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UniSource Energy Corporation

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October 10, 2008

AZ CORP COMMISSION
DOCKET CONTROL

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Arizona Corporation Commission
DOCKETED

RE: Tucson Electric Power Company and UNS Electric, Inc.
Comments on Resource Planning Draft Rules
Docket No. E-00000E-05-0431

Dear Docket Control:

Introduction

At the October 3, 2008 Resource Planning workshop, Commission Staff requested that interested parties provide written comments on the modifications to the Resource Planning Rules, Arizona Administrative Code (A.A.C.) R14-2-701, 702, 703 and 704. Commission Staff and the workshop participants agreed to provide comments on R14-2-705 on or before October 17, 2008.

Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNS Electric") (collectively, the "Companies") have attached a redlined version of the Companies joint comments in reference to the resource planning rules and definitions. In general, the Companies are in agreement with many of the proposed revisions; however, the Companies wish to restate some recommended revisions proposed in previous comments, but not incorporated into this draft. Additionally, the Companies have proposed other revisions, redlined on the attached draft; proposed substantive comments to the resource planning process are provided below.

Section R14-2-704. Commission Review of Utility Plans

In regard to the Commission's review of resource plans, Commission Staff indicated at the October 3, 2008 workshop that it proposed to incorporate a description of "acknowledgement" in R14-2-704.A.

The Companies continue to support an "acknowledgement" concept similar to the Oregon PUC Order No. 89-507. Order No. 89-507 sets forth the Commission's role in reviewing and acknowledging a utility's resource plan as follows:

> When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission.
>
> Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment. Similarly,

> inconsistency with the plan will not necessarily lead to unfavorable rate-making treatment, although the utility will need to explain and justify why it took an action inconsistent with the plan.
>
> We consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged integrated resource plans. Utilities will also be expected to explain actions they take that may be inconsistent with Commission-acknowledged plans.

The integrated resource planning process is a significant effort by the utilities and substantial financial commitments will be required to acquire resources identified in the plan. TEP and UNS Electric believe that their employee and financial investments warrant recognition, or acknowledgment, by the Commission. Due to the significance of "acknowledgement", the Companies believe it is necessary to incorporate it into the rules as a defined term.

TEP and UNS Electric appreciate the opportunity to provide comments and suggestions on these important rules. The Companies look forward to a continuing dialogue and workshops on the subject. Please feel free to contact me with any questions or comments.

Sincerely,

Michelle Livengood

Michelle Livengood
Regulatory Counsel

Enclosure: Draft Resource Planning Rules

CC: Ernest Johnson
Terri Ford
Barbara Keene

Emailed: Parties of Record

WORKING DOCUMENT
October 3, 2008

ARTICLE 7. RESOURCE PLANNING

R14-2-701. Definitions

The following definitions shall apply unless the context otherwise requires:

1. "Acknowledgement" – the Commission's finding of the reasonableness of a utility's plan that is based upon a determination that the plan considered all relevant resources, risks and uncertainties known or knowable, and produces a plan for needed resources that is in the best interests of customers at the time of the Commission's determination.

1. "Benchmark" - to calibrate against a known set of values or standards.
2. "Book life" - the expected time period over which a power supply source will be available for use by the utility.
3. "Capacity" - the amount of electric power in megawatts ("MW") which a power source is rated.
4. "Capital costs" - the construction and installation cost of facilities including land, land rights, structures, and equipment.
5. "Cogeneration" - the production of electrical energy and another form of useful energy , such as heat or steam, from the sequential use of energy.
6. "Coincident peak" - the sum of two or more peak demands which occur in the same demand interval. Demand intervals are defined on an annual, monthly, or hourly basis.
7. "Customer class" - a group of customers with similar characteristics such as amount of energy consumed; amount of demand placed on the energy supply system at the system peak; hourly, daily, or seasonal load pattern; type of activity engaged in by the customer; and location. Customer classes may include residential, commercial, industrial, agricultural, municipal, and other categories.
8. "Decommissioning" - the process of safely and economically removing a unit from service.
9. "Demand management" - beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time the demand for electricity.
10. "Derating" - reduction in a unit's capacity.
11. "Discount rate" - the interest rate used to calculate the present value of a cost or other economic variable.
12. "Emergency" - an unknown and unforeseeable condition (i) not arising from acts or omissions by the utility which are not in accord with good utility practice, (ii) that is temporary in nature, (iii) that threatens reliability or poses some other significant risk to the system, and (iv) where the subject procurement is not greater in quantity or duration than what is necessary for the utility to restore the system to a safe and reliable condition.
13. "End use" - the final application of electric energy such as heating, cooling, running a particular appliance, or lighting.
14. "Energy losses" - electric energy not available for sale to end users, for resale, or for use by the utility, attributable to transmission, conversion, distribution, and unaccounted for losses.

