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DIRECT TESTIMONY

OF

KEVIN C. HIGGINS

ON BEHALF OF
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION,
BHP COPPER, CYPRUS CLIMAX METALS, ASARCO,
PHELPS DODGE, AJO IMPROVEMENT COMPANY, AND
MORENCI WATER & ELECTRIC COMPANY

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

January 21, 1998

EXHIBIT
AECC et al. 3
Admitted

Direct Testimony of Kevin C. Higgins

Summary of Conclusions and Recommendations

The public interest dictates that the Commission strike an appropriate balance between customer and utility interests in implementing a stranded cost recovery program. It is also critical to design stranded cost recovery in a way which maximizes utilities' incentives to undertake successful mitigation activities.

These objectives can be accomplished by adopting the following proposed calculation, recovery, and mitigation approach in its entirety:

(1) A limited transition period of three to five years for calculation and recovery of strandable cost is designated.

(2) Strandable cost is calculated using a hybrid of the replacement cost valuation and net revenues lost approaches, in which:

(a) The net revenues lost approach is used to estimate strandable cost on a *year-to year* basis.

(b) *Total* strandable cost is calculated using the replacement cost valuation method. This calculation is designated to be the maximum allowable strandable cost over the transition period, providing an upper bound on the sum of year-to-year strandable costs.

(3) Customers pay for a portion of strandable cost through a transition charge levied on distribution service. During any given year, the transition charge applies only toward strandable cost associated with that same year.

(4) The portion of strandable cost recovered through the transition charge declines each year, such that the overall percentage falls within the lower-to-middle portion of the 25 to 50 percent range, e.g., 35 percent.

(5) Utilities are deemed to be at-risk for recovery of the remainder of their strandable cost (associated only with the competitive market). They are free to implement whatever mitigation actions they believe to be most effective, and retain the financial benefits when their mitigation efforts are successful (subject to any required adjustments associated with the portion of their retail business still receiving Standard Offer service).

(6) Any "true-ups" are limited to adjustments for deviations from the market price of power.

(7) At the end of the designated transition period, strandable cost is no longer estimated and the transition charge ceases.

This approach automatically builds in a price cap, ensuring that the final delivered price to consumers under competition is no greater than under regulation. A price cap is an essential objective in designing a strandable cost recovery mechanism.

In allocating the transition costs among customer classes, the Commission should follow the consensus recommendation of the Stranded Cost Working Group, which states that strandable cost should be allocated among customer classes "in a manner consistent with the specific company's current rate treatment of the stranded asset, in order to effect a recovery of stranded costs that is in substantially the same proportion as the recovery of similar costs from customers or customer classes under current rates." This provision is critical for preventing cost-shifting among customers in the recovery of strandable costs.

The Commission should also retain the important language in the Rule which states that any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand reduction attributable to any cause other than retail access shall not be used to calculate or recover any Stranded Cost from a consumer. Options such as self-generation and demand-side management have been available to customers for many years. These demand reductions are business risks to the utility which pre-date retail access. Customers in the past have not been subject to stranded-cost-type penalties when exercising these options, and the advent of retail access should not to be used as a pretext to start insulating utilities from these ordinary business risks now. In addition, strandable cost charges should not be assigned to service that had been interruptible under the customer's previous arrangement with the Affected Utility, because generation capacity is not constructed to provide interruptible service.

Retail competition will present opportunities and risks for both customers and utilities, while the burden of strandable cost represents a hindrance to both groups. Equity and efficiency require that a reasonable sharing of this burden be devised. This testimony proposes an approach in which a reasonable sharing is achieved and the incentive for mitigation is maximized. It combines calculation methods supported by both utilities and customers and presents a strategy for genuine transition to a competitive marketplace for consumers and utilities alike.

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am employed by Energy Strategies, Inc. (ESI) as a senior associate. ESI is a private consulting firm specializing in the economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition[1], BHP Copper, Cyprus Climax Metals, Asarco, Phelps Dodge, Ajo Improvement Company, and Morenci Water & Electric Company.

Q. What are your qualifications to testify in this proceeding?

A. My academic background is in economics, and I have completed all course work and examinations toward the Ph.D. in Economics at the University of Utah, and have served on the adjunct faculties of both the University of Utah and Westminster College. Prior to joining ESI, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I testified regularly before the Utah Public Service Commission on matters involving structural change in the provision of energy services, including introduction of retail

[1] Arizonans for Electric Choice and Competition is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Association of General Contractors, and Arizona Retailers Association.

competition in the natural gas industry, implementation of rules governing small power production and cogeneration, joint ownership of electric transmission facilities, and the merger between major electric utilities. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, one of the larger municipal governments in the western U.S., where I was responsible for development and implementation of a broad spectrum of public policy. In 1995, I joined ESI, where I assist private and public-sector clients in the area of energy-related economic and policy analysis.

For much of 1996, I was involved in the workshop process conducted by the Arizona Corporation Commission to develop rules governing the implementation of retail access. In 1997, I participated in the Working Group process established by the Commission, serving as one of five voting consumer representatives on the Stranded Cost Working Group; as part of that effort, I participated in each of the Working Group's three subcommittees.

Also during 1997, I provided expert testimony on stranded cost recovery in the Con Edison restructuring hearing conducted by the New York Public Service Commission. In that case, I recommended against adoption of the stranded cost recovery charge that had been incorporated into a settlement between Staff and the utility on the grounds that the resulting cost to customers would be excessive and thwart competition. The Commission agreed with this position and ordered that the stranded cost charge in the settlement be modified to reduce the cost to customers.

A more detailed description of my qualifications is contained in Exhibit KCH-1, attached to this testimony.

Q. What general areas will your testimony address?

A. My testimony addresses the nine stranded-cost-related questions posed in the Commission's Procedural Order of December 1, 1997, as amended December 11, 1997, and includes specific recommendations for supplementing the Commission's Electric Competition Rule ("Rule"). These recommendations are included in Exhibit KCH-2. Also included in my testimony are general policy recommendations, as well as a specific proposal for calculation, recovery, and mitigation of stranded cost using a hybrid of the replacement cost valuation and net revenues lost approaches. I recommend these policies be adopted by the Commission in its implementation of the Rule. These policy recommendations are presented in Exhibit KCH-3.

Two other witnesses are providing testimony in conjunction with mine. Dr. J. Robert Malko provides additional testimony pertaining to questions 3, 6, and 9. Dr. Malko's testimony focuses on the issue of risk sharing between customers and investors in the determination of a stranded cost recovery mechanism, and provides an evaluation of the risk-sharing proposal contained in my testimony.

Dr. Alan Rosenberg offers testimony pertaining to questions 3, 4, and 5. His testimony presents an assessment of stranded-cost calculation methodologies and recovery mechanisms, providing a helpful framework for selecting an appropriate approach in Arizona.

Q. <u>Should the Electric Competition Rules be modified regarding stranded costs? If so, how? (Question 1)</u>

A. If by "modifying the Rules" we mean changing fundamental features of the Rule, the answer is no: the Electric Competition Rules do not need to be modified regarding stranded cost. The Rules provide a workable definition of stranded cost and anticipate that utility-specific stranded cost determination will be resolved in evidentiary hearings. In addition, the Rules provide guidance by identifying the factors to be considered in designing a stranded cost recovery program.

However, if by "modifying the Rules" we mean adding supplemental and clarifying provisions to the existing Rules, the answer is yes. In responding to the questions posed in the Procedural Order, I will be making specific recommendations concerning utility filing deadlines, allocation of strandable cost among customers, and reinforcement of the Commission's intention to balance utility and customer interests. These recommendations can be adopted as supplements to the existing Rules, and as indicated previously, are presented in Exhibit KCH-2.

Q. **<u>When should Affected Utilities be required to make a "stranded cost" filing pursuant to A.A.C. R14-2-1607? (Question 2)</u>**

A. As a general proposition, Affected Utilities are *not* required to make a stranded cost filing -- nor should they be. Such a filing is only necessary if an Affected Utility wishes to recover potentially strandable cost from customers through a Commission-assessed charge. If a utility wishes to effect such a recovery, the burden should be on that utility to file far enough in advance of the date it wishes to initiate recovery.to allow for evidentiary hearings on the request. I recommend that such a period be no less than eight months.

Q. **If an Affected Utility's stranded cost situation is unresolved before January 1, 1999, should implementation of retail competition be delayed?**

A. Absolutely not. Affected Utilities have been on notice since 1996 that retail access would begin January 1, 1999. It is also clear that the burden of making a request for stranded cost recovery rests with the Affected Utility. If an Affected Utility does not take sufficient steps to address its stranded cost concerns in time to effect recovery starting January 1, 1999, then retail competition should begin as planned, with stranded cost recovery implemented at the time it is finally resolved.

Q. <u>What costs should be included as part of "stranded costs" and how should those costs be calculated? (Question 3)</u>

A. "Stranded cost" is a term used to refer to that portion of a utility's regulator-approved, generation-related fixed costs and regulatory assets which the utility does not recover due to the introduction of a competitive generation market and the resultant lower electricity prices. The Electric Competition Rule defines stranded cost in an equivalent manner: it is the net difference between the value of a utility's generation-related assets and obligations under traditional regulation and the market value of those assets and obligations directly attributable to the introduction of competition. As such, stranded cost is not an enumeration of costs per se, but the *difference* between these two valuations.

Stranded cost does not include any operating costs. If a facility's operating costs can not be recovered in a competitive market, economic rationality dictates that the facility be shut down. The exception to the shut-down rule would occur only in the case of a facility required to operate for reliability-related reasons. Such facilities require special pricing and operating treatment under retail competition.

It follows, then, that the only costs which should be included as part of stranded cost is some portion of Commission-approved, generation-related fixed costs and regulatory assets.

Q. The Rule indicates that retail access is to be phased in over a four-year period. What are the stranded cost implications of such a phase-in?

The only portion of an Affected Utility's fixed cost that has the potential to be "stranded" is the portion exposed to competition. Consequently, under the Rule, only 20 percent of a utility's retail generation business has any strandable cost exposure for the first two years of retail access. In subsequent years, the exposure will be proportionate to the share of the retail market which is open to competition under the Rule's phase-in provisions.

Q. Before proceeding to a more detailed discussion on calculation methods, are there any important overview considerations you wish to address?

A. Yes. It is particularly important to discuss: (1) the speculative nature of stranded cost, (2) the interrelationship between the magnitude of stranded cost and the design of the recovery program, and (3) equity considerations. It is important to address these matters at the outset, so that the discussion of calculation methods is placed in a proper framework.

Q. What do you mean by the "speculative nature" of stranded cost?

A. When we speak today of "stranded cost," we are really speaking of costs which are *at risk* of being "stranded" some time in the *future* – after the introduction of competition. This distinction is sometimes overlooked, because in common usage, the word *stranded* suggests an action which has *already* occurred, as in someone or something being left stranded in the desert. However, such is not the case with stranded cost. Prior to the introduction of competition, there is no stranded cost. To estimate, in the present, what stranded cost will turn out to be requires speculation about the future.

In order to emphasize the speculative or at-risk nature of "stranded" cost, some jurisdictions prefer the term *strandable* cost. It is a term I too will use in this testimony when referring to future or potential stranded cost.

Q. Why is it important to emphasize the speculative nature of stranded cost?

A. Emphasizing its speculative nature is important because too often stranded cost is discussed as if it can be known with great specificity in advance, whereas, in fact, for any utility there is a *range* of potential stranded costs, corresponding to a variety of possible future outcomes. Complicating matters further, part of this uncertainty involves the future performance of the utility itself -- e.g., whether it will be successful in reducing future operating costs, finding new markets for its products, and so on.

Q. How does a utility's future performance impact stranded cost?

A. Utilities which are successful in cutting costs or increasing market share will lower their stranded cost from what it would have been otherwise because they will be able to recover a greater portion of their fixed generation costs and regulatory assets from the marketplace. Thus, when we address the question, "What will be the magnitude of stranded cost and how do we estimate it?" we are simultaneously faced with the question, "How successful will the utility's mitigation efforts be?" Yet it follows that the success of a utility's mitigation efforts will depend, in large part, on the *design* of the stranded cost recovery program and the *incentives* to mitigate stranded cost which are incorporated into that program.

Significantly, then, the magnitude of stranded cost is dependent on the success of utility mitigation which, in turn, is dependent on the design of the recovery program.

Therefore, it is critical to design stranded cost recovery in a way which maximizes utilities' incentives to undertake successful mitigation activities.

Q. What type of mitigation incentives do you recommend?

A. The best mitigation incentive is for the utility to be at risk for recovery of a substantial portion of its potentially stranded cost, and to be financially rewarded when its mitigation efforts are successful. This type of incentive mechanism relies upon the basic principles of the marketplace to guide utilities towards efficient mitigation strategies and represents a significant step in effecting a transition from a regulatory to a competitive paradigm for the utilities involved. Note that during the phase-in period, the utility's exposure to strandable cost risk is limited to the portion of its historical customer base that participates in the competitive market.

Q. What approaches to recovery of strandable cost should be avoided?

A. We should avoid any recovery program in which all (or most) of the stranded cost risk is placed on customers (as was proposed, for example, by the former staff director in the Report of the Stranded Cost Working Group). Using such an approach, customers are required to guarantee recovery of a utility's potentially stranded cost under what are, in effect, worst-case conditions; then, if mitigation occurs, stranded cost charges are subject to a later reduction by means of a "true-up." From the perspective of both equity and efficiency, this type of approach represents the worst of both worlds: the burden of guaranteeing recovery of uneconomic costs is disproportionately borne by customers (inequitable), while the incentive mechanism for utilities to lower future stranded cost through mitigation is minimized (inefficient). In essence, such an approach presumes a worst-case scenario at the outset; then, by means of the recovery program design, the presumption of a worst-case scenario becomes a self-fulfilling prophesy.

Q. What equity issues should the Commission consider?

A. We must first recognize that the assignment of responsibility to customers for recovery of any potentially stranded cost is an extraordinary proposition. Regulatory change is a business risk inherent in all industries, and generally, it is expected that this risk is borne by company shareholders. But because the electric utility industry has been heavily regulated, utility advocates maintain that strandable cost recovery is the sole responsibility of customers under the terms of an implicit compact. Their argument presumes that deregulation of generation service is a one-way street: good for consumers, bad for investors. It ignores the fact that deregulation of generation prices will mean that investors will have the opportunity over the long-run to earn above a regulated return – using the very assets that will be the subject of stranded cost claims. Certainly, investors in electric utilities have been on notice for a number of years that restructuring and regulatory changes were coming which would introduce greater competition. These changes will provide long-term opportunities for some companies, but might also place full recovery of fixed costs at risk, at least in the short run. Because competition will provide opportunities for both customers and investors, it is inappropriate to conclude that changing the regulatory paradigm requires customers alone to shoulder the risk of strandable cost.

We should also bear in mind that the introduction of competition *by itself* does not cause stranded cost – nor is stranded cost caused by customers choosing new suppliers. Stranded cost can only occur if a monopoly generation provider is unable to recover all of its fixed costs plus regulatory assets in the new competitive market. This circumstance can only occur if competitive sellers are willing and *able* to sell generation at prices below what the former monopoly requires for recovery of fixed costs plus regulatory assets. *The ability of competitive suppliers to undercut incumbent utility prices is a situation which is not caused by customers*; nonetheless, the very concept of stranded cost recovery presumes that customers will be responsible for funding a program to subsidize some portion of above-market costs after the introduction of competition.

Given that the Rule contemplates that some customer charge for recovery of strandable cost will be levied, the public interest dictates that the Commission strike an appropriate balance between customer and utility interests in designing the recovery mechanism. The Commission recognizes this obligation in the Electric Competition Rules by enumerating eleven factors it will consider in determining stranded cost recovery. Included in these factors are: the impact of stranded cost recovery on prices paid by consumers in the competitive market, the impact on customers who do not participate in the competitive market, and the impact of stranded cost recovery on the effectiveness of competition itself. It is clear from these factors that the Commission seeks to balance customer and utility interests in approving a stranded cost recovery mechanism. To emphasize this intention, I recommend an addition to Section 1607(I) of the Rule which explicitly references this balancing, as indicated in Exhibit KCH-2. In addition, Section 1607(B) should be clarified by referencing the governing principles of 1607(I).

Q. **How can the Commission best achieve a balance between customer and utility interests in approving a stranded cost recovery mechanism?**

A. The recovery mechanism can be designed to ensure recovery of some reasonable portion of strandable costs via a transition charge paid by customers, while giving the utility the opportunity for recovery of the remainder through its mitigation efforts. The portion to be recovered through mitigation should be deemed to be "at-risk" for the utility from the outset; it should not be assigned at any time to the customers' transition charge.

Q. **What portion of potentially stranded cost should be ensured via a transition charge on customers?**

A. The answer to this question depends on the calculation method/recovery mechanism package which is adopted. For example, if the approach used to estimate strandable cost is relatively generous to the utility, then the portion of strandable cost recovered from customers through a transition charge should be lower. As a general proposition, the portion of strandable cost that is recovered through the transition charge should be in the range of 25 to 50 percent.

Q. **Please clarify what you mean when you refer to a calculation approach which is "relatively generous to the utility."**

A. As I have indicated previously in this testimony, when we speak today of stranded cost, we are really speaking of costs which are *at risk* of being "stranded" some time in the future; thus, for any utility there is a *range* of potential stranded costs, corresponding to a variety of possible future outcomes – some of which even depend on the utility's own future performance. Because there is a range of possible outcomes, the estimation of potential stranded cost will be very assumption-sensitive. The estimation will also be sensitive to the inclusion of certain variables in the calculation. How these variables and assumptions are treated will impact the magnitude of the estimate; certain treatments will result in strandable cost estimates which are higher, or more generous, than others. In general, the more an estimation approach builds into the strandable cost calculation the expectation that the utility's future *non-fixed* costs will continue to be equal to or above the levels experienced under regulation, the more generous the calculation is to the utility.

