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RESOURCE MANAGEMENT
INTERNATIONAL, INC.

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January 9, 1998

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

Subject: Docket No. U-0000-94-165

Ladies and Gentlemen:

Enclosed for filing is my testimony on behalf of Navopache Electric Cooperative, Inc. regarding stranded costs in Docket No. U-0000-94-165.

Sincerely,

Alan Propper

Alan Propper
Regional Manager

Arizona Corporation Commission
DOCKETED

JAN 09 1998

DOCKETED BY

BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
COMMISSIONER-CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
CARL J. KUNASEK
COMMISSIONER

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	))))	DOCKET NO. U-0000-94-165

TESTIMONY OF ALAN PROPPER

ON BEHALF OF

NAVOPACHE ELECTRIC COOPERATIVE, INC.

JANUARY 9, 1998

Summary of the
Testimony of Alan Propper
on behalf of
Navopache Electric Cooperative, Inc.

Docket No. U-0000-94-165

Navopache Electric Cooperative, Inc. is a distribution cooperative and its stranded costs come primarily from its all-requirements contract to purchase power from Plains Electric Generation and Transmission Cooperative, Inc. Navopache is actively seeking to restructure this all-requirements contract and thereby lower its potentially stranded costs.

I recommend that the Commission not foreclose creative solutions to stranded cost issues that could be worked out by distribution cooperatives and their generation and transmission suppliers.

I recommend that the Commission encourage all distribution cooperatives and G&Ts to reduce the risk of additional stranded investment exposure by avoiding obstacles to restructuring all-requirements contracts that they may work out. In particular, Arizona distribution cooperatives are working with G&Ts to convert all-requirements contracts to partial requirements contracts. The Commission should encourage this creation of opportunities to lower costs and enable member-customers of distribution cooperatives to have meaningful choices among electric suppliers.

I recommend that the Commission leave the current Rules as they are and retain the flexibility to deal effectively and fairly with all the utility-specific features that will be presented in stranded cost recovery hearings.

I recommend that the Commission give greater weight to calculations of stranded cost based on the sale price of generation resources than to calculations based on administrative methods.

I recommend that the market price of electricity used in administrative valuations of power supply stranded costs reflect the mix of spot market purchases and short, medium, and long term contracts.

I recommend that a true-up mechanism be used unless all potentially stranded resources are sold or unless there are no stranded costs.

Testimony of Alan Propper
on behalf of
Navopache Electric Cooperative, Inc.

Docket No. U-0000-94-165

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Q. Please state your name, position, and business address.

A. My name is Alan Propper. I am the Regional Manager and Principal Executive Consultant for Resource Management International, Inc. in Phoenix Arizona. My business address is 302 N. 1st Avenue, Suite 810, Phoenix, Arizona 85003.

Q. Whom are you representing in these proceedings?

A. I am specifically representing Navopache Electric Cooperative, Inc. (Navopache). However, my testimony expresses my beliefs, concerning stranded costs, for all distribution cooperatives, which include members of the Arizona Electric Power Cooperative, Inc. (AEPCO Members). Both Navopache and the AEPCO Members are electric distribution cooperatives in Arizona named as Affected Utilities in Arizona Corporation Commission (Commission) Decision No. 59943 concerning "Competition in the Provision of Electric Service".

Q. What are your qualifications to testify as an expert witness?

A. My qualifications appear in Attachment 1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the nine questions put forth as issues in the December 1, 1997 Procedural Order in this Docket and the First Amended Procedural Order dated December 11, 1997, discuss the nature of the electric distribution cooperative with regard to competition and stranded costs, and present Navopache's position on competition and stranded cost recovery in the provision of electric services by distribution cooperatives.