15. "Escalation" - the change in costs due to inflation, changes in manufacturing processes, availability of labor or materials, or other factors.
16. "Heat rate" - a measure of generating station thermal efficiency expressed in British thermal units (Btus) per net kilowatt-hour and computed by dividing the total Btu content of fuel used for electric generation by the kilowatt-hours of electricity generated.
17. "Interruptible power" - power made available under agreements which permit curtailment or cessation of delivery by the supplier.
18. "In-service date" - the date a power supply source becomes available for use by the utility.
19. "Maintenance" - the repair of generation, transmission, distribution, and administrative and general facilities, replacement of minor items, and installation of materials to preserve the efficiency and working condition of the facilities.
20. "Mothballing" - the temporary removal of a unit from active service and accompanying long-term storage activities.
21. "Operate" - to manage or otherwise be responsible for the production of electricity from a generating facility, whether that facility is owned by the operator, in whole or in part, or whether that facility is owned by another entity.
22. "Operating costs" - the power production costs that are directly related to producing electricity.
23. "Participation rate" - the proportion of customers who take part in a specific program.
24. "Probabilistic analysis" - a systematic evaluation of the effect on costs, reliability, or other measures of performance of the range of possible events affecting factors which influence performance, considering the chances that the events will occur.
25. "Production cost" - the variable operating and maintenance cost (including fuel cost) of producing electricity through generation and purchases of power sufficient to meet demand.
26. "Refurbish" - to make major changes in the power production, transmission, or distribution characteristics of a component of the power supply system more extensive than maintenance or repair, such as changing the fuels which can be used in a generating unit or changing the capacity of a generating unit.
27. "Reliability" - a measure of the ability of the utility's generation, transmission, and distribution systems to provide power without failures. Reliability should be measured separately for generation, transmission, and distribution systems. Measures may reflect the proportion of time that each system is unable to meet demand or the kilowatt-hours of demand that could not be supplied.
28. "Reserve requirements" - the capacity which the utility must maintain in excess of its peak load to provide for scheduled maintenance, forced outages, unforeseen loads, emergencies, system operating requirements, and reserve sharing arrangements.
29. "Resource planning" - integrated supply and demand analysis for the purpose of identifying the means of meeting electric energy service needs at the lowest total cost, taking into account uncertainty.
30. "Self generation" - the production of electricity by an end user by any means including cogeneration.
31. "Sensitivity analysis" - a systematic assessment of the degree of response of costs, reliability, or other measures of performance to changes in assumptions about factors which influence performance.

32. “Spinning reserve” - the capacity which the utility must maintain connected to the system and ready to deliver power promptly. The capacity may be expressed as a percentage of peak load, as a percentage of the largest unit, or as fixed megawatts.
33 "Staff" - Employees of the Arizona Corporation Commission, Utilities Division.
34. “Total cost” - all capital, operating, maintenance, fuel, and decommissioning costs incurred in the provision or conservation of electric energy services borne by end users, utilities, or others, and costs associated with mitigating any adverse environmental effects.
35. “Unit” - a specific device or set of devices that converts one form of energy (such as heat or solar energy) into electric energy such as a turbine and generator or set of photovoltaic cells; a power plant may have multiple units.
36. “Utility” - the public service corporation providing electric service to the public, unless otherwise provided herein.

R14-2-702. Applicability

A. All electric utilities under the jurisdiction of the Commission pursuant to Arizona Constitution Art. XV and Arizona Revised Statutes Title 40 which operate or own (in part or in whole) generating facilities of at least 5 MW combined, whether the power generated is for sale to end users or is for resale, are subject to the provisions of this Article. It is not the intent of these rules to apply to electric utilities which do not own generation facilities.
B. Any other electric utility under the jurisdiction of the Commission pursuant to Arizona Constitution Art. XV and Arizona Revised Statutes Title 40 is subject to the provisions of this Article upon two years’ notice by the Commission.
C. The Commission may exempt a utility from these requirements upon a demonstration by the utility that the burden of compliance with this Article exceeds the potential for cost savings resulting from its participation.

