ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

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Chairman
JIM IRVIN
Commissioner
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Commissioner

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. R14-22-1606	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	Docket No. E-01933A-98-0471

COMMENTS OF THE LAND AND WATER FUND OF THE ROCKIES ON STAFF'S LIST OF TRACK B ISSUES

On May 2, 2002, the Hearing Division issued a Procedural Order concerning implementation of retail electric competition in Arizona. Matters concerning competitive solicitation of power supplies to serve Standard Offer Customers were put into Track B. On May 13, 2002, Staff issued a Request for a Procedural Order to govern Track B proceedings regarding electric competition. In its request, Staff indicated that it would prepare a list of issues upon which it would like the parties to comment. On May 31, 2002, Staff issued its List of Track B Issues. Comments on the issues are due July 1, 2002 per the Procedural Order dated June 20, 2002. The Land and Water Fund of the Rockies ("LAW Fund") hereby provides its comments on Staff's list of issues.

The Threshold Question

Before providing specific responses, the LAW Fund wishes to raise the threshold question of whether retail electric competition is good public policy.

As suggested by Staff's list of issues there are many aspects to minimizing the long run price for electric energy services. There are no sure-fire answers to many of the questions contained in Staff's list of issues, i.e., no guaranteed superior resource acquisition process. In a competitive market, consumers make their choices based on price, service quality, risk management, and other factors and the suppliers who do well on these various factors are successful. Success is determined after the fact, based on outcomes, and cannot be guaranteed à priori no matter how carefully the process is planned.

If retail electric competition is vigorous, the Commission does not have to worry about the details comprising its list of issues. Consumers will choose among multiple suppliers including the Utility Distribution Company's Standard Offer Service. Utility Distribution Companies that can offer low prices and high quality service, and manage price and other risks will be successful. Utility Distribution Companies that do poorly will lose customers. But, based on experience to date, it is unrealistic to expect such competition to emerge in the near future due to the high transaction costs of making a competitive market and keeping it honest. Therefore, the Commission has a difficult task ahead, seeking to create:

- a wholesale resource acquisition process that will result in lower prices, better risk management, and better quality service than that achieved with regulated monopolies;
- with little pressure on Utility Distribution Companies to get a good deal on power supplies when they have so little competition for their retail customers;
- with no clearly superior resource acquisition process;
- while giving up some of its oversight over that new process as wholesale transactions are regulated by the Federal Energy Regulatory Commission.

Solicitation Issues

Assuming that the Commission desires to proceed with competitive solicitations, the LAW Fund believes there are several areas where the Staff's list of issues could be strengthened:

- By *requiring* that demand side management (DSM) and energy efficiency resources be used to help meet the demand for electric energy services instead of simply *permitting* DSM to be considered as a resource, as suggested by Issue 1(s).

- By requiring management of the risks associated with the potential for future environmental regulations such as regulation of carbon dioxide emissions or mercury.
- By requiring that risk management in general be explicitly factored into the evaluation of alternatives. Elements of risk management are implicit is several of Staff's Issues (4c, 2a, 1q, 1u, and 1v), but the topic is so crucial to creating a beneficial competitive market that it should be addressed explicitly.

Demand Side Management/Energy Efficiency

Whatever methods are adopted by the Commission for competitive resource acquisitions, Utility Distribution Companies should be required to actively seek cost effective demand side management resources and implement them. If this alternative to power supplies is not pursued, Arizona's bill for electric energy services will be higher than necessary to meet the demand for electric energy services. Also, DSM serves as a hedge against volatile electricity prices because DSM costs are largely fixed in contrast to the ups and downs of electricity and natural gas markets. Further, DSM is a means of dealing with potential future carbon regulation as described below.

