SOUTHWEST POWER POOL, INC. ("SPP") files its initial responses and comments in the matter of developing comprehensive resource planning guidelines for electric utilities. SPP is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP was formed in 1941 by a voluntary, intercompany agreement between 11 utilities, in response to critical national defense needs during World War II. In 1968, SPP became a regional Reliability Council, joining with several other such organizations, to form the predecessor to the North American Electric Reliability Council ("NERC").

SPP currently has 50 Members, serving more than 6.5 million customers in a 400,000 square-mile area covering all or part of the states of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. SPP's Members include 13 investor-owned utilities, 7 municipal systems, 8 generation and transmission cooperatives, 3 state authorities, 1 federal power marketing agency, 1 wholesale generator, and 17 power marketers. SPP's Members are responsible for 17 of the approximately 150 control areas in North America. SPP also serves as an independent security coordinator for the region.

SPP is one of ten NERC regional Reliability Councils. Its membership includes the following entities which serve load in Arkansas: Arkansas Electric Cooperative Corporation, Empire

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District Electric Company, Oklahoma Gas and Electric Company, Southwestern Power Administration, and Southwestern Electric Power Company. In this role, it is SPP’s function to establish reliability standards for the SPP region and ensure compliance with these standards. SPP’s criteria provide minimum standards for both generation and transmission adequacy. SPP is also the NERC security coordinator for the SPP region and as such is responsible for maintaining reliability by monitoring real-time power flows and instituting line loading relief and curtailments to protect regional reliability.

SPP currently administers an Open Access Transmission Tariff (OATT) providing transmission service over the transmission facilities of eleven transmission owning members who have placed their transmission facilities under the administration of SPP through an agency agreement. Under this tariff, SPP provides regional transmission service throughout its eight-state region on a non-pancaked basis, including all services provided by Order 888 of the Federal Energy Regulatory Commission (FERC). In this capacity SPP is responsible for the planning and expansion of the system as necessary to provide service under the SPP OATT. The transmission system under SPP’s tariff administration includes the transmission facilities of AEP-Southwestern Electric Power Company, Oklahoma Gas and Electric Company, Empire District Electric Company, and the Southwestern Power Administration within the State of Arkansas.

SPP anticipates serving the region that includes the aforementioned utility service territories within the State of Arkansas as an RTO or ISO pursuant to Orders and policies of FERC.

SPP provides the following responses to the questions and issues set forth in the proceeding.

I. Objectives of Resource Planning: The Commission seeks the parties’ views on the objectives of resource planning. By way of illustration, resource planning might focus narrowly on avoiding future energy shortfalls. Alternatively, planning could require
consideration of policies related to reducing consumer risks, enhancing consumer benefits, reducing price volatility, ensuring fuel diversity, or achieving other societal or environmental objectives. Comments should consider the possible objectives identified below.

SPP considers Resource Planning to be a key component in the overall Planning process. A major SPP planning goal is “to minimize costs, consistent with the reliability and other requirements” as stated in its membership agreement. In meeting this objective, consideration of several factors related to resources is necessary.

Criteria have been established by SPP for generation capacity resources and planning within the region. The generation planning criteria specifically require members to: 1) consider a balanced design of the system; 2) provide auxiliary power for safe shutdown; 3) have black start units; and 4) design generation to be capable of withstanding voltage dips. The criteria also require members to have an assurance of adequate fuel supply.

SPP has established criteria for planning the transmission system for reliable service to load within the region. In addition, the SPP OATT includes provisions for system expansion for the administration of transmission service.

A. Price and Market Objectives:
1. Minimize consumer costs (total costs, individual customer costs)

The SPP Membership Agreement provides minimization of costs as a stated goal.

2. Minimize price risk and price volatility

SPP has no policy on this at this time. Adequate capacity and fuel arrangements, in and of themselves, mitigate price risk and volatility. Conceptually, market efficiencies are improved by price volatility on the margin with such volatility providing a mechanism by which price risk can be taken by parties willing to bear those risks.

3. Foster increased market competition
   a. Establish portfolio limits for reliance on purchased power (planned amounts of spot purchased, short-term and long-term contracts)
   b. Ladder power purchase agreements
   c. Economically dispatch competitive resources for native load

Current methods of maintaining reliability of the transmission system and determination of and compensation for imbalance energy are not market based. These are areas where resource and transmission planning should be modified to allow for increased competition in the market.

