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August 3, 1992

FILED

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PUBLIC SERVICE COMMISSION

Mr. Brent Stewart
Executive Secretary
Missouri Public Service Commission
P.O. Box 360
Jefferson City, Missouri 65102

RE: Case No. EX-92-299 -- In the matter of the Proposed Commission Rules 4 CSR 240-22.010 through 22.080.

Case No. OX-92-300 -- In the matter of the Proposed Amendments to Commission Rules 4 CSR 240-14.010 through .040 and Proposed Recission of 4 CSR 240-14.050.

Dear Mr. Stewart:

Enclosed for filing in the above captioned cases are an original and fifteen (15) conformed copies of the COMMENTS OF THE STAFF OF THE MISSOURI PUBLIC SERVICE COMMISSION IN SUPPORT OF THE PROPOSED RULES, AMENDMENTS, AND RECISSION. Because of the two dockets, an extra copy is enclosed for filing.

Copies of these Comments are being mailed this date to the individuals identified on the attached list.

Very truly yours,

Steven Dottheim

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SD:rn

cc: Attached list

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of the Proposed Commission Rules 4 CSR 240-22.010 through 22.080	)	Case No. EX-92-299
In the matter of the Proposed Amendments to Commission Rules 4 CSR 240-14.010 through .040 and Proposed Recission of 4 CSR 240-14.050.	)	Case No. OX-92-300

COMMENTS OF THE STAFF OF THE MISSOURI PUBLIC SERVICE COMMISSION IN SUPPORT OF THE PROPOSED RULES, AMENDMENTS, AND RECISSION

The purpose of this rulemaking is to ensure that electric utilities implement thorough long-range planning procedures in order to provide the public with efficient and cost-effective energy services. The term "energy services" as used in the proposed rules recognizes the fact that consumers do not purchase electricity or any other form of energy for its own sake, but rather because they value the services it can provide, for example, lighting, cooking, refrigeration, space heating, air conditioning, water heating, motive power, and so on. This distinction is important because it provides the rationale for utilities to encourage the efficient use of energy rather than to focus only on supplying energy.

The purpose of the electric utility resource planning process as shown on Schedule 1 attached hereto is a resource acquisition strategy which includes the following elements:

(1) Preferred resource plan;

(2) Implementation plan; and

14.

(3) Specification of contingency options

To engage in strategic resource planning the utility must take into account the impact of unexpected events. The utility must identify those factors that can have the greatest impact on cost, take into account the likelihood that those factors will occur in its choice of a preferred resource plan and develop contingency plans that show how the utility will change its resource plan when critical levels of the identified factors are exceeded.

Integrated resource planning means that the utility considers not only building power plants and burning fuels (supply-side resources) to meet customer demands for electricity, but also considers programs which encourage customers to reduce load or conserve energy (demand-side resources). In addition, supply-side and demand-side resources must be evaluated on an equivalent basis. An equivalent basis for evaluation means that the utility must gather information on both supply-side and demand-side resources that has equal validity, and the analysis performed on each must not be biased in favor of either type of resource.

Strategic resource planning like integrated resource planning requires that the utility include in its analysis both supply-side and demand-side resources. The difference is that strategic resource planning also requires that the utility consider the way customer conservation programs can offset the impact that unexpected events can have on the utility's potential costs.

In 1989 the Missouri Public Service Commission (Commission) formed a Staff Project Team of individuals with expertise in economics, engineering, finance, accounting, and management to investigate resource planning processes used by the five largest investor-owned electric utilities within the Commission's jurisdiction. In April, 1990 the Project Team sent out a detailed questionnaire to the Empire District Electric Co., Kansas City Power & Light Co., Missouri Public Service (a division of UtiliCorp United, Inc.), St. Joseph Light & Power Co. and Union Electric Co. The responses described and documented then current resource planning methods and procedures at these utilities. The bulk of the responses were received in June, 1990 with additional information and modifications to prior responses being received throughout the remainder of 1990.

The Project Team issued its report entitled Strategic Resource Planning For Electric Utilities on August 2, 1991. It found wide variations and significant deficiencies in both the information quality and the scope and thoroughness of the analytical methods of resource planning being utilized in those instances where resource planning existed. Where the Project Team found satisfactory planning procedures, the planning procedures were only satisfactory in part. The report called for the Commission to adopt rules directing electric companies to collect certain data and to perform specific analyses related to resource planning. The rules would set minimum standards for strategic resource planning.

The report also recommended providing ample opportunity for informal input and comment by all interests, before starting the formal rulemaking process. The Staff drafted proposed rules for consideration and discussion which would direct electric utilities to adopt appropriate resource planning processes. The Staff also drafted amendments to the Commission's Chapter 14 Promotional Practices rules to, among other things, exclude from the category of prohibited promotional practices cost-effective demand-side programs that involve payment of consideration by the utility.

The proposed rules drafted by the Staff do not provide for Commission or Staff approval of the affected utilities' resource plans, resource acquisition strategies, or investment decisions. The Staff review required to be performed by the proposed rules is not intended to result in approval of the substantive findings, determinations, or analyses contained in the filings of the affected utilities. If substantive Commission and Staff approval of resource acquisition strategies is determined by the Commission to be the desired result of the adoption of rules on electric utility resource planning, then the rules promulgated by the Commission should be much more prescriptive than the rules that appear in the July 1, 1992 Notice of Proposed Rulemaking.

Need for Proposed Rules. These proposed rules are necessary for at least three reasons. First, over the last two decades there have occurred important and fundamental changes that affect virtually all aspects of the electric utility business. These changes cut across technical, economic, and political dimensions and are the source of major uncertainties about many of the critical factors that affect resource planning decisions. Second, due to the large size and long life of electric utility capital investments, such investment decisions can have significant long-term impacts on the public. Finally, a detailed investigation of the resource planning processes currently in use revealed that in many cases the utilities have failed to adapt their planning procedures to the changes that have occurred, and that these processes are inadequate to analyze and evaluate the financial risks associated with critical uncertain factors.

Fundamental Changes. It would be hard to overstate the significance of the cycle of change in the electric utility business that began around 1970 and is continuing. These changes are shifting the very foundation on which the existing industry structure was built, and the process of adapting to them is only beginning.

Exhaustion of Scale Economies. The most significant technological change is the virtual exhaustion of economies of scale in electric power generation. A typical 15 to 30 megawatt plant constructed in the 1930's was about half as efficient as a typical 400 to 600 megawatt plant of the 1960's. As these larger more efficient plants replaced the previous generation of small, inefficient plants, the much lower fuel cost of the new plants more than offset their larger capital cost, so that rates decreased as a result of new plant additions.

By contrast, neither the size nor typical efficiency levels of new plants have changed appreciably since the 1960's. In addition, materials, construction, operation, fuel, and maintenance costs have all increased significantly. These factors have combined to produce a situation where electric power production is no longer a decreasing-cost industry, and the addition of large new baseload facilities now typically requires substantial rate increases, rather than the rate decreases that were associated with such plant additions in the several decades prior to the 1970's.

One reason why this change is significant is that it means that a further expansion of the level of output and consumption does not necessarily contribute to the long run economic welfare as it does when average costs decrease as the market expands. Traditional ratemaking practice results in a price level that is approximately equal to average cost. But when average cost is increasing as a function of output, such a price will stimulate inefficient consumption. This economic efficiency argument is one rationale for the promotion of increased efficiency in the use of electricity by consumers. Another reason is the increasingly competitive nature of the industry.

Electricity Supply or Energy Service? Traditionally, electric utilities have been viewed by managers and regulators alike as monopoly suppliers of a homogeneous product--kilowatt-hours. An alternative view, however, is that the relevant market demand served by electric utilities is a demand for energy services -- lighting, heating, cooling, etc.--not a demand for electricity as such. Although this may at first seem like a trivial distinction, it actually constitutes a redefinition of the strategic mission of the utility business. Basically, it recognizes that the "monopoly supply" model is too narrow, and expands the scope of business planning to include the "partially competitive" nature of the demand for energy services. The implications of such a change for both utility planning and regulatory policy are profound.

Demand-Side Competition. The traditional view of electric utilities as monopoly suppliers of electric power has sometimes obscured the fact that there have always been competitive forces at work on the demand side of the utility business. For example electric utilities compete with natural gas utilities to provide space heating, water heating, and process heating services. Utilities compete with each other to obtain franchises to serve specific geographic areas and to attract new customers to their service territory. Both natural gas and electric utilities compete with fuel oil and propane suppliers to provide space heating, water heating, and process heating services.