Q. Do you have any general recommendations for the Commission?

A. I have several. Specific methodological recommendations are presented in detail later in my testimony. My general recommendations for the Commission are:

- Do not foreclose creative solutions to stranded cost issues that could be worked out by distribution cooperatives and their generation and transmission suppliers, as well as their lenders.
- Encourage the distribution cooperatives, like Navopache and the AEPCO Members, and the generation and transmission cooperatives (G&Ts), like Plains Electric Generation and Transmission Cooperative, Inc. (Plains) and AEPCO, to reduce the risk of additional stranded investment exposure by avoiding obstacles to restructuring all-requirements contracts that distribution cooperatives and G&Ts may work out.

- Retain flexibility. There are significant differences among the cooperatively-owned, municipally-owned, and investor-owned utilities, as well as individual utilities within these classifications. Further, knowledge of electric markets will grow over time. Do not lock into today's perceived solutions.
- Use the market. Administrative calculations of stranded costs will not reflect all the factors that potential purchasers of power plants would take into account, and there is a possibility that stranded costs will be over-estimated when administrative calculations are used. Whenever possible, market valuations of generating resources should be used.

Q. Do you have any specific recommendations for the Commission?

A. My specific recommendations are presented below in the context of responses to each of the questions/issues posed in the Procedural Orders.

Q. What are the most important issues to Navopache?

A. All of the issues raised in the Procedural Orders are important to Navopache. The most important are the first three – the need for modification of the rules, the timing of stranded cost filings, and the scope and calculation of stranded costs. The scope and calculation of stranded costs is the single most important issue.

1. Modification of Rules

Q. Should the Electric Competition Rules be modified regarding stranded costs, and if so, how should they be modified?

A. I believe that the Rules are sufficient as written. The Rules provide the Commission with the flexibility needed to accommodate the particular characteristics of each Affected Utility and its customers. Any specific guidance or directives issued by the Commission on stranded costs beyond the scope of the Rules should be done by Commission Order. It is highly likely that the Commission will modify any guidance or directives over time to reflect additional data and information, as well as experience in the application of the Rules.

2. Timing of Stranded Cost Filings

Q. When should Affected Utilities be required to make a stranded cost filing pursuant to A.A.C. R14-2-1607?

A. There are two cases. If an Affected Utility does not desire to recover stranded costs or if it has no stranded costs, no filing is necessary. If an Affected Utility desires to recover stranded costs, it should file at least six months before the date when it wishes to begin collecting revenues to recover stranded costs. This will give the Commission time to review the request.

3. Scope and Calculation of Stranded Costs

Q. What costs should be included as part of stranded costs?

A. The definition of stranded cost in A.A.C. R-14-2-1601(8) indicates that stranded costs are the verifiable net difference between all the prudent jurisdictional assets and obligations necessary to furnish electricity acquired or entered into prior to December 26, 1996 under traditional regulation and the market value of those assets and obligations directly attributable to the introduction of competition under the competition rules. I believe this definition provides the necessary flexibility for the Commission to consider the particular characteristics of each utility and its customers.

Q. For background, would you briefly discuss the concept and function of an electric distribution cooperative?

A. Looking back in our history, investor-owned utilities had little interest in extending their lines to serve rural consumers where low population density meant greater distances between service points. In 1935, fewer than 750,000 of the 6.8 million farms in the United States had access to central station electric service. Those that did paid high fees to cover the power company's investment in facilities to serve them and also paid higher power costs than electric consumers in urban areas. In 1935, the Rural Electrification Administration (now the Rural Utilities Service, RUS), was established to provide electric service to people in rural areas. The electric cooperative became the means by which this objective was to be achieved.

Distribution cooperatives were created under federal and state law as non-profit corporations and financed with direct federal loans or federally guaranteed loans. The function of the distribution cooperative has been to electrify their service areas and to bring a sense of community and community service to the areas they serve. Distribution cooperatives are service area specific, member-governed, non-taxable, and dedicated to providing service at cost plus a margin for contingencies, with all other margins and benefits being required by law to be returned to members.