4. Diversify types of generation fuel sources

SPP Criteria require that members consider fuel diversity in resource planning. Specifically, members must have an adequate and reliable fuel supply. Excess use of one fuel source may increase the risk of exposure to a non-diversified provider.

5. Promote particular energy resources (e.g., renewable power)

SPP criteria do not specifically promote one resource over another, but the characteristics of a resource must be considered along with any diversity objective.

6. Capitalize on cost-effective efficiency measures

SPP’s goal of cost minimization promotes the assessment of cost-effective efficiency measures.

7. Minimize environmental costs/internalize externalities
Cost assessments should include environmental costs, as appropriate.

8. increase jobs and economic growth in Arkansas
SPP promotes the efficient and reliable operation of the transmission system, enhancing the cost-efficiency of the wholesale power market, which should promote economic growth in all states within the region.

9. reduce market distortions (e.g. high capital/low cost sources vs. low capital/high cost sources)
The generation planning criteria stated should provide for consideration of market distortions.

B. System reliability objectives:
1. maintain or enhance system reliability
   a. bulk transmission reliability, including
      (1) resource adequacy
      (2) resource security
SPP, along with NERC, has established criteria and standards for maintaining transmission system reliability. These criteria include provisions requiring analysis of the contingent loss of resources that could happen in real-time operation.
   b. distribution reliability
SPP is responsible for the transmission system and has no role in distribution system reliability.

2. promote long-term transmission planning
   a. coordination of changes in the locations and amount of power generated
SPP evaluates changes in the projected location of generation through its annual development of transmission system models that reflect changes in resources necessary to serve native load. These annual evaluations allow planners to identify future transmission system limitations that could prevent service to native load, and provide a basis for development of mitigation plans.
   b. information-sharing and coordinated action among independent power producers, power marketers and brokers, transmission utilities, retail utilities, system operators, security coordinators, regional reliability councils and the North American Electric Reliability Council, FERC, and state regulatory commissions
SPP has a 60-year history of coordination and information sharing, not only with its members and market participants but also with neighboring reliability regions and transmission providers. This information sharing is key to maintaining a highly interconnected transmission grid and ensuring generation resources can be delivered to the load. All market participants should be required to share the necessary information for coordination of resource plans, subject to code-of-conduct requirements and limitations.

3. identify reliability problems and determine appropriate solutions, such as:
   a. transmission facilities/ upgrades
   b. traditional generation facilities
   c. distributed generation
   d. demand-side measures
Generation development during the past few years has provided additional capacity resources but a corresponding expansion of the transmission system to facilitate delivery has generally not occurred. However, despite this lack of expansion, there has not been a reliability problem to date. Much of the new generation has not been committed to a specific destination market. The planning process must facilitate transmission expansion.
II. Forecasting Future Supply and Demand: Resource plans require an assessment of future power forecasts and estimations of future demand. This part seeks the parties' views of the process for completing and the substance of the forecasting components of the resource plan. The questions are divided into three parts.

A. Forecasting Future Demand:
SPP criteria require its members to provide, on an annual basis, a 10-year forecast of peak demand and net energy requirements. SPP has performed biennial bandwidth forecasts of system load growth. These forecasts have created high and low growth bands around the forecasts of the members. SPP members should remain the key developers of demand load forecasts. The regional entity must be responsible for determining minimum generation reserve margins.

1. The following list contains factors that the Commission rules could require analysis of in demand forecast. Which factors are the most significant indicators of future demand? Are there any that are de minimus? Identify and missing factors.

SPP defers comment on the development of demand forecast to its members responsible for serving load.

2. Regarding Generation Reserve margins
   a. What generation reserve margin is needed to maintain reliability?

SPP uses a probabilistic method to conclude an appropriate reserve margin. A loss of load expectation of no more than one day in ten years is used as the standard for SPP. This is set as the standard for customers and ensures an appropriate minimum reliability margin. Consistent with this standard the SPP criteria require a 12% capacity margin for the region, with a reduction to 9% for hydro-based generation. The capacity margin is calculated by subtracting the net internal demand from the planned capacity resources and dividing by the planned capacity resources.

A 12% capacity margin equates to a 13.6% reserve margin. A reserve margin is traditionally computed as the planned capacity resources minus the net internal demand, divided by the net internal demand.

b. What are the costs associated with reserve margins?

SPP defines the minimum reserve required for its members. The costs of generation resources are determined by the individual member and vary.

   c. What methods are there to test whether the reserve margin has commensurate value for customers?