The strategic significance of demand-side competition is that the utility's interest is extended to the customer side of the meter. If the utility's strategic objective is to be a competitive provider of energy services, rather than a monopoly supplier of kilowatt-hours, it must concern itself with the efficiency characteristics of the buildings, equipment, processes, and behaviors that are involved in converting kilowatt-hours into final energy services.

Supply-Side Competition. A second reason why the exhaustion of scale economies in power generation is significant is that, together with the development of regional transmission networks and a viable bulk power market, it has effectively undermined the "natural monopoly" status of the power generation side of the electric utility business. In the past, both utility managers and regulators have operated on the assumption that the regulatory bargain involved an obligation to provide non-discriminatory service in exchange for a guarantee of protection against the entry of competitive suppliers of electricity.

This assumption is now being called into question by regulatory changes at the federal level which dramatically increase the potential for customer-owned generation as well as other forms of non-utility-owned wholesale power production. This process began with the Public Utility Regulatory Policies Act of 1978 (PURPA) and is continuing with the current debates over transmission system access and pricing at the Federal Energy Regulatory Commission (FERC) and legislative proposals to amend the Public Utility Holding Company Act of 1935 (PUHCA). Changes currently being discussed would effectively open up the wholesale power generation business to non-utility enterprises and increase the availability of transmission services to independent power producers, wholesale customers, and possibly to large retail customers as well.

Increase in Uncertainty. Another factor that has increased the complexity and difficulty of electric utility resource planning is a dramatic increase in the level of uncertainty about virtually all of the major variables that influence the choice of a resource plan. These uncertainties surround traditional supply-side resource options as well as demand-side alternatives. In addition, the uncertainty associated with environmental regulations has changed in type as well as in magnitude.

Supply-Side Uncertainty. The mideast oil embargoes of the 1970's were a rude awakening to the connection between political turmoil and fuel prices. Interest rate volatility since 1980 has increased the level of uncertainty about the future cost of capital. Both the cost and the time required to build new generation and transmission facilities has increased and become more variable due to heightened public concern about environmental impacts and public health and safety issues. At the federal level this concern has manifested itself in the form of more stringent safety standards and environmental regulations. At the local level, it has led to more vehement and effective opposition to the siting of such facilities. Regulatory disallowances of plant construction costs due to ineffective project management and excess capacity have demonstrated that cost recovery is not guaranteed, and the effects of substantive changes in the policy perspective and goals of federal regulation of wholesale markets for electric power and transmission services are just beginning to be realized.

Demand-Side Uncertainty. On the demand side of the planning equation, uncertainty is no less pervasive. For several decades prior to the 1970's the combination of falling real prices for electricity and rising real household incomes made it appear that electric demand was easy to forecast, and indeed it was, as long as these complementary trends continued unabated. But the sharp increase in fuel prices in the mid-1970's reversed the 50-year trend of declining electricity prices, and the addition of new high cost baseload capacity caused further rate increases.

The inflationary spiral of the late 1970's and the ensuing period of high interest rates slowed credit growth and sharply constricted consumer purchasing power. Coincidentally, this occurred at a time when the market for new air conditioning service was becoming saturated, and replacement equipment was becoming substantially more efficient. Although electric space heating received a temporary boost during the era of natural gas supply restrictions and high prices, the subsequent moderation in gas prices, and significant improvements in gas furnace efficiencies have combined to slow the growth in demand for electric space heating.

The net effect of these changes has been to decrease the annual rate of demand growth from the six to eight percent range that was typical before the early 1970's to a range of about one to three percent since that time. This moderation in the rate of demand growth persisted throughout the economic expansion of the mid- to late 1980's.

These changes have increased the uncertainty of the load forecasts that are the starting point for traditional supply-side resource planning. When utilities begin to broaden their planning perspective to include demand-side options, new uncertainties emerge. Virtually all demand-side resource options come down to attempts by the utility to influence decisions about building characteristics, equipment and appliance efficiency levels, and behavioral patterns in utilizing this stock of energy-using capital goods. The ability to influence these decisions requires a knowledge of who makes each type of choice, what factors are critical to them, and how to reach them at the right time with the right information.

These are not areas where utilities typically have much information or expertise. Consequently there is substantial uncertainty about their ability to cost-effectively influence energy-related decisions. The potential benefits from changing these choices in the direction of increased energy efficiency depends on the size of the resulting difference in utility loads, but the lack of accurate and detailed information about the efficiency level of the existing capital stock means that there is considerable uncertainty about such load impacts.

Environmental Regulations. Title IV of The Clean Air Act Amendments of 1990 - the so-called "Acid Rain" provisions - represents a significant departure from previous approaches to environmental regulation. The key feature that distinguishes it from the traditional "command and control" approach is the provision for tradeable emission "allowances". Each allowance confers on its holder the right to emit one ton of sulphur dioxide (SO_2) in a calendar year. The basic rationale is that since the policy objective is to reduce total emissions of SO_2, and since the geographic distribution of these reductions is not a critical factor, a market process can be used to allocate the required total reduction to each of the individual sources in a way that minimizes the total cost of compliance. Such an approach is based on sound economic theory, and provided that the necessary institutional framework can be built, it seems likely to work as intended.

The existence of a market for emission allowances has major implications for electric utility resource planning for two reasons. First, since allowances are transferable between generating units, it requires that compliance strategies must be evaluated on a total system basis rather than at the generating unit level. Second, because allowances are transferable between utility systems (via the market process) it means that if excess allowances are held, they constitute a type of inventory which has a carrying cost that must be paid. It also means that purchasing allowances at the market price must always be considered as an alternative to further reducing emissions by technical means. Thus, the emission allowance market introduces another source of financial risk into the planning process that is every bit as real as the risks associated with fuel prices, construction costs, load growth, or any of the other uncertainties that affect resource investments.

The potential for future additional legislation regarding emissions of greenhouse gasses, exposure to electric and magnetic fields, or any number of other emerging environmental concerns introduces additional uncertainty into the utility planning process. Although the specific issues that give rise to uncertainty will change and evolve over time, there is little doubt that the need to deal explicitly with uncertainty in the planning process is here to stay.

Regarding the drafting of rules, the Staff proceeded in the informal manner set out below. It is not the intent of the Staff to address any of the substantive matters discussed in these informal meetings which were open to the public. The Staff merely seeks to reflect the level of activity that has occurred to date. The chronology set out below does not reflect each instance where a participant submitted draft language for consideration by those who had assembled. The following chronology is not meant to be an all inclusive listing of what occurred. The Staff considered this process to have been very beneficial and is most appreciative to all of those who participated.

January 27, 1992 - Staff mailed early draft of electric utility resource planning rules (4 CSR 240-22.010 - 4 CSR 240-22.080) to Missouri Public Interest Research Group (MoPIRG). Staff had previously provided an early draft of electric utility resource planning rules (4 CSR 240-22.010 - 4 CSR 240-22.080) to Office of the Public Counsel (Public Counsel).

January 30, 1992 - Staff mailed or delivered early draft of electric utility resource planning rules (4 CSR 240-22.010 - 4 CSR 240-22.080) to the electrical corporations regulated by the Commission.

March 2, 1992 - Staff mailed or delivered redrafts of 4 CSR 240-22.010 and 4 CSR 240-22.030 to 98 individuals and entities including the electric and natural gas corporations regulated by the Commission, Public Counsel, frequent intervenors, members of the Legislature and legislative staff that have indicated an interest in the subject matter, Missouri Department of Natural Resources, and organizations that might or are known to have an interest in this subject matter. Notice was provided of informal discussion of the draft rules scheduled for April 2 and 3, 1992 in Jefferson City.

March 6, 1992 - Staff mailed or delivered redrafts of 4 CSR 240-22.060, 4 CSR 240-22.070, and 4 CSR 240-22.080 to individuals and entities on the aforementioned mailing list.

March 13, 1992 - Staff mailed or delivered redrafts of 4 CSR 240-22.020, 4 CSR 240-22.040, and 4 CSR 240-22.050 to individuals and entities on mailing list.

March 27, 1992 - Public Counsel mailed or delivered its proposed modifications to the draft rules previously distributed by the Staff.

April 2-3, 1992 - Informal meeting to discuss draft of proposed electric utility resource rules. The Staff agreed to a schedule of informal workshops for the week of April 20-24, 1992, excluding April 23.

April 14-15, 1992 - Staff mailed or delivered redraft of 4 CSR 240-22.030 to individuals and entities on mailing list.

April 15, 1992 - Union Electric Company (UE) mailed or sent by Federal Express to individuals and entities on the Staff's mailing list proposed changes to the draft rules previously distributed by the Staff.

April 20-24, 1992 (excluding April 23) - Informal workshops on the draft proposed rules and UE's proposed changes. On April 21, the Staff provided to those in attendance a draft of proposed amendments to 4 CSR 240-14.010 through 4 CSR 240-14.050 Promotional Practices.