Q. Can you give an example of the point you are making?

A. Yes. At the risk of getting ahead of the discussion on calculation methods, I will note that certain methods – notably the utility-preferred net lost revenues approach – produce results in which the estimate of strandable cost is driven by assumptions concerning future operating costs and administrative and general (A&G) costs, such that for every dollar increase in the present-value forecast of these *non-fixed* costs there is a one dollar increase in the calculation of *strandable* (fixed) cost. Using such an estimation approach, every dollar of A&G cost which is assigned to generation results in a dollar of strandable cost. It is easy to see, then, that if we use such a method, and assume that a utility plans not to reduce – but to increase – its A&G costs in a competitive market, the entire increase shows up in the strandable cost estimate, a result which is very generous to the utility indeed. Strandable cost estimated in a manner this favorable to the utility should be balanced by recovering a lower portion of strandable cost via the transition charge and by considering a commensurately greater portion of strandable cost to be at-risk.

Q. Are you familiar with the calculation methodologies discussed in the Report of the Stranded Cost Working Group?

A. Yes, I am.

Q. Please rank these approaches according to their desirability, as required by the First Amended Procedural Order.

A. My ranking of these approaches, from most desirable to least is:

1) Tie: Auction and divestiture

1) Tie: Replacement cost valuation

3) Net revenues lost

Not ranked: Stock market valuation

Q. Please explain your ranking.

A. Auction and divestiture is ranked in a tie for first because it is the most direct means to evaluate stranded cost. Using this method, stranded cost is the difference between net book value of generation assets (plus regulatory assets) and the proceeds from the sale of these generation assets at auction. This method matches up very well with the definition of stranded cost in the Rule, for net book value *is* the regulatory value of generation assets, and the proceeds from the sale of generation assets represents the value of these assets under competition.

Auction and divestiture has two decided advantages. First, by using a market transaction to value generation assets, the method avoids the use of an administrative procedure to estimate strandable cost. Second, a properly-designed auction will result in the valuation being set by the party who values the asset most. Rather than searching for consensus or mid-range assumptions about future conditions, it is the assumptions of the most bullish party which prevail. Such a result benefits both the utility and the customers, because a high sale price for the assets reduces the strandable cost which may remain.

I should note also that since an auction may result in the transfer of the asset to another party, the efficiency reasons for keeping the utility at risk for recovery of stranded cost disappear. In fact, the efficiency gains anticipated by the winning bidder ought to be reflected in that party's bid. Thus, if auction and divestiture is used to calculate stranded cost, the share of stranded cost assignable to the customer-paid transition charge should be determined on equity grounds alone; that is, it should be in the upper end of the 25 to 50 percent range.

Q. **Do you see any drawbacks to the auction and divestiture approach?**

A. Yes, unfortunately. While auction and divestiture provides the most accurate basis for determining stranded cost, it may be problematic for the Commission to require that such an auction take place if the utility is an unwilling seller. However, this problem may not be insurmountable, as other states are demonstrating that successful divestiture programs can be implemented. A more difficult drawback concerns the limited applicability of an auction process to nuclear assets. Federal restrictions on ownership of nuclear assets are likely to limit the field of bidders, artificially suppressing the value obtained from a winning bid. Therefore, although I rank auction and divestiture high on *conceptual* grounds, I do not consider it to be a preferred option when nuclear facilities are involved.

Q. **Please explain your ranking of "replacement cost valuation" as tied for first place.**

A. The replacement cost valuation approach to evaluating strandable cost is intended to serve as an administrative proxy for an auction, while avoiding the difficulties of a forced divestiture. Using this method, strandable cost is estimated on an asset-by-asset basis, by taking the difference between: (1) the net book value of a utility's generation assets plus regulatory assets (regulatory value) and (2) the current replacement cost of those assets (market value), using the most cost-effective technology available. In this application, the replacement cost would include an adjustment for any capitalized energy value implicit in utility facilities that have variable energy costs lower than the replacement technology. It may also include an adjustment for life expectancy of each utility facility.

This method also matches up very well with the definition of stranded cost in the Rule, as strandable cost is estimated by taking the difference between the regulatory and market values of a utility's generation assets. As with auction and divestiture, the regulatory value of a utility's generation assets is net book value. The market value of the utility's generation assets is represented by the assets' replacement cost, appropriately adjusted for capitalized energy value and life expectancy.

Q. Why use replacement cost as the measure of the market value of the utility's generation assets?

A. The change from a regulatory to a competitive environment for retail electric generation is a long-term proposition, as the resources controlled by generation owners will be freed *permanently* from price regulation. While, on the one hand, competition will result in generally lower prices than under cost-plus regulation, there will also be periods when high returns are likely, especially for owners of facilities that have been substantially depreciated. Economic theory tells us that in the long run, prices gravitate toward long-run marginal costs in competitive markets. In electricity generation, long-run marginal costs will be set by the fixed costs and operating costs of the most cost-effective generation technology available, i.e., replacement cost. Therefore, the best measure of the long-term value of the utility's generation assets in a competitive market is the installed cost of the technology which could replace those assets, appropriately adjusted for capitalized energy value and life expectancy.

Q. Can you provide a simple example of how the replacement cost valuation approach would work?

A. Yes. Assume a utility had 2000 megawatts of generation with a net book value of $1.2 billion. Assume also, for this illustration, that the operating cost of the utility's generation and the life expectancy of its facilities were comparable to a new, gas-fired combined-cycle facility, so that no adjustments to the replacement cost value are necessary. If the installed cost of the combined-cycle facility is $500 per kilowatt, then the replacement cost of the utility's existing generation – following an asset-by-asset analysis – would be estimated to be $500/kw times 2 million kw, or $1 billion. Since strandable cost is the difference between net book value and replacement cost, we subtract $1 billion from $1.2 billion to arrive at a strandable cost estimate of $200 million. Of this $200 million, some portion – but no more than 50 percent by my recommendation – would be recovered through a transition charge on customers. The remainder would be at-risk to the utility, which would have the incentive to undertake mitigation actions to recover it.

Q. What are the advantages of using the replacement cost valuation approach?

A. As I indicated previously, this approach has the advantage of matching up well with the definition of stranded cost in the Rule. It also has the advantage of reflecting the long-term valuation of utility generation assets. One hazard in estimating strandable cost is to make the mistake of overemphasizing the impact of short-term periods when electricity prices may be below long-run marginal costs. Such an overemphasis would likely lead to a stranded-cost-recovery windfall for utilities. This hazard is especially acute when using the net revenues lost approach, as will be discussed shortly. By using a long-term measure of asset value, the replacement cost valuation approach captures the essence of the long-term change in paradigm which will come with the introduction of retail competition. Periods of pricing below long-run marginal costs will likely be punctuated by periods of pricing above long-run marginal costs; predicting the deviations and durations of these periods is very difficult, but it is reasonable to expect the long-term trend to gravitate to the long-run marginal cost of the most cost-effective replacement technology.

I conclude that the replacement cost valuation method is the preferred administrative approach to calculating strandable cost. It was also the unanimous choice of the consumer participants in the Stranded Cost Working Group.

Q. Why do you rank the net revenues lost approach last?

A. The net revenues lost approach estimates strandable cost by taking the present value of the difference between the generation-related revenue the utility might have been expected to collect under continued regulation and the generation-related revenue anticipated under competitive market pricing. Typically, the expected revenue under continued regulation is based on projections of the utility's generation costs, including return on rate base. A utility requesting stranded cost recovery using this method would likely include in its generation-related costs all operating costs – such as fuel, O&M, and materials – plus fixed costs, primarily depreciation and return on generation-related rate base. To this amount will be added property taxes, purchased power costs, amortization and return on regulatory assets, plus a portion of the utility's administrative and general costs that is allocated to generation.

Generation-related revenue anticipated under competitive market pricing is essentially a forecast of market price (inclusive of capacity charges) times a projection of kilowatt-hours sold.

The salient feature of the net revenues lost approach is its presumption that stranded cost is whatever additional amount consumers would have had to pay for electric power if regulation continued and competition never occurred. I rank this approach last because, carried to its extreme, it completely defeats the purpose of moving to a competitive market.

One of the chief flaws of the net revenues lost approach is that it saddles consumers – through the strandable cost calculation – with the *operating* costs of the utility that would have been expected if regulation were to continue into the foreseeable future. Even though strandable cost is limited to fixed costs plus regulatory assets, the mathematics of the net revenues lost method results in a direct correspondence between operating cost assumptions and the strandable cost estimate. The result is that for every one-dollar increase in the present value of future operating costs assumed under continued regulation, there is a one-dollar increase in strandable cost. This same relationship occurs for administrative and general costs, as well as each of the other components included in the projection of generation costs under continued regulation.

Keep in mind that the objective in the strandable cost calculation is to identify the generation-related *fixed* costs and regulatory assets that might not be recovered under competitive market pricing. Yet, ironically, the estimate of strandable cost which results *from a net* revenues lost calculation is driven by the assumptions concerning *future operating* and *A&G* costs which *would have been* incurred had competition not been introduced. In other words, the more inefficient and bloated an organization would expect to be absent competition, the higher the calculation of strandable cost. Needless to say, this is not a comforting prospect for consumers. Of course, if utilities are given the proper incentive to undertake mitigation actions, *actual* future operating and A&G costs might very well *decline* on a unit-cost basis. But such prospective cost cuts are unlikely to find their way into the net revenues lost calculation unless mandated by the regulator.

Q. **Do you have other concerns about the net revenues lost approach?**

A. Yes. The results of the net revenues lost approach are also heavily dependent on assumptions made regarding the future market price of power – a highly speculative endeavor. This problem does not occur using auction and divestiture because the market value of the utility's generation assets under that approach is set by the winning bidder. This issue is also less of a problem under the replacement cost approach, because that approach sets the long-term market value of the utility's generation assets at the cost of the replacement technology.

Q. Are there any circumstances under which the net revenues lost approach would be acceptable as a measure of strandable cost?

A. Without losing sight of its shortcomings relative to other approaches, there may be some applications in which the net revenues lost approach could be an acceptable measure of strandable cost; however, its acceptability would be conditional on it being packaged with other recovery mechanism features which would limit the otherwise huge downside this approach represents for consumers. To this end, I have prepared a hybrid approach to calculating strandable cost which incorporates both replacement cost valuation and the use of the net revenues lost method on a year-to-year basis.

Q. Please explain.

A. One of the more onerous features of the net revenues lost approach is that it is potentially so open-ended. Indeed, in the Report of the Stranded Cost Working Group, the former staff director proposed that net lost revenues be calculated for the remaining life of a utility's generation assets – an approach equivalent to imposing continued regulatory pricing for the next twenty-five or thirty years. On the other hand, if (1) the transition period for strandable cost eligibility were kept within a limited period of time – i.e., three to five years, and (2) the customer-paid transition charge were kept well within the 25 to 50 percent range, and (3) the magnitude of strandable cost were double checked using replacement cost valuation – then the net revenues lost approach could be credibly used to estimate strandable cost on a year-to-year basis.

Q. Please explain how your proposal to use a hybrid approach would work. Begin by clarifying what you mean by estimating strandable cost on a "year-to-year" basis.

A. Estimating strandable cost on a year-to-year basis means forecasting the Commission-approved, generation-related fixed costs and regulatory assets that a utility might not recover under competitive market pricing for each of a series of years, such as 1999 through 2002. Under the hybrid proposal, this exercise would be performed using the net revenues lost approach. Customers during any given year would only pay for strandable cost associated with that year. As part of the transition design, the portion of strandable cost recovered through the transition charge should decline each year, such that the overall percentage fell within the targeted 25 to 50 percent range. For example, for a four-year transition period, customers could be assigned transition charges amounting to 55, 45, 30, and 10 percent of each successive year's strandable cost, resulting in an (unweighted) average transition charge burden of 35 percent. At the end of the designated transition period, strandable cost would no longer be estimated and the transition charge would cease.

This type of year-to-year approach would be particularly useful in sorting out strandable cost charges during the phase-in period, when some customers are participating in the competitive market, and others are taking Standard Offer service.

Q. If strandable cost were estimated on a year-to-year basis using the net revenues lost approach, would there not be a potential hazard of overemphasizing short-term market conditions to the detriment of consumers?

A. Yes, as I indicated previously in my testimony, such a hazard would exist, and this is where the hybrid aspect of the proposal is important. The stated hazard would be mitigated by taking two steps: (1) by assigning customer responsibility for strandable cost recovery in the lower-to-middle portion of the 25 to 50 percent range, e.g., 35 percent, and (2) by performing the additional calculation of *total* strandable cost using replacement cost valuation, which would then be designated as the maximum allowable strandable cost over the three-to-five year transition period. In this way, total strandable cost using the replacement cost valuation method would act as an upper bound on the sum of year-to-year strandable cost estimates, on a present value basis.

Q. Would calculating strandable cost using *both* the net revenues lost and replacement cost approaches constitute an undue administrative burden?

A. No. Strandable cost is a big-ticket item. Affected Utilities will be requesting Arizona customers to pay strandable cost claims totaling *billions* of dollars. If an administrative method of evaluating strandable cost is adopted, it would be wise to use more than one approach, so that the Commission would have the benefit of more than one perspective. The hybrid approach I am proposing uses the two administrative approaches that had support in the Stranded Cost Working Group. Generally, the utility participants preferred net revenues lost. Unanimously, consumer participants preferred replacement cost valuation. In evaluating the magnitude of strandable cost, the results provided by a second calculation method should serve as a sanity check on the results of the first.

Q. How should the market price of generation be treated under your proposal?

A. As I indicated previously, replacement cost valuation calculates the long-term value of the utility's generation assets based on the cost of the replacement technology, appropriately adjusted for capitalized energy value and life expectancy. It does not require an explicit forecast of market price, although implicit in the analysis is the expectation that long-term market prices will gravitate to the long-run marginal cost of the replacement technology.

Calculating strandable cost using net revenues lost requires the use of market price assumptions which capture the average price of retail generation sold in the competitive market by Arizona utilities. Components of the average retail market price will include the underlying wholesale price of power (e.g., DJ Palo Verde Index), plus a retail mark-up of perhaps 10 percent. (This mark-up is distinct from the unbundled transmission and distribution delivery charges that will be levied.) In addition, the retail price to consumers will include various ancillary services, most of which require the use of generation resources. Typically (though not always) these services will be provided by the host utility and the associated net revenues should be an offset against strandable cost. Examples of these services include regulation and frequency response, operating reserves (if not included in the generation price), voltage support from generation, and energy imbalance service to support retail transactions. Other generation-related services which will add to the market price are must-run units, back-up service, and supplementary power.

In addition, we must be careful not to presume that the relevant underlying wholesale price is the hourly spot market. Many retail customers will want price certainty. Consequently, they will pay a premium that will be incorporated into the retail market price. Therefore, the appropriate underlying wholesale price will be a blend of spot and longer-term pricing.

Q. **What are the implications of Financial Accounting Standard No. 71 resulting from your proposed approach?**

A. FAS No. 71 may require that a portion of generation-related regulatory assets be written down if market pricing replaces regulated rates. The degree to which this standard may be invoked under my proposal will vary according to the circumstances of the individual utility, the magnitude of strandable cost identified, the ameliorating effects of the phase-in, and the extent to which the utility anticipates it can successfully mitigate its strandable cost.

Q. Please summarize your recommendations concerning strandable cost calculation methods.

A. Auction and divestiture is the best method, *conceptually,* for determining overall strandable cost. Unfortunately, it is probably not applicable to nuclear assets, which figure prominently in Arizona. The best administrative method for determining overall strandable cost is the replacement cost valuation method. This method matches up well with the definition of stranded cost in the Rule, has the advantage of capturing the long-term valuation of utility generation assets, and is relatively straightforward to calculate. The least desirable method considered is the net revenues lost approach. This method presumes that stranded cost is whatever additional amount consumers would have had to pay for electric power if regulation continued and competition never occurred. It effectively saddles consumers with the *operating* and *A&G* costs of the utility that would have been expected if regulation were to continue into the foreseeable future. Carried to its extreme, use of this method completely defeats the purpose of moving to a competitive market.

However, if the Commission were to designate a limited transition period of three to five years, the net revenues lost approach could have qualified application for estimating strandable cost on a year-to year basis. To that end, I propose a hybrid approach to calculation, recovery, and mitigation of strandable cost that has the following provisions:

(1) A limited transition period of three to five years for calculation and recovery of strandable cost is designated.

(2) Strandable cost is calculated using a hybrid of the replacement cost valuation and net revenues lost approaches, in which:

(a) The net revenues lost approach is used to estimate strandable cost on a *year-to year* basis.

(b) *Total* strandable cost is calculated using the replacement cost valuation method. This calculation is designated to be the maximum allowable strandable cost over the transition period, providing an upper bound on the sum of year-to-year strandable costs.

(3) Customers pay for a portion of strandable cost through a transition charge levied on distribution service. During any given year, the transition charge applies only toward strandable cost associated with that same year.

(4) The portion of strandable cost recovered through the transition charge declines each year, such that the overall percentage falls within the lower-to-middle portion of the 25 to 50 percent range, e.g., 35 percent.

(5) Utilities are deemed to be at-risk for recovery of the remainder of their strandable cost (associated only with the competitive market). They are free to implement whatever mitigation actions they believe to be most effective, and retain the financial benefits when their mitigation efforts are successful (subject

to any required adjustments associated with the portion of their retail business still receiving Standard Offer service).

(6) Any "true-ups" are limited to adjustments for deviations from the market price of power. [Explained later in response to Question 7]

(7) At the end of the designated transition period, strandable cost is no longer estimated and the transition charge ceases.

Q. **<u>Should there be a limit on the time frame over which stranded costs are calculated? (Question 4)</u>**

A. This question presumes that strandable cost is calculated using *annual* data which can be cut off at a given point – an approach such as net revenues lost – in contrast to a method which provides a *total* strandable cost estimate at the outset, such as auction and divestiture, or replacement cost valuation.