In the past, generation reserve or capacity margins have been based on optimizing supply-side resources to achieve a targeted minimum reliability standard which did not consider the customers' value of service. Quantifying the value of reliability to a specific customer or a class of customers is difficult at best. The value of unserved energy associated with electric service curtailments is extremely time dependent. The value changes as a function of many variables including current weather conditions and future forecasts, outage frequency, duration, and start/stop time. Although reliability values may be subjective, time-sensitive, and hard to quantify in absolute terms for a specific scenario, probabilistic techniques based on typical data have been used to allocate limited resources based on the relative rankings or benefits of reliability service improvement projects. Similar techniques could be incorporated into
determining generation reserve levels as a function of customer value. Price transparency and associated demand response are key factors of future energy markets. The price elasticity for end-use customers is a potentially valuable asset for optimal resource planning.

B. Forecasting Future Supply:
The SPP criteria define the adequacy of existing generation resources. In order for the capacity of a resource to be considered "firm power" it must be owned or purchased capacity. All capacity must have available firm transmission service to the load. For SPP accreditation, firm power does not include "financially firm" power. SPP also has criteria defining the rating of units and operational requirements. Each unit is to be rated every three years; an operational test must be performed annually to verify the generation resources claimed.

On an annual basis SPP Members are required to supply a 10-year resource plan for inclusion in SPP’s EIA-411 Report to the Department of Energy. These resource plans should be adequate to serve the forecasted load during the period.

1. An important aspect of resource planning is the determination of the adequacy of existing generating capacity and power purchase agreements to meet future demand. The resource plan must determine whether these resources are a cost effective means of meeting future demand relative to the alternatives. Comment on how the resource plan should make this determination.

SPP allows for members to obtain external capacity, which may be more cost effective, as long as firm transmission exists from generation resource to the load.

2. Comments should distinguish between utility-owned capacity and purchased power and explain why the assumptions for either should be different.

SPP provides resource credit for utility-owned capacity and purchased power resources. SPP does not treat these resources differently as long they are meeting the standards and criteria for generation resources and have appropriate transmission service.

3. What information, if any, should utilities provide about the environmental effects of each generating facility and purchase agreement?

SPP has no role in assessing the environmental effects of generating facilities.

C. Forecasting Future Transmission Needs

1. Comment of the following list of possible purposes for transmission planning. Are the purposes consistent with one another? Should any purpose take priority over any other? How would prioritizing the purposes affect long-term plan for the transmission system? What other purposes should be considered?
   a. market purpose, such as promoting wholesale competition
   b. reliability
   c. maintaining adequate deliverability for existing generation embedded in base rates
   d. new generator development
   e. interconnection of alternative and small forms of generation
   f. economic growth

A stated goal of the SPP transmission system planning process is to minimize costs and maintain reliability. SPP also provides fair and non-discriminatory access to its transmission system. In
performing regional planning, SPP considers the above purposes as well as others, such as Transmission Loading Relief (TLR) of congestion.

2. Transmission system planning procedures under the status quo
   a. Which of the following are affected adversely by limitations in the current transmission system?
      (1) reliability
      (2) inability of generators to reach customers
      (3) generation market power
      (4) congestion
      (5) losses

SPP considers congestion to be an economic consequence of the current limitations of the transmission system. Congestion at higher levels can lead to reliability concerns, as well as limit the ability of generators to reach customers, which can result in localized generation market power. In addition, congestion may prevent full utilization of lower cost generation. In such instances transmission improvements may provide cost-effective solutions. Determination of the cost of congestion will lead to a cost/benefit assessment of solutions. Construction of new transmission and upgrading of existing transmission capacity can be assessed against the congestion costs. New generation can also be evaluated against transmission options.

   b. What are the possible solutions to any problems identified? Comment on the feasibility of the following possible solutions and identify other possible solutions:
      (1) transmission construction
      (2) transmission upgrades (including installation of new technology options on existing transmission paths or line replacement/enhancement)
      (3) distributed generation
      (4) energy efficiency or demand side management
      (5) new generation or generation upgrades

All proposed solutions should be considered in the resolution of problems. The process, however, must be integrated so that each solution is evaluated in light of the full effect on the reliability of the transmission system and cost-effective delivery of energy to the customers.

   c. Identify the processes by which new generators obtain interconnections to the grid.

SPP has a defined procedure for interconnecting generation to transmission owner systems under the OATT. These procedures provide for the standardized coordination of generation interconnection requests within the SPP region. The interconnection allows the generation to connect to the existing transmission system. In addition, a generator or its customers may request transmission service and have the transmission system expanded as necessary to accommodate the requested service.

   d. Is the current transmission line siting process consistent with the planning purposes identified above? If not, should it be changed?