May 6, 1992 - Staff mailed or delivered redraft of 4 CSR 240-22.030 to individuals and entities on mailing list.

May 7, 1992 - Staff mailed or delivered redrafts of 4 CSR 240-22.020, 4 CSR 240-22.040, 4 CSR 240-22.050, 4 CSR 240-22.060, and 4 CSR 240-22.070, and one additional revision in 4 CSR 240-14.010 to individuals and entities on mailing list.

May 13-14, 1992 - Informal workshops on the redrafted proposed rules. On May 13, the Staff provided to those in attendance a redraft of 4 CSR 240-22.010.

May 27, 1992 - Staff mailed, delivered, or sent by overnight courier service redrafts of proposed rules 4 CSR 240-22.010 - 4 CSR 240-22.080, and 4 CSR 240-14.010 - 4 CSR 240-14.050.

May 29, 1992 - Final informal workshop on the redrafted proposed rules.

4 CSR 240-22.010 Policy Objectives

Section 1. In broad terms, the objective of regulatory policy is to ensure that the public interest is adequately served. Regulatory requirements constitute a set of constraints and incentives that affect the decisions of utility managers. A fundamental assumption of these proposed rules is that resource planning and investment decisions are, and should remain, the responsibility of utility managers rather than regulators. But regulators do have a responsibility to define the objectives of the resource planning process in such a way that the public interest is protected, and to ensure that these decisions are based on thorough and competent analysis of an adequate base of high-quality information. Consequently, the focus of the proposed rules is on the objectives and the quality of the planning process itself rather than the particular plans or decisions that result from the process. Specifically, the rules identify the fundamental objective of the resource planning process, and set minimum standards for the scope, quality, and documentation of the information and analysis that supports resource planning and investment decisions.

Section 2. The proposed rules define the objective of utility resource planning to be the provision of energy services, not simply to deliver a supply of electric power. This is the fundamental basis for the requirement to analyze demand-side resources on a consistent and equivalent basis with supply-side alternatives. It also provides a sufficiently broad perspective to encompass the increasingly competitive nature of the utility business.

Although the rule requires that the primary criterion for selecting a preferred resource plan is minimization of the present worth of long-run utility costs, it also explicitly allows for other considerations to affect the choice. This flexibility is necessary because of the unavoidable uncertainties that affect the outcomes of planning decisions. Mitigation of the risks associated with these uncertainties may justify some departure from a strict expected-cost-minimization criterion.

4 CSR 240-22.030 Load Analysis and Forecasting

Need for the Rule. The Staff Project Team specifically reviewed the load analysis and forecasting methods being used by the five largest investor-owned utilities. The findings of that review are set out in the executive summary statement in that Staff report:

> 1. Load Forecasting Practice
>
> There are a wide variety of load forecasting methods being used by the five electric utilities. For peak demand forecasts, the current practice ranges from detailed class and end use types of forecasts to simple correlations of peak demand with weather and service territory economic activity and/or customer growth. The

> diversity of energy forecasting methods is similar, although four of the five utilities do forecast energy use at the customer class level. All five utilities provided some form of alternative scenarios for their forecast; however, for only two of the five could these forecasts be traced back to alternative assumptions regarding the basic determinants of population and economic growth within their service territories.
>
> For none of the five utilities is it obvious that those who make the final resource decisions have a clear understanding of what is driving the forecasts. Even though the questions were separated between management and technical staff, the documentation given the Project Team is of such a technical nature that decision makers would find it difficult or impossible to do anything more than a cursory evaluation of the load forecast. There is therefore a need for better load forecast documentation which will make transparent the underlying assumptions and causal relationships that drive the forecast. Such a goal needs to be combined with the highest possible level of analysis which considers the impact of key variables on the decisions that affect customers' demand for electricity.

The purpose of the rule on load analysis and forecasting is to set minimum standards which each utility must meet for information used in its load forecasts as well as for its methodological approach. It is important to realize that while improved forecasting accuracy is an important goal, it is not the primary goal in load forecasting. There is uncertainty in the load forecast that cannot be reduced no matter how much time, effort, and money are spent on information and methods. Therefore, the primary goal in load forecasting is to have a set of information and analysis available which will allow decision makers to evaluate the risks (costs and likelihoods) which an inaccurate forecast will cause. In addition, if the utility is serious about investing in demand-side resources, it must be able to analyze the various end-uses for electricity (e.g., lighting, cooking, space heating, air conditioning, refrigeration, water heating, and motive power) and determine how a demand-side program will impact its forecast of these end-uses. The current state of load forecasting by the five largest investor-owned utilities falls short of this goal.

Details of the Rule. The proposed rule on load analysis and forecasting is quite detailed. The high level of detail is necessary because:

(1) load forecasting is a highly technical and complicated process; and

(2) to insure minimal standards are met, each aspect of that process must be addressed.

The proposed rule on load analysis and forecasting is set out in eight sections and each section represents a building block of the process.

Section 1 - Historical Data Base. This section specifies the level of detail required for data which forms the basis of the utility's load forecast. The primary focus of this section is the specification of the level of aggregation at which the utility should perform its analysis of loads; i.e., what classes should be used, what loads should be analyzed and what period of time should be considered.

Section 2 - Analysis of Number of Units. The growth in the number of units (e.g., residential customers) is the primary factor causing the growth in loads. This section deals with the specification of assumptions and forecasts of economic and demographic factors which form the basis of the forecasted growth in the number of units.

Section 3 - Analysis of Use Per Unit. In order to determine the impact of demand-side programs on forecasted loads it is necessary that the forecasts be performed at a level that will interface with these programs. The only way this can be done properly is if the utility has analyzed loads at an end-use level. This rule requires the utilities to disaggregate the use per unit by end-use.

Section 4 - Analysis of Load Profiles. In order to determine the resource cost of meeting future loads, the utility must not only forecast peak demands and energies, it must be able to translate these forecasts into hourly load profiles. This rule requires that such load profiles be developed and sets out the minimum number and types.

Section 5 - Base-Case Load Forecast. This section specifies the level of detail, the relationship of the forecast to the historical data base and the documentation required for the utility's base-case load forecast.

Section 6 - Sensitivity Analysis. This section identifies key driver variables to the load forecast, and requires each utility to determine how changes from the base-case assumptions for these variables will impact its load forecast.

Section 7 - High-Case and Low-Case Load Forecast. This section requires the utility to determine at least high-case and low-case load forecasts and to assign the probabilities which it believes are appropriate for each.

Section 8 - Reporting Requirements. This section sets out the information which the utility must file to show that it has complied with the rule on load analysis and forecasting.

Implementation Cost of the Rule. The cost for each utility to meet the provisions of the rule will vary by utility because each utility is at a different starting place. There are virtually no differences in the cost of meeting the minimum requirements because of utility size. This means that the cost to the smaller utilities will be higher per kilowatt-hour sold. The proposed rule does allow the utility to demonstrate that the expected cost of acquisition of end-use information outweighs the expected benefits from that information. Such a demonstration would be reviewed by the Staff in order to make a recommendation to the Commission whether or not the utility should be given a waiver or variance from the rule. Thus, a high cost of implementation by an affected utility is not a valid reason for the Commission to not adopt the rule.

<u>4 CSR 240-22.040 Supply-Side Resource Analysis</u>

Much of the proposed supply-side rule represents current practice at several of the electric utilities covered by the proposed rule. Supply-side analysis as required by the proposed rule begins with the identification of a variety of potential supply-side resource options. A covered utility is to collect generic cost and performance information, which among other things is to include environmental impacts, for each potential resource option. The proposed rule places considerable emphasis on the assessment of the impacts of environmental legislation and rules on supply-side resource options.

Each supply-side resource option identified by the utility is to be ranked based on its relative annualized utility costs as well as its probable environmental costs. The utility is to identify a list of environmental pollutants for which there is, in the utility's judgment, a nonzero probability that additional laws or regulations will be imposed. The utility also is to estimate the cost to the utility of mitigating the environmental impacts required to comply with said additional environmental laws or regulations.

The utility is to assess the age, condition, and efficiency level of existing transmission and distribution facilities, and analyze the feasibility and cost effectiveness of transmission and distribution system loss-reduction measures as a supply-side resource. This requirement should not be construed to entail a line-by-line analysis.

The rule also emphasizes the importance of fuel costs in supply-side planning by requiring the consideration of a number of factors that affect fuel costs. The fuel forecasts of even recent supply-side resource plans have shown significant error. The intent of the proposed rule is to require a more in-depth study of the factors and trends that affect fuel prices so as to provide a more reliable set of fuel price forecasts. Uncertainties in the fuel price forecasts are required to be associated with a subjective probability distribution.