If strandable cost is calculated using annual data, then the time frame for making that calculation should be limited to a three-to-five year transition period, as I propose in the hybrid approach just discussed.

Q. **<u>Should there be a limitation on the recovery time frame for "stranded costs"? (Question 5)</u>**

A. Yes. As I have indicated in response to the previous question, strandable cost can be calculated on a year-to-year basis, and customers should only pay for strandable cost associated with that year. In designing the recovery mechanism this way, the important objective of a price cap would be ensured.

Limiting the calculation/recovery period to three to five years provides utilities with a reasonable period to recover some of their above-market generation costs through a transition charge, while providing customers certainty regarding when their obligation to pay this transition charge would end. With transition charges in neighboring California scheduled to decline significantly in early 2002, it is important that Arizona's economic climate not be disadvantaged for very long thereafter.

Designing the transition charge to decline each year achieves a gradual weaning away from reliance on this non-market mechanism. With each year of experience in a competitive environment, and properly incentivized, incumbent utilities will identify new mitigation opportunities, diminishing the importance of the transition charge in recovering strandable cost.

Q. **Who should pay for "stranded costs" and who, if anyone, should be excluded from paying for stranded costs? (Question 6a)**

A. The Rule states that stranded cost may only be recovered from customer purchases made in the competitive market [R14-2-1607(J)]. In context, this means that a *transition charge to effect strandable cost recovery* may only be levied on purchases made in the competitive market. When the Commission adopted the Rule, it was determined that those customers who would not be participants in the competitive market would pay for strandable cost in their regulated Standard Offer rates [Opinion and Order, Appendix B, p. 48].

I concur with the Commission's reasoning, and find the Rule in its current formulation to be appropriate on this point.

The Rule also goes on to specify that:

> Any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand

> reduction attributable to any cause other than the retail access provisions of this Article shall not be used to calculate or recover any Stranded Cost from a consumer. [R14-2-1607(J)]

The reasoning behind this latter provision is straightforward. Options such as self-generation and demand-side management have been available to customers for many years. These demand reductions are business risks to the utility which pre-date retail access. Customers in the past have not been subject to stranded-cost-type penalties when exercising these options, and the advent of retail access should not to be used as a pretext to start insulating utilities from these ordinary business risks now. Thus, the Commission found that "there is no compelling reason to impose Stranded Cost responsibility on self generators under these Rules, when none has been imposed in the past." [Opinion and Order, Appendix B, p. 49]

I concur with the Commission's reasoning on this point as well.

Q. Some parties have proposed that the Rule be amended to assign strandable cost recovery charges to Standard Offer customers. Do you agree?

A. As the Commission has indicated, under the Rule, Standard Offer customers will pay for strandable cost in their rates. If instead, these customers were made to pay the transition charge, I would find such a change reasonable if two conditions were met:

(1) The Standard Offer rate is reduced by the amount of the transition charge, such that the final price for power paid by these customers is not increased.

(2) The Rule's existing treatment of self-generation, demand-side management, and other demand reductions unrelated to retail access is not changed.

Q. Have other parties supported these two conditions?

A. Yes. It is a consensus recommendation of the Stranded Cost Working Group to assign the transition charge to Standard Offer customers *subject to these two conditions.* [Report of the Stranded Cost Working Group, p. iv]

Q. The Rule indicates that in determining strandable cost charges, the Commission should consider eleven factors, one of which is the applicability of strandable cost to interruptible customers. What *is* the applicability of strandable cost to interruptible customers?

A. Generation capacity is not constructed to provide interruptible service. Consequently, when an interruptible customer elects to purchase competitive power, there is no stranded investment that is left behind. Therefore, there should be no strandable cost charges assigned to service that had been interruptible under the customer's previous arrangement with the Affected Utility. The Commission was correct in singling this service out for special consideration.

Q. Do customers who receive interruptible service currently pay for any fixed, generation-related costs that are potentially strandable in their existing contracts?

A. A customer who receives interruptible service may be making a contribution to the fixed costs of generation. I realize it could be argued that such a customer should pay a strandable cost charge that is proportionate to that current contribution. However, I disagree that a charge is warranted, because the justification offered by the utilities for strandable cost collection – the "obligation to construct" -- does not apply to this type of service.

Q. <u>How should strandable cost charges be collected? (Question 6b)</u>

A. The transition charge is most effectively levied as a "wires" charge on distribution service, which is where the Commission has clear jurisdiction. There was consensus in the Stranded Cost Working Group that the charge should be levied on the customer's energy and/or demand usage. There was also consensus that strandable cost should be allocated among customer classes "in a manner consistent with the specific company's current rate treatment of the stranded asset, in order to effect a recovery of stranded costs that is in substantially the same proportion as the recovery of similar costs from customers or customer classes under current rates." [Report of the Stranded Cost Working Group, p. iv] This provision is critical for preventing cost-shifting among customers in the recovery of strandable costs. I recommend that it be incorporated into the Rule.

The consensus statement adds that "updated rate design to correct flaws in the current rate design would be acceptable." I concur with this recommendation also.

Q. **<u>Should there be a true-up mechanism and, if so, how should it operate? (Question 7)</u>**

A. If the recovery mechanism design incorporates an equitable and efficient sharing of responsibility for strandable cost recovery, then there is little need for a true-up, with the possible exception of adjustments for deviations from forecasted market price. However, even in this latter case, there is a reasonable alternative to a true-up.

Q. **Please explain.**

A. Ostensibly, a true-up mechanism would lead to future adjustments in the transition charge, based on changed circumstances that were not foreseen at the time strandable cost was first estimated. Such changed circumstances might include successful utility mitigation efforts, as well as deviations from forecasted market price.

At first blush, a true-up mechanism may seem to be a reasonable component of strandable cost recovery. After all, one might argue, if the utility successfully cuts its costs or finds new markets, why shouldn't strandable cost charges to customers be reduced?

To answer this question we must look at the design of the recovery program. Earlier in this testimony, I stressed the importance of providing utilities an effective incentive to mitigate strandable cost. I then recommended that the most efficient approach to mitigation would be one in which the utility was at risk for a portion of its potentially stranded cost, and stood to gain financially when its mitigation actions were successful. If the utility is placed sufficiently at risk for strandable cost recovery at the outset of the program, there is no need to reduce strandable cost later through a true-up, after mitigation actions are successful. In fact, such a true-up would be counterproductive, because it would dilute the utility's incentive to undertake mitigation activities.

The area in which a true-up might be appropriate is deviations from forecasted market price, particularly if the net revenues lost approach is used. As I noted previously, the net revenues lost approach is calculated by taking the net difference between (1) the generation-related revenues the utility would have earned had regulation continued, and (2) the generation-related revenues earned as a result of introducing retail competition in generation services. Estimating the latter term requires a forecast of market price of generation over the strandable cost calculation period. Underestimating this price would result in an overestimation of strandable cost; conversely, overestimating market price would result in an underestimation of strandable cost.

Because, unlike mitigation, the setting of market price in a competitive market should be independent of any individual supplier's control, it is possible to establish a market-price-related true-up mechanism that does not distort behavior. However, I would caution against designing a true-up mechanism which attempted to achieve an exact correction for deviations from forecasted prices, with the concomitant regulatory and administrative burdens. Instead, the objective of a market-price-related true-up should be one of protecting both sides from significant deviations from expectations. In this way, a true-up can be designed to be triggered if average market price over a given period (e.g., one year) deviates a given percentage (e.g., 10 percent) from the market price assumption used in estimating strandable cost.

Q. **Can you give an example of how such a true-up mechanism might operate?**

A. Yes. Suppose the average market price assumed for retail electricity in a given year was forecasted to be 3.0 cents per kWh when strandable cost was initially estimated. Further, assume that 10 percent (plus or minus) is selected as the trigger point for the true-up, which would mean that the true-up would be triggered at market prices below 2.7 cents or above 3.3 cents. Then suppose that actual average price turns out to be 3.45 cents, or 15 percent higher than forecast. Then, in this example, an amount equal to: (1) .15 cents per kWh (i.e., 3.45 cents – 3.3 cents) times (2) the kWh which had been subject to the transition charge that year, would be subject to a true-up. In this example, the true-up would result in an adjustment to lower the future strandable cost obligations of customers by the amount outside the trigger point. This adjustment could be accomplished by either a rebate, a reduction of strandable cost on a going-forward basis, or an acceleration of the termination date of the strandable cost calculation period. While a rebate may generally be the least desirable approach from an administrative standpoint, it may be the best approach if a true-up is triggered in the final year of the strandable cost calculation/recovery period.

Q. Previously, you stated that there was a reasonable alternative to "truing up" the market price of power. Please explain.

A. In lieu of "truing up" the market price of power, each retail access customer who pays a transition charge could be granted the option of purchasing competitive generation from the Affected Utility (and/or its marketing affiliate) which is the recipient of that payment at the market price used to estimating strandable cost in that year. In other words, if APS' strandable cost were estimated using a forecast of 3 cents per kWh for the market price of power, then under this approach, retail access customers paying the APS transition charge would be granted the option to purchase generation from APS at that same price of 3 cents per kWh. This approach would be fair because APS would be collecting strandable cost charges based on the 3-cent forecast. There would be no restriction on the price of generation APS sold to parties not paying the APS transition charge, nor on the price these customers paid for generation from non-APS sources. APS would also be free to sell generation to customers paying its transition charge at prices below 3 cents.

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 it be calculated? (Question 8)

A. A price cap should be part of the development of a stranded cost recovery program. In addition, rate ceilings on traditional, bundled service, which are already in effect for certain utilities, should be continued for Standard Offer service.

Q. Please describe what you mean by the term "price cap."

A. In general, the term "price cap" simply refers to a ceiling on prices. However, in the context of strandable cost recovery in Arizona, particularly in the discussions of the Stranded Cost Working Group, "price cap" has been used in a very specific way. In this context, incorporating a price cap into the design of the strandable cost recovery program means that, for any customer, the sum of the transition charge plus delivery charges (i.e., transmission, distribution, ancillary services, system benefits charge) plus the market price of generation (used in calculating strandable cost) does not exceed current rates for that customer. The purpose of a price cap in this context is to design the strandable cost recovery program in a way to ensure that the final delivered price to consumers under competition is no greater than under regulation.

Q. Can you provide a simple example to illustrate this application of a price cap?

A. Yes. Suppose a particular customer (or customer class) pays 9 cents per kWh for electric service under current regulated rates. Further suppose that the unbundled charge for delivery services is 3.5 cents per kWh and that, for a given year, the forecasted market price of generation used to calculate strandable cost is 3.25 cents per kWh. Then if a price cap were required in the recovery program design, the transition charge for this customer could not exceed 9 cents minus 3.5 cents minus 3.25 cents, or 2.25 cents per kWh. Note that the price cap is accomplished not by regulating the price of generation – which, of course, under competition is set by the market; instead, the price cap results from the design of the transition charge, which is constrained to be no greater than the contribution to strandable cost that a customer makes under regulated rates. As I stated previously, this design feature can be met by calculating strandable cost on a year-to-year basis, and by having customers pay only for strandable cost associated with that year.

Q. What is the proper interpretation of the transition charge that is calculated under the price cap principle?

A. It is important to keep in mind that a price cap simply provides an *upper limit* on the transition charge. It identifies the *maximum* transition charge that could be levied on a customer; it is by no means the *target* level. Mathematically, a transition charge which is calculated/recovered on a year-to-year basis *and* which is designed to be less than 100 percent of strandable cost would meet the objectives of the price cap with room to spare.

This assurance notwithstanding, a price cap should still be part of the recovery mechanism design, at least as a backstop, because other parties' proposals for strandable cost recovery might very well caused delivered prices to be above what would be permitted under a price cap. For example, the former staff director advocated the use of the net revenues lost approach to *calculate* strandable cost over the remaining life of generation assets – 25 to 30 years; at the same time, he advocated *recovery* in ten years – but opposed making a price cap part of the recovery design. Under such a proposal, the introduction of competition could be accompanied by a price increase to customers that was directly attributable to the design of the strandable cost recovery program. If indeed, strandable cost recovery were designed in a manner that violated the price cap principle, the results would be nothing less than a regulatory fiasco.

Q. <u>**What factors should be considered for "mitigation" of stranded costs? (Question 9)**</u>

A. The Rule makes it clear that any activity undertaken by an Affected Utility that lowers cost or increases net revenue is considered to be mitigation of strandable cost. The question that faces us here is how to design strandable cost recovery such that cost-effective mitigation is given maximum encouragement.

By their nature, mitigation actions are an integral part of corporate strategy that should be governed by the principles of risk and reward, rather than regulatory prescription or second-guessing. Previously in this testimony, I recommended that the best mitigation incentive is for the utility to be at risk for a substantial portion of its strandable cost, and to be financially rewarded when its mitigation efforts are successful. This is accomplished by designing the transition charge to cover no more than 50 percent of strandable cost in a given year. Then, we can leave it to the utilities to implement whatever mitigation actions they believe to be most effective. As I testified, this type of incentive mechanism relies upon the basic principles of the marketplace to guide utilities towards efficient mitigation strategies represents a significant step in effecting a transition from a regulatory to a competitive paradigm for the utilities involved.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

KEVIN C. HIGGINS
Senior Associate, Energy Strategies, Inc.
39 Market St., Suite 200, Salt Lake City, UT 84101
(801) 355-4365

Vitae

PROFESSIONAL EXPERIENCE

Senior Associate, Energy Strategies, Inc., Salt Lake City, Utah, February 1995 to present. Responsible for energy-related economic and policy analysis, regulatory intervention, and strategic negotiation on behalf of industrial, commercial, and public sector interests.

Adjunct Instructor in Economics, Westminster College, Salt Lake City, Utah, September 1981 to May 1982; September 1987 to May 1995. Taught in the economics and M.B.A. programs. Awarded Adjunct Professor of the Year, Gore School of Business, 1990-91.

Chief of Staff to the Chairman, Salt Lake County Board of Commissioners, Salt Lake City, Utah, January 1991 to January 1995. Senior executive responsibility for all matters of county government, including formulation and execution of public policy, delivery of approximately 140 government services, budget adoption and fiscal management (over $300 million), strategic planning, coordination with elected officials, and communication with consultants and media.

Assistant Director, Utah Energy Office, Utah Department of Natural Resources, Salt Lake City, Utah, August 1985 to January 1991. Directed the agency's resource development section, which provided energy policy analysis to the Governor, implemented state energy development policy, coordinated state energy data collection and dissemination, and managed energy technology demonstration programs. Position responsibilities included policy formulation and implementation, design and administration of energy technology demonstration programs, strategic management of the agency's interventions before the Utah Public Service Commission, budget preparation, and staff development. Supervised a staff of economists, engineers, and policy analysts, and served as lead economist on selected projects.

Utility Economist, Utah Energy Office, January 1985 to August 1985. Provided policy and economic analysis pertaining to energy conservation and resource development, with an emphasis on utility issues. Testified before the state Public Service Commission as an expert witness in cases related to the above.

Acting Assistant Director, Utah Energy Office, June 1984 to January 1985. Same responsibilities as Assistant Director identified above.

Research Economist, Utah Energy Office, October 1983 to June 1984. Provided economic analysis pertaining to renewable energy resource development and utility issues. Experience includes preparation of testimony, development of strategy, and appearance as an expert witness for the Energy Office before the Utah PSC.

Operations Research Assistant, Corporate Modeling and Operations Research Department, Utah Power and Light Company, Salt Lake City, Utah, May 1983 to September 1983. Primary area of responsibility: designing and conducting energy load forecasts.

Instructor in Economics, University of Utah, Salt Lake City, Utah, January 1982 to April 1983. Taught intermediate microeconomics, principles of macroeconomics, and economics as a social science.

Teacher, Vernon-Verona-Sherrill School District, Verona, New York, September 1976 to June 1978.

EDUCATION

Ph.D. Candidate, Economics, University of Utah (coursework and exams completed, 1981).

Fields of Specialization: Public Finance, Urban and Regional Economics, Economic Development, International Economics, History of Economic Doctrines.

Bachelor of Science, Education, State University of New York at Plattsburgh, 1976 (cum laude).

Danish International Studies Program, University of Copenhagen, 1975.

SCHOLARSHIPS AND FELLOWSHIPS

University Research Fellow,.University of Utah, Salt Lake City, Utah 1982 to 1983.
Research Fellow, Institute of Human Resources Management, University of Utah, 1980 to 1982.
Teaching Fellow, Economics Department, University of Utah, 1978 to 1980.
New York State Regents Scholar, 1972 to 1976.

EXPERT TESTIMONY

"In the Matter of the Implementation of Rules Governing Cogeneration and Small Power Production in Utah," Utah Public Service Commission, Case No. 80-999-06, pp. 1293-1318. Prefiled testimony submitted January 13, 1984 (avoided costs), May 9, 1986 (security for levelized contracts) and November 17, 1986 (avoided costs); cross-examined February 29, 1984 (avoided costs), April 11, 1985 (standard form contracts), May 22-23, 1986 (security for levelized contracts) and December 16-17, 1986 (avoided costs).

"In the Matter of the Investigation of Demand-Side Alternatives to Capacity Expansion for Electric Utilities," Utah Public Service Commission, Case No. 84-999-20. Prefiled direct testimony submitted June 17, 1985. Prefiled rebuttal testimony submitted July 29, 1985; Cross-examined August 19, 1985.

"In the Matter of the Application of Sunnyside Cogeneration Associates for Approval of the Cogeneration Power Purchase Agreement," Utah Public Service Commission, Case No. 86-2018-01. Rebuttal testimony submitted July 16, 1986; cross-examined July 17, 1986.

"In the Matter of the Investigation of Rates for Backup, Maintenance, Supplementary, and Standby Power for Utah Power and Light Company," Utah Public Service Commission, Case No. 86-035-13; prefiled direct testimony submitted January 5, 1987. Case settled by stipulation approved August 1987.

"Cogeneration: Small Power Production," Federal Energy Regulatory Commission, Docket No. RM87-12-000. Statement delivered March 27, 1987, on behalf of State of Utah, in San Francisco.