The SPP planning process provides for the opportunity to evaluate a broad variety of options. In order to facilitate the planning process the siting requirements should allow for transmission expansion by utilities and merchant generation in a reasonable timeframe. The ability to rapidly...
build new facilities and upgrade existing facilities is very important to provide for immediate, low cost expansion.

3. Future Transmission Planning Procedures
   a. Regarding the substance of the transmission component of the resource plan –
      (1) What information is necessary to establish a comprehensive plan for transmission in Arkansas?
      The information necessary to establish a comprehensive plan is, for the most part, already available. This information includes the demand and resource forecasts as well as the existing transmission system plans.
      (2) Can transmission planners and generation planners act independently? Should they?
      The generation planners can act independently in determining resources necessary to serve customers. Without the assistance of transmission planners to ensure that the resources can be delivered to the desired load, those plans may not be effectively implemented. In order to provide a least-cost reliable system plan, the transmission planners and generation planners must work together through the generation interconnection and transmission service processes in designing a cost-effective, reliable system. This cooperation must be over a wide, regional area that would reflect the networked and interconnected nature of the transmission systems.
      (3) What form should projection of future expense and upgrades take? For example, should the transmission planner present yearly cost figures or break costs down according to cost components? How should it anticipate costs of new facilities and technologies?
      Consideration of new transmission should be presented on a yearly-cost basis. Commercial availability of new technologies is, at a minimum, hard to project. Projects should be based on the least cost technology available at the project approval time. If new technologies become available, a re-evaluation should be made to assess the cost effectiveness of their implementation based on the then current status of a project.
      (4) Nontransmission alternatives to transmission related problems
         (a) Comment on how the Commission’s rules should address the following nontransmission alternatives to major transmission projects:
            (i) Generation construction, including distributed generation
            (ii) Demand-side management
            (iii) Pricing mechanisms, such as time of use pricing or interruptible rates
         (b) Who should have responsibility for assessing nontransmission alternatives?
      Transmission planning should consider alternatives to construction, as practicable. Implementation of a market system can permit quantification of the costs of congestion against which alternatives to transmission solutions can be evaluated and properly assessed. SPP is restricted by FERC guidelines from making recommendations as to siting of generation to relieve transmission congestion.
      (5) Comment on whether and how the Commission’s rules should address the impact of new transmission facilities and new transmission technologies on the electricity market in Arkansas. For example:
(a) **How will new facilities or technologies affect the potential exercise of market power by transmission owners? By generators?**

(b) **How will the costs of new facilities and technologies compare to the benefits? Where, geographically, will anticipated benefits be realized? Will benefits flow to all customer groups?**

Transmission system planning will evolve over time as new technologies are introduced. These new technologies may provide for lower cost and/or more rapid expansion of the system, and should not affect market power. A cost/benefit analysis must be performed to assess the use of any new technologies. SPP recently used a new technology to reconductor an existing transmission line while energized, maintaining reliability, reducing redispatch costs, and providing additional transmission capacity at a significantly lower cost than other alternatives.

b. **What should be the respective role of each of the following entities in the development of the transmission component of the resource plan?**

1. **Commission and Commission Staff**

   The Commission should continue to encourage development of the state and regional transmission system. The Commission should be actively involved in the Regional State Committee (RSC) providing oversight to the RTO/ISO.

2. **Arkansas utility**

   Transmission utilities should participate in a regional planning process to promote a cost-effective and reliable transmission system.

3. **All Arkansas transmission owners**

   Transmission owners should participate in a regional planning process to promote a cost-effective and reliable transmission system.

4. **RTO or ISO**

   The RTO/ISO should be responsible for regional transmission planning in coordination with its transmission owners. The planning process should be open and allow for participation by all market participants. It should consider both intra- and inter-regional needs.

5. **Generators**

   The generators should participate in the open transmission planning process provided by the RTO/ISO.

4. **Should the Commission promote merchant transmission facilities? If so, how?**

   Consider the following categories of incentives:
   a. financial incentives
   b. eminent domain
   c. modifications to siting regulations
   d. dispatch

   The Commission should provide an environment that allows for equal participation of merchant transmission. Merchant transmission should not receive more or less favorable treatment than traditional transmission providers.