Another important uncertain factor for which ranges of values and probabilities are required to be developed is capital cost estimates. As with fuel price forecasts, capital cost estimates are to be obtained from a qualified consulting firm with specific expertise in the subject area unless the utility has available expert knowledge and experience. The development of fuel forecasts meeting the requirements of this proposed rule is an area where the affected utilities could cooperate in sharing the cost of compliance. The affected utilities might share the cost of fuel forecasting on a formula related to utility size. Such a procedure is presently used to apportion the costs of power pool studies.

Supply-side resource analysis also is required to consider the following potential supply-side resource options: life extension and refurbishment at existing generating facilities; purchased power from utility sources, cogenerators, or independent power producers; renewable energy sources; new plants using existing generation technologies; and new plants using new generation technologies. Technical support organizations such as EPRI and user groups formed to support special types of plant installations may offer at little cost the expert engineering knowledge needed to develop the costs of various types of plants and components.

4 CSR 240-22.050 Demand-Side Resource Analysis

Section 1. The intent of this section is to ensure that the utility takes a comprehensive approach in developing a menu of potential end-use measures. Narrowing the scope too early in the process to particular technologies or customer classes runs the risk of missing opportunities for creative combinations of end-use measures in demand-side programs that are tailored to the unique needs and characteristics of specific market segments.

Section 2. For end-use measures that pass the screening test (section 4) it is important to know the size of the potential impact on the utility's system load because this information has direct relevance to the question of how much effort and expense is likely to be justified for market research (section 5).

Section 3. The purpose of the avoided cost estimates required by this section is limited to cost-effectiveness screening of end-use measures and demand-side programs. The methods specified are believed to be appropriate for this purpose.

It is recognized that any generic avoided cost methodology involves approximation and simplification of the real electric power supply system, and can therefore be criticized for failing to capture some aspects of the cost of electricity production. The real question, however, is whether the results are sufficiently accurate for the purpose at hand. The intent of this section is to be as non-prescriptive as possible, while being detailed enough to require a methodology that captures the essential components of cost and allocates them in a way that is appropriate for cost-effectiveness screening of demand-side options.

Section 4. End-use measure screening is the first of three steps or levels of cost-effectiveness testing. After measures are combined into a potential demand-side program, the program is screened for cost-effectiveness (section 6). The final stage is the integrated resource analysis (4 CSR 240-22.060) which combines all demand-side and supply-side resources and analyzes them in the context of the existing supply system. The intent is to require the use of relatively generous screening criteria in the early stages and to move toward progressively more stringent criteria at the end. This is done to prevent the premature rejection of end-use measures that do not appear cost-effective in isolation, but may have important advantages when combined with other demand-side or supply-side options.

It is also intended to allow the use of the simplest approximation of costs and benefits that will suffice at each stage of the analysis. Consequently, less precision and time-differentiation is required for estimates of load impacts and avoided costs for end-use measures than for demand-side programs. Also, the use of levelized avoided costs for end-use measure screening does not consider the issue of the timing of resource additions, whereas the present worth calculations used in subsequent stages do address this issue.

Section 5. The kinds of activities that this section requires the utility to engage in are essential to a credible and effective effort to develop demand-side resources. They are also vital to implementing a business strategy that focuses on the provision of energy services rather than electric power supply. The need is for a much more comprehensive and detailed base of information about how customers currently use electricity and how they make energy-related decisions. This kind of information is necessary in order to identify the key market segments that are the basis of demand-side program design.

Section 6. The intent of this section is to emphasize the importance of market analysis as the basis for the design of demand-side programs. Whereas end-use measures generally correspond to particular technologies, demand-side programs correspond to market segments. Typically, within each market segment there will be some diversity of customer characteristics and needs so that an appropriate demand-side program will include several end-use measures as "menu items".

Of course, not every member of the target market segment will need or want every item on the menu, but since a large share of total marketing costs is associated with making individual contact with the decision maker, it is essential for efficiency reasons to have something to offer that is appropriate to the decision maker's situation. It is also much more likely to leave the impression that the utility cares about the individual needs of the customer rather than treating everyone as a standardized unit. Although separate demand-side programs may sometimes be justified for certain end-use measures, this should be the exception rather than the rule, and is most likely to be limited to the large commercial or industrial sectors.

Section 7. This section specifies the cost-effectiveness screening method for potential demand-side programs. There are three important differences between this procedure and the end-use measure screening test (section 4). First, this test requires load impact estimates for every avoided cost period in every year of the planning horizon. This detail allows the test to capture both the intra-year and the inter-year pattern of costs and benefits.

Second, the program screening test includes utility costs to administer, deliver, and evaluate the program whereas the end-use measure screening test does not. This is the appropriate place to include these costs because properly designed programs will spread such costs over several end-use measures. Finally, the use of present worth analysis rather than levelization of net benefits is designed to reflect differences in the value of load reductions that are related to the variation in avoided supply costs over the planning horizon.

The requirement to carry out both a "utility cost test" (subsection C) and a "total resource cost test" (subsection D) is related to the important question of incentive payments to induce customers to participate in demand-side programs. The utility cost test includes such payments while the total resource cost test does not. Although it is the total resource cost test that determines whether a program is passed on to the integrated resource analysis stage, a program that fails the utility cost test is not likely to fare well in that analysis because incentive payments add to utility revenue requirements. Thus, the utility cost test can serve as an "early warning" flag for marketing plans that depend too heavily on incentives and may need to be reevaluated.

Section 8. The load impacts required by this section will typically be more detailed than those required for the program screening tests of section 7. Models used for integrated resource analysis often require load profiles for several different day types within each season or calendar month, and some may need a full 8,760-hour annual load sequence. The expense and difficulty of developing credible program load impacts at this level of detail is one reason for the cost-effectiveness screening tests required by section 7.

Section 9. Ongoing evaluation is an essential and integral part of demand-side resource development. The art and science of program evaluation is very young and much research and experimentation is needed to develop techniques that are sufficiently accurate without being prohibitively expensive.

Process evaluation (subsection A) addresses issues associated with demand-side program design and delivery and tries to improve the focus and effectiveness of programs in influencing energy-related decision makers. This is primarily a marketing problem.

Impact evaluation (subsection B) is concerned with measuring the changes in utility loads that are attributable to demand-side programs that have been implemented. This is primarily a statistical problem, but engineering methods are also relevant.

Section 10. It is essential that the utility keep sufficiently detailed records to allow demand-side program costs to be distinguished from costs associated with load building and other marketing and promotional activities that may make use of some of the same information and techniques. Without this detail it would be impossible to accurately perform the cost-effectiveness screening tests required by section 7 or to calculate the present worth of revenue requirements for resource plans that do not include load-building programs as required by 4 CSR 240-22.060(4).

Section 11. The level of detail in reporting requirements is intended to be sufficient to convey the essential results of the analysis without being unduly burdensome to the utility or unwieldly for reviewers.

4 CSR 240-22.060 Integrated Resource Analysis

Section 1. This section reiterates the requirement that alternative resource plans must be designed to achieve at least the objectives identified in 4 CSR 240-22.010(2). The explicit requirement to consider risk mitigation in addition to cost minimization as a planning objective means that several alternative plans must be developed and analyzed.

Section 2. The performance measures enumerated in this section are intended to be sufficient to identify those resource plans that are most likely to satisfy the planning objectives.

Section 3. Different combinations of resource alternatives will be most likely to maximize different measures of plan performance. The intent of this section is to ensure that utilities develop a comprehensive set of alternative resource plans that are diverse enough to address the full range of identified objectives.

The exclusion of load-building programs at this stage of the analysis is necessary because such programs increase the need for future resources. Plans that balance supply and demand without such programs must be formulated first to provide a meaningful reference point for the subsequent evaluation of load-building programs required by section 5.

Section 4. The intent of this section is to specify the level of detail required, the modeling assumptions, and the essential capabilities of the computer simulation model(s) used to calculate performance measures for each alternative resource plan. At this stage the calculation is deterministic, i.e., uncertain factors are assumed to take on the values that decision makers believe to be most likely.

The requirement that the model be capable of simulating system operation on a year-by-year basis is essential in order to capture the interactions between key factors and the cumulative performance of plans. It is also essential that the modeling procedure reflects the financial and rate implications of alternative plans.

The requirement to use the modeling assumption that rates are adjusted annually to reflect changes in loads and costs is intended to standardize and simplify the analysis in order to provide meaningful comparisons. The actual decision of when to file a rate case is a management decision that depends on many different considerations. But for purposes of comparing the performance of alternative plans over a twenty-year horizon there is nothing to be gained by requiring the analysis to simulate this decision process.