Distribution cooperatives constructed the distribution facility infrastructures which have made electricity available to consumers in rural Arizona. These distribution systems either self-generated or purchased their electricity from investor-owned or public facilities until the late 1950s and early 1960s. During that period they joined together in Arizona and New Mexico to create the generation and transmission organizations we know as AEPCO and Plains. Distribution cooperatives can survive and continue to provide their special brand of services to their ownermembers if the Commission carefully constructs its program of statewide competition.

Q. Are there any unique features of cooperatives that bear on stranded costs?

A. Yes. Unlike investor-owned utilities, cooperatives do not have investors who could shoulder some of the stranded costs. Distribution cooperatives are required to operate as non-profit entities under special tax law provisions. They have no common or preferred stock or stockholders and they fund operation expenses from margins and from debt.

Cooperatives have borrowed from the federal government to pay for serving their certificated areas, and they must be able to repay their debts to the United States to the extent possible. Therefore, the ability to recover stranded costs is of the utmost importance to the customer-members of Navopache and, presumably, to the AEPCO Members.

In addition, as all-requirements and potentially partial-requirements customers of the G&Ts, the interests of the distribution cooperatives, with respect to stranded cost recovery, could differ from the interests of the G&Ts as I will discuss below Thus, the methodology for the calculation and recovery of stranded costs will have a major effect on the ability of the distribution cooperatives to compete and survive in the unregulated marketplace. Until stranded costs and rates are determined for the power supplying entities, the distribution cooperatives cannot establish their own rate levels and designs, or their terms and conditions for service.

Q. What is the source of most of the potentially stranded costs of the distribution cooperatives?

A. A distribution cooperative service area is a community with two potential stranded costs. The first is potential stranded costs related to distribution infrastructure for which there is associated debt. This debt must be paid by the service area community. Second, as the agent of this community, the distribution cooperative has an all-requirements contract to purchase electricity equivalent to its load. At present, the all-requirements contract is the major source of potentially stranded costs of distribution cooperatives such as Navopache as well as AEPCO Members.

Q. What is the purpose of all-requirements contracts?

A. Distribution cooperatives were not required to guarantee the loans made by the United States government to the G&Ts. In lieu of a guarantee by the distribution entities, the United States accepted an agreement whereby the distribution cooperatives would agree to buy all their requirements for electricity from the G&T, which became the actual borrower of funds.

Currently, both Navopache and the AEPCO Members buy power and energy from generation and transmission cooperatives, Plains and AEPCO, respectively, under such all-requirements contracts. The purpose of these specific agreements was to give the United States government (specifically the RUS) collateralization and security for the loans it made to Plains and AEPCO for construction of power plants and associated transmission facilities. For Plains, it was the Escalante plant (PEGS), and for AEPCO, it was the Apache plant. It should be noted Navopache was accepted into Plains by Plains and RUS after all of the Plains debt for its PEGS power plant was approved with no reliance on Navopache membership as a security element for the loan.

It was not the philosophy of the all-requirements contract, nor was there any need for the lender, to expect such a restrictive agreement to be effective in perpetuity, since the loan to be secured was tied to specific generation and transmission facilities. This is particularly true for a plant that is operated at capacity, such as PEGS. Yet, these agreements still exist, though they are being rigorously contested before several forums by Navopache and other distribution cooperatives across the United States. RUS and other lenders to cooperatives are now willing to consider different types of collateralization for both old and new loans, and are developing partial-requirements as opposed to all-requirements contracts. The restructuring of the six billion dollar debt of the Oglethorpe Power Cooperative in Georgia is an example of the use of partial-requirement contracts.

Q. Why are such all-requirements contracts creating major competition-related problems today?

A. Many distribution cooperatives, such as Navopache are unable to buy power and energy, even for incremental sales to new or expanding loads, at market prices, but must continue to pay above-market prices for the uneconomical power supply blends of their G&Ts. This creates an uncompetitive situation and, therefore, a stranded cost. Without Commission intervention or other action, there is little incentive for a G&T to enter into the best power supply deals available and no market discipline for poor performance. The current all-requirements contracts should not be interpreted as a permanent restriction on distribution cooperatives. Indeed, in light of national energy policy, as well as the Commission's desire to obtain the benefits of competition for retail consumers, it is reasonable to expect that the all-requirements contracts may be modified to enable distribution cooperatives to make market priced electricity available to the member-customers at least for power and energy required for loads in excess of a distribution cooperative's computed share of the capacity of the specific G&T resources constructed or purchased in the past. If member-customers of the distribution cooperative are permitted choice among power suppliers, then the distribution cooperative should also be permitted a choice of power suppliers.

