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August 4, 2005

HAND DELIVERED

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Re: *AEPCO's Comments on the Resource Planning Workshops; Docket No. E-00000E-05-0431*

Dear Sir/Madam:

Attached are the original and 13 copies of AEPCO's Comments on the Resource Planning Workshops in Docket No. E-00000E-05-0431. Because of filing timing constraints, these Comments have not been reviewed by AEPCO's Board of Directors, nor the Boards of its member distribution cooperatives. AEPCO reserves the right to amend and supplement its positions as this matter proceeds.

Very truly yours,

GALLAGHER & KENNEDY, P.A.

Michael M. Grant

By:
Michael M. Grant

MMG/plp
10421-1/1289041
Attachment

Original and 13 copies delivered to
Docket Control this 4th day of August, 2005.

cc (w/attachment): Cliff Cathers, AEPCO

AEPCO's Comments on the Resource Planning Workshops

Docket No. E-00000E-05-0431

The Arizona Electric Power Cooperative, Inc. ("AEPCO") submits these comments and recommendations on the Integrated Resource Planning ("IRP") workshop process. For the reasons discussed, AEPCO suggests that the Commission take no action at this time to reinstate the IRP process (leaving in place, however, the utilities' obligation to file certain historic data). Alternatively, if the Commission does want to proceed further, AEPCO suggests that the IRP Rules (A.A.C. R14-2-701, *et seq.*) be modified to result in a simpler, more individualized process which utilizes existing utility planning efforts which are already in place.

Background

The IRP Rules were first adopted by the Commission in early 1989. They required APS, TEP, Citizens (at that time) and AEPCO to submit demand and supply-side data annually. Every three years, the utilities also provided demand forecasts, supply plans and uncertainty analyses together with an integrated resource plan for a ten-year period setting forth a least-cost plan for meeting demand as well as an action plan summarizing supply and demand-related actions over a three-year period. The Salt River Project also participated in the IRP process on a voluntary basis. The Commission then conducted extensive hearings on the filed plans and entered its Order.

Two rounds of IRP were completed in the 1990s. The first commenced with plan filings in early 1990, hearings in November and December of that year and concluded with the issuance of Decision No. 57589 on October 29, 1991—almost two years after the process began. The second started with plan filings in December 1992 to March of 1993, involved workshops and hearings in October and December of 1993 and concluded with the issuance of Commission Decision No. 58643 on June 1, 1994—about 18 months after the process began.

After the initial adoption of the Retail Electric Competition Rules in 1996, the Commission stayed most of the IRP Rules. Decision No. 60385 dated August 29, 1997 (and a subsequent procedural order) continued to require the annual filing of certain historic data, but suspended the integrated resource plan filing requirements of the Rules until further order of the Commission.

Comments and Recommendations

AEPCO suggests that an initial workshop be scheduled to critically examine whether there remains a need for an IRP process as envisioned by the current rules. Much has changed in the more than 15 years since the Rules were originally adopted. At that time, utilities were essentially "sole source providers" for meeting the energy needs of the state. Today, merchant power plants, renewable resource providers, distributed generation options, on-site customer installations and several other developments have significantly impacted the planning process as well as utilities' role in, and control of, it.

Also, the Commission has adopted or is in the process of formulating several initiatives which did not exist when the IRP Rules were promulgated in 1989 and which deal with subjects the IRP process was designed to evaluate. For example, the Environmental Portfolio Standard Rule is currently being substantially revised. In addition to setting a percentage of energy needs which must be met by renewables over a long-term horizon, it also, as currently drafted, requires that a certain portion of the requirement be met through public bidding for Renewable Purchase Power Agreements. Both of these subjects were heavily addressed in the original IRP process, but are now covered by other regulatory requirements. Similarly, in case-specific orders, the Commission has required some utilities to conduct bid solicitation processes to meet a portion of their energy supply requirements. The Commission also has dockets underway to evaluate standards and requirements for Demand Side Management and Distributed Generation—again these subjects were key considerations in the IRP process.

AEPCO believes that these and other changes in the industry and regulation argue strongly against any return to the IRP process. At a minimum, we believe that these processes should at least be allowed to operate for a time before assessing whether a need for yet another process like IRP is required in addition to them.

Alternatively, AEPCO also believes this workshop process should focus on creating a simpler, more individualized procedure that utilizes utility planning processes already in place. The existing IRP process that required each utility to prepare a resource plan which then was collectively reviewed with other plans was exceptionally expensive and complicated to administer. In AEPCO's case, outside consultants had to be hired to comply with the Rules and preparation of the IRP plan required additional, extensive internal resources. The testimony and hearing process involving all utilities was protracted and often confusing given, among other things, the significantly different characteristics of the utilities involved (IOU, cooperative and municipal, in the case of the SRP), the different load, climate and demographic nature of the territories they serve and varying supply resource portfolios. As noted earlier, the first round of IRP took almost two years to complete and the second round lasted about 18 months. Basically, a round of IRP was completed about the time the preparation process for the next round of IRP had to be started.

