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 (voice) or Relay Missouri at 711.

Editor's Note: The Dissent of Commissioner Jeff Davis to the Proposed Rulemakings Revising the Commission's Chapter 22 Electric Utility Resource Planning Rules follows 4 CSR 240-22.080 on page 1776 of this issue of the Missouri Register.

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

PROPOSED AMENDMENT

4 CSR 240-22.080 Filing Schedule *[and]*, *Filing* Requirements, *and Stakeholder Process*. The commission is amending the title and purpose statement, deleting sections (1)–(13), and adding new sections (1)–(17).

PURPOSE: This proposed amendment sets out updated filing requirements and time lines. The rule requires annual filings by the utilities and includes a way for commissioners and other stakeholders to identify contemporary issues for the utilities to address in their annual filings.

*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 [stated in 4 CSR 240-22.010(2)(A)–(C)] **of chapter 22. 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 1991 shall make a filing with the commission every three (3) years that demonstrates compliance with the provisions of this chapter. The utility's filing shall include at least the following items:

(A) Letter of transmittal;

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

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

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

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

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

(2) The electric utility's compliance filing may also include a request for nontraditional accounting procedures and information regarding any associated ratemaking treatment to be sought by the utility for demand-side resource costs. If the utility desires to make any such request, it must be made in the utility's compliance filing pursuant to this rule and not at some subsequent time. If the utility desires to continue any previously authorized nontraditional accounting procedures beyond the three (3)-year implementation period, it must request reauthorization in each subsequent filing pursuant to this rule. Any request for initial authorization or reauthorization of these nontraditional accounting procedures must—

(A) Be limited to specific demand-side programs that are included in the utility's implementation plan; and

(B) Include specific proposals that contain at least the following information:

1. An explanation of the specific form and mechanics of implementing the proposed accounting procedure and any associated ratemaking treatment to be sought;

2. A discussion of the rationale and justification of the need for a nontraditional treatment of these costs;

3. An explanation of how the specific proposal meets this need for nontraditional treatment; and

4. A quantitative comparison of the utility's estimated earnings over the three (3)-year implementation period with and without the proposed nontraditional accounting procedures and any associated ratemaking treatment to be sought.

(3) The electric utilities shall make their initial compliance filings on a staggered basis in order of decreasing size of gross annual Missouri operating revenues from retail electric sales for calendar year 1991. The electric utility with the largest gross annual Missouri operating revenues shall make its initial filing seven (7) months (December 1993) after the effective date of this chapter (May 5, 1993). The remaining electric utilities shall make their initial filings in successive increments of seven (7) months from the effective date of this chapter (May 5, 1993).

(4) The commission will establish a docket for the purpose of receiving the compliance filing of each affected electric utility. The commission will issue an order that establishes an intervention deadline, sets an early prehearing conference and provides for notice.

(5) The staff shall review each compliance filing required by this rule and shall file a report not later than one hundred twenty (120) days after each utility's scheduled filing date that identifies 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 which, in its limited review, the staff determines would cause the electric utility's resource acquisition strategy to fail to meet the requirements identified in 4 CSR 240-22.010(2)(A)–(C). If the staff's limited review finds no deficiencies, 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.

(6) Also within one hundred twenty (120) days after an electric utility's compliance filing pursuant to this rule, the office of public counsel and any intervenor may file a report or comments based on a limited review that identify any deficiencies in the electric utility's compliance with the provisions of this chapter, any deficiencies in the methodologies or analyses required to be performed by this chapter, and any other deficiencies which the public counsel or intervenor believes would cause the utility's resource acquisition strategy to fail to meet the requirements identified in 4 CSR 240-22.010(2)(A)–(C).

(7) 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 made available in accordance with any protective order to the staff, public counsel and any intervenor for use in its review of the periodic filings required by this rule. Each electric utility shall retain at least one (1) copy of the officially adopted resource acquisition strategy and all supporting information for at least ten (10) years.

(8) If the staff, public counsel or any intervenor finds deficiencies, it shall work with the electric utility and the other parties to reach, within forty-five (45) days of the date that the report or comments were submitted, a joint agreement on a plan to remedy the identified deficiencies. 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 forty-five (45) 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.

(9) If full agreement on remedying deficiencies 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 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.