"In the Matter of the Application of Utah Power and Light Company for an Order Approving a Power Purchase Agreement," Utah Public Service Commission, Case No. 87-035-18. Oral testimony delivered July 8, 1987.

"In the Matter of the Application of Mountain Fuel Supply Company for Approval of Interruptible Industrial Transportation Rates," Utah Public Service Commission, Case No. 86-057-07. Prefiled direct testimony submitted January 15, 1988; cross-examined March 30, 1988.

"In the Matter of the Application of Utah Power & Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. and Authorizing the Issuance of Securities, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith," Utah Public Service Commission, Case No. 87-035-27; prefiled direct testimony submitted April 11, 1988; cross-examined May 12, 1988 (economic impact of UP&L merger with PacifiCorp).

"In the Matter of the Review of the Rates of Utah Power and Light Company pursuant to The Order in Case No. 87-035-27," Utah Public Service Commission, Case No. 89-035-10. Rebuttal testimony submitted November 15, 1989; cross-examined December 1, 1989 (rate schedule changes for state facilities).

"In the Matter of the Investigation of the Reasonableness of the Rates and Tariffs of Mountain Fuel Supply Company," Utah Public Service Commission, Case No. 89-057-15. Pre-filed direct testimony submitted July 1990. Surrebuttal testimony submitted August 1990.

"In the Matter of the Application of Mountain Fuel Supply Company for an Increase in Rates and Charges," Utah Public Service Commission, Case No. 95-057-02. Prefiled direct testimony submitted June 19, 1995. Rebuttal testimony submitted July 25, 1995. Surrebuttal testimony submitted August 1995.

"Questar Pipeline Company," Federal Energy Regulatory Commission, Docket No. RP95-407. Direct testimony prepared, but withheld subject to settlement. Settlement approved July 1, 1996.

"In the Matter of the Application of PacifiCorp, dba Pacific Power & Light Company, for Approval of Revised Tariff Schedules and an Alternative Form of Regulation Plan," Wyoming Public Service Commission, Docket No. 2000-ER-95-99. Prefiled direct testimony submitted April 8, 1996.

"In the Matter of Arizona Public Service Company's Rate Reduction Agreement," Arizona Corporation Commission, Docket No. U-1345-95-491. Direct testimony prepared, but withheld consequent to issue resolution. Agreement approved April 18, 1996.

"In the Matter of the Petition of Sunnyside Cogeneration Associates for Enforcement of Contract Provisions," Utah Public Service Commission, Docket No. 96-2018-01. Prefiled direct testimony submitted July 8, 1996.

"In the Matter of Consolidated Edison Company of New York, Inc.'s Plans for (1) Electric Rate/Restructuring Pursuant to Opinion No. 96-12; and (2) the Formation of a Holding Company Pursuant to PSL, Sections 70, 108, and 110, and Certain Related Transactions," New York Public Service Commission, Case 96-E-0897. Testimony filed April 9, 1997. Cross examined May 5, 1997.

OTHER RELATED ACTIVITY

Member, Desert Star ISO Investigation Working Groups: Operations, Pricing, and Governance, April 1997 to present.

Member, Independent System Operator and Spot Market Working Group, Arizona Corporation Commission, April 1997 to present.

Member, Unbundled Services and Standard Offer Working Group, Arizona Corporation Commission, April 1997 to present.

Member, Customer Selection Working Group, Arizona Corporation Commission, March 1997 to present.

Member, Stranded Cost Working Group, Arizona Corporation Commission, March 1997 to present.

Member, Electric System Reliability & Safety Working Group, Arizona Corporation Commission, November 1996 to present.

Consultant to business customers, "In the Matter of Competition in the Provision of Electric Services Throughout the State of Arizona," Arizona Corporation Commission, Docket No. U-0000-94-165. Preparation of comments and participation in staff workshops. Rule on retail electric competition adopted December 23, 1996.

Chairman, Salt Palace Renovation and Expansion Committee, Salt Lake County/State of Utah/Salt Lake City, multi-government entity responsible for implementation of planning, design, finance, and construction of an $85 million renovation of the Salt Palace Convention Center, Salt Lake City, Utah, May 1991 to December 1994.

State of Utah Representative, Committee on Regional Electric Power Cooperation, a joint effort of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners, January 1987 to December 1990.

Member, Utah Governor's Economic Coordinating Committee, January 1987 to December 1990.

Chairman, Standard Contract Task Force, established by Utah Public Service Commission to address contractual problems relating to qualifying facility sales under PURPA, March 1986 to December 1990.

Chairman, Load Management and Energy Conservation Task Force, Utah Public Service Commission, August 1985 to December 1990.

Alternate delegate for Utah, Western Interstate Energy Board, Denver, Colorado, August 1985 to December 1990.

Articles Editor, Economic Forum, September 1980 to August 1981.

Recommended additions to the Competition Rule

1. R14-2-1607.(B)

The Commission shall allow recovery of unmitigated Stranded Cost by Affected Utilities IN ACCORDANCE WITH THE PROVISIONS OF R14-2-1607(I).

2. R14-2-1607.(G)

~~The~~ AN Affected Utilit~~ies~~Y shall file estimates of unmitigated stranded cost AT LEAST EIGHT MONTHS PRIOR TO THE DATE IT REQUESTS STRANDED COST RECOVERY CHARGES TO BEGIN. Such estimates shall be fully supported by analyses and by records of market transactions undertaken by willing buyers and sellers.

3. R14-2-1607.(I)

The Commission shall, after hearing and consideration of analyses and recommendations presented by the Affected Utilities, Staff, and intervenors, determine for each Affected Utility the magnitude of Stranded Cost, and appropriate Stranded Cost recovery mechanisms and charges. In making its determination of mechanisms and charges, the Commission shall BALANCE UTILITY AND CUSTOMER INTERESTS BY considerING at least the following factors:

1. The impact of Stranded Cost recovery on the effectiveness of competition;
2. The impact of Stranded Cost recovery on customers of the Affected Utility who do not participate in the competitive market;
3. The impact, if any, on the Affected Utility's ability to meet debt obligations;
4. The impact of Stranded Cost recovery on prices paid by consumers who participate in the competitive market;
5. The degree to which the Affected Utility has mitigated, or ~~offset~~ SHOULD BE AT RISK FOR MITIGATING, Stranded Cost;
6. The degree to which some assets have values in excess of their book values;

7. Appropriate treatment of negative Stranded Cost;

8. The time period over which such Stranded Cost charges may be recovered. The Commission shall limit the application of such charges to a specified time period;

9. The ease of determining the amount of Stranded Cost;

10. The applicability of Stranded Cost to interruptible customers;

11. The amount of electricity generated by renewable generating resources owned by the Affected Utility.

4. R14-2-1607.(M)

STRANDED COST SHALL BE ALLOCATED AMONG CUSTOMER CLASSES IN A MANNER CONSISTENT WITH THE SPECIFIC COMPANY'S CURRENT RATE TREATMENT OF THE STRANDED ASSET, IN ORDER TO EFFECT A RECOVERY OF STRANDED COSTS THAT IS IN SUBSTANTIALLY THE SAME PROPORTION AS THE RECOVERY OF SIMILAR COSTS FROM CUSTOMERS OR CUSTOMER CLASSES UNDER CURRENT RATES.

Recommended Policies for Implementing the Competition Rule

1. The Commission should strike an appropriate balance between customer and utility interests in implementing a stranded cost recovery program. In addition, the program should be designed in a manner which maximizes utilities' incentives to undertake successful mitigation activities.

2. The portion of strandable cost recovered from customers through a transition charge should be in the range of 25 to 50 percent, depending on the specific calculation/recovery program that is adopted.

3. Utilities should be deemed to be at-risk for recovery of the remainder of their strandable cost (associated with the competitive market). They should be free to implement whatever mitigation actions they believe to be most effective, and should retain the financial benefits when their mitigation efforts are successful (subject to any required adjustments associated with the portion of their retail business still receiving Standard Offer service).

4. The strandable cost recovery mechanism should be designed to incorporate a price cap, ensuring that the final delivered price to consumers under competition is no greater than under regulation. Incorporating a price cap into the design of the strandable cost recovery program means that, for any customer, the sum of the transition charge plus delivery charges (i.e., transmission, distribution, ancillary services, system benefits charge) plus the market price of generation (used in calculating strandable cost) does not exceed current rates for that customer.

5. The Commission should retain the important language in the Rule which states that any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand reduction attributable to any cause other than retail access shall not be used to calculate or recover any Stranded Cost from a consumer.

6. Strandable cost charges should not be assigned to service that had been interruptible under the customer's previous arrangement with the Affected Utility, because generation capacity is not constructed to provide interruptible service.

Specific Proposal for Calculation, Recovery, and Mitigation of Strandable Cost

1. A limited transition period of three to five years for calculation and recovery of strandable cost is designated.

2. Strandable cost is calculated using a hybrid of the replacement cost valuation and net revenues lost approaches, in which:

   (a) The net revenues lost approach is used to estimate strandable cost on a *year-to year* basis.

   (b) *Total* strandable cost is calculated using the replacement cost valuation method. This calculation is designated to be the maximum allowable strandable cost over the transition period, providing an upper bound on the sum of year-to-year strandable costs.

3. Customers pay for a portion of strandable cost through a transition charge levied on distribution service. During any given year, the transition charge applies only toward strandable cost associated with that same year.

4. The portion of strandable cost recovered through the transition charge declines each year, such that the overall percentage falls within the lower-to-middle portion of the 25 to 50 percent range, e.g., 35 percent.

5. Utilities are deemed to be at-risk for recovery of the remainder of their strandable cost (associated only with the competitive market). They are free to implement whatever mitigation actions they believe to be most effective, and retain the financial benefits when their mitigation efforts are successful (subject to any required adjustments associated with the portion of their retail business still receiving Standard Offer service).

6. Any “true-ups” are limited to adjustments for deviations from the market price of power.

7. At the end of the designated transition period, strandable cost is no longer estimated and the transition charge ceases.

REBUTTAL TESTIMONY

OF

KEVIN C. HIGGINS

ON BEHALF OF
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION,
BHP COPPER, CYPRUS CLIMAX METALS, ASARCO,
PHELPS DODGE, AJO IMPROVEMENT COMPANY, AND
MORENCI WATER & ELECTRIC COMPANY

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

January 21, 1998

EXHIBIT
AECC, et al 4
Admitted

Rebuttal Testimony of Kevin C. Higgins

Summary

The following rebuttal testimony is offered:

Balancing of Customer and Utility Interests – Mr. Bayless' claim that customers must bear the costs of TEP generation for up to thirty years after the introduction of competition is unreasonable on efficiency and equity grounds. However, Dr. Fessler offers some useful examples from California of shareholder sacrifice that are relevant for Arizona – lower returns on equity and a price cap.

Calculation method – A number of utility witnesses express support for the net revenues lost approach. Carried to its logical end, this approach completely defeats the purpose of competition. Auction and divestiture and replacement cost valuation are both superior methods for calculating strandable cost. Any use of the net revenues lost approach must be accompanied by important safeguards, which are outlined in the Rebuttal testimony, and addressed in greater detail in Higgins Direct testimony.

Mitigation – A number of utility witnesses seek to have the Commission change the Rule's treatment of mitigation by excluding the net revenues earned by the utility or its affiliates in unrelated enterprises. As indicated in Higgins Direct testimony, accounting for mitigation activities is best resolved by deeming the utility to be at risk – up front – for recovery of a substantial portion of its potentially stranded cost, and to allow the utility to be financially rewarded when its mitigation efforts are successful. Under this approach, it is not necessary to distinguish between the mitigation efforts of related and "unrelated" enterprises.

Market price – Mr. Bayless proposes a market price index which is reflective of wholesale market prices. A similar concern exists for Mr. Davis' proposal. Appropriate adjustments to convert these indices to retail prices would have to be made.

Treatment of Self-generation and Demand-Side Management – Proposals to repeal the Rule's present treatment of these customer options should be rejected.

Changes in the Definition of Stranded Cost – Proposals to modify the definition of stranded cost should be rejected.

CONTENTS

REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

I. INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am employed by Energy Strategies, Inc. (ESI) as a senior associate. ESI is a private consulting firm specializing in the economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition[1], BHP Copper, Cyprus Climax Metals, Asarco, Phelps Dodge, Ajo Improvement Company, and Morenci Water & Electric Company.

Q. Have you filed other testimony in this proceeding?

A. Yes. I have filed direct testimony.

Q. What is the purpose of this testimony?

A. In this testimony I offer rebuttal to the direct testimony of Tucson Electric Power (TEP) Witnesses Bayless, Gordon, and Fessler; Arizona Public Service Co. (APS) Witnesses Davis and Hieronymus; Arizona Electric Power Cooperative (AEPCO) Witness Minson, and Citizens Utilities Witness Breen.

[1] Arizonans for Electric Choice and Competition is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Association of General Contractors, and Arizona Retailers Association.

Q. How is your rebuttal testimony organized?

A. The rebuttal testimony is arranged by topic.

II. BALANCING OF CUSTOMER AND UTILITY INTERESTS

Q. Does Mr. Bayless (TEP) propose a reasonable approach to balancing customer and utility interests in the recovery of strandable cost?

A. No, he does not. Mr. Bayless maintains that customers have the obligation to pay for all strandable costs over the remaining life expectancy of TEP's generation assets, a period in excess of thirty years. Mr. Bayless justifies this claim by referring to an implied regulatory compact that he believes binds customers for the coming decades to the cost incurred by TEP to build and operate its generation facilities.

Mr. Bayless' view is unreasonable. The regulatory environment in which TEP has heretofore operated does not convey a blanket responsibility upon customers to bear the costs of TEP generation for up to thirty years after the introduction of competition. His argument presumes that deregulation of generation service is a one-way street: good for consumers, bad for investors. It ignores the fact that deregulation of generation prices will mean that investors will have opportunities over the long-run to earn above a regulated return – using the very assets that will be the subject of stranded cost claims. As pointed out in my direct testimony and by others, investors in electric utilities have been on notice for a number of years that restructuring and regulatory changes were coming which would introduce greater competition. These changes will provide long-term opportunities for some companies, but might also place full recovery of fixed costs at risk, at least in the short run. Because competition will provide opportunities for both customers and investors, it is inappropriate to conclude that changing the regulatory paradigm requires customers alone to shoulder the risk of strandable cost.

Q. Are there other grounds for your objections to Mr. Bayless' position?

A. Yes, there are significant efficiency reasons for not assigning all potentially stranded costs to customers. First, strandable cost charges distort the price of electric power by making the effective price to consumers higher than the true long-run marginal cost. Today there are technologies and suppliers which can provide electric power at an overall lower cost than incumbents can using higher-cost technology. The economically efficient price for electric power is one which reflects this lower cost. In an efficient market, owners of production facilities with relatively high fixed costs would be forced to lower their prices to meet the new market standard. These production facilities would continue to be operated so long as the market price covered their variable cost.

In contrast, strandable cost charges keep prices artificially high. With strandable cost charges to pay, a business considering locating or expanding in Arizona would face electricity prices that are higher than true long-run marginal costs. This incorrect price signal would discourage business expansion or retention which would otherwise be efficient.

Second, assigning full responsibility for strandable cost to customers is inefficient because it weakens the utility's incentive to mitigate strandable cost.

As I stress in my direct testimony, the best mitigation incentive is for the utility to be at risk for recovery of a substantial portion of its potentially stranded cost, and to be financially rewarded when its mitigation efforts are successful. This type of incentive mechanism relies upon the basic principles of the marketplace to guide utilities towards efficient mitigation strategies and represents a significant step in effecting a transition from a regulatory to a competitive paradigm for the utilities involved.

Q. **What is your analysis of Mr. Bayless' claim that assigning full responsibility for recovery of stranded cost to customers is good for the nation's economy?**

A. Assigning full responsibility for recovery of stranded cost to customers may be good for TEP's shareholders, but it is not good for TEP's customers or for the economy of Arizona. As I have just indicated, stranded cost charges will distort price signals to the detriment of the local economy. To the extent that a transition charge is levied on customers, it can only be argued in terms of equity considerations. There are no efficiency benefits.

This point is very well illustrated by Mr. Bayless' own example of OLDCO vs. NEWCO [Bayless Direct, pp. 8-9]. In Mr. Bayless' example, the incumbent, OLDCO, has sunk plant costs of 5 cents/kWh, and the new entrant, NEWCO, has new plant costs of 2 cents/kWh. Both companies have identical short-run marginal costs of 1 cent/kWh and mark-ups of 1 cent/kWh. Therefore, OLDCO sells power at 7 cents/kWh, while NEWCO is willing to sell it for 4 cents/kWh. In Mr. Bayless' view, society should discourage construction of NEWCO's plant, because OLDCO has plant available to do the job. Mr. Bayless believes that the proper vehicle to carry out this policy is a stranded cost charge, in which a customer purchasing from NEWCO would have to pay OLDCO 3 cents/kWh, removing NEWCO's price advantage and effectively discouraging construction of its plant.

What Mr. Bayless fails to present is the efficient market solution, in which OLDCO lowers its price to 4 cents/kWh to meet the new long-run marginal cost. It is true that, in doing so, OLDCO will not be able to cover all of its sunk costs. But after all, its technology is obsolete – or its original construction costs were just too high. It will have to write down the asset and/or restructure its financing or ownership, but it will remain in OLDCO's interest to keep operating, given its low marginal cost. On the whole, society benefits, because prices reflect true long-run marginal costs and customers can make efficient purchasing decisions.

To see this point another way, simply change Mr. Bayless' example from power plants to apartment houses. Both OLDCO and NEWCO offer identical apartments, but NEWCO's can be constructed at a lower cost. OLDCO's rent for $700/month; NEWCO's can rent for $400/month. Could it possibly be in society's interest to discourage construction of NEWCO's apartments by placing a rental surcharge on NEWCO's tenants of $300/month payable to OLDCO? On *efficiency* grounds? Can society possibly be better off if apartment prices were forced by the government to rent for $700/month when new properties could actually be built profitably at $400/month? Just so "unnecessary" apartments weren't built? Of course not.

