BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING ISSUES.	Docket No. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606.	Docket No. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR.	Docket No. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	Docket No. E-01933A-02-0069
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	

RUCO'S OPENING BRIEF

The benefits of electric restructuring have proven to be much more elusive than originally expected, but the Arizona Corporation Commission ("Commission") has been vigilant to protect electric customers from the danger posed by uncertain wholesale markets. In light of the dysfunctional wholesale electric market, the Commission in Decision No. 65154 stayed the requirements that the State's major utilities divest their generation assets and obtain all power for standard offer customers from the wholesale electric market. However, the reduced level of the solicitation of power from that market that will result from this proceeding still poses risks to customers. The Commission should not let its guard down in protecting standard offer customers from the danger of procuring power from immature and dysfunctional wholesale markets.

The Residential Utility Consumer Office ("RUCO") made a number of recommendations for improvements to the solicitation process proposed in the Staff Report. Staff's rebuttal testimony offered no criticisms of those recommended improvements. RUCO continues to support the following clarifications or modifications to the solicitation process outlined in Staff's Report.

GOAL: LOWEST COST TO CUSTOMERS

The Commission has stated clearly that it will not sacrifice the interests of customers in transitioning to competition and that the Track B solicitation process must protect ratepayers. Decision No. 65154 at 23-24, Finding of Fact No. 46 at pg. 31 and Finding of Fact No. 37 at pg. 30. The parties are nearly unanimous in their agreement that the goal of competitive power solicitation should be a least-cost mix of reliable power to customers. Exh. APS-6 at 4-5 (Wheeler); Exh. TEP-2 at 10 (Hutchens); Exh. Sempra-1 at 7,8 (Mitchell); Exh. W-4 at 3-4 (Kendall); Exh. Reliant-1 at 4 (Kebler); Tr. at 888-889 (Roach); Tr. at 910 (Broderick); Exh. RUCO-1 at 22 (Rosen); Tr. at 168 (Kessler). The competitive power solicitation should yield cost savings for customers compared to what they pay today and what they expect to pay in the future. Exh. S-1 at 1 (Staff Report); Tr. at 255 (Johnson). The Commission can meet these goals if the solicitation gives standard offer customers a least-cost portfolio of reliable electricity services.

COMPARE BIDS TO REGULATED COST OF SERVICE

Utilities can determine the appropriate least-cost mix of reliable resources by considering what customers would pay if traditional rate regulation were continued, including regulated generation planning. Exh. RUCO-1 at 5 (Rosen). The Commission should require utilities to provide bids for new generation and transmission on a regulated cost-of-service basis. Such bids can serve as a baseline for evaluating bids from the unregulated market. Exh. RUCO-1 at 23 (Rosen); *see also* Tr. at 256-262 (Kessler and Johnson). The wholesale power market is not sufficiently competitive if the competitive power costs more than traditional regulation. Exh. RUCO-1 at 5 (Rosen). If the regulated cost-of-service bids are lower than market-based bids, customers should continue to benefit from the lower-priced electricity from a vertically integrated utility. Exh. RUCO-1 at 23; *see also* Tr. at 363-4 (Kessler).

In its Track A Decision, the Commission found that the wholesale electric market for Arizona is "poorly structured and susceptible to possible malfunction and manipulation." Decision No. 65154, Finding of Fact No. 16, pg. 28. Utilities will be soliciting bids from this dysfunctional wholesale market. The Commission recognized that undue reliance on the wholesale market, with its uncertainties and limitations, could result in unjust and unreasonable rates for captive standard offer customers. *Id.* at Finding of Fact No. 25, pg. 29. Cost-of-service based proxy bids from the incumbent utilities can serve as backstop to insure that customers are not harmed by premature exposure to the inadequate wholesale market. On the other hand, if market-based bids are below the cost-based proxy bids, the Commission will begin to have assurance that the wholesale market is functioning and benefiting customers.