. . .

Q. How are proposals for restructuring the G&Ts related to the competitive issues being examined at this time, and, particularly, in the development and handling of stranded costs?

A. As members of the G&Ts, Navopache and the AEPCO Members are aggressively pursuing restructuring plans for Plains and AEPCO, respectively, that would allow them to become partial requirements members, to sever their relationships with the G&Ts altogether, or to remain all-requirements members but lower their power supply costs to a marketplace level at least for incremental purchases and sales.

Navopache has embarked on a two and a half year analysis on behalf of its member-customers to determine how to make available to them market based electricity and services now contemplated by the Commission Rules. Navopache has taken the highly visible position that Plains must find a way to significantly lower its power supply costs, whether through merger with a financially healthier G&T, debt forgiveness by RUS, or even bankruptcy. However, even if such a remedy is found and implemented, Navopache would want its freedom to choose partial requirements service or complete independence from Plains.

AEPCO is in the process of concluding a restructuring program which resulted in its members accepting a report which, if implemented, will direct AEPCO to divest itself of generation and transmission and to create three new entities, a Genco, a Transco and a services entity, all of which will be separate corporations. The AEPCO Members have committed to creating partial requirement contracts for its Genco and Transco services based on formulas for "capped" financial responsibility, developed by the AEPCO Members and AEPCO staff. This process is anticipated to be completed in late in 1998, and the Commission should urge and facilitate its completion.

This restructuring of the G&Ts, with resulting lower power supply costs and at least partial marketplace freedom for the distribution cooperatives, is essential for the survival of Navopache and, in my opinion, AEPCO Members in a competitive marketplace. It should also lower the stranded costs attributable to uneconomical power supply agreements.

Q. How could the timing of the introduction of competition into existing service areas affect stranded costs?

A. The potential for lowering power supply costs in the near future is very real for the distribution cooperatives. If this occurs, the magnitude of stranded costs could be significantly lowered. In addition, the very nature of a distribution cooperative's business and relationship to its member-customers could be altered, or kept from being altered, by such a cost change. This, in turn, could affect the magnitude and nature of the competition a distribution cooperative would experience and, ultimately, the nature of the organization that the cooperative would become. There should be some coordination of the timing of the lowering of power supply costs with the introduction of competition for the distribution cooperatives.

Q. How does the nature of the distribution cooperative relate to the concept of stranded costs?

A. The methodology for calculating stranded cost should focus on an allocation of the electricity-providing resources fairly attributed to a distribution cooperative at a certain point in time. That would constitute the maximum amount of generation-related cost and investment to be examined. Whether or not it is stranded is another matter. If it is stranded, the member-customers of the distribution cooperative ought to have a period of time to recover the stranded costs. At the same time, it should be freed from all-requirements contracts binding it to an uneconomic power supply source, and allowed to chose supplemental suppliers.

Q. How does the nature of distribution cooperatives have any bearing on the methodology for calculating and recovering stranded costs?

A. In dealing with the allocation of power supply resources, or stranded costs, of the cooperatives, purchased power contracts are involved as opposed to a direct investment in uneconomical generating facilities. Possibly complicating the issue is the fact the there is an involvement in these facilities by the distribution cooperatives who are the members of the G&Ts. Another complicating factor is that the methodology chosen to define the stranded costs of the G&Ts will undoubtedly affect the stranded costs of the distribution cooperatives.