Q. Do other utility witnesses also argue for 100% customer responsibility for strandable cost?

A. Yes. Dr. Gordon (TEP), Mr. Breen (Citizens), and Mr. Minson (AEPCO) also make this assertion. The rebuttal I offer to Mr. Bayless' position generally applies to their testimony on this issue as well.

Q. Do any utility witnesses make a case for shareholder sacrifice?

A. Yes. Dr. Fessler (TEP) describes the sacrifices imposed on investors in California [Fessler Direct, pp. 16-17]. Of particular interest for Arizona is California's mandated reduction on allowed equity return for assets receiving stranded cost support. This reduction in return on equity is to a level ten percent below that of long-term debt. I suggest that if the net revenues lost approach is used to calculate strandable cost in Arizona, a similar reduction in the return on equity should be applied to stranded assets to account for absorption of shareholder risk provided by the transition charge.

Q. Does Dr. Fessler describe any other shareholder sacrifices of relevance to Arizona?

A. Yes. Dr. Fessler notes that the California Commission adopted a price cap because it "recognized that a major goal of the restructuring effort was to lower the price consumers paid for electricity." [Fessler Direct, p.17] As obvious as that goal sounds, Arizona utilities continue to quibble about a price cap. For example, Mr. Bayless' endorsement of a price cap appears limited to conditions in which TEP shareholders face almost no risk [Bayless Direct, p. 17]. In contrast, the California price cap places shareholders significantly at risk for recovery of strandable cost, a policy Dr. Fessler supported with his vote as Commissioner. Yet when it comes to price cap for Arizona, Dr. Fessler seems to be lukewarm. Perhaps, he suggests, Arizona Commissioners should just place their faith in the market. My response is that it is not the market we are worried about – it's the stranded cost charges. It is essential that the design of the strandable cost recovery program incorporate a price cap. And a price cap does not mean regulating the price of generation; it means designing the transition charge appropriately.

III. CALCULATION METHOD

Q. Many utility witnesses advocate use of the net revenues lost approach to calculating strandable cost. What is your position to this recommendation?

A. The net revenues lost approach is advocated by Mr. Davis (APS), Dr. Hieronymus (APS), Mr. Minson (AEPCO), and Mr. Bayless (TEP). Somewhat qualified support is provided by Dr. Gordon (TEP) and Dr. Fessler (TEP). My direct testimony includes an extensive discussion on the net revenues lost approach. I point out that the salient feature of the net revenues lost approach is its presumption that stranded cost is whatever additional amount consumers would have had to pay for electric power if regulation continued and competition never occurred. I do not consider this to be an appropriate presumption for establishing fair and efficient transition charges to customers. Carried to its logical end, this approach completely defeats the purpose of moving to a competitive market – at least for the foreseeable future. In general, I am opposed to its use.

I rank auction and divestiture, as well as replacement cost valuation as superior approaches. However, in my testimony, I suggest that the net revenues lost approach could have limited application for calculating strandable cost on a year-to-year basis, if accompanied by each of the following important safeguards:

(1) the transition period for strandable cost eligibility is kept within a limited period of time, i.e., three to five years,

(2) the customer-paid transition charge is kept well within the 25 to 50 percent range, e.g., 35 percent,

(3) customers in a given year pay only for strandable cost associated with that year, and

(4) the magnitude of strandable cost is capped using replacement cost valuation.

Q. Do you have any other observations on the testimony of utility witnesses regarding the net revenues lost approach?

A. Yes, Dr. Gordon (TEP) implies that the net revenues lost approach necessarily incorporates an adjustment to the strandable cost charge in response to changes in actual market prices. I agree that such adjustments can be attempted, but the method, as it has been discussed in Arizona, does not necessarily include the feature described by Dr. Gordon. Instead, strandable cost is presumed to be calculated using market price estimates, followed by after-the-fact true-ups.

Q. Do you have any observations on Dr. Fessler's testimony concerning the net revenues lost approach?

A. Yes. I think Dr. Fessler's discussion on the subject is thought provoking. [Fessler Direct, Q.43] He draws an important distinction between California's treatment of strandable cost and the treatment recommended by the former Arizona staff director in the Report of the Stranded Cost Working Group. The California transition charge was designed to allow a return *of* investor capital, but not a return *on* that capital. In contrast, as Dr. Fessler points out, the net revenues lost approach espoused in Arizona "seeks to protect the expectations formed under the existing regulatory regime with respect to both the recovery of an investment *and the income stream on that investment.*" [Fessler Direct, p. 37, emphasis added] In my direct testimony I refer to calculation approaches that are "relatively generous to the utility." The net revenues lost approach described in the Working Group Report is an example of what I mean.

IV. MITIGATION

Q. Some utility witnesses recommend changes in the Rule's treatment of mitigation. What is your recommendation on this issue?

A. Mr. Davis (APS), Mr. Minson (AEPCO), Mr. Breen (Citizens), and Mr. Bayless (TEP) seek to have the Commission change the Rule's treatment of mitigation by excluding the net revenues earned by the utility or its affiliates in unrelated enterprises. As I indicate in my direct testimony, accounting for mitigation activities is best resolved by deeming the utility to be at risk – up front

-- for recovery of a substantial portion of its potentially stranded cost, and to allow the utility to be financially rewarded when its mitigation efforts are successful. Under this approach, it is not necessary to distinguish between the mitigation efforts of related and "unrelated" enterprises.

V. MARKET PRICE

Q. What is your assessment of the market price recommendations made by Mr. Davis (APS) and Mr. Bayless (TEP)?

A. Both Mr. Bayless and Mr. Davis recommend using the net revenues lost approach to calculating strandable cost. If that approach is used, it is necessary to calculate the value of the utility's generation in the competitive retail market. Mr. Bayless suggests using the DJ Palo Verde price index for the purpose; however, the DJ Palo Verde price index is an index of *wholesale* prices. It essential that appropriate adjustments be made to any wholesale prices index to reflect the average cost at the retail level. I suggest a number of such adjustments in my direct testimony on pages 22-23.

Mr. Davis proposes using the California Power Exchange as a basis of market price. While I believe the Power Exchange will serve a useful function for Arizona, the packaging of Power Exchange generation for sale in Arizona seems likely to develop into a wholesaler activity that will be accompanied by a retail mark-up. As I indicated in my response to Mr. Bayless' proposal, it is the retail price which matters here. If the California Power Exchange is used as the basis of market price for calculation of strandable cost, an appropriate adjustment to convert the California price into a meaningful Arizona retail price would have to occur.

VI. TREATMENT OF SELF-GENERATION AND DEMAND-SIDE MANAGEMENT

Q. Do you object to any of the positions taken by utility witnesses on the treatment of self-generation and demand-side management?

A. Yes. Mr. Minson (AEPCO) proposes deleting Section 1607(J) of the Rule. This section states:

> Stranded cost may only be recovered from customer purchases made in the competitive market using the provisions of this Article. Any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand reduction attributable to any cause other than the retail access provisions of this Article shall not be used to calculate or recover any Stranded Cost from a consumer.

As I stated in my direct testimony, the reasoning behind this provision is straightforward. Options such as self-generation and demand-side management have been available to customers for many years. These demand reductions are business risks to the utility which pre-date retail access. Customers in the past have not been subject to stranded-cost-type penalties when exercising these options, and the advent of retail access should not to be used as a pretext to start insulating utilities from these ordinary business risks now. Thus, in adopting the

Rule, the Commission found that "there is no compelling reason to impose Stranded Cost responsibility on self generators under these Rules, when none has been imposed in the past." [Opinion and Order, Appendix B, p. 49]

This important provision should remain in the Rule.

VII. CHANGES IN THE DEFINITION OF STRANDED COST

Q. Do any utility witnesses propose changes in the definition of stranded cost in the Rule?

A. Yes, Mr. Davis proposes to substitute the word "cost" for "value" in the Rule. This particular debate occurred during the rulemaking process, and the Commission concluded that this change was unnecessary. [Opinion and Order, pp. 42-43] Likewise, it was a consensus recommendation of the Stranded Cost Working Group not to change the definition in the Rule.

Of greater concern, Mr. Davis proposes to delete language that limits stranded cost recovery to assets or obligations acquired or incurred prior to adoption of the Rule. This deletion should not be made. Customers should not be placed at risk for recovery of utility generation assets or obligations yet to be acquired. A cut off point is necessary. If the cut off date is to be changed, there is as much (or more) reason to move it backward in time as there is to move it forward. I recommend that the definition of stranded cost remain unchanged.

Q. Does this conclude your rebuttal testimony?

A. Yes, although I may be filing additional rebuttal on February 2.

BEFORE THE ARIZONA CORPORATION COMMISSION

SECOND REBUTTAL TESTIMONY

OF

KEVIN C. HIGGINS

ON BEHALF OF
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION,
BHP COPPER, CYPRUS CLIMAX METALS, ASARCO,
PHELPS DODGE, AJO IMPROVEMENT COMPANY, AND
MORENCI WATER & ELECTRIC COMPANY

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF
ELECTRIC SERVICE THROUGHOUT THE STATE OF ARIZONA
DOCKET NO. RE-00000C-94-0165

February 4, 1998

EXHIBIT
AECC et al. 5
Admitted

Second Rebuttal Testimony of Kevin C. Higgins

Summary of Conclusions and Recommendations

Balancing of Customer and Utility Interests

I agree with Dr. Rose (Staff), Dr. Rosen (RUCO), Dr. Coyle (City of Tucson), Dr. Cooper (Arizona Consumers Council), Mr. Smith (Navy), Ms. Pruitt (ACAA), and Mr. Lopezlira (Attny Gen), who recommend that utilities be at risk for recovery of a portion of strandable cost. I disagree with Mr. Dabelstein, who believes that parties advocating a sharing of responsibility for strandable cost should bear the burden of proof to demonstrate why customers should not be 100 percent responsible. Strandable cost recovery is an extraordinary proposition. On a forward-going basis, it represents payments from customers for *no services rendered.* Clearly, the burden is on the recipients to justify the appropriateness of the portion requested from customers, and not the other way round.

Calculation Methods

I support proposals for auction and divestiture, but also support having a viable administrative alternative. I am in general agreement with Dr. Coyle (City of Tucson) and Mr. Smith (Navy) that replacement cost valuation is the preferred administrative approach, although I reiterate my support for the specific proposal offered in my Direct Testimony, which incorporates both replacement cost valuation and net revenues lost approaches. In my proposal, net revenues lost is used to calculate strandable cost on a year-to-year basis over a three-to-five year period. This approach differs from the time period recommended by Dr. Rosen (RUCO) and Mr. Dabelstein, both of whom recommend that the calculation be carried out for the remaining life of the generation assets, some twenty to thirty years. I recommend against such a long-term calculation, both because of the speculation involved and the desirability of avoiding a long-term true-up mechanism which perpetuates cost-of-service regulation.

Regarding the stock market valuation approach, I would be hesitant to commit Arizona customers to strandable cost payments based solely on a Wall Street determination of the value of split stock.

Mitigation

I concur with the reasoning of Dr. Rose (Staff) and Mr. Smith (Navy) that mitigation of strandable cost is best encouraged by placing the utility at risk for a portion of its strandable cost.

Other Issues

Mr. Neidlinger (Navy) asserts that special contract customers should pay strandable cost charges. However, the Rule in its current form limits strandable cost charges to those customers participating in retail access. Special contract customers are not in that group. Therefore, they do not pay strandable cost charges under the Rule. If strandable cost charges are extended to all standard offer customers, then the accompanying conditions I recommended in my Direct Testimony should also be adopted, namely: (1) The Standard Offer rate should be reduced by the amount of the transition charge, such that the final price for power paid by these customers is not increased, and (2) The Rule's existing treatment of self-generation, demand-side management, and other demand reductions unrelated to retail access should not be changed.

Collection of strandable costs through meter charges, as advocated by Dr. Block (Goldwater) and Mr. Lopezlira (Attorney General), based on historical usage may resolve the problem of economic distortions introduced by usage-based charges. However, the new set of equity and administrative problems this approach would introduce suggests that this recovery mechanism should be avoided.

Mr. Meek, Mr. Dabelstein, and Mr. Saline view price caps as requiring continued Commission regulation of generation prices. I reiterate that a price cap is an essential component of recovery mechanism design. In the context of stranded cost recovery, a price cap does *not* mean regulating the price of generation. Rather, it means designing the *transition charge* to accommodate the price cap objective.

Mr. Dabelstein suggests that it might be desirable to levy exit fees on self-generators. I disagree. Options such as self-generation and demand-side management have been available to customers for many years. Customers in the past have not been subject to stranded-cost-type penalties when exercising these options, and the advent of retail access should not be used as a pretext to start insulating utilities from these ordinary business risks now. There should be no exit fees levied on self-generators, nor should the reduction in electricity purchases resulting from self-generation be penalized with stranded cost charges.

Both Dr. Hieronymus (APS) and Dr. Rosen (RUCO) maintain that generation-related A&G costs should be included in strandable costs. I disagree. I note a subtle, but important, distinction. The net revenues lost approach uses projections of A&G costs in the *calculation* of strandable cost – but that is not the same as saying A&G costs are themselves strandable costs.

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SECOND REBUTTAL TESTIMONY OF KEVIN C. HIGGINS

I. INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 39 Market Street, Suite 200, Salt Lake City, Utah, 84101.

Q. By whom are you employed and in what capacity?

A. I am employed by Energy Strategies, Inc. (ESI) as a senior associate. ESI is a private consulting firm specializing in the economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Arizonans for Electric Choice and Competition[1], BHP Copper, Cyprus Climax Metals, Asarco, Phelps Dodge, Ajo Improvement Company, and Morenci Water & Electric Company.

Q. Have you filed other testimony in this proceeding?

A. Yes. I have filed direct testimony and rebuttal testimony addressing issues raised by witnesses sponsored by Affected Utilities.

Q. What is the purpose of this testimony?

A. I will provide rebuttal testimony which addresses issues raised by the parties who are not Affected Utilities. I will assess these parties' basic approaches to the critical questions of: (1) balancing customer and utility interests, (2)

[1] Arizonans for Electric Choice and Competition is a coalition of energy consumers in favor of competition and includes Cable Systems International, BHP Copper, Motorola, Chemical Lime, Intel, Hughes, Honeywell, Allied Signal, Cyprus Climax Metals, Asarco, Phelps Dodge, Homebuilders of Central Arizona, Arizona Mining Industry Gets Our Support, Arizona Food Marketing Alliance, Arizona Association of Industries, Arizona Multihousing Association, Arizona Rock Products Association, Arizona Restaurant Association, Arizona Association of General Contractors, and Arizona Retailers Association.

calculation method, and (3) mitigation of strandable costs. I will then use this framework to evaluate the extent to which other parties' recommendations may be consistent with, or at variance with, the calculation/recovery/mitigation proposal I made in my Direct Testimony. In some cases, I will offer explanations to clarify apparent differences. I will also address some points of disagreement outside these three major questions.

II. BALANCING OF CUSTOMER AND UTILITY INTERESTS

Q. In your direct testimony, you stated it was in the public interest for the Commission to balance customer and utility interests in implementing a strandable cost recovery program, and recommended that utilities be at risk for recovery of a substantial portion of strandable cost. Does the testimony of other witnesses support this view?

A. Yes. This view is supported by the testimony of Dr. Rose (Staff), Dr. Rosen (RUCO), Dr. Coyle (City of Tucson), Dr. Cooper (Arizona Consumers Council), Mr. Smith (Navy), Ms. Pruitt (ACAA), and Mr. Lopezlira (Attny Gen).

Dr. Rosen and Dr. Cooper each testify that the portion of strandable cost assigned to customers should not be greater than 50 percent. Mr. Lopezlira recommends a customer share of 70 percent. Dr. Rose and Dr. Coyle do not make specific recommendations as to customers' share, but strongly recommend that it should be less than 100 percent. Mr. Smith does not make a specific recommendation, but points out that placing utilities at risk for recovery of some portion of strandable cost is an appropriate mitigation incentive.

Q. How does your recommendation for sharing the risk of strandable cost compare with the specific proposals that were made by others?

A. In my direct testimony, I recommend that the transition charge levied on customers should be designed to recover between 25 and 50 percent of a utility's strandable cost. On this general point, my recommendation is consistent with those of Dr. Rosen (RUCO) and Dr. Cooper (Arizona Consumers Council). However, my testimony also includes a specific proposal for an administrative calculation of strandable cost in which I suggest that the appropriate portion for customers should be in the lower-to-middle region of that range, e.g., 35 percent. In the context of that specific proposal, this lower customer share is warranted in order to accommodate the use of the net revenues lost approach over a three-to-five year period.

Q. Do you believe that your 35 percent recommendation is low relative to Dr. Rosen's recommendation?

A. Not necessarily. Dr. Rosen recommends the use of a net revenues lost calculation approach over an extended period, up to 22 years following introduction of retail competition. He projects that strandable cost for APS and SRP would be negative over that full period. For reasons I will discuss further in the next section, I do not favor using a net revenues lost approach over such an extended period of analysis. However, Dr. Rosen's analysis clearly illustrates the potential for shareholder benefit in a competitive market. This is consistent with my contention that deregulation of generation prices will mean that investors will have the opportunity over the long-run to earn above a regulated return. It is in recognition of this long-term opportunity – and in recognition that a short-term analysis may overemphasize the impact of today's excess capacity on strandable cost – that I recommend setting the transition charge at around 35 percent of year-to-year strandable cost, in my administrative proposal.

Q. Are there parties who are not Affected Utilities who do not support placing the utility at risk for a portion of its strandable cost?