(10) If the utility determines that circumstances have changed so that the preferred resource plan is no longer appropriate, either due to the limits identified pursuant to 4 CSR 240-22.070(10)(C) being exceeded or for other reasons, the utility, in writing, shall notify the commission within sixty (60) days of the utility's determination. If the utility decides to implement any of the contingency options identified pursuant to 4 CSR 240-22.070(10)(D), the utility shall

file for review in advance of its next regularly scheduled compliance filing a revised implementation plan.

(11) Upon written application, and after notice and an opportunity for hearing, the commission may waive or grant a variance from a provision of this chapter for good cause shown.

(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.

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

(13) The commission will issue an order which contains findings 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 240-22.010(2)(A)–(C), and which addresses any utility requests pursuant to section (2) for authorization or reauthorization of nontraditional accounting procedures for demand-side resource costs.]

(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. Companies submitting their triennial compliance filings on the same schedule may file them jointly. 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 volumes(s) the reports, analyses, and all resulting actions are presented.

(D) The highly-confidential form of the capacity balance spreadsheet completed in the specified format 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 impact on retail rates; 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 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 twenty (120) 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 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 twenty (120) 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 or concerns which the public counsel or intervenor believes could prevent the utility's resource acquisition plan from effectively fulfilling the objectives of the electric resource planning rules. Public counsel or intervenors shall provide at least one (1) suggested remedy for each identified deficiency or concern. Public counsel or any intervenor shall provide its workpapers 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 forty-five (45) 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 forty-five (45) 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.

(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 volumes(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. 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 performance 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.

(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.

(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 240-22.070 for good cause shown.

(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) 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.

AUTHORITY: sections 386.040, 386.250, [RSMo Supp. 1991] 386.610, and 393.140, RSMo [1986] 2000. Original rule filed June 12, 1992, effective May 6, 1993. Amended: Filed Oct. 25, 2010.

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will cost private entities two hundred eighty-four thousand four hundred dollars ($284,400) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed amendment with the Missouri Public Service Commission, Steven C. Reed, Secretary of the Commission, PO Box

360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before January 3, 2011, and should include a reference to Commission File No. EX-2010-0254. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/case-filing-information. A public hearing regarding this proposed amendment is scheduled for January 6, 2011, at 9:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Room 305, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 (voice) or Relay Missouri at 711.

FISCAL NOTE
PRIVATE COST

I. Department Title: Missouri Department of Economic Development
Division Title: Missouri Public Service Commission
Chapter Title: Chapter 22 - Electric Utility Resource Planning

Rule Number and Title:	4 CSR 240-22.080 Filing Schedule, Filing Requirements and Stakeholder Process
Type of Rulemaking:	Rule Revision

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the first year cost of compliance with the rule by the affected entities:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities (years 2-4):
4	Investor-owned electric utilities	$284,400	$284,400

III. WORKSHEET

1. KCPL estimated an increase in additional labor due to this rule of $79,400 and an annual cost for consultants of $200,000.
2. Empire estimates an additional $30,000 cost due to increase report writing
3. AmerenUE did not include any fiscal impact due to changes to this rule.

IV. ASSUMPTIONS

- The estimates given by KCPL are for both KCP&L and KCP&L Greater Missouri Operations Company. Annual cost for each utility is ($79,400+$200,000)/2 or $139,700.
- Changes to filing frequency for Empire result in Empire having to meet the full rule requirements every six years instead of the current requirement of every 3 years, annual cost for Empire is estimated at $5,000
- *Therefore, the total cost for compliance with this proposed rule is estimated to be $284,400.*

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of a Proposed Rulemaking	)	
Regarding Revision of the Commission's	)	**File No. EX-2010-0254**
Chapter 22 Electric Utility Resource	)	
Planning Rules	)	

DISSENT OF COMMISSIONER JEFF DAVIS TO THE PROPOSED RULEMAKING REVISING THE COMMISSION'S CHAPTER 22 ELECTRIC UTILITY RESOURCE PLANNING RULES

I respectfully dissent from my colleagues' order to promulgate these rules as they are currently written.

Anyone who has ever been involved in the integrated resource planning (IRP) process knows these rules have desperately needed revision for years. It's taken a long time to get where we are. These rules are an improvement in some respects, but something important is missing: accountability for the Public Service Commission and the PSC Staff for any outcome in these IRP proceedings. It may seem like an antiquated note, but I think we need to take responsibility for the decisions we make – or in this case – fail to make.