Staff, TEP and APS join RUCO in recognizing the benefit of comparing regulated prices to market-based bids. Tr. at 256-262, 363-364 (Kessler for Staff); Tr. at 492-493 (Hutchens for TEP); Tr. at 707 (Carlson for APS). Further, the Staff Report proposed determining a price for the bids to beat, from which the resulting contract automatically could be deemed prudent. Exh. S-1 at 24-26 (Staff Report). Panda proposed that the "price to beat" focus on comparing bids to the unbundled generation costs of APS's existing power resources as adjusted for fuel and inflation. Exh. Panda-2 at 30-31 (Roach). While Staff has withdrawn its "price to beat" proposal due to concerns raised by numerous parties, Panda's testimony demonstrates that Panda also believes that a comparison to the utilities' cost to generate power themselves is appropriate to determine the reasonableness of bids received from independent power producers.

SYSTEM MODELING IS ESSENTIAL

Evaluating bids to achieve a least-cost mix is not a simple process. One cannot merely rank-order bids by cost, because determining the cost of a bid is not a straightforward matter. New resources have both fixed and variable costs, and the total cost of a bid will differ depending on the percentage of time the plant is actually producing power (this is commonly called the "capacity factor" of the plant). To determine the capacity factor of a resource, one must know the mix of other resources that will also be utilized to meet the utility's load. A "chicken and egg" situation results, because in determining the least-cost mix, the capacity factor of one resource depends on the mix of all resources, and the mix of all resources depends on the capacity factors of the resources in the mix. See Exh. RUCO-1 at 16-17 (Rosen); *see also* Tr. at 704 (Carlson); Exh. Sempra-1 at 6 (Mitchell).

To ascertain the least-cost mix of resources, the total present value of revenue requirements ("PVRR") for all possible, technologically compatible resource portfolios must be compared to the PVRR for all other such portfolios over the relevant planning period. Exh. RUCO-1 at 7-8 (Rosen); Exh. Sempra-1 at 7 (Mitchell). No single resource bid can be evaluated by itself, without reference to the cost and technical characteristics of every other resource bid that might be part of the least-cost portfolio. Exh. RUCO-1 at 8 (Rosen); Exh. Sempra-1 at 5-7 (Mitchell). The utility must perform production cost simulations of the various combinations of resources to obtain the least-cost result. Exh. Sempra-1 at 7-8; Exh. W-4 at 4-5 (Kendall); Tr. at 107-8 (Kessler). *See also* Tr. at 908-909 (Broderick).

The planning horizon over which the PVRR should be measured should be long—at least 20, or perhaps as much as 30, years. Exh. RUCO-1 at 25 (Rosen). However, using a long planning horizon does not mean that all bids must be for long-term contracts. A lengthy planning horizon captures the long-run tradeoffs between fixed and variable costs that various generation and demand side management ("DSM") resources might present. Exh. RUCO-1 at 26 (Rosen); Exh. W-4 at 4-5 (Kendall). If the planning period were only a few years, resources with lower up-front capital investments (such as peaking plants) may appear to be least-cost, even though their higher operating costs might make their total costs greater over the long run. *See* Exh. RUCO-1 at 26 (Rosen).

The use of a traditional least-cost planning methodology allows all potential resources—generation, transmission and DSM—to be evaluated simultaneously. Exh. RUCO-1 at 7 (Rosen). To ensure that sufficient amounts of cost-effective DSM will be bid into the solicitation, the Commission should require the regulated utility to bid incremental or new DSM programs that would reduce its peak load by up to 2 percent on a successive annual basis. Exh. RUCO-1 at 28 (Rosen). This should provide enough new DSM options to choose from to yield a least-cost portfolio. Of course, the utilities should implement only those DSM bids that system modeling determines are part of the least-cost portfolio.

In addition, a traditional integrated resource planning ("IRP") process provides a framework for addressing environmental implications of resource planning, as well as cost implications. Tr. at 732 (Rosen). For example, an IRP process could compare the PVRR over a planning period to the PVRR plus the monetized values of environmental externalities, so that a judgment could be made whether it is worth spending extra money for a renewable resource. Tr. at 732-733 (Rosen); *see also* Tr. at 828 (Berry).