In AEPCO's case, it has an extensive, on-going planning effort in place—much of which is mandated by federal regulations—that could be utilized in the Commission's IRP process without the need to add additional and duplicative IRP plan preparation requirements. AEPCO has All-Requirements Members who contract for all of their demand and energy from the Cooperative's resources and a Partial-Requirements Member who has a proportionate share of AEPCO's existing resources and is responsible for its own power supply to meet growth above its AEPCO resource allocations. AEPCO serves the six Class A Member-owners at wholesale and AEPCO has no retail end-use customers. Each Class A Member serves mostly rural customers although some urbanization is occurring around larger communities. Many of the end-use retail customers served by each Class A Member are modest to low-income households with low customer density. In direct comparison with the state's municipal and investor-owned utilities, a higher cost of service per mile is still the rule in rural Arizona.

AEPCO's primary loan guarantor is the Rural Utilities Service ("RUS"), via the lender, the Federal Financing Bank ("FFB"). RUS and FFB function under the auspices and governmental budgetary structures of the United States Department of Agriculture, and the Department of the Treasury, respectively. FFB through RUS makes loans available to Cooperatives under the Rural Electrification Act of 1936. The Cooperative Finance Corporation ("CFC"), organized as a cooperative financial institution, also provides supplemental financing at market rates for AEPCO.

In terms of planning, AEPCO's Corporate Planning department deals with emerging wholesale power markets. The department is a synergistic mix of load forecasting, resource planning and financial planning services and personnel with diverse backgrounds and significant utility experience. Each three-year load forecast work plan and annual Class A Member load forecast is developed by Corporate Planning, coordinated with each Class A Member and is reviewed and approved by their respective Boards of Directors. It is then used in financial planning, operations and subsequent loan applications. AEPCO's load forecasts are also reviewed and approved by the respective Boards of Directors and subsequently by RUS.

AEPCO has also formed an internal Power Supply Task Force to deal with the increasingly complex facets of planning, procuring and securing future power supply. Pursuant to task force recommendations, AEPCO's Board of Directors has adopted reserve criteria that require a 12% minimum and take into account spinning reserves provided by the Southwest Reserve Sharing Group. Status reports on current resource plans developed by the Power Supply Task Force and approved by the Class A Member Boards of Directors are given at Annual Consumer/Member Meetings to inform the general membership of those plans and allow for public feedback.

Further, RUS approval is required for loans requesting financing for all capital resource additions and modifications. The Code of Federal Regulations requires that each borrower must provide and RUS must approve an annual load forecast, a construction work plan, a long-range financial forecast, which includes the new resource(s), DSM or renewable energy facilities for which loan funds are being requested, a power cost study and, where applicable, a Borrower's Environmental Report. Comprehensive project-specific engineering and cost studies to support financing requests and construction of additional generating capacity, including existing capacity replacement, must be produced. These studies include detailed economic present value analyses of the costs and revenues of available self-generation, load management, energy conservation, competitively priced purchased power, financial viability of the purchased power supplier(s), assessments of service reliability and financing requirements and risks. These studies must also consider alternative unit types and sizes, fuel alternatives, system stability, impacts on the interconnected transmission system and system dispatch.

Loan applicants are also required, by RUS regulation, to solicit proposals from all reasonable potential sources of power such as other Cooperatives, investor-owned utilities, municipal utility organizations, Federal and state power authorities, independent power producers and co-generators. These solicitations for proposals are required to be published in at least three national publications in addition to direct contact. The applicant is also required to inform RUS of progress in the solicitation as negotiations progress. Final plans must include sufficient detail to show that present-value analyses of alternatives and their effects on total power costs over the forecast period result in the most economical and effective means of meeting AEPCO's power requirements.

Finally, new loans available for DSM and Renewable Energy facilities, both on and off grid, are required to be supported by an RUS approved Integrated Resource Plan that includes the benefits and costs of all supply and demand-side options. The ability to verify energy and cost savings achieved through DSM, energy conservation and renewable energy systems must be included and the durability of such savings measured over time must be evaluated in the process.

As this brief description indicates, AEPCO routinely engages in a robust planning process which involves participation and analysis from a wide variety of sources. Member/consumers also have input into the plans through their elected representatives and annual member meetings.

Other Arizona utilities involved in IRP have extensive planning processes as well. AEPCO suggests that a workshop focus on using these existing efforts and products as a base instead of requiring, as the current IRP Rules do, a wholly separate planning effort. One possibility would be to continue the annual historic data filings and then periodically—perhaps every three years—require each utility to file a summary of its current planning products together with associated detail and supporting information. A Staff and Commission review process similar to the one conducted on transmission ten-year plan filings pursuant to A.R.S. 40-360.02.G would then be conducted. Public hearings and/or workshops could be integrated into this review process.

Conclusion

AEPCO recommends two workshops. The first should focus on the regulatory and industry changes which have occurred since the IRP Rules were adopted and discuss whether, in light of these developments, the IRP process should be reactivated now or in the future. The second should be devoted to examination of existing utility planning procedures and the efficient use of these efforts as a basis for the Commission's IRP procedures as described above.