Both the Missouri Energy Development Association (MEDA) and the Missouri Department of Natural Resources (MDNR) offered language whereby the Commission would at least "acknowledge" the utility's resource plan. "Acknowledgement" of the plan would enhance the process because it would force the parties and the staff to focus on outcomes as well as the process by which those outcomes were determined. After all, outcomes should be the purpose of the IRP process. More importantly, electric utilities could use the acknowledgement process to establish the prudence of making--or not making--certain large capital expenditures that are going to amount to billions of dollars over the next decade (e.g.

– whether to shut down and decommission one or more coal plants or to continue retrofitting all of them) before they get to a rate case and have to argue over imprudence or lack thereof.

Whether and how we address IRP decisions will definitely impact customer rates for years to come. Failing to act on the substance of IRPs constitutes a decision in and of itself. The Commission's failure sends a message of uncertainty to the utilities we regulate, their investors and Wall Street saying either "we want to be free to disavow your plan and disallow the expenses later" or "we are afraid to be criticized for acknowledging a plan that later failed."

Ultimately, our failure to address the substance of utility resource plans increases financing costs for capital investment projects as well as litigation costs in future rate cases because parties will litigate the issue in future cases and knowing the Commission may disallow expenses, lenders and investors will want higher returns. That uncertainty will assuredly cause Missouri investor-owned electric utilities to place the least possible amount of investment capital at risk short-term. This is important because the cheapest plan today will not likely be the cheapest plan over the next one to five years, and even less likely over the long-term (from 30 to 50 years). Thus, the ratepayers could end up paying higher rates long-term so the utility can consistently save a few dollars on the front end, or because the utility opted for cheaper, less reliable technology.

The importance of this issue is best illustrated by the decisions the Commission faces regarding our aging fleet of coal plants. In September, Wood Mackenzie's North American power research group issued a startling report that almost 60 gigawatts of coal-fired electric plants could be retired over the next decade. Independent verification of that estimate comes from Ellen Lapson, Managing Director of Corporate Ratings for Fitch Rating Agency. On

September 30, 2010, at the Financial Research Institute, Director Lapson said that Wood Mackenzie's number was a reasonable number. At least two Commissioners were present at that meeting.

The findings of the Wood Mackenzie report ought to send a shiver down the spine of everyone here at the PSC as well as anyone employed by a Missouri utility. More than 80% of the electricity consumed in this state is fueled by coal. Collectively, Missouri utilities probably own around 10,000 megawatts of coal-fired generation, if not more. Ameren Missouri is the largest Missouri utility and owns several thousand megawatts of coal-fired generation all by itself, but everyone including the utilities who've camouflaged themselves as being leaders in the green revolution have similar risks. So, when the Wall Street analysts say "Coal is in the crosshairs" they mean pretty much every Missouri utility, but especially Ameren because they own the most coal plants, and that ultimately every utility customer in the state is in the crosshairs. Each and every one of our investor-owned electric utilities is going to make significant investment decisions regarding the retirement or retrofitting of a large fleet of coal plants averaging more than 40 years or older as well as the addition of new resources to replace these retiring coal plants, meet growing demand and comply with government mandates for utilities to buy certain amounts of "renewable" electricity.

Presidents and governors don't punt and this Commission shouldn't punt either. Hundreds of millions, if not billions, of dollars are at stake when our electric utilities make these decisions and customer rates are hanging in the balance. We owe it to the ratepayers and to the utilities we regulate to be decisive and thereby meet this Commission's statutory obligation to assure safe and adequate service for consumers at a just and reasonable rate. It's silly and unconscionable to spend a couple of years working on more than 60 pages of rules that force the utility to think of every scenario, to document how every calculation is made, to check to see if the work was performed correctly and then do nothing with such documents except hold them, waiting to whip them out on some unsuspecting utility executive for not following a plan we don't intend to make them follow until the day they deviate from it.

In conclusion, a Commission majority that has shown a willingness to micro-manage electric utilities by requiring them to undertake low-income assistance programs and make our utilities buy Missouri wind-generated electricity ought not have a problem "acknowledging" whether an electric utility's preferred resource plan seems like a good or a bad one.

Respectfully submitted,

Jeffrey N. Davis

Jeff Davis, Commissioner

Dated at Jefferson City, Missouri
On this 25th day of October, 2010.