It is recognized that the measurement of price feedback on electricity demand is a complex and demanding task, and the intent here is not to necessarily require a high degree of precision and detail in its estimation. The purpose is rather to ensure that such impacts are not assumed to be nonexistent simply because they are hard to measure.

The intent of subsection D is to ensure that the analytical framework used to evaluate the mix, sequence, and timing of resource additions is sufficiently detailed to reflect the incremental cost and operational impact of resource additions within the context of the existing system. For demand-side resources, the practical implication of this provision is that in order to support an analysis that is substantially equivalent to what is typically done for supply-side options, two conditions must be met. First, the integrated analysis of demand-side resources must be carried out at the program level rather than at the end-use measure level. Second, demand-side programs must be represented in terms of hourly load impacts at the level of detail required by the supply-system simulation model (typically, by month, and by day type) over the planning horizon.

The basic judgment that is implicit in this requirement is that "avoided cost" is an inherently inexact and approximate concept. As such, it is appropriate as a screening tool, but dces not meet the criterion of full equivalence with standard methods of supply-side resource analysis.

It is recognized that forecasts of hourly load impacts due to demand-side programs may be quite uncertain. But this uncertainty is no more problematical from an analytical point of view than, for example, the uncertainties about fuel prices and construction costs on the supply side. The ability to evaluate and balance these uncertainties within an internally consistent analytical framework is one of the great strengths of the techniques of decision analysis required by 4 CSR 240-22.070.

Section 5. The intent of this section is to ensure that load-building programs are analyzed within the context of resource plans that have first been designed to meet the existing demand for energy services. The possibility of benefits from load-building arises from the potential to increase the utilization of existing generation capacity. However, to the extent that the increased loads persist, they hasten the need for additional capacity. Thus, short term benefits may be offset by long term costs. For demand-reducing programs, the converse is usually true, i.e., short term costs are offset by long-term benefits. In order to avoid confusing these opposite effects it is necessary to analyze load-reducing and load-increasing programs sequentially rather than simultaneously.

The distribution of any short term load-building benefits between ratepayers and shareholders is strongly dependent on the frequency of actual rate case filings. The modeling assumption of annual rate adjustments required by section 4 overstates the share of these benefits that will actually accrue to ratepayers, and represents an upper-bound estimate of such benefits.

Section 6. The level of detail in reporting requirements is intended to be sufficient to convey the essential results of the analysis without being unduly burdensome to the utility or unwieldly for reviewers.

4 CSR 240-22.070 Risk Analysis and Strategy Selection

The findings of the Staff Project Team respecting the risk analysis and strategy selection methods utilized by the five largest investor-owned utilities are set out in the executive summary statement in that Staff report:

6. Strategic Planning Practice

> Only one of the five utilities explicitly considers the implications of a variety of external events for the resource plan. Even in this case, the resource plan is primarily based on the reference case and cannot truly be called a resource acquisition strategy; i.e., a strategy which contemplates how the resource acquisition plan will change under alternative outcomes of future external events.
>
> The five utilities have not incorporated concepts of risk management through either (1) the assignment of weights (subjective probabilities) to critical uncertain events, or (2) making a determination of which events would be unlikely to occur simultaneously. The assignment of subjective probabilities is needed in order to evaluate the risks associated with a given resource strategy. The determination of which events are not

> likely to occur simultaneously is needed in order to design a portfolio of options which takes into account both expected cost and expected risk.
>
> The five utilities have not explicitly considered the development of strategic planning elements which would give them the greatest flexibility in facing an uncertain future. This is not to say that flexibility was ignored in developing the resource plan, rather that the approach of developing flexibility was not a planning emphasis.
>
> Finally, the state of resource planning at best can be characterized as having moved from the traditional supply-side capacity planning of the late 70's and early 80's to a process in which uncertainty and demand side options have been given basic recognition. However, the planning process still looks like the old supply-side capacity planning process only with more options and more computer output. There is a need to move from "budget" type planning to "strategic" type planning.

One particular aspect of the planning of all of the utilities which stood out as needing a change in outlook and technique was the general failure to explicitly incorporate the consideration of risk. The traditional method of considering risk has been for planners to choose a tentative preferred plan based on some measure of costs, for instance, present value of revenue requirements, and then to check the sensitivity of the plan to changes in the variables that affect the cost of the plan. The disadvantage of this method is the consideration of risk in the values of the key cost-driving variables is not explicitly considered until a tentative preferred plan has been identified. The more modern approach requires that early in the planning process a set of probability distributions defining the likelihood of the cost drivers assuming a range of values are defined for all the promising resource strategies. The preferred plan is then allowed to identify itself based on these inputs. The probability distributions incorporate the best information that the utility can feasibly obtain, but at the same time explicitly indicate to the reviewers where subjective judgment had to be applied.

The advantage of this approach is that it allows the management of the utility to take a much more active role in the selection of the plan and creates a set of records that make it much easier for reviewers to determine how the decisions were made. This change in thinking about risk has been widely used in the nuclear field to assess the likelihood of serious accidents to power reactors and the expected consequences, and thereby to concentrate design improvements to minimize these risks. It is also being used in general business and financial planning, such as in contracting for fuel supplies by utilities.

This type of risk analysis recognizes the extreme difficulty of identifying an optimum plan in the face of an unknown future, but instead concentrates on identifying a plan that will reduce the likelihood of the utility and its customers suffering serious harm from future events. This new approach also permits the planners to quantify the value of information that can be acquired with the expenditure of additional resources of time and money, for example, in research on trends in fuel prices.

Several of the utilities have been moving in the direction of adapting this type of risk analysis to their planning processes.

Software incorporating these concepts is presently available from the Electric Power Research Institute (EPRI) and other suppliers. The main thrust of the risk analysis and other rules is to create a framework that will allow the Commission and any interested entities to determine how the decisions were made and to explicitly identify the risks inherent in the plan.

Proposed section 6 addresses the requirement of maintaining the reliability of the power supply over the long-term as a necessary attribute of any resource plan. It uses as a gage of reliability the number of hours that the utility cannot serve its commitments from its own generating units or the capacity it has purchased from others on a long-term basis. These hours are termed "unserved hours." Increasing unserved hours is associated with decreasing reliability in the sense that the utility is more dependent on sources it cannot control to serve its customers. The proposed rule requires each utility to calculate these hours using a computer model to simulate its operations under its preferred resource plan, as realistically as the state of the art permits.

4 CSR 240-22.080 Filing Schedule and Requirements

Section 1. An electric utility is covered by the proposed Chapter 22 rules if the utility sold more than one million megawatt-hours to retail electric customers for calendar year 1991 as identified in its annual report on file with the Commission. One million megawatt-hours appeared to be a natural breaking point and annual reports for calendar year 1991 are the most current data on file with the Commission for all electrical corporations within the Commission's jurisdiction. The number of megawatt hours in 1991 sold by each of the electrical corporations regulated by the Commission is as follows:

Name of Electric Company	Mo. Juris. MWH's 1991
Union Electric Co.	25,193,680
Kansas City Power & Light Co.	7,326,152
Missouri Public Service	3,354,237
Empire District Electric Co.	2,372,893
St. Joseph Light & Power Co.	1,393,793
Citizens Electric Corp.	620,135
Cuivre River Electric Service Co.	68,711
Sho-Me Power Corp.	0

Thus, not all of the electric utilities regulated by the Commission are covered by the proposed Chapter 22 rules. Sho-Me Power Corporation (Sho-Me) which asserts that it is no longer within the Commission's jurisdiction, Citizens Electric Corporation (Citizens), and Cuivre River Electric Service Company (CRESCO) are not covered by the proposed Chapter 22 rules, although they are covered by Chapter 14.

The electric utilities that are regulated by the Commission but are not covered by the proposed rules involve utilities that do not have any residential customers (Sho-Me), do not have any generating facilities of their own (Citizens) or the Commission's jurisdiction over the associated generating facilities is arguably attenuated (Sho-Me and CRESCO), or the number of megawatt hours of electricity sold and the number of residential customer is very small (CRESCO). Thus, the benefit of the proposed electric utility resource planning rules is questionable, or seemingly not cost effective, regarding these electric utilities.

Gas utilities regulated by the PSC are not covered by the proposed Chapter 22 rules. Subsequent to the adoption of the electric utility resource planning rules, the Staff intends to draft gas utility resource planning rules. The Staff has not set a timetable for issuance of gas utility resource planning rules, but presently intends to follow the same procedure as it has respecting the electric utility resource planning rules.