It is not realistic to expect that demand side management occurs or will occur at a sufficient level to minimize the costs of meeting the demand for electric energy services in the absence of utility acquisition of DSM. Currently, markets do not come anywhere close to efficiently deploying DSM for residential and smaller commercial and industrial consumers, primarily because of transaction costs. These transaction costs include lack of information about DSM and energy use by residential and small commercial consumers and by suppliers of appliances, homebuilders, etc. In addition, consumers may be hindered by perceptions of opportunism in the DSM "industry" or by fear of poor performance by DSM measures. DSM programs for residential and smaller commercial and industrial consumers can be cost effective if they are carefully targeted to buildings and appliances where they will have the most impact.

Utility Distribution Companies are in the energy business, have recurring contact with consumers, are generally regarded as reliable by consumers, and are subject to the regulation of the Commission. Therefore, utilities can serve as vehicles for deploying DSM programs. The Commission can promote cost effective DSM by requiring utilities to implement, on a large scale, a mix of: (i) installation programs, (ii) rebate or other subsidy programs to reduce up-front costs to consumers, and (iii) market transformation programs aimed at educating consumers and suppliers and at providing incentives to suppliers to promote energy efficient appliances and buildings to their customers.

There are several ways in which DSM and energy efficiency projects could be implemented, including:

- A competitive solicitation for DSM and energy efficiency that is separate from the solicitation for supply side resources with its own target MW and MWh (separate solicitation).

- A competitive solicitation for DSM and energy efficiency that is part of the general solicitation for all resources (combined solicitation). The amount of DSM acquired would be dependent on the costs of DSM and the costs of supply side resources.

The LAW Fund recommends a separate solicitation for DSM and energy efficiency. With a combined solicitation there is no guarantee that the utilities will select cost effective DSM.

With a separate solicitation, utilities should set aside a specified, realistic amount of MW and MWh to be obtained from DSM and energy efficiency. The Southwest Energy Efficiency project estimates that Arizona utilities could save 7.4 percent of GWh by 2010 through energy efficiency.[1] The Corporation Commission's 1993 resource planning report indicates that APS and TEP planned to save about 5 percent of demand through DSM by 2001, starting in 1993.[2] The LAW Fund proposes that APS and TEP obtain DSM and energy efficiency resources sufficient to meet at least 7 percent of their demand and energy requirements by 2011 and that these resources be obtained through a solicitation process separate from supply side resource acquisitions. It would be useful for the utilities to conduct a DSM study before acquiring resources to assess expected energy and demand savings. The utilities should propose cost recovery mechanisms for the Commission's consideration in a hearing in which other parties may participate. Costs may be recovered from all Standard Offer customers as purchased power costs are recovered or some costs may be recovered from participants in DSM programs, for example.

The utilities may elect to implement the demand side resources themselves or to contract with DSM vendors to administer the demand side programs on behalf of the utilities. Annual reports to the Commission on DSM progress, savings, and costs should be required. The Commission could also consider setting up a separate entity to implement DSM programs if the utilities are unwilling or unable to implement DSM programs themselves or to use DSM vendors to administer the programs.

In conclusion, whatever processes the Commission adopts for Utility Distribution Companies to acquire resources for Standard Offer Customers, the Commission should require the Utility Distribution Companies to actively seek out DSM and to implement those DSM offers whose costs are less than the costs of alternative resources or which

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[1] Southwest Energy Efficiency Project, *Utility Energy Efficiency Programs and Systems Benefits Charges in the Southwest*, Boulder, CO, 2002, Table 2.

[2] Arizona Corporation Commission, *Staff Report on Resource Planning*, 1993. In the subsequent resource planning period, utilities reduced the planned amount of DSM in response to anticipated changes in the regulatory environment and changing market conditions. In the 1993 resource plan, APS forecasted about 21,000 GWH of retail sales in 2001 (excluding DSM) and TEP forecasted about 8250 GWH of retail sales in 2001 (excluding DSM). APS planned for about 250 MW of additional DSM by 2001 and TEP planned for about 80 MW of additional DSM by 2001. Assuming a 50 percent load factor for DSM, APS' savings would have been 5.2 percent of energy demand and TEP's DSM savings would have been about 4.2 percent of energy demand.

help the Utility Distribution Company manage the risks of electricity or fossil fuel price volatility or which reduce the costs of potential future carbon regulation. Full recovery of power costs by the Utility Distribution Companies should be contingent upon both active solicitation of DSM resources as evidenced by responses received in the acquisition process and implementation of a significant amount of DSM based upon the DSM offers received.