5. **How should the Commission's planning regulations account for federal regulatory requirements?**

   The Commission should recognize the inter-state nature of the transmission facilities located within the state and their function in the transmission grid. SPP is encouraged by the Commission's leadership in the establishment of a Regional State Committee that would provide that inter-state coordination.
6. **What is the proper relationship between a utility's transmission plan and the Regional State Committee's and the ISO and RTO's planning responsibilities?**
   a. Should utilities be required to adopt plans developed by the ISO or RTO?
   b. Should utilities be required to prepare individual plans based on the assumptions in the ISO/RTO's plan or contingent upon the ISO/RTO's plan?
   c. What should the role of the Regional State Committee be?

The RSC should be part of the approval process for the transmission plan. SPP is currently developing its regional transmission planning process. The current process under review requires the transmission owners and other market participants to submit their plans to the RTO/ISO. All of these plans are reviewed and serve as the basis for a regional plan. The regional plan is presented through an open process to allow for comments and recommendations prior to formal submittal to the RTO/ISO Board of Directors and RSC. SPP welcomes the participation of the RSC in the development and refinement of the regional planning process.

7. **Do Arkansas transmission siting requirements need to be updated to keep up with the changing nature of wholesale markets and ISO/RTO development?**

The Arkansas transmission siting requirements should provide for the expansion of the existing system and development of new facilities necessary for the economically efficient and reliable operation of the interstate transmission system.

III. **Identification of Resource Alternatives**

   Resource planning involves the examination of alternatives for filling energy needs identified in the forecast. This part seeks the parties' views on the identification of resource alternatives. The questions are divided into two parts: supply-side alternatives and demand-side alternatives.

   A. **Supply-Side Alternatives**

   1. **The Supply alternatives examined in a resource plan could include those in the list below. Should the Commission require that the plan analyze and compare specific alternatives? Should the Commission establish any priorities or percentages for particular supply alternatives?**
      a. Purchase all or portion of existing generation facilities
      b. Long-term power purchase agreement
      c. Distributed generation
      d. Customer-owned generation and net metering
      e. Extending the life of any existing utility-owned generating capacity planned for retirement
      f. Construction of new generation facilities, either utility-owned or non-traditional

   2. **Should the Commission adopt a methodology for assigning capacity credits to generation sources?**

   3. **Regarding cost estimates, for what different assumptions and alternatives scenarios should cost estimates be provided?**

Supply-side alternatives must have firm transmission service available to the dependent load to be credited as capacity. The supply-side alternatives should be dispatchable consistent with
existing standards and criteria. Additionally, measures should be taken to ensure the existing capacity is not double counted. (This double counting occurs when the owner of a resource lists the entire resource as capacity and a third party that has purchased unit or system capacity lists it as a resource as well.) There are also contracts considered "financially firm". These financially firm contracts are not necessarily backed with capacity, but by a financial commitment to make a party whole if the energy is not available. These contracts do not necessarily provide reliable supply in times of shortage.

B. Demand Side Alternatives

1. Who should have responsibility, and what type of responsibility, for assessing the potential for designing and implementing desirable DSM programs?

2. DSM Options
   a. What criteria should the decision maker apply to determine what DSM programs are desirable?
   b. Comment on the usefulness of the following tests that regulators should use to evaluate the cost-effectiveness of energy efficiency or load management programs:
      (1) Total resource cost test
      (2) Ratepayer impact test
      (3) Participant test
      (4) Utility cost
      (5) Other
   c. Assuming the Commission requires utilities to increase the efficiencies or cost-effectiveness of their generation practices from current levels, what requirements are most appropriate and why?
   d. What rate design options are available to promote efficiency? What are the pros and cons of each option? Among others, consider the following three options:
      (1) time-of-use rates
      (2) interruptible rates
      (3) inclining block rates

3. Who should have responsibility for assessing, designing and implementing desirable DSM programs?
   a. Should the same entity (a) assess the need and desirability of demand-side measures, (b) design the specific programs, and (c) implement the programs? What are the advantages and disadvantages of assigning responsibility for these three tasks to different entities?
   b. What advantages do utilities have over third parties over program design or implementation?
   c. What disadvantages do utilities have compared to third parties with respect to energy efficiency program design or implementation?

SPP recognizes DSM programs as a reduction in the net forecasted load. These programs are established by individual utilities. Continued use of DSM programs will reduce the resource obligation for the region.
IV. Selection of Resources

The selection of resources requires that the decision maker (whether the Commission, a utility or another entity) first compare the resource options. After the comparison is complete, the utility needs to acquire the resource. This part seeks comment on these issues and is organized accordingly into two parts: Comparison of Resources and Resource Acquisition.