R14-2-703. Utility reporting requirements

A. Historical demand-side data. Each utility shall file in Docket Control the demand data indicated in subsections (A)(1) through (4) below, by April 1 of each year. If records are not maintained for any item, the utility shall provide its best estimates, such as sample survey data, application of factors from one year’s data to another year, or other methods, and fully describe how such estimates were made.
   1. Hourly demand for the previous calendar year disaggregated by:
      a. Sales to end users,
      b. Sales for resale,
      c. Energy losses, and
      d. Other disposition of energy such as energy furnished without charge and energy used by the utility.
   2. Coincident peak demand (megawatts) and energy consumption (megawatt-hours) by month for the previous ten years disaggregated by customer class.
   3. Number of customers by customer class by year for the previous ten years.
   4. Reduction in load (kilowatt and kilowatt-hours) due to existing demand management measures, by type of demand management measure, in the previous calendar year.
B. Historical supply-side data. Each utility shall file in Docket Control the supply data indicated in subsection (B)(1) through (4) by April 1 of each year. If records are not

maintained for any item, the utility shall provide its best estimates and fully describe how those estimates were made.

1. For each generating unit and purchased power contract for the previous calendar year:
   a. In-service date and book life or contract period,
   b. Type of generating unit or contract,
   c. Capacity in megawatts (utility share),
   d. Maximum unit or contract capacity by hour, day, or month, if such capacity varies over the year.
   e. Annual capacity factor (generating units only),
   f. Average heat rate of generating units and, if available, heat rates at selected output levels,
   g. Average Fuel cost for generating units in dollars per million Btu for each type of fuel,
   h. Other variable operating and maintenance costs for generating units in dollars per megawatt hour,
   i. Purchased power energy costs for long-term contracts of three years or more expressed in dollars per megawatt-hour,
   j. Fixed operating and maintenance costs of generating units in dollars per megawatt for the year,
   k. Demand charges for purchased power,
   l. Fuel types for generating units,
   m. Minimum capacity at which the unit would be run or power must be purchased,
   n. Whether, under standard operating procedures, the generating unit must be run if it is available to run,
   o. Description of the expected duty cycle of a generating unit, such as base load, intermediate, or peaking.
   p. Environmental impacts, including air emission quantities (metric tons or pounds) and rates (quantities per megawatt-hour) for carbon dioxide, sulfur dioxide, nitrogen oxides, mercury ~~,~~and particulates~~, and other air emissions subject to current or expected future environmental regulation~~; and water consumption quantities and rates.
2. For the power supply system for the previous calendar year:
   a. A description of unit commitment procedures,
   b. Production cost,
   c. Reserve requirements,
   d. Spinning reserve,
   e. Reliability of generating, transmission, and distribution systems,
   f. Purchase and sale prices, averaged by month, for the aggregate of all short-term purchases and all short-term sales related to contracts of less than three years, and
   g. Energy losses.
3. The level of cogeneration and other forms of self generation in the utility's service area for the previous calendar year.
4. As available, a description and map of the utility's transmission system, including the utility's scheduling capacity of each applicable segment of the transmission system. The map shall include both utility-owned transmission and the utility's long-term contractual transmission rights used to meet the resource needs of customers.
5. Explanation of exceptions from using an RFP for procurement of resources, pursuant to

R14-2-705.B., during the previous calendar year.

C. Demand forecasts. Each utility shall provide the following data and analyses to the Commission by April 1, 2010, and every two years thereafter. If no changes are forecast for any item, the utility may refer to previous filings for that item.
   1. A forecast of system coincident peak load (megawatts) and energy consumption (megawatt hours) for at least ten years, by month and year, separately for residential, commercial, industrial, interruptible, and other customers, for resale, and for energy losses.
   3. Disaggregation of the demand forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component indicating the change in load due to forecasted demand management measures.
   4. Descriptions of demand management programs and measures included in the demand forecast, including:
      a. Plans for implementing the demand management measures,
      b. The participation rate of customers by customer class with regard to each demand management measure,
      c. The expected change in demand resulting from each of the measures,
      d. Reductions in air emissions and water consumption attributable to the demand management program, and
      e. The life of each program.
   5. Description of each demand management program which was considered but rejected and the reasons for rejecting each program.
   6. The capital and operating and maintenance costs of each demand management measure considered, including practical measures which were rejected.
   7. Documentation of all data, analyses, methods, and assumptions used in making the demand forecasts, including:
      a. A description of how the forecasts were benchmarked,
      b. Justifications for selecting the methods and assumptions used, and
      c. If requested by the staff, data used in the analyses.