The Staff has addressed resource planning for electric utilities first because the potential impact of adequate resource planning on the electric industry is more immediate than for the gas industry. For Missouri gas utilities, there is nothing comparable to the amount of investment that Missouri electric utilities have embedded in generating facilities. Rather than capital intensive generating facilities, Missouri gas utilities rely on gas supply contracts. The Federal Energy Regulatory Commission (FERC) is in the process of changing the market structure in which these gas supply contracts will be negotiated. The Commission is presently involved as a party in negotiations between the pipelines and their customers which the FERC has mandated as a part of the restructuring process. Thus, even though at present there are no proposed resource planning rules for gas utilities, the Commission is active in a somewhat related area for gas companies.

The five largest investor-owned electric utilities regulated by the Commission are required by the proposed Chapter 22 rules to file with the Commission, on a staggered basis over a three year period, and then subsequently every three years, information that demonstrates compliance with the resource planning rules, including compliance with the planning objectives of the rules. The Staff believes that a three year cycle meets the needs of (1) the Commission to have current information on resource planning for the covered electric utilities, (2) the utility to perform the planning and submit the reports on a regular basis that is timely, but not unduly burdensome, and (3) the Staff to review on a timely basis the reports for compliance, without the necessity for additional Staff. Although the Staff believes that no additional F.T.E.s will be required in order to administer the new Chapter 22 and the amended Chapter 14 rules, there is likely for the foreseeable future to be a need for professional and technical funds to retain qualified consultants to assist the Staff in its review of compliance filings. The fiscal note on state agency cost reflects this projected need.

If a utility seeks to file any information under seal in order to prevent public disclosure of what it considers to be trade secrets or confidential or private technical, financial or business information, the utility must request, no later than at the time of its filing, that the Commission issue a protective order.

The Staff believes that Section 393.140(11) RSMo 1986 requires that tariff sheets must be filed for demand-side programs. See State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Serv. Comm'n, 585 S.W.2d 41, 57 (Mo. banc 1979). The Staff also believes that demand-side programs involving consideration constitute promotional practices.

Section 2. The Staff anticipates that the electric utilities covered by proposed Chapter 22 and possibly other commenters will assert in their comments that nontraditional accounting and/or ratemaking procedures will be required if the Commission is to reasonably expect that these utilities will develop demand-side resources or if the Commission directs that they are to do so. Based upon what has been presented to the Staff to date, the Staff does not believe that the Commission should engage any nontraditional accounting and/or ratemaking procedures, barring truly extraordinary circumstances. Nonetheless, if the Commission wants to entertain the possibility of so proceeding or if the Commission is set on so proceeding, the Staff believes that the information required to be submitted by proposed 4 CSR 240-22.080(2) is necessary in order for the Commission to make an informed determination whether to authorize any particular nontraditional accounting and/or ratemaking methodology. By requiring that a utility indicate the nontraditional accounting and/or ratemaking treatment it eventually will seek, this would not mean that a utility is prohibited from later seeking different nontraditional accounting and/or ratemaking treatment.

The Staff expects that generally there will be three basic arguments offered for nontraditional accounting and/or ratemaking for demand-side programs. The overarching contention which likely will be made is that there are economic disincentives for implementing demand-side programs under traditional accounting and ratemaking.

The first argument which may be made is that under traditional ratemaking, a large amount of the costs associated with demand-side resources would be expensed rather than put into rate base. With increasing material expenses over time, it is argued that the utility will have to file annual rate cases in order to recover these costs. Using traditional test year concepts, the utility would always be behind in its recovery and it would be placed in the position of having to file annual rate cases. On the supply-side, the utility files a rate case to synchronize the rate basing of the investment with its "fully operational and used for service" date, and so the recovery of costs is not subject to the same type of test year lag.

The second argument which may be made is that demand-side resources are not on a level playing field with supply-side resources because the cost of supply-side resources are allowed to accrue interest during construction (AFUDC). Since demand-side options are implemented on a continuous basis with increasingly material costs over time, and generally involve costs that under traditional ratemaking would be expensed, the utility would have to file a rate case every year in order to recover these expenses and earn a return on this investment. Supply-side costs are also incurred on a continuous basis, but the utility is allowed to accumulate a capitalized return on those funds until that point at which the plant is declared and appropriately determined to have become "fully operational and used for service." Therefore, all other things being equal, the utility will prefer the supply-side option to the demand-side option.

The third argument which may be made is that demand-side resources which result in decreasing energy use, also result in lower revenues with an associated loss in contributions to fixed cost. This argument is the "lost revenues" issue.

The Staff view is that traditional accounting and ratemaking treatment should be applied to demand-side programs. The Staff is opposed to the adoption of nontraditional accounting and ratemaking procedures for anything besides "extraordinary items." Extraordinary items are events that are unusual in nature, nonrecurring, and have a material impact on the utility's earnings. Deferral of expenses associated with extraordinary items is an accepted regulatory practice. Demand-side expenditures are recurring in nature, and thus would appear to be a cost that can be adequately recovered through traditional ratemaking practices. Deferral of expenses associated with demand-side expenditures also would be inappropriate in that it would ignore the possibility that revenue increases, expense decreases respecting other items, or a declining rate base may offset all or a part of any earnings deficiency caused by demand-side expenditures. If the Commission were to allow a deferral of demand-side expenditures, the Commission should require the affected utility to record and recognize any related savings as offsets.

The Staff asserts that the deferral of demand-side costs is not comparable to AFUDC calculated for capital expenditures. AFUDC is allowed to be recovered in the cost of plant additions because of the Commission's policy to deny rate base treatment of CWIP. (For electric utilities, this is a statutory prohibition under Section 393.135 RSMo 1986). AFUDC is a capitalized cost of money, which is included in the asset's total plant in service balance, and charged to expense over the asset's life. To not allow utilities deferred recovery of the cost of money used to finance construction during the period CWIP is denied rate base treatment would deny the utilities the opportunity to fully recover their costs of construction. In contrast, there is no statutory prohibition that would deny utilities the opportunity to recover recurring demand-side costs, generally an expense rather than a capital item, through timely rate case filings.

Moreover, AFUDC is not designed to shield utilities completely from regulatory lag associated with rate base plant additions. AFUDC is calculated only during the construction period of an asset. There may be, and almost always is, a certain amount of regulatory lag between the time an asset is fully operational and used for service and the time rates are set reflecting that asset's inclusion in rate base. Deferral procedures which involve carrying charges, in contrast, are designed to give utilities the opportunity to completely protect against regulatory lag on the item being deferred. The deferral procedures which may be proposed would likely provide utilities an advantage for demand-side expenditures which is not permitted for other expense items, and would likely provide an advantage for demand-side costs which is not provided for capital expenditures, i.e., potential full protection from regulatory lag. Accordingly, deferral proposals do not create a level playing field for demand-side expenditures.

Another type of nontraditional ratemaking which may be suggested is the use of forecasted test years. Traditional ratemaking in Missouri entails the use of historical test years. The Staff generally has opposed the use of forecasted test years, but has engaged in the use of forecasted data for ratemaking purposes on several occasions to meet extraordinary situations. The Staff utilized a forecasted fuel procedure in the early to mid-1980's to address double-digit inflation's impact on the single largest expense for electric utilities, and the Staff used a forecasted test year for purposes of the 1983 Southwestern Bell Telephone Company divestiture case. The Staff does not view the costs of demand-side resources as rising to the level of the extraordinary circumstances that were associated with the Staff's use of forecasted fuel in the first part of the 1980's and the forecasted test year in 1983 for Southwestern Bell.

Section 3. The affected electric utilities are to make their filings with the Commission on a staggered basis, with the first utility filing seven months after the effective date of the Chapter

22 rules, and the succeeding affected utilities filing on the basis of one utility every seven months thereafter. Each covered utility is to make subsequent filings on a staggered basis three years after its prior filing. In the Staff's view, this cycle of staggered filings keeps the data current, does not unduly burden the affected utilities, and permits the Staff to perform its review of the compliance filings without requiring additional F.T.E.s.

The order of the affected utilities' filings is set on the basis of gross annual operating revenues, with the utilities filing in order of successive size from largest to smallest for calendar year 1991 as reported in the annual reports on file with the Commission. It is the Staff's view that presently the proximity to compliance of each of the affected utilities is in the order of their gross annual operating revenues, such that the larger the gross operating revenues, the closer the utility is to compliance. Therefore, the utilities that are furthest from compliance will be provided the most time from the effective date of the proposed rules to bring themselves closer to compliance before the first and each successive filing.

Section 4. When an affected utility files the reports and information that constitute its compliance filing, the Commission will establish a docket for this and any associated filings. Although the Commission will establish an intervention deadline, set an early prehearing conference, and provide notice, the Commission will not set any hearing dates at this stage and may not establish hearing dates at any point.