Resources selected by SPP members must meet the SPP criteria and standards of performance in order to be credited by SPP as capacity resources.

A. Comparison of Resource Options

1. What factors should the Commission consider in issuing requirements for comparing resources, and what relative weight should each have?
   a. Should the Commission view net costs and long-term cost-effectiveness as the most important of the public policy objectives inherent in comprehensive resource planning? What time horizon should be utilized?
   b. Should the Commission favor resources that protect consumers from fluctuating costs (i.e., volatility) and over what period of time?
   c. Should the Commission view favorably resources that will result in greater diversity of the ownership of energy resources? If so, how?
   d. Should the Commission view favorably resources that will tend to promote greater wholesale competition? If so, how?
   e. Should the Commission consider the potential effect of a utility's unregulated business activities in its assessment of the regulated resource plan?
   f. How should utility self-build options be compared with purchase power options?

2. How should supply-and demand-side alternatives be compared and evaluated in light of your views on goals of resource planning?
   a. Should supply-side and demand-side options be costed out and then viewed on an equal basis in deciding what combination of resources should go into the utility's resource portfolio?
   b. In evaluating purchase power options, should the externalities and social goals of the underlying generating plants be evaluated in the same manner as would the externalities associated with utility-owned generation?
   c. Regarding the analysis of facilities already in rate base –
      (1) Should such facilities be assumed to be within the plan?
      (2) Should such facilities be given preferential treatment over new resource options? If so, to what extent and how?
      (3) Should the utility be required to consider retiring or selling existing rate base assets, if another resource is demonstrated to be more cost-effective for ratepayers?
      (4) Should the utility be required to structure, or restructure, its portfolio to better match its load shape and load characteristics?

3. Besides environmental externalities, what other externalities, or social goals, should the Commission make as part of the evaluation process? Should fuel
diversity and diversified portfolio planning be part of the evaluation process? How?

B. Resource Acquisition
1. Regarding the Commission’s authority over resource acquisition—
   a. Section 23-18-1069 (a) provides the Commission authority to adopt regulations “under which electric utilities shall seek commission review and approval of the processes, actions, and plans by which the utilities ... [a]cquire electric energy, capacity, and generation asset; or (u)tilize alternative methods to meet their obligations to serve Arkansas retail electric customers.”
   b. Do the following methods of meeting electric demand fall within the language “electric energy, capacity and generation assets,” thereby providing the Commission authority to regulate their acquisitions?
      (1) Construction of generation
      (2) Purchase of all or part of an existing asset or new generation assets
      (3) Upgrades or repowering of existing generating facilities
      (4) Long-term power purchase agreement
      (5) Short-term power purchases
      (6) Energy efficiency and demand side management
      (7) Purchase of energy efficiency services from third parties
   c. If any methods do not fall within the “electric energy, capacity and generation assets” language, does the statutory language providing the Commission authority over “alternative methods to meet [utility] obligations” authorize the Commission to regulate the utility’s acquisition of the methods of meeting electric demand that are identified above?
   d. Are there other types of energy, capacity or generation assets that should be subject to rules on acquisition and which are not listed above?

2. Regarding the respective roles of the Commission and utilities in resource acquisition, should utilities file with the Commission a plan that fully sets forth the various resource options considered, explains the evaluation methodology, and supports the final combination of resources that the utility recommends for Commission approval?

3. Should the Commission issues regulations that specify acquisition procedures, allow each utility to propose its own resource procurement procedures, or adopt some combination of the two?

4. Regarding the treatment of different resources under the acquisition rules:
   a. The commission’s rules on asset acquisition, and its procedural rules for informal prior review versus more formal Commission pre-approval, could distinguish between the acquisition of different types of resources. What factors, if any, would justify treating resources differently under the rules?
   b. If the acquisition rules do not cover all energy resources identified in the resource plan, how can the Commission ensure that the utility’s resource acquisitions are consistent with resource planning objectives?
   c. How should a utility respond to short-lived opportunities to acquire assets such as so-called “fire sales” of generating assets) that are not specifically accounted for by the resource plan?
d. What other emergency, extenuating, or interim circumstances should be allowed as deviations from a utility’s filed and approved resource plan?