In the case of the AEPCO Members, their supplier, AEPCO, is an Affected Utility under the Commission's jurisdiction whose stranded costs will ultimately be defined by the Commission. However, in the case of Navopache, its supplier, Plains, is not an Affected Utility under the jurisdiction of the Commission, and, therefore, we do not know at this time how and when Navopache's stranded costs will be defined.

Q. How should stranded costs be calculated for an electric utility cooperative?

A. For the case of a distribution cooperative, the calculation is a two stage process. The first stage is independent of the operations of the distribution cooperative. The G&T must define and calculate the stranded costs associated with its power supply facilities. The second stage is for the distribution cooperative to define and calculate the stranded costs associated with its individual wholesale power supply agreement with the G&T, plus any other stranded costs of the distribution cooperative.

. . .

Q. How should the stranded costs associated with the power supply facilities of a G&T be calculated?

A. I believe that two general methodologies should be considered. I refer to them as administratively calculated stranded costs and stranded costs based on the market valuation of assets.

Q. Please describe administratively calculated stranded costs.

A. Administratively calculated stranded costs should reflect a net present value calculation of the net revenues of sales from the utility's generation sources. The net present value calculation should examine the stream of revenues from sales by the utility, in this case the sales of the G&T to the distribution cooperatives. The present value calculation should also examine the stream of avoidable power production costs facing the G&T. These include fuel and variable purchased power costs, variable operating and maintenance costs, and future capacity additions. A more sophisticated analysis would use a model which examined several scenarios and weighted each by the probability of its occurrence.

If the present value of the stream of revenues minus the present value of the stream of avoidable costs is positive, those net revenues should be compared with the book value of the potentially stranded costs (such as obligations to pay the principal on loans made for the construction of the generating plant). Recovery of the book value through rates would be allowed under traditional regulation. If the present value of the net revenues is less than the book value of fixed obligations, the difference between the two is stranded cost. If the present value of the net revenues is greater than the fixed obligations, there is no stranded cost.

In the case where the present value of the stream of revenues is less than the present value of the stream of avoidable costs, the net revenues should be zero for the purpose of calculating stranded costs, and the utility should cease operating its generation facilities or buying power.

These administratively calculated stranded costs should be used when the market value of power production assets is not obtainable.

Q. Please describe market valuation of power production assets.

A. A buyer contemplating the purchase of power production assets such as a generating plant would consider the present value calculation described above. But, in addition, it would also consider the strategic value of the assets in providing reliable service, in enhancing its marketplace position, and in gaining credibility by having adequate resources to supply power in the region. In other words, some entities, who would be candidates to purchase physical power supply assets, could value those assets differently than would occur in a "standard" electric utility evaluation. As a result, a buyer might pay more than the present value of the net revenues from the resources as calculated using the administrative method described above. Further, different buyers may have different estimates of the present value of net revenues, of market prices, and of strategic values. The buyer with the highest value should be used to set the market price. Consequently, alleged stranded costs determined by market value could be significantly lower than estimated under the administrative calculation and could possibly be zero. Market valuation also provides a more accurate depiction of stranded costs, providing valid data are available.

Q. Have buyers paid more than the book value of power production resources?

A. Yes. U.S. Generating purchased 5,000 MW of generation assets from New England Electric System for $1.59 billion which exceeded book value by over $500 million. Southern California Edison sold 10 fossil-fueled generating plants for $1.115 billion; the book value of the plants was $421 million. Duke Energy Power Services bid $501 million for three Pacific Gas and Electric plants (2,645 MW) which is about $120 million more than book value.[1]

Q. How should the market price of electricity be estimated for use as a factor in the determination of stranded costs described above?

A. The market price is a critical factor in calculating stranded costs when an administrative calculation is used. I believe that generating utilities should use the best estimate of the average price paid for electricity in the competitive market. This estimate should consider not only spot market purchases (such as at the spot market at Palo Verde and other southwestern hubs) but also prices paid for electricity purchased under short, medium, and long term contracts.