A. Yes. Mr. Dabelstein, Ms. Firkins (IBEW), Ms. Petrochko (Enron), and Mr. Meek (Shareholders) support 100 percent recovery of strandable cost from customer charges. I disagree with this position and address this issue generally in my Direct Testimony [pp. 9-11] and previous Rebuttal [pp. 2-7]. Also, very convincing testimony in opposition to 100 percent recovery from customer charges is provided by Staff in Dr. Roses's testimony, as well as by Dr. Rosen (RUCO) and Dr. Cooper (Arizona Consumers Council).

Mr. Dabelstein believes that parties advocating a sharing of responsibility for strandable cost should bear the burden of proof to demonstrate why customers should not be 100 percent responsible. I strongly disagree. Strandable cost recovery is an extraordinary proposition. On a forward-going basis, it represents payments from customers for *no services rendered*. Clearly, the burden is on the recipients to justify the appropriateness of the portion requested from customers, and not the other way round.

I also wish to address Mr. Dabelstein's statement that even though many members of the Stranded Cost Working Group felt there should be sharing of stranded cost recovery between ratepayers and shareholders, "none of the parties offered any substantive explanation or justification for requiring utility investors to assume any of the stranded cost." [Dabelstein Direct, p. 42, lines 12-14] As one who participated actively in that working group, I can offer some insight here: Mr. Dabelstein, as chairman of the Working Group, expressly prevented this issue from being considered. He told the Working Group, over protests, that we were to proceed *as if* 100 percent recovery were assured. The determination of *whether* 100 percent recovery should occur was not to be considered by our group. According to Mr. Dabelstein, this issue was to be determined elsewhere.

III. CALCULATION METHODS

Q. How do you characterize the approaches of the non-utility parties with regard to the calculation of strandable cost?

A. The non-utility parties' positions fall into three broad categories: 1) Exclusive or very strong preference for a market approach [Ogelesby (PG&E), Petrochko (Enron), Lopezlira (Attny Gen), Block (Goldwater), Nelson (ECC)], 2) Preference for a market approach, if feasible, but with an administrative alternative proposed [myself, Smith (Navy), Pruitt (ACAA)], and 3) Preference for an administrative approach [Rose (RUCO), Coyle (City of Tucson), Dabelstein, Meek (Shareholders), Firkins (IBEW)].

Q. What is your opinion regarding the market approaches that are being proposed?

A. Mr. Ogelsby (PG&E) and Ms. Petrochko (Enron) advocate auction and divestiture. As I indicate in my Direct Testimony, I support this approach, when practicable. Dr. Block (Goldwater) and Mr. Lopezlira (Attny Gen) advocate a stock market valuation approach that involves a splitting of utility stock into A shares and B shares. The A shares provide the investor the usual rights and benefits of a shareholder, while the B shares provide a claim against strandable cost [Block, Direct, p. 14]. Stranded cost is calculated as the difference between the book value of the company before deregulation and the value of the A share, measured at some pre-specified time. While I believe this approach is theoretically interesting, I am concerned that its implementation may not be viable. That is, there may be institutional and legal barriers to carrying out the proposed stock split. In addition, I am concerned about measurement issues. The stock valuation approach commits customers to paying for stranded cost based on the divergence between book valuation and the A shares as determined on Wall Street. We know that stock valuation is a dynamic process, affected by many variables internal and external to the firm; further, we know that the utilities in question are complex organizations – more than just generation companies. How can we be sure that the difference between book value and the A shares is a true measurement of strandable cost, and not the result of other dynamic changes in the financial marketplace? The answer is: we can't be sure, and I would be hesitant to commit Arizona customers to strandable cost payments based solely on a Wall Street determination of the value of A share stock.

Q. What is your opinion regarding the administrative approaches that are being proposed?

A. I am in general agreement with Dr. Coyle (City of Tucson) and Mr. Smith (Navy) that replacement cost valuation is the preferred administrative approach.

However, in my Direct Testimony, I make a specific proposal which incorporates both replacement cost valuation and net revenues lost approaches. In my proposal, net revenues lost is used to calculate strandable cost on a year-to-year basis over a three-to-five year period. This approach differs from the time period recommended by Dr. Rosen (RUCO) and Mr. Dabelstein, both of whom recommend that the calculation be carried out for the remaining life of the generation assets, some twenty to thirty years.

Q. Please explain your preference for using a three-to-five year calculation period instead of a twenty-to-thirty year period, if the net revenues lost approach is used.

A. As I explain in my Direct Testimony, the net revenues lost approach is very assumption-sensitive, and requires that projections be made concerning the annual operating and A&G costs which would have been incurred by the utility had competition not been introduced. In addition to the general objections I register about this approach, I am particularly concerned about the viability of projections of annual average market price and operating/A&G costs beyond a three-to-five year period. While Dr. Rosen (RUCO) demonstrates that a case can be made that annual strandable cost for APS may turn negative somewhere between years 6 and 8 (i.e., 2004-06) [Ex. RAR-4, p.2; RAR-5, p.4], I have little doubt that this "crossover year" can be moved further out in time by assuming higher utility operating costs. Because the market price and operating costs for such years are highly speculative, I am pessimistic that disputes over the appropriate projections for the "out years" can be readily resolved. One possible remedy, the use of a long-term true-up mechanism to correct for miscalculations, is tantamount to maintaining a state of quasi-regulation of generation prices for the next twenty to thirty years, a prospect I consider to be at variance with the intent of the Competition Rule. For these reasons, if the net revenues lost approach is used, I recommend using a three-to-five year calculation/recovery period in combination with a transition charge designed to recover about 35% of expected strandable cost. (In addition, replacement cost valuation should be calculated to double-check the results of the net revenues lost estimation.)

Q. Would it be reasonable to use the eight-year calculation period recommended by APS as a compromise between the three-to-five year period you recommend and the 22-year period recommended by Dr. Rosen?

A. No. If Dr. Rosen's analysis is correct, the eight-year period recommended by APS corresponds to the approximate period that annual strandable cost for APS is positive. In Dr. Rosen's analysis, adding years of analysis beyond the eighth year brings the calculation of strandable cost down; likewise, truncating the analysis well before year eight does the same thing. Ending the analysis exactly at year eight may result in maximizing the strandable cost calculation to the benefit of the utility. [See Ex. RAR-5, p. 4]. Because the move to an "intermediate" time period probably benefits the utility from either direction, I do not consider an eight-year period to be a "middle ground" between Dr. Rosen's recommendation and my own. I see the question boiling down to whether a longer-term or shorter-term analysis is preferable. For the reasons given, I strongly prefer using the shorter period of analysis, with the stated qualifications.

IV. MITIGATION

Q. Do other parties recognize that mitigation of strandable cost is best encouraged by placing the utility at risk for a portion of its strandable cost?

A. Yes. This point is recognized by Dr. Rose (Staff), Mr. Smith (Navy), and others. I concur with their reasoning on this issue. By their nature, mitigation actions are an integral part of corporate strategy that should be governed by the principles of risk and reward, rather than regulatory prescription or second-guessing. As I state in my Direct Testimony, the best mitigation incentive is for the utility to be at risk for a substantial portion of its strandable cost, and to be financially rewarded when its mitigation efforts are successful. This is accomplished by designing the transition charge to cover no more than 50 percent of strandable cost in a given year. Then, we can leave it to the utilities to implement whatever mitigation actions they believe to be most effective. This type of incentive mechanism relies upon the basic principles of the marketplace to guide utilities towards efficient mitigation strategies and represents a significant step in effecting a transition from a regulatory to a competitive paradigm for the utilities involved.

V. OTHER ISSUES

a. Special Contracts

Q. Mr. Neidlinger (Navy) asserts that special contract customers should pay strandable cost charges. Would you comment on this?

A. The Rule in its current form limits strandable cost charges to those customers participating in retail access. Special contract customers are not in that group. Therefore, they do not pay strandable cost charges under the Rule.

If strandable cost charges are extended to all standard offer customers, then the accompanying conditions I recommended in my Direct Testimony should also be adopted, namely: (1) The Standard Offer rate should be reduced by the amount of the transition charge, such that the final price for power paid by these customers is not increased, and (2) The Rule's existing treatment of self-generation, demand-side management, and other demand reductions unrelated to retail access should not be changed.

These essential provisions apply just as much to special contract customers as to standard tariff customers. If a strandable cost charge is levied on special contract customers, their special contract rate should be reduced by the amount of the transition charge, such that the final price for power paid by these customers is not increased. The determination of these charges should be made in accordance with the proportional cost allocation principle agreed upon by consensus of the Stranded Cost Working Group, and which I restate in my Direct Testimony [Higgins Direct, p. 30, lines 4-13]. Special contract customers are entitled to the same price cap provisions that are necessary for all customers generally. They should not be singled out to bear discriminatory cost increases under the guise of stranded cost recovery.

b. Meter charges

Q. What is your opinion regarding the proposal by Dr. Block (Goldwater) and Mr. Lopezlira (Attny Gen) to use meter charges to collect strandable costs?

A. Dr. Block and Mr. Lopezlira are correct when they assert that usage-based charges to collect strandable cost will introduce economic distortions. Unfortunately, the remedy they propose – meter charges based on historical usage – introduces a new set of implementation difficulties which may be more objectionable than the distortions they are intended to overcome. First, assigning future strandable cost charges based on past usage is likely to be administratively cumbersome, potentially requiring unique charges for each customer. Second, special difficulties arise in handling customers who change residences or business locations – and there will be many over the recovery period. Third, equity considerations arise in the case of customers who install energy conservation measures, or businesses which shut down part of their operations. Should such customers be saddled with strandable cost charges stemming from an earlier period's usage? I suggest not.

Collection of strandable costs through meter charges based on historical usage may resolve the problem of economic distortions introduced by usage-based charges. However, the new set of equity and administrative problems this approach would introduce suggests that this recovery mechansim should be avoided.

c. Price caps

Q. Mr. Meek, Mr. Dabelstein, and Mr. Saline have raised questions over the appropriateness of a price cap. Do you wish to respond?

A. Yes. These witness express concerns because they view price caps as requiring continued Commission regulation of generation prices. I wish to reiterate that a price cap is an essential component of recovery mechanism design. In my direct testimony, I explain that, in the context of stranded cost recovery, a price cap does *not* mean regulating the price of generation. Rather, it means designing the *transition charge* to accommodate the price cap objective. [Higgins Direct, pp. 33-35]. I should point out that, under this application of a price cap, the Commission is not intended to provide a blanket "insurance policy" for all customer transactions in the competitive market. Rather, the transition charge is designed to accommodate a price cap at the market price of power used for calculating strandable cost. Customers who strike retail access deals above the market-clearing price of power, may, in fact, see their individual prices go up.[2] On the average, however, a price cap is in force. Standard Offer customers – even if assigned strandable cost charges – are held harmless.

d. Self-generation

Q. Mr. Dabelstein suggests that it might be desirable to levy exit fees on self-generators [Direct, pp.16-17]. Do you agree?

A. No. I address this issue in my Direct Testimony (pp. 27-29) and previously-filed Rebuttal (pp. 11-12). In that testimony, I state that the current Rule treats self-generation (and demand-side management) appropriately by mandating that "any reduction in electricity purchases from an Affected Utility resulting from self-generation, demand side management, or other demand

[2] Even this can be avoided, however, by using the true-up option I discuss on p. 33 of my Direct Testimony. Under this option, the utility receiving transition payments is required to offer generation to

reduction attributable to any cause other than the retail access provisions of this Article shall not be used to calculate or recover any Stranded Cost from a consumer." [R14-2-1607(J)]

The reasoning behind this provision is correct. Options such as self-generation and demand-side management have been available to customers for many years. These demand reductions are business risks to the utility which pre-date retail access. Customers in the past have not been subject to stranded-cost-type penalties when exercising these options, and the advent of retail access should not to be used as a pretext to start insulating utilities from these ordinary business risks now. There should be no exit fees levied on self-generators, nor should the reduction in electricity purchases resulting from self-generation be penalized with stranded cost charges.

e. Administrative and General (A&G) Costs

Q. Both Dr. Hieronymus (APS) and Dr. Rosen (RUCO) maintain that generation-related A&G costs should be included in strandable costs. [Hieronymus Direct, p. 7; Rosen Direct, p. 61.] Do you agree?

A. In general, no. A subtle, but important, distinction is necessary here. The net revenues lost approach uses projections of A&G costs in the *calculation* of strandable cost – but that is not the same as saying A&G costs are themselves strandable costs. Unlike fixed generation costs, such as long-term debt, A&G costs are "going-forward" costs, such as the president's salary. In general, these costs are within the discretion of the utility, and should not be considered "strandable."

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the payers at the price used to calculate strandable cost.

It is easiest to see this distinction by illustration. Assume a market retail generation price of 3.5 cents per kWh. Assume also that the utility has annual fixed generation costs of 2.5 cents per kWh, operating costs of 2 cents per kWh, and A&G costs (functionalized to generation) of 1 cent per kWh – resulting in total generation-related costs of 5.5 cents per kWh. Under the net revenues lost approach, strandable cost is 5.5 cents minus 3.5 cents, or 2 cents per kWh. Note that, in this example, the market price is covering all generation-related operating and A&G cost (3 cents together), plus a portion of fixed generation cost (.5 cent). "Stranded" cost is limited to the portion of fixed generation cost that is not recovered at the market price. A&G cost, while used in the calculation, is itself not a stranded cost.

Now assume a lower market price of 2.5 cents per kWh. The utility can cover all its operating costs and half of its A&G cost, but none of its fixed generation cost. Thus, all 2.5 cents per kWh of fixed generation costs are stranded. But what about the half cent of unrecovered A&G cost? Should this be added to stranded cost? I would argue not. The issue is not whether A&G costs are legitimate costs – it is whether it is legitimate to assign these discretionary costs to customers as strandable cost. It is one thing to make customers partly responsible for sunk, generation-related costs which were incurred under regulation. It is another matter to burden customers *who no longer take generation service* with the discretionary A&G costs that are "assigned" to generation. These costs (plus generation-related operating costs) should be recoverable only from the competitive market. If the utility is unable to do so, it should absorb the unrecovered portion without recourse to strandable cost charges.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT
ECC-2
admitted

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 DOUGLAS C. NELSON, PH.D.

ON BEHALF OF

ELECTRIC COMPETITION COALITION

JANUARY 15, 1998

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Summary of the Testimony of Douglas C. Nelson, Ph.D.
on Behalf of the Electric Competition Coalition

Docket No. U-0000-94-165

My direct testimony supports the divestiture approach to stranded costs. This market-based approach of divesting generation provides a simple, fair, accurate and workable way to identify and measure stranded assets. It grants the Affected Utility the flexibility of deciding whether or not to retain those assets and assume the risk of potential costs, or to sell those assets and seek recovery of any stranded cost. This divestiture method provides the least distortion for true electric price competition. Furthermore, it avoids the uncertainty and bias of numerous assumptions and data used in economic models, such as the Net Revenue Lost approach. The Commission argued and the Superior Court agreed that there is no "regulatory compact" requiring the continuation of monopolistic services. I oppose the use of the "net revenues lost" approach because it attempts to reinstate the "regulatory compact" theory of more regulation and higher rates to consumers.

Q. Please state your name, business address, affiliation, and your educational and business qualifications.

A. My name is Douglas C. Nelson. I am the Executive Vice President of the Electric Competition Coalition (ECC). ECC is an Arizona nonprofit corporation whose members support electric competition. My qualifications and business address are presented in the Attachment to this testimony.

Q. Who are you presenting testimony on behalf of in these proceedings?

A. I am presenting testimony on behalf of ECC and in particular Nordic Electric Arizona, L.L.C. and Calpine Corporation as members of ECC.

Q. What are your general recommendations and observations for the Commission?

A. Stranded costs could have a profound impact on electric competition in Arizona. The greater the amount of "stranded cost" which a utility is able to recover, the greater the barrier to entry of electric generation and the greater the price to consumers. Consumers will be required to pay "stranded cost charges" to the utility in addition to market based rates. Obviously, these charges will be added to the customers' bills and will distort market prices. In addition, these charges will act as subsidies to the utilities which will allow them to price their generation below its actual costs in order to drive out competitors or they will cause competitors to price their electricity well above their real market prices by using the utility's prices, and the stranded cost charge, as a ceiling price. Neither option is good for the Arizona consumer.

For the reasons I just mentioned, I recommend that the Commission

- require any Affected Utility seeking to recover stranded cost to divest of their generation assets,
- require all Affected Utilities to engage in cost-effective mitigation efforts to lower their potential stranded costs, and
- require any Affected Utility that desires to sell electricity (or other services) in the competitive market to create a functionally separated affiliate and adopt standards of conduct that are subject to Commission approval.

Q. What issues have you identified as being the most important?

A. The assurance of a market-based method, rather than an administratively developed economic model, for determining stranded costs is the most important issue before the Commission. Of equal importance, I believe the prompt commencement of the competitive sale of electric generation is vital to the containment of those accruing stranded costs.

1. Modification of Rules

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

A. The Rules provide a reasonable basis for determining stranded costs and a fair opportunity for the Affected Utilities to recover any stranded costs. The definition of "stranded cost", in R14-2-1601.8, properly refers to the net difference between "the value of all the prudent jurisdictional assets and obligations necessary to furnish electricity" acquired prior to December 26, 1996 and "the **market value** of those assets and obligations" which are "**directly attributable to the introduction of competition** . . ." (emphasis added). As I will explain later, this definition provides the basis for the Commission to order the Affected Utility to file a generation divestiture plan if an Affected Utility desires to recover stranded costs.

The Rules appropriately update the Commission's regulations to reflect new technologies and new competitive markets of electric generation. Some economists believe that economic efficiency would be best served by ignoring the sunk costs of stranded investments and moving on with competition. I believe that a simple and fair approach in identifying and quantifying these strandable costs is necessary so that competition may progress swiftly and smoothly for all. The divestiture plan I am proposing accomplishes these objectives consistent with the market-based approach adopted by the Commission in its Rules.