Greenhouse Gas Emissions

With record temperatures and droughts in the Southwest and growing evidence that the earth's climate is being altered by emissions of carbon dioxide and other greenhouse gases, including recent recognition of climate change by the White House, it is increasingly likely that the United States will act in the near future to prevent exacerbating this situation. Responses to greenhouse gas regulation include DSM, fuel substitution, substitution of renewable resources, and sequestration of CO_2. Prudent resource acquisition processes by Utility Distribution Companies should take into account the potential costs of complying with future greenhouse gas regulations and opportunities for reducing greenhouse gases in voluntary programs.

The competitive solicitation process adopted by the Commission should explicitly require Utility Distribution Companies to take potential greenhouse gas regulation into account and to prudently manage the risk of such potential regulation, including an explicit discussion of the allocation of that risk. The solicitation process should ensure that resource alternatives that pose minimal to zero risk to ratepayers of increased costs from future carbon regulations (either because the resource alternative is inherently lower in carbon emissions, such as DSM or renewables, or because the supplier has contractually agreed to assume that risk) are not competitively disadvantaged in the bid evaluation process in favor of resource alternatives that seek to shift environmental risks to ratepayers. The solicitation process should also encourage Utility Distribution Companies to voluntarily reduce greenhouse gas emissions and the carbon intensity of their resource portfolios without penalty. Furthermore, the Commission should make it clear that shareholders will be responsible for costs incurred as a result of imprudent management of greenhouse gas emission risks.

The potential costs of future carbon regulations are a critical component to selecting the optimal portfolio of resources, including DSM resources. Table 1 shows estimated costs of carbon reduction.[3] Cost estimates vary widely, but they all illustrate the potential for significant cost impacts on carbon-intensive resource options. For example, at a cost of $55 per metric ton of carbon reduction (by scrubbing, sequestration in forests, fuel substitution, or purchase of carbon credits), the cost impact on generating electricity at a conventional sub-critical pulverized coal-fired power plant would be about

[3] The table reports only on studies of developed countries.

$0.0135 per kWh, a significant impact.[4] The example makes use of a cost that is toward the lower end of the range of estimated costs.

Risk Management Generally

Given the uncertainties of energy markets, it is not possible to be sure that a particular resource acquisition strategy will attain the minimum cost (see Staff's Issue 1(x) concerning an optimal portfolio and Issue 6 concerning bid evaluation). Consequently, in addition to focusing on minimizing cost, the Commission's process should also focus on risk management. Besides the management of risks associated with greenhouse gas emissions, the competitive solicitation process should explicitly include the management of a number of other market risks, including:

- Uncertain future prices of energy and capacity, including price volatility.
- Uncertain future demand for electricity.
- Opportunistic behavior of energy traders and suppliers.
- Poor performance of resources, such as high forced outage rates or inadequate transmission capacity.
- Poor performance of suppliers due to lack of creditworthiness.

It is critical that Utility Distribution Companies actively seek to manage these and other risks. Risk management means bounding the potential adverse impacts of these risks. Risk management does not mean conducting an analysis concluding that the risks have a small probability of occurring and then ignoring them or losing sight of individual risks by focusing on an amalgam of risks expressed as expected values of outcomes (i.e., as weighted averages of possible outcomes). Each individual risk must be managed because effective risk management techniques vary from risk to risk. In addition, some low probability events can have catastrophic consequences and must be addressed.

[4] At $55 per metric ton, carbon reduction would cost $0.0246 per pound. Assuming 10,000 Btu/kWh for a coal fired power plant, 10,000 Btu of heat content per pound of coal, and 0.55 pounds of carbon emitted as CO2 per pound of coal, 1 kWh of electricity generation would yield 0.55 pounds of carbon emitted as carbon dioxide. At a removal cost of $0.0246 per pound, the cost per kWh would be $0.0135 per kWh.