Before competition starts, the average price is unknown. Estimates of average spot prices would be about $25 per MWH based upon prices paid at Palo Verde. Spot prices at all southwestern hubs should be included. In the long run, prices should tend toward long run marginal cost. At favorable natural gas prices, long run marginal cost could be $35 per MWH but if natural gas prices rise, long run marginal cost could be $45 per MWH. Specific selection of long run marginal costs should be made using clearly stated assumptions about technology, capital costs, operating and maintenance costs, fuel costs, heat rates, capacity factors, time horizons, and discount rates. Specific assumptions should withstand scrutiny by the Commission and other parties.

I recommend that any needed estimates of market prices consider both spot market prices and contract prices and that the Commission take into account pertinent testimony in stranded cost hearings regarding the relative importance of spot market and contract purchases.

[1] *Independent Power Report*, August 22, 1997, p. 20; *Global Power Report*, November 28, 1997.

Q. Should the Commission give greater weight to a generating utility's administrative calculation of stranded costs or to the comparison of book value with the sale price of a resource?

A. Greater weight should be accorded to the comparison of book value with the sale price, when such information is available. As I suggested above, administrative estimates cannot take into account all the factors that affect the value of a resource to a buyer. The Commission should consider the range of administrative estimates of stranded costs submitted by utilities and other parties in stranded cost hearings. In contrast, the sale price (assuming the sale were an arms-length transaction) is solid evidence of the market value of the resource which can be compared with the regulated book value. The deference given to sales prices should be an incentive for utilities to sell generating resources where possible if a major priority of the utility is to recover all stranded costs.

Q. How should stranded costs associated with power supply be calculated for a distribution cooperative?

A. In general two approaches can be taken. The first would be to assume that an allocation of the stranded costs of the G&T would be passed through to the distribution cooperative and would become the distribution cooperative's power supply related stranded costs. The second would be to perform a similar calculation to that discussed above for a G&T, except that the costs associated with the distribution cooperative's power supply contract would be substituted for the G&T's generation costs. Though the results of the two approaches may be similar, the concepts are quite different, with the second approach being more theoretically correct since it is the power supply contract with the G&T that is causing the distribution cooperative to have a stranded cost and not the power supply resource itself.

Q. How should the revenue from retail sales be computed?

A. If a determination of net present value of the net revenues from retail sales is to be made before competition starts, it would be necessary to value these sales at regulated rates. After competition starts, the sales should be valued at market prices. During a phase-in period, sales in the competitive market should be valued at market prices and sales in the regulated portion of the market should be valued at regulated prices. In addition, after competition starts, the Commission, under A.A.C. R14-2-1614, will have better information on kWh sales and revenues in the competitive market from each energy service provider. Those data can be used to calculate average market prices.

Q. What are the implications of the Statement of Financial Accounting Standards No. 71 (SFAS 71) resulting from the recommended stranded cost calculation and recovery methodology?

A. I am not able to address this issue from an accounting perspective since I am not an accountant. However, from a common sense perspective, if stranded costs are small or zero, it should not be an issue. If a utility has the opportunity to recover its stranded costs, as determined by the Commission, SFAS 71 would not seem to be an issue.

4. Time Horizon for Calculating Stranded Costs

Q. Should there be a limitation on the time frame over which stranded costs are calculated?

A. Yes. As I indicated above, streams of future costs and revenues must be calculated. Therefore, a time horizon must be selected for the calculation. I propose that the following time horizon be selected (which could be different for each utility):

The shorter of:

a) the average remaining book life of the utility's relevant assets and obligations, and
b) 15 years.

There is great uncertainty about future costs and revenues, so the present value of net revenues should be calculated with a commensurably large discount rate. Discounting future costs and revenues render insignificant events after 15 years and possibly events ten years out.

5. Time Period for Recovery of Stranded Costs

Q. Should there be a limitation on the recovery time frame for stranded costs?

A. When the Commission reviews stranded cost recovery proposals, it should consider the impact on the utility and consumers of varying the time period for recovering stranded costs. For example, too short a time period might result in a stranded cost recovery charge that is so high that it imperils competition. Conditions will vary from case to case.