2. Timing of Stranded Costs Filings

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

A. If an Affected Utility intends to seek recovery of stranded costs, it should file a divestiture plan with the Commission. Before an affiliate company of the Affected Utility may bid on its generation assets, I recommend that the Commission adopt regulations covering transactions between any Affected Utility and its affiliate. The divestiture plan should then include the standards of conduct between the Affected Utility and its affiliate, to ensure that consumers' interests are not harmed by anticompetitive dealings. Under this framework, the Commission would be able to prevent subsidization of affiliates at the expense of the utility's ratepayers. Following the divestiture, the Affected Utility may then file an application for recovery of stranded costs, if necessary.

3. Scope and Calculation of Stranded Costs

Q. What costs should be included as part of stranded costs and how should those costs be calculated?

A. The wider concept of stranded costs includes stranded assets, stranded liabilities, regulatory assets, and stranded social programs. Stranded assets refer to generation or related assets that become uneconomic with the advent of competition and which cannot be sold. Stranded liabilities are typically contracts with unregulated generators, but they may include contracts with fuel suppliers and contingent liabilities such as environmental regulations. Regulatory assets are primarily deferred expenses that appear as assets on the balance sheets. Stranded social programs may include cross-subsidized pricing of services, environmental compliance, and demand-side management expenditures. Although I would prefer a narrower definition of stranded cost, I am of the opinion that the market-based method for computing these values is more important than the label.

Q. Which investments should be considered strandable?

A. Generation should be the focus of stranded cost calculation and recovery at this time.

Q. What is the most challenging aspect of calculating stranded costs?

A. A major problem of identifying and treating stranded costs is the assumption of the market clearing price that may prevail. Obviously there will be no price until a competitive market is created. The market price of electricity will dictate the magnitude of stranded costs. The divestiture approach I'm recommending does away with the complex issues involving the calculation of stranded costs. Furthermore, this divestiture method may occur during any time in the transition period. It is not necessary to wait until commodity electric markets mature, because the divested assets create the market price. Implicitly, a plant's sale price (or "market valve") will equal its expected discounted net revenue over the lifetime of the plant.

Some have suggested the use of the Dow Jones Palo Verde index or the California Power Exchange as indicators of market price.[1] These very short-term prices of electricity may not however reflect the market value of electricity over a long-term calculation period desired by the Affected Utilities. These indices may not accurately reflect market conditions in Arizona. Supporters of these indices suggest that the recoverable stranded costs should "float" as the market price changes over the course of the transition period. I oppose this approach because the highly variable stranded cost charge would then become a barrier to entry for new competitors. Consumers will not be able to compare the full cost of competitive generation and the stranded cost charge to the rates for bundled services from the utility.

Q. How will the timing of competition affect stranded costs?

A. The experience of robust competition is necessary before the Commission may determine whether or not any asset may be stranded. Furthermore, the prompt introduction of competition will give the Affected Utilities the opportunity to further mitigate any of their potential stranded assets. Under the divestiture proposal, the Affected Utility has the choice of deciding whether or not to seek stranded cost recovery and divest itself of generation facilities, or keep those units in anticipation of reducing stranded costs and perhaps transfer the generators to a competitive affiliate.

Q. How should stranded costs be calculated?

A. Sale of stranded assets through divestiture is the most accurate method of calculating potential stranded costs. These arm-length transactions will reflect the market price which may be compared to the depreciated book value of the asset. For any nonmarketable asset, they should be calculated by using the asset-by-asset methodology of appraisal which is sometimes referred to as the "bottom-up" approach.

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1 Testimony of Charles Bayless (TEP) at 14-15 (Jan. 9, 1998) (Dow Jones Palo Verde index) & Testimony of Jack Davis (APS) at 9 (Jan. 9, 1998) (California Power Exchange or similar market index).

Q. How would divestiture work?

A. Under the divestiture plan, the utility would be required to sell its generation assets to a third-party or an "approved affiliated" company of the utility at a market price, if the utility seeks recovery of stranded costs. To assure the fair market price of generation, the utility would describe each of its generation facilities, their depreciated book values, and offer the generation facility or facilities to the highest bidder during an open bid period of 180 days. Under the supervision and approval of the Commission, the generation facility or facilities would then be sold to the third party or an "approved affiliated" company who offered the highest price. The utility would continue to own the distribution system and be compensated for its use through its unbundled rates.

If a generation facility sells at a price less than the depreciated book value, the difference would be deemed the stranded cost. If the selling price is higher than the depreciated book value, the surplus would be applied to reduce the stranded cost. The total net difference for all generating facilities, if less than the depreciated book value, would be recovered through a stranded cost charge. If the total selling price is greater than the depreciated book value, there of course would not be any stranded cost recovery.

Q. Under the Electric Competition Rules, how would divestiture occur?

A. The stranded cost section of the Rules, R14-2-1607.G, requires the Affected Utility to file estimates of stranded costs "supported by analyses and by **records of market transactions undertaken by willing buyers and willing sellers.**" (emphasis added). This provision allows for the Commission to order the divestiture bid process that I have outlined.

Q. What are the advantages of divestiture?

A. Divestiture maximizes the deregulation of electric generation. It emphasizes market principles by granting open access to generation capacity and it encourages the owners of generation to maximize the efficiencies in plant operations. Divestiture will assure the Arizona consumer of a competitive generation market and mitigate market power.

Another advantage of divestiture is that it does not presuppose or require a particular form of market, such as a regional power exchange or market index for electricity. The actual sale of generation in Arizona, rather than a California power exchange or Wall Street index, would be used in marketing power and computing any stranded cost. Divestiture provides symmetry in both the electric generation market and the stranded cost program.

Q. Has the divestiture approach been applied in other jurisdictions?

A. Yes, in several states. Maine and Massachusetts, for example, require divestiture. The California restructuring law requires some form of divestiture. Montana has a voluntary divestiture program.

Q. Should the Affected Utility be able to decide which generation assets are strandable?

A. No. If an Affected Utility elects to seek stranded cost recovery, it is my preference for the utility to make its entire portfolio of generation subject to divestiture. Otherwise the Affected Utility will only keep the low-cost generators and unload the high-cost plants. To allow Affected Utilities to pick and choose would be contrary to the very foundation of their argument for recovering stranded cost. They claim that their portfolio of generation was developed with the expectation that they would have to meet the projected load of their captive customers. Old plants may be fully depreciated and therefore the value of those generators may offset some of the potential stranded cost of other facilities.

Furthermore, it is unlikely any Affected Utility could identify which generator was installed for the benefit of any consumer or customer class. Another reason for requiring all generation to be divested is that excess power is sometimes sold on the wholesale market. It would be inequitable to allow the utility to retain low marginal cost generators and sell that power in the wholesale market while at the same time requiring its captive customers to purchase the high marginal cost power.

Q. Would the divestiture plan work if the utility was required to sell only a portion of its generation, let's say 50 percent?

A. Yes, although the utility would likely retain its most efficient units and divest those with high marginal cost. As a consequence, it would make it more difficult to determine what the total net stranded cost of the utility might be. The Commission could require the utility to conduct an asset-by-asset appraisal of the facilities that are not divested so that any "negative" stranded cost from those facilities may be used to offset any stranded costs incurred from the sold units. If a facility is not offered for sale, the market value of that generation may be extrapolated from those units that were sold. This information could be used in the appraisal of those units and in the calculation of stranded cost. Instead of using this approach, I believe it is more efficient to require the sale of all generation assets if a utility applies to recover stranded costs.

Q. What happens if there is no market for some generation facilities, such as Palo Verde nuclear generators?

A. If a facility does not sell, theoretically the generation unit should be "shut down" and the book value would be declared the stranded cost. From an economic perspective the "sunk costs" and the ongoing operating costs should be curtailed so as to "stop the bleeding." However, from a practical and political perspective, some high-cost generators may have to be operated for at least an interim period. For these reasons, I support the appraisal method in addressing unsold units. If this condition should occur, the Commission could then require the utility to fund an independent appraisal of the generator by a qualified expert approved by the Commission. The appraised value of the plant would be compared to the depreciated book value in calculating the stranded cost. An important requirement, however, is that the utility must agree to sell the plant at the appraised value in the future. This will assure consumers that the utility will not seek an unreasonably low value in the appraisal.

Nuclear generation may become more valuable in the future, after significantly more depreciation is taken and with relatively low variable operating costs. In comparison, fossil fuel plants may incur replacement or other life extension capital costs which may make some of them less economical to operate. It is difficult to say whether nuclear generators will not be more marketable than other generation sources, so it seems unnecessary to foreclose the option to sell those nuclear units.

Q. How would the appraisal be conducted?

A. Using traditional appraisal techniques, an expert may determine the generator's market value based upon the selling price of comparable generators (assuming such sales are available), examine its replacement cost, and analyze its revenue stream, perhaps adopting some of the Net Revenue Lost concepts that the utilities have advocated. Thereafter, the expert would provide those three figures and based upon all factors determine the appraised market value.

Q. Earlier you mentioned the Palo Verde nuclear generators. Will it be difficult to forecast the future cost of nuclear waste disposal and decommissioning the generators?

A. Yes but possible. These same projections of nuclear waste disposal and decommissioning would have to be made in the Net Revenue Lost approach which implicitly considers those estimated costs and any revenue stream from a "system benefits charge." The expert appraiser could apply the industry standards used across the country in determining the future cost of operating and decommissioning the plant.

Rather than rely on an indefinite "system benefits charge" which would be imposed upon consumers, I support the one-time integration of those projected costs within the appraised value (and hopefully ultimate sale of the generators). The Rules in R14-2-1608 provide for collection of nuclear power plant decommissioning costs as part of the system benefits charge. I recommend that this phrase be deleted from that section so that those charges would be reflected in the appraisal or sale of those nuclear units.
The investors in those generators should bear those risks and not the consumers. It is also important to keep in mind that all generators, including fossil fuel plants, have future risks and costs of environmental requirements and closure. When these plants have been divested in other jurisdictions, the purchasers have had to impute those risks and costs in their purchase prices. These same concepts may be applied to nuclear generation whether the plants are sold or appraised.

Q. How would the divestiture bid and appraisal program work under the existing Electric Competition Rules?

A. As I mentioned earlier, R14-2-1607.G requires the consideration of willing buyer and willing seller market transactions in the computation of stranded cost. Another section says the Commission shall determine for each Affected Utility the magnitude of stranded costs, and appropriate stranded cost recovery mechanisms and charges. In doing so, the Commission is to at least consider (a) the degree to which some assets have values in excess of their book values, and (b) the ease of determining the amount of stranded cost, among other factors. R14-2-1607.I. The Commission, I believe, may order the utility to file its divestiture plan under this provision.

Q. May the Affected Utility file an accurate forecast of stranded costs?

A. Generally no. Estimates of stranded costs vary widely. Critical assumptions that affect the projected levels of stranded costs include the share of retail electricity sales subject to competition, the share of retail electricity sales lost by the Affected Utility as a result of competition, future load growth, the sale of the Affected Utility's at-risk capacity, the projected market clearing price of electricity, and the number of years used in computing stranded investments.

All stranded cost estimates apply speculative assumptions of the characteristics of the new competitive market conditions, the role of new entrants, and the level of future natural gas and other fuel prices. The lack of available data with respect to the unamortized costs (or investments), along with the related plant operating cost data, present additional obstacles in estimating the potential stranded costs. Any of these assumptions and factors may cause a serious bias in projecting these potential stranded costs.

Q. Should the Net Revenue Lost approach be used?

A. Absolutely not. The Net Revenue Lost approach is premised on the false assumption of a "regulatory compact" between the Commission and the Affected Utility. Some Affected Utilities claim the Commission agreed to not change their monopoly services. As the name implies, the Affected Utility would receive the same net revenue as if competition had not occurred. Those Affected Utilities appealed the Electric Competition Rules and argued that a regulatory compact precluded the Commission from allowing the competitive sale of generation. The Commission successfully convinced the Court that no regulatory compact existed. As a consequence, the Court has rejected the notion of a regulatory compact and implicitly the use of the Net Revenue Lost approach.[2] The Commission should not endorse this approach which is based upon the regulatory compact theory.

Q. What are some of the pitfalls of the Net Revenues Lost approach?

A. All stranded costs are not transition costs associated with competition. Some assets or deferred expenses may become stranded for reasons other than increased competition, as illustrated by the write-down of assets in the past. Changes in load growth or demand side management, for example, may have caused some generation not to be fully used or uneconomical. The Net Revenues Lost approach masks these differences. Allowing recovery of stranded costs under the Net Revenue Lost approach gives the greatest

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[2] In the consolidated appeal of the Rules, Judge Colin Campbell addressed whether "the competition rules issued by the Arizona Corporation Commission breaches a regulatory contract with TEP, . . ." and the Court denied "TEP's motion for summary judgment insofar as it seeks a ruling that the Commission cannot as a matter of contract change from a regulated marketplace to a competitive marketplace." *Tucson Electric Power Co. v. The Arizona Corporation Commission, et al.*, Maricopa County Superior Court No. CV97-03748 (Consolidated) (Minute Entry dated November 19, 1997).

reward to those utilities which made the worst business decisions. The use of other approaches make each asset or deferred expense subject to close inspection and comment.

A common argument made by the utilities is that they had an obligation to serve and, therefore, all generation costs incurred to meet that obligation should be fully recovered. But in a fully competitive market, simply owning generation does not create stranded costs; only owning capacity that has depreciated book value of more than its market price creates stranded costs.

Another weakness of the Net Revenue Lost approach is that it assumes that no strandable asset has market value. This is clearly a false assumption based upon the recent divestitures that have gone on in other jurisdictions.

Another shortcoming of the Net Revenues Lost approach pertains to how regulatory assets are handled. Stranded cost recovery of any regulatory asset should be traceable to a particular function, such as, generation, transmission or distribution. Only those regulatory assets that are directly attributable to competitive generation should be potentially recoverable as stranded. The Net Revenues Lost approach avoids these calculations by assuming the consumer should be at risk and pay any unrecovered regulatory asset regardless as to the type of function.

With the "before" and "after" competition comparison of the revenue stream, the customers would be obligated to pay the full cost of stranded costs, as I discussed earlier. The Net Revenue Lost approach would require the Commission to make a policy decision on how much of the stranded cost should be borne by shareholders (if any) by authorizing a fraction of the full net revenue stream. These equity issues are difficult and that is another reason why I support the divestiture approach.

Q. Earlier you said that the Net Revenue Lost approach is premised on the notion of a regulatory compact, please explain.

A. The Net Revenue Lost approach protects the market share of the monopolistic utility and reduces (or eliminates) the risk of utility shareholders. It is a continuation of the "regulatory compact" concepts that the utilities have advanced in their appeals and again in this proceeding. For example, Tucson Electric Power Company (TEP) in its direct testimony raises the notion of "a compact" entitling it to recover stranded costs. Bayless at 6; Daniel Wm. Fessler at 26-30. According to TEP's expert, the Net Revenues Lost approach "seeks to protect the expectations formed under the existing regulatory regime with respect to both the recovery of an investment and the income stream on that investment." Fessler at 37. I believe the Affected Utilities should not be able to apply the regulatory compact theory of stranded cost recovery by giving it another name, "the Net Revenue Lost approach."

Q. What should be included within strandable costs?

A. The Affected Utilities generally visualize a wider concept of "stranded costs" than I believe is appropriate. They include costs that would normally be recovered with the continuation of a monopoly environment, under the current regulatory cost-of-service rate-based regime. They in essence are seeking full compensation for all costs in the transition to a competitive environment. For example, environmental mandates are imposed on all industries, whether or not they are within the jurisdiction of the Commission. Preferential treatment should not be awarded to the Affected Utilities merely because they are complying with local, state and federal laws. These obligations are the responsibility and costs of all industries. Furthermore, these compliance obligations would be incurred regardless of the Electric Competition Rule.

Q. Should the Commission reexamine whether the stranded investment was prudently incurred?

A. The divestiture approach I have suggested does not require the Commission to reexamine whether or not the generation investment was prudently incurred. If another approach is used, such as the Net Revenue Lost concept, questions arise as to whether or not the utility's management decisions were discretionary and in accordance with the prior intent of the Commission. These thorny issues may be avoided with the divestiture approach.

4. Time Horizon for Calculating Stranded Costs

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

A. The divestiture method I discussed earlier does not require the consideration of a time horizon for calculating stranded cost. The willing bidders of the generation will impute the value or cost of those obligations and liabilities within their offers. In contrast, the Net Revenue Lost approach would require a complex inventory, proration and computation of those assets which were acquired or contracted for prior to the adoption of the Rules. The Commission would then have to determine how the market values of each of those assets changed as a result of the adoption of the Electric Competition Rules. This administrative determination, with costly experts and hearings, would likely be more confusing and complex than any cost of service rate case.

5. Time Period for Recovery of Stranded Costs

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

A. Yes. The Commission should impose the shortest time frame possible without unreasonably burdening the consumer. Preferably this recovery period should not extend beyond four years, no later than January 1, 2003--when full competition is authorized under the Rule.

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. The recovery of stranded costs should be competitively-neutral as to all customers. This means that those customers who purchase competitive power should only pay that portion of the stranded cost that they would have implicitly paid if they were purchasing power from the incumbent utility.

If an Affected Utility sells generation to a new retail customer outside of its service territory, will that customer be obligated to pay both its incumbent utility's stranded cost and the Affected Utility's stranded cost? For example, a shopkeeper in Phoenix may desire to purchase electricity from Tucson Electric Power Company. Will the shopkeeper receive a stranded cost charge from TEP as well as from Arizona Public Service Company? The Rule does not appear to address this question. The divestiture proposal resolves this issue by requiring the Affected Utility to create an affiliate entity if the utility seeks to recover stranded costs. The customers stranded cost obligation would then be only to APS. Similarly, I recommend that the Commission consider requiring any Affected Utility that desires to sell retail generation outside of its service area to first divest of its facilities so as to avoid the double stranded cost payment issue.