Table 1. Summary of Recent Studies of Carbon Removal Costs

Study	Analysis	Cost
1. Richard Newell and Robert Stavins, "Climate Change and Forest Sinks: Factors Affecting the Costs of Carbon Sequestration," *Journal of Environmental Economics and Management* 40: 211-235 (2000)	Marginal cost of carbon sequestration (5 million tons of annual sequestration above baseline in study region; baseline is about 4 million tons)	$26 to $39 per ton of carbon
2. Charles Kolstad and Michael Toman, *The Economics of Climate Policy*, Resources for the Future Discussion Paper 00-40REV, June 2001, Washington, DC.	Stanford Energy Modeling Forum data on marginal cost of controlling carbon in several countries (1990 US $ per ton of carbon for various percentage reductions from year 2010 baseline)	@ 10% reduction: $50 to $130 per ton of carbon
3. Dallas Burtraw, Karen Palmer, Ranjit Bharvirkar, and Anthony Paul, *The Effect of Allowance Allocation on the Cost of Carbon Emission Trading*, Resources for the Future Discussion Paper 01-30, August 2001, Washington, DC.	Price of emission allowances in 1997 $ per metric ton of carbon assuming a reduction of 150 million metric tons of carbon from 2012 baseline of 626 million metric tons of carbon	$100 to $150 per metric ton of carbon
4. Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 5th International Conference on Greenhouse Gas Control, Cairns, Queensland, Australia, August 14-16, 2000.	Incremental cost of scrubbing carbon dioxide from an integrated coal gasification combined cycle power plant in 2000	$95 per metric ton of carbon avoided
5. Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, Report # SR/01AF/2000-05.	Projected carbon fees (1999 $ per metric ton carbon equivalent) in 2010 assuming 7% reduction of power sector CO2 below 1999 levels by 2008. Cost impact largely due to shift away from coal to natural gas and renewable energy	$108 to $143 per metric ton of carbon equivalent
6. Andrew Plantinga, Thomas Mauldin, and Douglas Miller, "An Econometric Analysis of the Costs of Sequestering Carbon in Forests," *American Journal of Agricultural Economics* 81: 812-824 (November 1999)	Marginal cost of carbon sequestration in Maine, South Carolina, and Wisconsin assuming 25% of agricultural land enrolled in forest sequestration. 1995 $ per metric ton of carbon sequestered.	$45 to $120 per metric ton of carbon

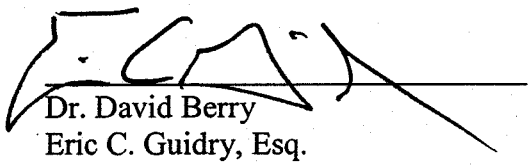
The use of a purchased power adjustment clause to recover costs (Staff Issue 5a) can insulate a Utility Distribution Company from poor risk management. The costs of mistakes are merely passed through to Standard Offer Customers, most of whom, as a practical matter, have few or no competitive alternatives to go to as a substitute.

Risk management may be handled by Commission review of resource acquisition packages after a Utility Distribution Company has put together a package or changes a package of resources, but before that package goes into effect. If the Commission finds that risks are not being adequately managed, it could order the Utility Distribution Company to renegotiate resource acquisition contracts. The Commission's risk management review could be considered as a limited pre-approval of Standard Offer Service resources.

Conclusion

As part of the competitive solicitation process, the Commission has the opportunity to ensure that energy efficiency, environmental factors, and risk management are fully incorporated into resource acquisition decisions. The Commission has established an impressive track record for taking environmental issues and risks seriously through its power plant siting decisions and in its adoption of an Environmental Portfolio Standard. The LAW Fund encourages Staff to follow the Commission's lead and incorporate the recommendations set forth above into the competitive solicitation process.

RESPECTFULLY SUBMITTED this 29th day of June, 2002.



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