Section 5. Within 120 days of the submission of the compliance filing, the Staff shall review the filing and submit a report. The Staff's review of the compliance filing is intended to be limited in scope. The paramount purpose of the Staff's compliance review is to determine whether the affected electric utilities are implementing the specific requirements of 4 CSR 240-22.030 through 4 CSR 240-22.070, the intent of which is that the affected electric utilities put in place and utilize thorough long-range planning procedures which will provide the public with efficient and cost-effective energy services. The Staff will not conduct an operations audit. Other than deficiencies in meeting the specific non-substantive requirements of the Chapter 22 rules, the Staff will identify deficiencies of the following nature if it discovers them in the course of its compliance review: (1) major failings in the implementation of the methodologies and analyses required to be performed by the Chapter 22 rules and (2) any other failings which would cause the affected utility's resource acquisition strategy to not meet the planning objectives specified by 4 CSR 240-22.010(2)(A)-(C). The Staff's compliance review is not intended to result in a substantive determination by the Staff that the affected utility's resource acquisition strategy is correct, accurate, or appropriate.

The 120 days provided for the Staff to conduct its review and draft its report is intended to permit adequate time under the circumstances for the Staff to perform its limited review with no additional F.T.E.s and still perform its other Commission functions. A more comprehensive review than a compliance review would require additional time and/or F.T.E.s. If a greater amount of time for Staff review of each filing is permitted, then the cycle of affected utilities' filings and Staff review of these filings, once every three years for each affected utility, is not possible without additional F.T.E.s. The Staff's opposition to a substantive review of the filings required by Chapter 22 and an objective, goal, or end result being Commission approval of the resource acquisition strategy is not just based on Staff concern about resources and logistics, but is grounded in part on conceptual differences as to what should be the objective, goal, or end result of this entire process if strategic resource planning is mandated by the Commission.

Section 6. Public Counsel and any intervenor have 120 days from the date of the utility's filing to file their own reports or comments. The scope of such reports or comments are limited as is the Staff's.

Section 7. All materials supporting the resource acquisition strategy in the possession of the particular utility or any contractor that was utilized to produce any part of the resource acquisition strategy for the utility must be retained for a period of at least 10 years which is one year beyond the filing of the third subsequent resource acquisition strategy. The Staff expects that all of the affected utilities will request waivers or variances for portions of the Chapter 22 rules for one or more reporting periods. The retention of records for this period of time is necessary for purposes of evaluating not just the most recent filing but possibly the next three filings.

Section 8. If purported deficiencies in the resource acquisition strategy are identified, the utility and the other parties are given 45 days from the date of the filing of the reports and comments denominating the deficiencies to reach agreement on a plan respecting how the purported deficiencies will be remedied. If full agreement cannot be reached, this inability to reach complete agreement is to be reported to the Commission in a joint filing within the same 45 day period. Since it is the Staff's position that the review of the resource acquisition strategy is to be limited to a compliance review, the deficiencies identified by the Staff and other parties are likely to entail in particular very technical and highly esoteric matters rather than broad policy. As a consequence, the Staff believes that there should be a procedure where an intense effort is made to resolve these matters without requiring the Commission to make the necessary determinations.

Section 9. If the affected utility and other parties do not reach complete agreement on how purported deficiencies in the resource acquisition strategy are to be addressed and resolved, the utility may file a response to the other parties and the other parties may file a response to each other within 60 days from the date that reports or comments were filed regarding the utility's compliance filing. The Commission in its discretion may order a hearing on some or all of the matters on which agreement has not been attained and would issue a procedural schedule if a hearing were ordered. These matters do not rise to the definition of a "contested case" under Section 536.010(2) RSMo 1986,[1] nor is a hearing required under the provisions of Chapters 386 or 393.

Section 10. It is not the intent of the Staff that it or the Commission by adoption of the proposed Chapter 22 rules engage in the micro-management of the affected utilities. Thus, there is no requirement in the proposed rules that either the resource acquisition strategy or any deviation from it be approved by the Commission. This section of the proposed rules merely requires that the utility (1) notify the Commission if it determines that its preferred resource plan is no longer appropriate and (2) file for review in advance of its next regularly scheduled compliance filing, a revised implementation plan if it decides to implement any contingency options identified pursuant to the Chapter 22 rules.

Section 11. The intent of this section is to provide the Commission with great flexibility respecting the individual circumstances of the affected utilities. The Staff does not expect that any of the affected utilities will be in complete compliance with the rules during the first three year cycle of filings. The Staff does not expect that all of the affected utilities will be in complete compliance with the rules during the second three year

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[1] Section 536.010(2) RSMo 1986 defines contested case as "a proceeding before an agency in which legal rights, duties or privileges of specific parties are required by law to be determined after hearing."

cycle of filings. Rather than not adopt rules at this time because no affected utility may be in complete compliance, and some are far from being in complete compliance, the Staff believes that the better approach is to adopt the proposed rules and waive or grant variances from specific provisions of the rules for good cause shown. A proper showing by a utility that compliance with a provision of a rule is not cost-effective for that particular utility may constitute good cause for granting a waiver or variance. At the same time, the Staff believes that it needs to be clear that waivers or variances will be utility specific and there is no affected utility that will not be able to comply at least in part with the rules during even the first three year cycle.

Section 12. See the comments above respecting Section 11.

Section 13. The requirement that the Commission will issue an order making the specified findings and addressing requests for authorization or reauthorization of nontraditional accounting procedures for demand-side resource costs provides what the Staff believes is an appropriate degree of closure to the electric utility resource planning process for each affected utility.

4 CSR 240-14.010 General Provisions

Presently, Chapter 14 of the Commission's rules prohibits the offering of consideration by electric and gas utilities in competition for load with each other, i.e., engaged in inter-industry competition. Chapter 14 does not prohibit the offering of consideration by electric utilities regulated by the Commission to meet competition from rural electric cooperatives, municipal utilities, or other Commission regulated electric utilities. In general, the proposed amendments to Chapter 14 are intended to make clear what activities are not prohibited promotional practices. Consideration provided in order to acquire cost-effective demand-side resources is not a prohibited promotional practice for which the utility must obtain a variance, but it is still a promotional practice that must be filed as a tariff. Activities that fall outside the category of prohibited promotional practices are, for example, demand-side programs that promote "energy efficiency" or "energy management" as defined in 4 CSR 240-22.020(17) and 4 CSR 240-22.020(18). Programs that attempt to induce energy-related decision makers to switch from gas to electricity, or vice-versa, for the provision of energy services are intended to remain prohibited promotional practices.

The test of cost-effectiveness for demand-side resources is based only on intra-industry costs and benefits. If, for example a gas utility believes that a proposed demand-side program by a competing electric utility will induce fuel switching, it will have the opportunity to object to the electric utility's promotional practice tariff filing. The potential opposition of a competing utility is another reason why all promotional practices should be tariffed.

Some electric utilities have expressed displeasure as to the length of time that it takes the Staff to process a request for authorization of a proposed promotional practice. Thus, one or more electric utilities may indicate in comments their concern that requiring promotional practices to be filed as tariffs, potentially draws out what is a simple filing to an eleven month ordeal. The Staff's position that promotional practices should be tariffed is not based on a desire to provide the Staff as much time as lawfully possible to review such proposals. The Staff first would note that it believes that all promotional practices are required to be tariffed by Section 393.140(11) RSMo 1986. See State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Serv. Comm'n, 585 S.W.2d 41, 57 (Mo. banc 1979). Second, as tariffs filed with a 30 day effective date, the Commission could let the tariffs go into effect by operation-of-law by not suspending them, regardless of whether the Staff, Public Counsel, or some interested entity requests that they be suspended.

Deletion of Present Section 3. This section is being deleted to reflect that the rule which it was intended to recognize, 4 CSR 240-20.020 Residential Electric Underground Distribution System, was rescinded August 15, 1983.

Section 4. Activities designed to evaluate the cost effectiveness of potential demand-side programs are not deemed to be prohibited promotional practices.

Section 5. The provision of consideration necessary to acquire a cost effective demand-side program is not deemed to be a prohibited promotional practice.

Subsections 6 (D), (E), (F), (H), (I) and (L). Terms respecting demand-side programs involve intra-industry measurements and analysis, i.e., within the electric industry or gas industry, not inter-industry measurements and analysis, i.e., not between the electric industry and the gas industry.

Subsection 6(L). The new language reflects that electric utilities have filed for authorization, as permitted promotional practices, programs and contracts for the purpose of influencing a person's choice or specification of the efficiency characteristics of appliances, equipment, buildings, utilization patterns, or operating procedures.

Section 8. This new section reflects that the Commission has authorized electric utilities to engage in this activity.