D. Supply plans. Each utility shall provide the following data and analyses to the Commission by April 1, 2010, and every two years thereafter. If no changes are forecast for any item, the utility may refer to previous filings for that item.
   1. A plan for at least ten years providing for each year:
      a. The data required in subsection (B)(1)(a) through (p) of this Section for each generating unit and purchased power source, and the data required in subsection (B)(2)(a) through (g) of this Section.
      b. For each generating unit that is new or refurbished during the period:
         i. The data required in subsection (B)(1) of this Section for applicable years, and
         ii. The capital cost, construction time, and construction spending schedule.
      c. The escalation levels assumed for each component of cost for each generating unit and purchased power source.
      d. For the discontinuation, decommissioning, or mothballing of any power source and permanent deratings of any generating facility:
         i. Identification of the power sources or units involved,
         ii. The costs and spending schedule of such discontinuation, decommissioning, mothballing, or derating, and

iii. The reasons for discontinuation, decommissioning, mothballing, or derating.

e. The capital and operating and maintenance costs of new or refurbished transmission and distribution facilities, and a description of the need for and purpose of such facilities. The utility shall incorporate its most recent transmission plan filed pursuant to A.R.S. 40-360.02.A and any relevant provisions of the Commission's most recent decision on Biennial Transmission Assessment regarding the adequacy of transmission facilities in the state of Arizona.

f. Cost analyses and cost projections.

2. Documentation of the data, assumptions, and methods or models used to forecast production costs and power production in subsection (D)(1) of this Section, including the method by which the forecast was calibrated or benchmarked.
3. Description of each potential power source which was rejected, the capital and operating and maintenance costs of each rejected source, and the reasons for rejecting each source.
4. A forecast for at least ten years of cogeneration and other self generation by customers of the utility in terms of annual peak production (megawatts) and annual energy production (megawatt hours).
5. Disaggregation of the forecast of subsection (D)(4) of this Section into a component in which no additional efforts are made to encourage such generation, and a component consisting of the change in supply due to additional forecasted cogeneration and self generation measures.
6. A forecast for at least ten years of capital and operating and maintenance costs by year of all cogeneration and other self generation included in subsection (D)(5) of this Section.
7. Documentation of the analysis of cogeneration and other self generation in subsection (D)(4) through (6) of this Section.
8. A plan to consider generation using a diverse range of fuels and technologies, including nuclear and renewable resources.
9. Calculation of the benefits of renewable resources.
10. Calculation of costs to back-up renewable resources.
11. A plan to increase the efficiency of the utility's fossil fuel generation.
12. Data to support technology choices for supply-side resources.

E. Analyses of uncertainty. Each utility shall provide to the Commission the following information by April 1, 2010, and every two years thereafter:

1. Analyses using appropriate methods such as sensitivity analyses and probabilistic analyses, to assess errors and uncertainty in:
   a. Demand forecasts,
   b. The costs of demand management measures and power supply,
   c. The availability of sources of power,
   d. The costs of complying with existing and expected environmental regulations.
   e. Any analysis that the utility has done in consideration of the likelihood of additional or enhanced environmental requirements,
   f. Changes in fuel prices and fuel availability, and
   g. Other factors which the utility wishes to consider.
2. Identification of those options which enable the utility to best respond to significant changes in conditions where future characteristics are uncertain, including:
   a. Continual monitoring of critical variables and making commensurate changes in plans if those variables deviate significantly from the forecast,

b. Building several smaller units instead of one large unit,
c. Participating in regional generation and transmission projects, and
d. Conducting well monitored pilot programs.

F. Integrated resource plan. Each utility shall provide the Commission with an integrated resource plan by April 1, 2010, and every two years thereafter containing:
 1. The plan or flexible set of plans for at least ten years which, on the basis of the analyses required in this Article, including the uncertainty analysis, ~~will tend to minimize the present value of the total cost of meeting the demand for electric energy services~~ provides the framework for ensuring reliable, low-cost resource options while effectively managing risk and future uncertainty.
 2. Complete description and documentation of the resource plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized.
 3. An action plan indicating the supply and demand-related actions to be undertaken by the utility over the next two years in furtherance of the integrated resource plan.
 4. A comprehensive, self-explanatory load and resources table summarizing the utility's plan.
 5. A brief executive summary.
 6. An index to indicate where the filing requirements can be found.
 7. Definitions of terms.

G. Work plan. Each utility shall file in Docket Control a work plan no later than twelve months prior to the due date of an integrated resource plan. The work plan shall include:
 1. An outline of the content of the integrated resource plan to be developed by the utility,
 2. The utility's method and assumptions for assessing potential resources, and
 3. An outline of the timing and extent of public participation and advisory group meetings to be held prior to the completion and filing of the integrated resource plan.