Analyses of stranded costs conducted for other utilities suggest that there is no one best time frame, considering the magnitude of the stranded cost recovery factor and the impact of that factor on consumers. However, as a rough guide, I believe it would be appropriate for the Commission to indicate that it expects that the opportunity to recover stranded costs will expire by December 31, 2005. An outer limit gives consumers a signal that the benefits of competition will not be long delayed.

6. Paying for Stranded Costs

Q. How and who should pay for stranded costs and who, if anyone, should be excluded from paying for stranded costs?

A. Stranded costs should be recovered by the utility through a separate non-bypassable charge. Such costs could be assessed in dollars per kWh, dollars per kW, or dollars per month. I believe that most competitive purchases of energy will be priced in terms of dollars per kWh. Further, most residential and small commercial consumers are metered only for kWh. Therefore, the stranded cost recovery factor should be expressed in dollars per kWh. For larger commercial and industrial consumers with demand meters, a dollar per kW charge could be assessed in lieu of, or in combination with, a dollar per kWh charge. When suitable, dollars per kVA could be used in place of dollars per kW.

Consumers subject to the stranded cost recovery charge are all (and only) consumers purchasing in the competitive market. Consumers purchasing bundled standard offer services during the phase-in period are already paying the full freight on the utility's assets and obligations. They should not be double-charged. Consumers purchasing services in the competitive market would leave the utility with no means to recover stranded costs in the absence of a non-bypassable stranded cost recovery charge.

Q. Do you have any additional comments to make concerning payment for stranded costs that directly relate to distribution cooperatives?

A. The dollars recovered from a stranded cost recovery mechanism should flow to the entity responsible for the debt which gives rise to the stranded costs. A careful evaluation must be made to address specific circumstances between distribution cooperatives and G&Ts. The situation is further affected by whether the distribution cooperatives are partial requirements customers of the G&T or all-requirements customers of the G&T.

7. True-Up Mechanism

Q. Should there be a true-up mechanism?

A. In general, yes. Customers subject to stranded cost recovery charges should know those charges up-front. Therefore, the Commission should set stranded cost recovery charges before they are to be imposed and should not impose them retroactively.

As I indicated above, the market price of electricity in the competitive market is not known. Therefore, the Commission's initial stranded cost recovery factor will be in error and should be adjusted to ensure that the utilities recover the proper amount of money. Further, the market price will evolve over time and the recovery factor should be modified.

A true-up would not be needed if stranded cost were known for certain as would occur if all strandable generation assets were sold. In some instances for cooperatives, the Commission may wish to encourage a sale to avoid a subsequent complex true-up process.

Q. How would a true-up mechanism operate?

A. I believe the stranded cost recovery factors for each utility should be reset every one to two years using the most recent market price data, collections made via the stranded cost recovery charge, changes in the magnitude of potentially stranded costs, and other pertinent information. The Commission would conduct an abbreviated hearing to set the new stranded cost recovery factors. The analyses and hearing would be roughly similar to a fuel and purchased power cost adjustment review.

8. Price Caps and Rate Freeze

Q. Should there be price caps or a rate freeze imposed as part of the development of a stranded cost recovery program and, if so, how should they be calculated?

A. No. Price caps and rate freezes have been combined with the introduction of competition in some states as part of a package. Development of such a package in Arizona that is acceptable to many diverse parties may be time-consuming and delay the introduction of competition. Further, the rate freeze would have to be agreed to by each utility. Price caps would probably require full-blown rate hearings unless the utilities agreed to them. We have already gone well down the road to competition with the rule adopted by the Commission in 1996. Changing course now would probably be counter-productive.