4 CSR 240-14.030 Promotional Practices Standards

Section 1. The deletion of the second sentence in the existent version of 4 CSR 240-14.030(1) is necessary because Chapter 14 is being amended to cover demand-side promotional practices which are intended to reduce rather than stimulate sales. Although the criteria identified by the sentence that is proposed to be deleted should continue to be applied to non-demand-side promotional practices, the Staff believes that this criteria is subsumed within the scope of the first sentence.

Section 2. The words "undue or unreasonable" which have been added to the language of the second sentence merely reflect the language of Section 393.130.3 RSMo 1986. The deletion of the fourth sentence has no practical effect because it merely permits what statute permits.

Section 3. The new language requires that any new promotional practice must be filed with the Commission on a tariff. As noted above, the Staff believes that all promotional practices are required by Section 393.140(11) RSMo 1986 to be tariffed. See State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Serv. Comm'n, 585 S.W.2d 41, 57 (Mo. banc 1979).

4 CSR 240-14.040 Filing of Promotional Practices

Section 1. Pursuant to the amendment of this section, utilities will be required to file with the Commission in tariff form all promotional practices which they are presently authorized to engage in and which they are seeking to engage in. The current section requires such promotional practice filings to be on a "schedule" filed with the Commission. One utility in particular has interpreted the term "schedule" to include a non-tariff filing. The amendment requires that existing and future promotional practices be placed on tariff sheets. This change will ensure that the public will have access to all promotional practices approved by the Commission since utility tariffs are required to be open and available to the public. To the extent that any promotional practice causes a rate or charge to be different from that generally available to ratepayers, such different rate or charge should be tariffed, as all rates or charges a utility collects should be tariffed.

The language regarding the transition to the requirements of the amendment allows 45 days from the effective date of the amendment for utilities to comply. This amount of time is adequate for the utilities to prepare and meet the filing requirements listed in the subsections of section 1. Forty-five days from the effective date will allow utilities adequate time to meet all the filing requirements contained in the amended rule.

The amended Section 1 also effectuates the movement of language contained in the current 4 CSR 240-14.040 (1)(H) to the body of section 1.

The last and second to last complete sentences in section 1 of the amendment, before subsection (A), contain language seeking to assure consistency between previously approved promotional practices and those to be filed in tariff form pursuant to the amendment. Review and approval by the Commission will assure that there are no substantive changes to previously approved promotional practices in the process of their transition to tariff sheets. Entities other than the Commission are provided time to verify that the proposed tariffs are consistent with what the Commission previously approved and these entities may advise the Commission if that is not the case.

Subsections (1)(D) and (E). The changes in these subsections require that the utility include an explanation in its tariff filings of the purpose or objective of the promotional practice, and eliminates the existing provision that the utility provide a description of any advertising or publicity to be employed with respect to the proposed promotional practice.

A description of any advertising or publicity related to a promotional practice is not considered by the Staff essential to the determination of whether the filing has merit. This requirement related to specific concerns that existed at the time the rule was first promulgated. The costs of and need for advertising or publicity are reviewed in the context of a general rate proceeding. Since this information is not essential to the determination of the merits of the filing and because such information is reviewed for ratemaking purposes in the context of rate proceedings, this requirement should be eliminated from the rule.

Subsection 2(B). As previously noted, it has been the Staff's experience that some electric utilities are concerned as to the amount of time that it takes the Staff to process a proposed promotional practice. So as to address promotional practice proposals in as timely a manner as possible, this subsection requires that the electric utility seeking Commission authorization file concurrently with its promotional practice tariff certain specific information. The Staff, Public Counsel, and intervenors are saved the time and delay of submitting initial data requests and waiting for responses by proceeding in this manner. If a utility wants to expedite the process as much as possible, then it should have no objection to filing this information concurrent with the filing of its tariff.

The statement of the purpose or objective of the proposed promotional practice is necessary to assist any entity interested in the filing, the Staff, and the Commission in the determination of whether the merits of the promotional practice warrant its approval.

4 CSR 240-14.050 Compliance

This rule is proposed to be rescinded because it is outdated and no longer needed. The need for this rule was the short-term period after the promulgation of Chapter 14 in the early 1970's.

Public Hearing

Generally, the members of the Staff specified below will respond to questions respecting the following areas at the public hearing on September 10-11, 1992 should the Commissioners or Hearing Examiner have any questions:

4 CSR 240-22.010	Martin Turner Michael Proctor
22.020	Martin Turner
22.030	Michael Proctor
22.040	John Renken
22.050	Martin Turner Michael Proctor
22.060	Martin Turner

22.070	John Renken Michael Proctor Martin Turner
22.080	Martin Turner Steven Dottheim Mark Oligschlaeger
4 CSR 240-14.010 - 14.050	Martin Turner Randall Hubbs

Respectfully submitted,

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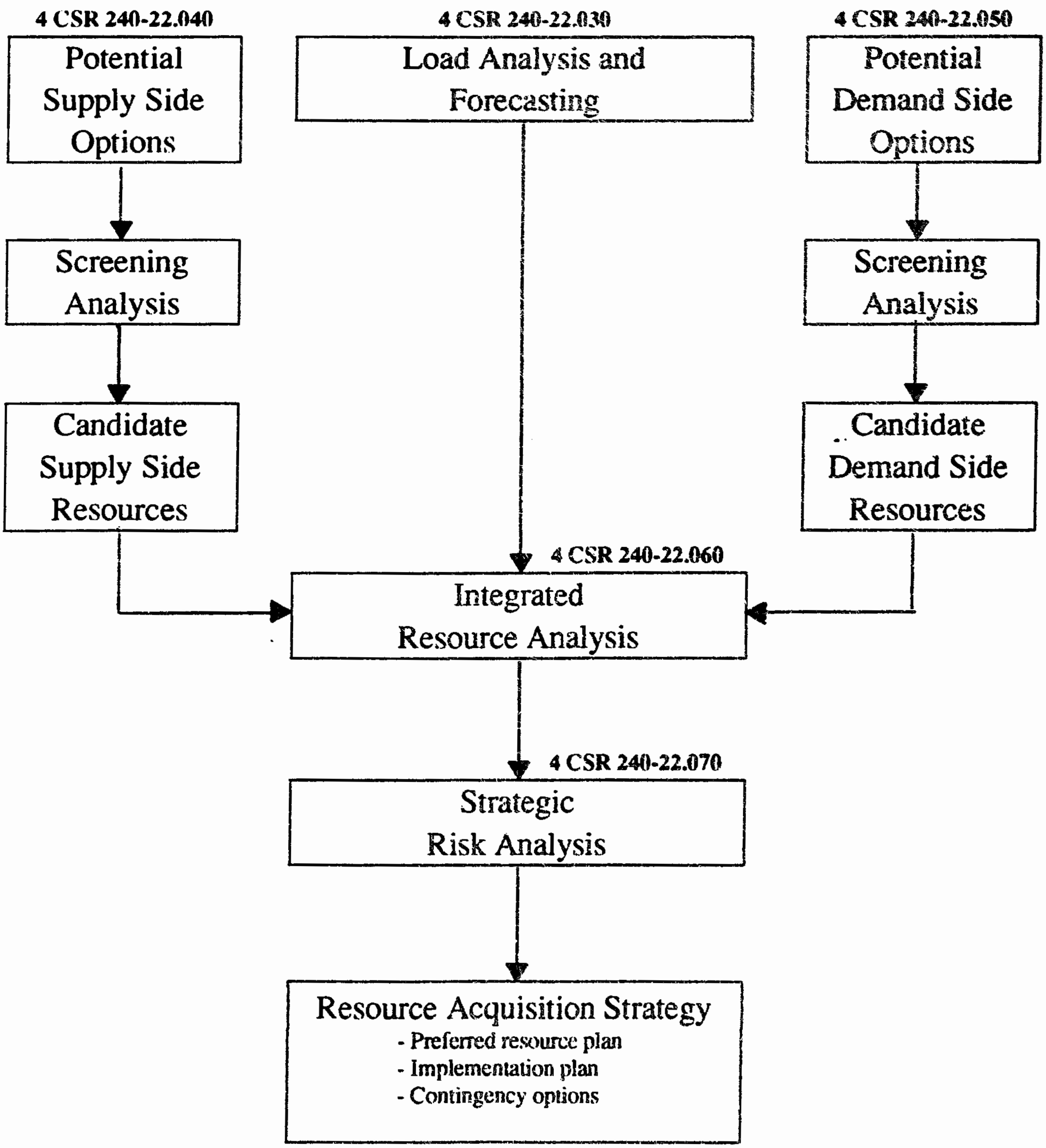
INTEGRATED RESOURCE PLANNING



Schedule 1