5. Regarding competitive procurement, consider the following categories of questions.

a. General considerations
   (1) Once a utility’s resource plan indicates a need for some type of incremental or substitute resource, should the utility be required to competitively procure those resources identified in the resource planning process?
   (2) Should one set of uniform rules govern competitive procurement?
   (3) Alternatively, should each utility have the ability to propose its own processes for competitive procurement subject to review and approval by the Commission?
   (4) Should different procurement processes be utilized for different types of resources? What should those be?
   (5) Should waivers be allowed for “good cause shown?” What should constitute “good cause?”
   (6) Should the traditional principles of “economic dispatch” be taken into consideration in the procurement process? Should traditional “economic dispatch” principles be reconsidered in the context of today’s competitive generation market?

b. Administration of competitive procurement process
   (1) Who should administer the competitive process?
      (a) What should the Commission’s role be in the competitive procurement process?
      (b) Should the utility administer the competitive procurement process, so that once a resource need is identified, the utility can issue an RFP, select a provider, and enter into a contract?
      (c) Should the Commission require a third-party independent contractor to design and administer the RFP, and select the provider(s)?
      (d) Alternately, should the utility issue the RFP and retain a third party entity to review, evaluate and rank the bids in conformance with pre-approved bid criteria and selection parameters?

c. Contents of RFP
   (1) What type of information should the RFP include in order to encourage the broadest possible response?
      (a) Specifically, should the RFP include the following:
         (i) type of generation (such as base-load, intermediate, load following (swing), and/or peaking, and preferred fuel type), demand side or other services sought
         (ii) extent and degree to which resources dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control.
         (iii) Proposed standard contracts for the acquisition of resources
         (iv) Proposed contract term lengths
         (v) General planning assumptions
         (vi) Bid evaluation criteria
(vii) **Reasonable estimates of transmission costs** for resources located in different areas.

d. **What rules should the Commission consider to prevent the pool of bidders from being artificially limited?**

(2) Identify any other information necessary to implement a fair solicitation process.

(3) Parties may attach to their comments copies of RFPs which they view as well-developed.

d. **Bid evaluation criteria**

(1) **What criteria should be used to evaluate and select a bidder?**

   (a) preferred fuel types
   
   (b) for supply-side resources, transmission issues such as –
   
   (i) transmission constraints on the utility's system and on adjoining utility systems
   
   (ii) permitting constraints
   
   (iii) local conditions and dispatchability
   
   (iv) estimates of transmission costs
   
   (c) reliability requirements and objectives, and the method(s) for evaluating compliance with the requirements;
   
   (d) desirability of firm pricing and contract terms of various durations;
   
   (e) level and schedule of required capacity and energy payments;
   
   (f) status of project development; or operational readiness and ability to deliver the products;
   
   (g) demonstrated financial viability of the project and the owner;
   
   (h) owner's prior experience in the field;
   
   (i) independence from, or affiliation with, other industry stakeholders

(2) **Should utilities have the discretion to give more weight to certain factors, so long as potential bidders are given advance notice of the way in which factors will be weighted?**

c. **Affiliate procedures**

(1) Regarding utility affiliate participation in a competitive solicitation, what are the benefits and risks of allowing utility affiliates to participate?

(2) If affiliates are permitted to participate in competitive solicitations, should special procedures be required for utility affiliates that submit bids?

(3) **Would special procedures be necessary if the utility's selection process is not run by an independent third party auditor or subject to ongoing Commission review?** Consider the following:

   (a) regulations specifying a higher degree of Commission scrutiny where an affiliate competes in the solicitation
   
   (b) regulations intended to ensure that the affiliates gain no advantage in the solicitation as a result of their affiliation with the utility.

d. **Rate treatment**

(1) **Should a utility be entitled to recover the costs of energy or capacity procured through a competitive process without additional prudence review?** If so, should the Commission first...
approve the competitive process? What criteria should the competitive process satisfy?

(2) Does your response to the previous question change if the Commission or staff area involved in the RFP?

SPP has no additional comments related to this section at this time.

V. The Interactions Between Resource Planning Requirements and Other Regulatory Responsibilities.
   A. Comment on the intersection between resource planning and existing rate design.
   B. In a prudence review, how should the Commission determine that market opportunities were fully utilized?
   C. What modifications, if any to the Entergy Cost Recovery Rider would lead to more efficient use of purchased power?
   D. How should individual commission-approved utility resource plans be used by the state commission, RTO, and FERC market monitors?

The approved utility resource plans should be used by the RTO in its planning processes.

VI. Administrative Procedures and Filing Requirements:
   The commission seeks comment on the rules governing the planning process.