The Commission should require an evaluation criterion that minimizes the net present value of revenue requirements. Harquahala Generating Company proposed an alternative evaluation standard that the Commission should reject. In his pre-filed testimony, Harquahala witness Broderick proposed that the solicitation evaluate bids with the goal of minimizing the net present value of *rate impacts*. Exh. Harquahala-1 at 23 (Broderick). By contrast, traditional least-cost planning looks to minimize the net present value of *revenue requirements*, not rates. Exh. RUCO-2 at 2 (Rosen). An evaluation criteria that looks to *rate impacts* does not consider the impact of the growth in demand on the total amount of money spent for electricity services, and therefore does not minimize the total cost of a given resource portfolio to Arizona consumers. Exh. RUCO-2 at 3 (Rosen). In addition, the rate impact criterion is misleading because it can falsely indicate that cost-effective DSM is a bad investment for society. Exh. LAW-2 at 2 (Berry). At the hearing, witness Broderick backed away from endorsing the *rate impact* standard, and indicated that he had no objection to the *revenue requirement* standard. Tr. at 910 (Broderick). The traditional *revenue requirements* criterion minimizes total costs of a given resource portfolio, and should be adopted. Exh. RUCO-2 at 3 (Rosen).

A number of other complex issues arise from redesigning a power supply portfolio, including the reasonableness of the prices, the reliability and deliverability of the supply, the creditworthiness of the counterparties, and short and long term impacts on customers. Tr. at 265, Exh. S-3 at 5 (Kessler). All of these complex issues can be addressed in a least cost planning/IRP-type process. Tr. at 265 (Kessler).

THE "NUMBERS"

Much of the dispute between parties in this matter concerns the "numbers" that represent the contestable loads of APS and TEP. There is no good reason for limiting the solicitation to the amount of energy that a utility is unable to generate from its own assets. Exh. RUCO-1 at 37 (Rosen). The Commission should establish the amount of <u>capacity</u> for which the utilities should solicit bids, but the Commission need only establish a minimum amount of <u>energy</u> that should be solicited. Soliciting for capacity is more important, because once the utility has sufficient capacity, the dispatch of that capacity will be determined by the variable cost of each MW of capacity and the demand in each hour. *Id;* Exh. RUCO-2 at 3 (Rosen).

Bids should be solicited for low-, medium- and high-cost capacity, that would have corresponding high, medium and low variable costs, respectively. Exh. RUCO-1 at 37 (Rosen). A proper least-cost planning process will automatically subject all of the utility's generating units to competition in every hour of the year. Exh. RUCO-2 at 4 (Rosen). If cheaper energy than assumed in the inputs to the planning analysis becomes available for purchase in the future, the utility can (and should) purchase that cheaper energy to save money for customers. Exh. RUCO-2 at 6 (Rosen).

THE RIGHT SOLICITATION PROCESS IS MORE IMPORTANT THAN A FAST SOLICITATION PROCESS

In Decision No. 65154, the Commission required the Track B solicitation process to begin by March 1, 2003. Decision No. 65154 at 33. Staff's proposed solicitation, therefore, suggests that power for the next 1 to 3 years be acquired pursuant to an *initial solicitation* to begin by March 1, 2003. Exh. S-1 at 6 (Staff Report). The March 1, 2003 deadline imposed by Decision No. 65154 is necessary for reliability purposes, to insure that APS and TEP have adequate power to meet customer loads for 2003. However, because of rate freezes in place for APS and TEP through mid-2004 and later, there will be no rate impacts to customers for the power acquired for 2003.

Having a process that gives consumers the lowest costs in the long run is far more important than having a process that begins by March 1, 2003. Exh. RUCO-1 at 33 (Rosen). Too much money is at stake for the Commission to rush into a process that ignores the important details of an effective solicitation. Exh. RUCO-1 at 33 (Rosen).

The Staff Report proposes that utilities have 7 days to evaluate price, deliverability and other issues of bids, and six additional days to engage in post-bid negotiations, prior to announcing the winners of a Request for Proposal solicitation. Exh. S-1 at 29, lines 23-26 (Staff Report). These brief periods are inconsistent with a formal solicitation process. The Track B proceeding is about developing a more formalized process for utilities to access the wholesale power markets. Tr. at 124 (Kessler). A more formal process should give utilities time to evaluate bids more deliberately.