9. Mitigation of Stranded Costs

Q. What factors should be considered for mitigation of stranded costs?

A. Each utility has different opportunities to mitigate stranded costs. In general, these include selling energy at wholesale or retail in other markets made available by competition, sale of non-traditional services, and cost-cutting. The specific mix would vary from utility to utility depending on each utility's competence, strategies, and feasible opportunities. The Rules require that each utility assertively pursue mitigation. A G&T cooperative should seek out mitigation alternatives and RUS has a program whereby a G&T can be evaluated in the marketplace to determine what is best for the consumers, lenders, and distribution owners of the G&T.

Conclusions

Q. Please summarize your recommendations.

A. My recommendations on each of the questions posed in the Procedural Orders are presented above. I would like to highlight some of these recommendations:

- I recommend that the Commission not foreclose creative solutions to stranded cost issues that could be worked out by distribution cooperatives and their generation and transmission suppliers.

- I recommend that the Commission encourage all distribution cooperatives and G&Ts to reduce the risk of additional stranded investment exposure by avoiding obstacles to restructuring all-requirements contracts that they may work out. In particular, Arizona distribution cooperatives are working with G&Ts to convert all-requirements contracts to partial requirements contracts. The Commission should encourage this creation of opportunities to lower costs and enable member-customers of distribution cooperatives to have meaningful choices among electric suppliers.

- I recommend that the Commission leave the current Rules as they are and retain the flexibility to deal effectively and fairly with all the utility-specific features that will be presented in stranded cost recovery hearings.

- I recommend that the Commission give greater weight to calculations of stranded cost based on the sale price of generation resources than to calculations based on administrative methods.

- I recommend that the market price of electricity used in administrative valuations of power supply stranded costs reflect the mix of spot market purchases and short, medium, and long term contracts.

- I recommend that a true-up mechanism be used unless all potentially stranded resources are sold or unless there are no stranded costs.

Q. Does this conclude your direct testimony?

A. Yes.

Attachment 1

EXPERT WITNESS QUALIFICATIONS

OF

ALAN PROPPER

Mr. Propper is a veteran of the electric and gas utility industry with over 30 years' experience as an industry consultant and utility company manager specializing in the cost analysis, pricing, economics, and regulatory areas of this business. He holds the degrees of Mechanical Engineer from Stevens Institute of Technology and Master of Business Administration from San Francisco State University. He is certified as an Instructor of Engineering and Business Administration by the Arizona State Community College Certification Board. He has also completed Advanced Alternative Dispute Resolution Training and has been certified to act as a Mediator by the Northwest Regional Transmission Association and by the Western Regional Transmission Association.

In addition to holding the position of Regional Manager in Phoenix for Resource Management International, Inc. (RMI), he serves the firm as a Principal Executive Consultant whose areas of expertise include embedded and marginal cost analyses, pricing and rate design, special marketing and load management programs, State and Federal regulatory matters, contract negotiations between utilities concerning resale and wheeling services, contract negotiations between utilities and their major retail customers, and organizational training and restructuring. Mr. Propper is also a highly experienced and accomplished expert witness, having successfully testified on numerous occasions on contract provisions, pricing, and cost matters before many State and Federal regulatory agencies.

Prior to joining RMI, Mr. Propper served as Principal Consultant and Director of Consulting Services for A&C Enercom, Manager of Rate Services for Arizona Public Service Company, Supervisor of Rates for Consumers Power Company, Executive Consultant for Commonwealth Services, Forecast Engineer and Rate Engineer for Pacific Gas & Electric Company, and in Power Plant Operations for Public Service Electric & Gas Company.

Mr. Propper is recognized by his peers as an active participant in the utility industry organizations, helping to resolve many of the current regulatory, restructuring, and rate related problems facing the industry. He is an active associate member of National Rural Electric Cooperative Association. He has served on the Edison Electric Institute's Rate Committee and its Transmission Access Technical Task Force, as well as numerous other industry committees involved with training and educating utility industry personnel on today's technical and regulatory problems. He is also is member of the American Gas Association's Rate Research Committee and contributing author of their widely used text, Gas Rate Fundamentals, Fourth Edition.