   A. What should be the timing of and frequency with which filings are made under the resource planning regulations?
      1. How soon after the issuance of final rules should filings be required?
         a. data/informational filings
         b. draft resource plan
         c. final plan
      2. What is the proper planning horizon for the initial plan?
         SPP normally uses a 10-year planning horizon for its transmission planning activities and recommends a planning horizon no longer than that.
      3. How frequently should resource plans be updated and filed?
      4. What requirements should the Commission adopt for plan updates, amendments, or interim plans?
         a. How frequently should a utility file updates to its plan?
         b. What is the proper time horizon for plan updates?
         c. What events should trigger an obligation to file an information update to the plan?
         d. What conditions justify the filing of an interim plan?
         e. Should the decision to file an interim plan be discretionary with the utility?
         f. What should trigger a Commission requirement to file a new plan update?
      5. Should a resource plan include implementation benchmarks?
         a. What should the benchmarks be?
         b. What consequences should attach to a failure to meet them?
   B. What information should utilities provide the Commission?
      1. What evidence should be filed in support of a proposed plan or course of action?
         a. If the Commission requires specific data or information, what level of detail should be required? For example, should the Commission require –
(1) A breakdown of electrical energy consumption by customer class and use consumption data and patterns over an historical period, including seasonal data with peak and off-peak consumption.

(2) A discussion of existing or potential customer self-generation.

(3) Details about programs undertaken to reduce consumption by Arkansas consumers with dollar amounts spent.

(4) Assessments of the effectiveness of load management or energy efficiency programs, including tariff or rate schedule options.

(5) A description of any environmental effects of existing generation facilities and past efforts to ameliorate them, along with potential future costs of continuing to operate those facilities in compliance with applicable laws.

(6) An assessment of the transmission and distribution network and system reliability.

(7) An assessment of the various transmission technology enhancements that could be made and the utility's comments on and plans to do so, and how this should or would affect the utility's resource options.

(8) A description of unregulated activities and their impact on regulated operations.

(9) A report on utility wholesale activity, both as a seller and buyer of power, as it might affect the utility's operations and rates in this region.

b. What information should utilities be required to file with respect to the projection of future energy demand? What time period should be used for the future load forecast, taking into consideration lead-times required for making optimal portfolio choices and investments? For example, should the Commission require-

(1) Economic projections.

(2) Historical demand data, including details of utility load and annual kwh sales aggregated by customer class.

(3) Other data used in preparing the utility's demand projection.

(4) All data used to generate both base and alternative forecasts.

c. What information should a utility be required to file with respect to its projection of the costs of meeting future demand? For example, should the Commission require-

(1) Data underlying the utility's assessment of the cost of new generation, purchased power, or DSM programs.

(2) Comparisons between various options of meeting future demand.

(3) A description of the utility's fuel inventory and procurement practices.

(4) Historical data on the utility's generation and fuel costs.

(5) Assessment of the cost of continuing to utilize existing plants in rate base, including any reasonably projected costs of upgrades, refurbishments, or improvements needed for operational efficiency or regulatory compliance purposes.

d. Should the utility file projection cost models for comparing alternative plans? For example, should the Commission require the plan to analyz2

(1) What models should the Commission consider?

(2) What alternative assumptions should the Commission require the plan to analyze?
(3) What data should be required to support model performance?

e. What information should a utility be required to file with respect to its avoided cost calculations?
(1) avoided generation and purchased power costs
(2) avoided transmission costs
(3) avoided distribution costs
(4) avoided operating costs, including fuel, plant operation and maintenance, spinning reserves, emissions allowances, and transmission and distribution operation and maintenance costs.

2. What information should be submitted that doesn’t directly support a proposed plan?

a. What information should utilities be required to file with respect to alternatives that are not pursued?

b. Which alternatives should be part of a resource plan filing even if not part of a utility’s proposed resource mix?

c. Should the Commission require utilities to include third-party data?

3. Should the Commission require an independent audit of the data in a resource plan?

SPP has no additional comments related to this section at this time.

VII. “Alternative Methods” for Meeting Utility Obligations:

A. What services might consumers want from their utility provider, which their utility is uniquely positioned to provide, but does not now provide? Consider the following –

1. Rate options
2. Billing options
3. Metering Options
4. Other services

SPP has no comments related to this section at this time.

Conclusion

SPP wishes to thank the Commission for this opportunity to comment.

Respectfully submitted,

[Signature]

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CERTIFICATE OF SERVICE

I, Stacy L. Duckett, do hereby certify that on July 15th, 2003, a true and correct copy of the foregoing Initial Responses and Comments was mailed by U.S. Mail, with sufficient postage prepaid to:

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