Paradoxically, while the Staff proposes a timetable that requires the utilities to evaluate bids in 7 calendar days, Staff also believes that the Commission should not be rushed in determining the prudence of the results of a solicitation process. Exh. S-2 at 2, lines 17-18 (Johnson). Instead, Staff believes that the Commission should take the time to do a "thoughtful review" prior to making any finding of prudence. Tr. at 123 (Kessler). Staff recognizes that an expedited approval process may "relieve the utility of its <u>responsibility</u> to procure power in a prudent manner." Exh. S-2 at 3, lines 18-19 (Johnson) (emphasis added). Yet Staff overlooks how requiring the utility to undertake an expedited determination of winning bids might relieve the utility of the <u>opportunity</u> to procure power in a prudent manner. The utilities will more likely need 6-8 weeks to adequately review the available options before determining the most prudent course of action. Exh. RUCO-2 at 7 (Rosen); Exh. Sempra-1 at 8 (Mitchell).

The Commission rightly should not forgo its opportunity to undertake "thoughtful review" of the utilities' procurements prior to making any determination of prudence. Likewise, the Commission should give the utilities an opportunity to undertake "thoughtful review" of the bids prior to determining the most prudent procurement mix. Therefore, RUCO recommends that the utilities use a more *ad hoc*, but prudent, planning process to cover their needs for the summer of 2003. The more formal solicitation process established by this proceeding could begin for resources required for the 2004-2006 time period. Exh. RUCO-1 at 33 (Rosen).

PRUDENCE DETERMINATION

Parties have disputed whether the results of the solicitation should automatically be deemed prudent. RUCO generally shares Staff's concerns about prematurely declaring contracts prudent. However, the review that accompanies a traditional IRP process is sufficient to assure the Commission that the utility has engaged in prudent planning. Exh. RUCO-1 at 33-34 (Rosen); Exh. RUCO-2 at 7-8 (Rosen). But the Commission should not predetermine whether the utility prudently implemented the plan based on information that became available <u>after</u> completing the planning process. That aspect of prudence should be reserved for a proceeding that determines final cost recovery. Any resources obtained for summer of 2003 through a solicitation process that is not the final process should not be granted a planning prudence presumption.

THE IMPACT OF RUCO'S POSITION IN THE APS FINANCING DOCKET ON THE TRACK B PROCESS

On December 13, 2002, RUCO filed testimony in the APS Financing proceeding, Docket No. E-01345A-02-0707. RUCO recognizes that the adoption of its recommendations in that proceeding would have significant impact on the need for solicitation that is the subject of this Track B proceeding. RUCO's recommendations in this proceeding regarding how a solicitation should be structured and executed is not meant to suggest that RUCO believes such a solicitation would in fact be necessary if RUCO's recommendations in the APS Financing docket are adopted by the Commission.

CONCLUSION

The solicitation process must be structured to yield a least-cost portfolio of reliable electricity services for customers. Bids should be evaluated in comparison to the regulated cost of new generation, to insure that customers are not required to pay more for electricity than they would pay if a vertically integrated utility continued to provide all generation on a regulated cost-of-service basis. Production costs simulation models must be run, and bids must be evaluated in portfolios, to determine the resource mix that results in the lowest cost for consumers. A long-term planning horizon is necessary to properly capture the long-term trade-offs between fixed and variable costs that different resources present. The formal IRP process also allows the Commission to evaluate the cost of the environmental impacts of resources so that it can assess whether more environmentally-friendly resources are worth the additional direct expenditures.

The development of a power solicitation process is complex, and a flawed procedure presents enormous risks to consumers. The Commission should ensure that the process will produce the intended results of lower costs over the long run, even if the process would require more time than is available to acquire resources for the coming summer. The utilities can use an interim procedure for resources for this summer, and the full procedure can be utilized for procurements for future years.

The solicitation of power from the current wholesale market may or may not result in just and reasonable rates for customers. Tr. at 120 (Johnson). Therefore, the Commission must take extreme care to ensure that the solicitation process protects against an undesirable result. If the solicitation fails to produce sufficient cost savings for customers, the Commission should allow utilities to continue providing electrical services as a vertically integrated utility on a cost-of-service basis.

RESPECTFULLY SUBMITTED this 18th day of December, 2002.

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