H. Action Plan. Each Utility shall provide the Commission with an action plan based on the results of the integrated resource planning process. The action plan will:
 1. Include a summary of actions to be taken on future resource acquisitions.
 2. Include details on resource types, resource capacity, and resource timing.
 3. Cover a timeframe of a minimum of two years following the Commission's acknowledgement of the resource plan and action plan.

R14-2-704. Commission review of utility plans

A. Within 120 days of the submission of demand forecasts, supply plans, uncertainty analyses, and integrated resource plans by the utilities, the Commission shall schedule a hearing or hearings to review utility filings and to ~~determine whether to order an~~ acknowledge~~ment of~~ the integrated resource plan. ~~Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given.~~ No particular ratemaking treatment shall be implied nor inferred by the Commission's acknowledgement, however, the Commission will give considerable weight to the Utility's actions that are consistent with its acknowledged integrated resource plan in a rate case or other proceeding before the Commission.

B. The Commission may request additional analyses to be conducted by the utilities to improve specified components of the utilities' analyses.

C. In making its acknowledgment determination, the Commission shall consider the following factors:

1. The total cost of electric energy services.
2. The degree to which the factors which affect demand, including demand management, have been taken into account.
3. The degree to which non-utility supply alternatives, such as cogeneration and self generation, have been taken into account.
4. Uncertainty in demand and supply analyses, forecasts, and plans, and the flexibility of plans enabling response to unforeseen changes in supply and demand factors.
5. The reliability of power supplies including fuel diversity and non –cost considerations.
6. The reliability of the transmission grid.

D. The Commission will consider the information reported in the integrated resource plan when it evaluates the performance of the utility in rate and other proceedings.

E. A utility may seek Commission approval of specific resource planning actions.

F. The utility may file amendments to its acknowledged integrated resource plan and action plan if material changes in conditions or assumptions require a material change before the next scheduled integrated resource plan filing.

R14-2-705. Procurement

A. The following procurement methods are considered to be acceptable for the wholesale acquisition of energy, capacity, and physical power hedge transactions:
   1. Purchases through third party, on-line trading systems, including but not limited to the Intercontinental Exchange, Bloomberg, California Independent System Operator, New York Mercantile Exchange, or similar on-line third party systems.
   2. Purchases from qualified, third party, independent energy brokers.
   3. Purchases from non-affiliated entities through auctions or a request for proposals (RFP) process.
   4. Bilateral contracts with non-affiliated entities.
   5. Bilateral contracts with affiliated entities, provided that non-affiliated entities are provided notice of and an opportunity to beat any proposed contract before executing the transaction.
   6. Any other competitive procurement process approved by the Commission.

B. Utilities shall use an RFP as the primary acquisition process. Exceptions may include the following:
   1. For emergencies.
   2. For short-term acquisitions to maintain system reliability.
   3. For other components of energy procurement, such as transmission projects, fuels, and fuel transportation.
   4. When the planning horizon is two years or less.
   5. When a utility encounters a genuine, unanticipated opportunity to acquire a power supply resource at a clear and significant discount, when compared with the cost of acquiring new generating facilities, that will provide unique value to customers.
   6. For transactions that satisfy obligations under the Renewable Energy Standard rules and for demand-side management/demand response programs.

C. An independent monitor shall be used in all RFP processes for procurement of new resources.

D. The utility shall consult with staff and jointly select three to five companies or consultants (vendor list) who can serve as an independent monitor.
E. The utility shall file its vendor list in Docket Control for interested parties' review. Parties will have 30 days to object to a vendor's inclusion on the list.
F. Within 60 days of the filing of the vendor list, staff shall identify the vendors it determines are appropriate. Once the vendors are identified by staff, the utility would be able to retain any of the authorized vendors for future RFPs. The utility shall provide written notice to staff of its retention of the independent monitor.
G. The utility shall enter into a contract with the monitor and shall pay the monitor. Reasonable bidders' fees may be used to help offset these costs. When appropriate, the utility may request recovery of its payments to the monitor in customer rates.
H. One week prior to the deadline for submitting bids, the utility shall provide the independent monitor with a copy of any bid proposal prepared by the utility or its affiliate, or any benchmark or reference cost the utility has developed against which to evaluate the bids. The independent monitor shall take steps to secure the utility bid or benchmark price in a location not known or accessible to any of the bidders or the utility or its affiliate.
I. The independent monitor shall provide reports, at least monthly, to staff throughout the RFP process.