Q. How should consumers pay for stranded costs?

A. A "stranded cost charge" should be prorated among consumers according to their historic power usage and the utility's total stranded cost should be proportioned among classes of customers based upon their historic power usage. Using the utility's present rate design, the charge could be assessed against the kilowatts, kilowatts per hour, or both. This line item charge should be reflected on the bills of both those consumers who purchase generation from the incumbent utility and those who buy generation from others and are invoiced for distribution services. By highlighting this transition charge, the public will be better informed and be able to compare the relative cost of generation.

Q. Should the shareholders of the Affected Utility share any of the stranded cost risk?

A. Yes. Investment decisions in the utility industry are based upon future load growth, technological changes, the comparative cost of self-generation, the portfolio of power generation mix, the terms of power supply contracts, interest and inflation rates, changes in market conditions, and a host of other factors. Investors may desire to purchase stock in low or high risk utility companies, or in other industries, depending upon their investment strategy. As I mentioned earlier, the Net Revenue Lost approach would assume that only the change to a competitive generation market caused the differential in any change in the revenue stream. Clearly, this is a false assumption. By using the Net Revenue Lost approach the full future risk of these factors is placed solely on the consumer.

Q. How would you propose to share the stranded cost risk between the shareholders and consumers?

A. The divestiture approach avoids the issue of segregating stranded costs between shareholders and consumers. If the asset's market value is below its depreciated book value, the net difference is the amount the Commission may include in the stranded cost recovery account for the Affected Utility. To the extent other assets have market values above their depreciated book values, those amounts should be used to offset the asset with a negative value. The net result is that the shareholders would recover (and share the risk) of the utility's true market value which would be translated through the utility's share price. To the extent the generation assets have total divestiture market values less than their depreciated book values, the consumers could be assessed a fixed proportionate amount which could be either paid in a lump sum or over time by both those consumers who remain with the incumbent utility or decide to purchase generation from others.

7. True-Up Mechanism

Q. Should there be a true-up mechanism and, if so, how would it operate?

A. In general, no. When making the application for recovery of stranded costs, the Affected Utilities should be reasonably precise in defining the asset and the magnitude of the stranded cost that resulted from the divestiture or appraisal. Without such precision, customers may experience a retroactive cost in purchasing competitive power. If there is uncertainty about the full cost of competitive power, competition will be muted because consumers will be uncertain of their total cost in receiving competitive generation.

Another problem with a true-up mechanism is customers will change over time. Any true-up mechanism will create inequities among customers depending upon when they participated in the competitive market or when they came into or left the service area.

Q. How will a true-up mechanism operate?

A. If a true-up mechanism becomes necessary, because of unforeseen circumstances, the Commission may initiate a hearing process to implement a process for adjusting the overcollection or undercollection of stranded cost for a particular utility. Efforts to develop a true-up mechanism at this stage would seem premature, particularly since it is unknown what factors may affect any potential over or under collection of stranded cost.

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. As a general proposition there should not be any need for a price cap or rate freeze, although I am not opposed to a price cap. The price cap should be the sum total of all charges the customer is paying under current rates of the Affected Utility.

The Commission should encourage the aggregation of <u>all</u> customers into purchasing groups so that they may reap the benefits of competition without the necessity of a price cap or rate freeze. The Commission's Rules ensures that all classes of customers benefit from electric competition. Residential and commercial customers comprise the large majority of electric demand. Rather than impose a price cap or rate freeze, the Commission should encourage residential and commercial customers to aggregate their electric loads and purchase generation from the competitive market.

In particular, I am opposed to any rate freeze because any benefits resulting from the utility's cost reductions would flow only to shareholders without any rate reduction to consumers. Any cost savings caused by the competitive transition should be reflected in both the bundled and unbundled rates of the regulated services offered by the Affected

Utility. A rate freeze would take away the most important consumer protection remedy--the ability to change generation suppliers.

9. Mitigation of Stranded Costs

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

A. The Rules require the Affected Utilities to "take every feasible, cost-effective measure to mitigate or offset" stranded costs. R14-2-1607.A. Each Affected Utility should aggressively be mitigating its stranded costs as part of prudent management. Each Affected Utility should file with its application for recovery of stranded costs a description of its previous mitigation efforts and a plan of action for mitigating any potential stranded costs.

One method for reducing stranded costs, as mentioned in the Rule, is for the utility to offer "a wider scope of services for profit." R14-2-1607.A. Although the Rule is not clear, I recommend that the Commission interpret this provision as requiring the creation of an affiliate company before any competitive enterprise may be engaged in by the Affected Utility. As I suggested earlier, I believe the Commission may order the utility to divest itself of those assets used in the profit-generating enterprise. In doing so, the revenue from the transferred assets may be used in offsetting stranded costs, and then the profits and risks of that competitive enterprise would flow to the shareholders of that affiliate company. If this provision of the Rule is unclear, I recommend that the phrase "or offering a wider scope of services for profit" be deleted from R14-2-1607.A.

Conclusions

Q. Please summarize your recommendations.

A. The market-based approach of divesting generation provides a simple, fair, accurate and workable way to identify and measure stranded assets. This concept grants the Affected Utility the flexibility of deciding whether or not to retain the generation assets and assume the risk of potential stranded costs, or to sell those generators and seek recovery of any stranded cost. This divestiture method provides the least distortion for true electric price competition. Furthermore, it avoids the uncertainty and bias of numerous assumptions and data used in economic models, such as the Net Revenue Lost approach.

Another advantage of the divestiture proposal is that competition may begin without delay. Until retail energy markets are open for competition, estimates on what will be uneconomic assets in a competitive market are highly speculative and possibly meaningless. I recommend that competition begin no later than January 1, 1999. Customers will benefit from lower-priced generation, because the divested generation will be subjected to cost efficiencies imposed by the competitive market. For these reasons and others I discussed in my testimony, I strongly urge the Commission to carefully consider the divestiture approach for the resolution of stranded costs and remain committed to the January 1, 1999 commencement date.

Q. Does this conclude your direct testimony?

A. Yes.

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Douglas C. Nelson, Ph.D.

Education:

Ph.D./Natural Resource Economics
University of Nebraska (with credits from Arizona State University)
M.S./Agricultural Economics
University of Nebraska
J. D./Law
University of Nebraska
B.S./Agricultural Economics
University of Nebraska

Professional Affiliations:

Nebraska Bar
Arizona Bar
Federal District Court

Douglas C. Nelson, P.C.
7000 North 16th Street
Suite 120-307
Phoenix, Arizona 85020
(602) 395-1612
(602) 395-1943-Fax
E-mail: dcn@netwrx.net

Doug Nelson is in private practice with an emphasis in energy and natural resource law. He is executive vice-president of the Electric Competition Coalition, an organization that encourages open electric competition.

Doug has worked extensively on electricity and natural gas matters in Arizona since 1973. He has negotiated and administered power contracts, conducted economic evaluations of power alternatives, and developed energy management programs.

Doug also has extensive experience in federal, state and local government affairs, administrative law and related litigation. On numerous occasions, he has appeared before legislative committees and regulatory agencies on electrical, natural gas, water, and environmental matters.

Doug has a Juris Doctorate degree and Ph.D. in Natural Resource Economics from the University of Nebraska. He has published several professional articles on energy, water, environmental and other natural resource issues. In addition, Doug has made formal presentations to professional organizations on these subjects.

Doug is founder and serves as the Executive Vice-President of the Arizona Rural Water Association, a coalition of rural counties, cities and towns. He is a past President of the Arizona Chapter of the Federal Bar Association and is a member of the Arizona Water Systems Coordinating Council, Valley Leadership Alumni Association, Water Resources Research Center Advisory Board (University of Arizona), American Agricultural Economics Association, National Association of Business Economists, and Natural Resources & Environment and Administrative Law Sections of the State Bar of Arizona. Doug is active in a variety of other professional and civic organizations.

EXHIBIT

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admitted

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

REBUTTAL TESTIMONY OF DOUGLAS C. NELSON, PH.D.

ON BEHALF OF

ELECTRIC COMPETITION COALITION

FEBRUARY 4, 1998

Summary of the Rebuttal Testimony of Douglas C. Nelson, Ph.D. on Behalf of Electric Competition Coalition

Docket No. U-0000-94-165

The "rolling" stranded cost method proposed by the Arizona Public Service Company would be anticompetitive and discourage the mitigation of stranded costs.

The Federal Energy Regulatory Commission, in its Order 888, has adopted the "revenues lost" approach which grants wholesale customers the option of marketing the excess generation that may result if that customer departs from the utility. FERC requires that these stranded costs be determined upfront and be fixed. Furthermore, FERC grants the customer the ability to select the method of payment. The Net Revenue Lost approach, as proposed by some in this proceeding, does not include the market-based principles which were adopted in the FERC approach. As a consequence, I support the divestiture of generation assets so that both retail and wholesale customers may rely on the market-based value of any strandable excess generation.

REBUTTAL TESTIMONY OF DOUGLAS C. NELSON, PH.D.
ON BEHALF OF
ELECTRIC COMPETITION COALITION

FEBRUARY 4, 1998

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Q. What is the nature of your rebuttal testimony?

A. Some of my rebuttal testimony was presented in my January 15, 1998 testimony, which was filed on January 21, 1998. For instance, I discussed the shortcomings of using the Dow Jones Palo Verde Index or the California Power Exchange as indicators of market price at page 4. In addition, I raised concerns about the failed "regulatory compact" theory in Arizona and how it relates to the Net Revenue Lost approach, at pages 8 and 9.

Q. Do you have additional rebuttal testimony?

A. Yes, although I will limit my response to some very specific issues. First, I would like to address the "rolling" calculation of stranded costs as proposed by Arizona Public Service Company (APS). Testimony of Jack E. Davis (January 9, 1998) at 8-11. Second, I wish to comment on why the Federal Energy Regulatory Commission (FERC) may have used a variation of the net revenue approach but that method should not be applied to retail generation facilities. Testimony of William H. Hieronymous (January 9, 1998) at 14.

The APS "Rolling" Stranded Cost Method

Q. Please explain your concerns about using the "rolling" stranded cost recovery approach suggested by the Arizona Public Service Company.

A. The APS methodology would greatly discourage and perhaps foreclose the competitive sale of generation. Consumers and competitors would not know what the future stranded costs obligation might be. Therefore, consumers are likely to take a "wait and see" attitude and stay with the utility's standard offer. Competitors would be unable to offer a fixed total electric price to consumers, because APS would be controlling the stranded cost component. Customers will be further confused because they will not know if they can return to the standard offer if it might be less than the combined competitive-generation and stranded cost component.

To further complicate this situation, APS has been silent on how it would unbundle its transmission, generation, distribution, and ancillary services. Competitors and consumers will know how much generation will cost, but they won't know what the other unbundled rates or the "rolling" stranded cost might be. Consumers will be unable to make "apple to apple" comparisons; new entrants will be unable to set a "market" price; and the utilities might falsely claim customers are satisfied because they didn't change suppliers.

Another major problem with the APS approach is that it does not create an incentive for APS to manage its stranded costs. All consumers, both those that stay with APS generation and those that buy from others, will likely pay more for stranded costs under the APS approach, as compared to any market-based approach.

Q. You mentioned that a relatively precise stranded cost figure is needed in order for competition to occur. Have the utilities been able to provide a relatively precise estimate of stranded costs using future market value models?

A. Generally no. The utilities hire consultants who use different models and formulae in an effort to forecast the future market value of generation. For example, PECO Energy estimated its future value of its generation in a competitive environment ranging from $1.865 billion to $3.65 billion, using three witnesses and a variety of methods and assumptions. Application of PECO Energy for Approval of its Restructuring Plan under Section 2806 of the Public Utility Code and Joint Petition for Partial Settlement, Docket Nos. R-00973953/P-00971265, Pennsylvania Public Utility Commission (December 11, 1997) at 44-48.

The PECO Energy experience illustrates how difficult it is to forecast the future market value of generation without divestiture.

Comparison of FERC's Revenues Lost Method to the Proposed Net Revenue Lost Approach

Q. You mentioned the FERC Order 888 and that FERC's "revenues lost" approach would not be an appropriate method to use in addressing stranded cost while restructuring the retail electric industry. Please explain.

A. The Federal Energy Regulatory Commission focused on individual wholesale requirements contracts dealing with specific transmission owners and generation facilities in adopting Order 888.[1] These contracts pertain to specific facilities and lines which allow for the clear identification of rates (or prices). Recovery of wholesale stranded costs from departing customers is by direct assignment. Individual cost-based pricing of each facility lends itself to a precise calculation of the rate before competition as compared to the price after open access.

These circumstances are far different from a situation where a utility has numerous facilities with vertically integrated transmission, generation, distribution, and ancillary services. The Net Revenue Lost approach, as suggested in this proceeding, cannot track the individual contract (customer tariff) or facility cost-component rate as compared to the wholesale experience under FERC Order 888.

Another important distinction is that the strandable costs associated with wholesale generation and transmission are relatively minor when compared to retail generation. The margin of error in over or under collection of stranded costs is much less when using the revenues lost approach in the wholesale industry, as compared to the Net Revenue Lost approach for a vertically integrated utility in the retail industry.

Q. What would you consider to be the key differences between FERC's revenues lost approach and the Net Revenue Lost approach being proposed by some in this proceeding?

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1 See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. 31,036 (1996), order on reh g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC 61,248 (1997).

A. The names sound similar but the formulae and conditions are different. There are at least three important distinctions between FERC's revenues lost approach and the Net Revenue Lost approach suggested by some here.

First, the customer has the opportunity to buy the strandable generation, under FERC Order 888. Excess generation (and associated energy) may occur when the customer leaves the utility. The utility is required to identify the amount of system capacity (and associated energy) that will be released by the departing customer and used in its revenue lost calculation. The departing customer has a choice, to market the released capacity (and associated energy) and receive an asset for his or her stranded payment. That market condition assures the customer that the utility will not place an unreasonably low market value on that excess capacity and associated energy.

Second, the stranded cost values are determined upfront and are fixed. This allows the customer the opportunity to budget and plan. Competitors have defined parameters for marketing generation. Utilities have incentives to mitigate those fixed stranded costs.

Third, the customer may choose the method of payment, such as by lump-sum or periodic payments, or perhaps through a transmission wires charge. This allows the customer to tailor the payment plan to his or her cash flow requirements. These conditions are substantial different from the notion of the Net Revenue Lost approach which is being talked about in this proceeding.

Q. How does FERC protect the wholesale consumer and competitors?

A. Generation capacity is freed up when a customer departs. The recovery of stranded cost will subsidize the fixed cost of that capacity, allowing the utility to remarket that capacity at artificially low prices in other jurisdictions. Both the captive customers and competitors of the utility are disadvantaged when "the customer pays" and "the utility owns" the stranded asset. FERC grants the consumer and competitors some protection by allowing the consumer to market the excess generation if the customer believes the utility's estimate of market values are too low.

Q. What would the Corporation Commission have to do if it applied FERC's revenues lost approach?

A. In applying FERC's revenues lost approach, the Corporation Commission would have to implement these steps for each departing customer:

1. The utility must offer proof of the time period the utility could have reasonably expected to serve the departing customer, which is different from the useful life or amortization period of the utility's generation facilities.

2. The utility would identify the amount of released capacity (and associated energy) that will be freed up as a result of the customer's leaving the utility.

3. The average amount paid by the customer over the past 3 years for generation services would be calculated.

4. The utility would estimate the average annual revenue that it would have received from the released capacity and energy, using the future period when it could have reasonably expected to serve that customer.

5. The customer would provide the actual average annual cost of that replacement capacity and energy. The customer would then have the option of using its replacement cost or the utility's estimate (described in step 4) to figure the stranded cost.

These 5 steps are dramatically different from the Net Revenue Lost approach suggested by some in this proceeding. First, all revenue changes, not just those relating to generation and the departing customer, would be recovered under the Net Revenue Lost approach. Second, the utility would not have to identify which generation asset might become stranded. Third, the retail customer does not have the option of using the utility's estimate of future revenue from released power or its own replacement cost. Fourth, the FERC "reasonable expectation period" for recovering stranded cost is the duration of wholesale contractual commitment; not necessarily the entire life of the asset, as proposed in the Net Revenue Lost approach. Further, the utility would have to show the reasonable expectation of serving the particular customer who decided to depart. This may be difficult, especially for those customers that received special discount contracts in the past, those that thought about self-generation, those that engaged in significant demand-side management, and those that considered creating their own municipal utility.

Q. May the FERC revenues lost approach be applied on the retail level?

A. It would be extremely difficult. An individual residential customer or even a group of customers may not have the resources to exercise the purchase option the utility may set for the market value of its excess generation. In keeping with the FERC market-based principles, I support the divestiture of generation assets so that collectively all of the utility customers would benefit from the exercise of that market option. This market driven approach, under the supervision of the Corporation Commission, would benefit all consumers and not just those that have the ability to purchase at wholesale.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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SCO = (RSE - CMVE) x L
FERC Revenues Lost Approach

SCO = Stranded Cost Obligation
Cap with Neutral Impact

RSE = Revenue Stream Estimate
3 year Average Annual Revenues

CMVE = Competitive Market Value Estimate
(1) Utility's estimate of average annual value
(2) Customer's annual cost of replacement power

L = Length of Obligation
"Reasonable Expectation" of Serving Customer

What is AUIA?

The Arizona Utility Investors Association (AUIA) was established in March, 1994, as a grassroots organization to represent the common interests of individual and business investors who own shares or bonds in utility companies that operate in Arizona. Qualifying utilities include electric, gas, water, telecommunications and pipeline companies.

AUIA's Mission

AUIA's mission is to pursue legislative and regulatory initiatives to maximize the influence of Arizona utility investors on public policies and governmental actions which may impact the well-being of investors and their utility investments. AUIA 's specific action programs will be determined by its board of directors which represents a cross section of experience and geography.

Why is an organization like AUIA important?

A new generation of issues will bring tremendous change to the utility industry as the decade progresses. Changing technologies are redefining utility markets and services. Government policies and economic conditions are thrusting traditional monopolies into competition. Utility regulators face conflicting pressures from consumer, environmental and industry advocates. And governments at all levels continually threaten utilities and their shareholders with new taxes to fill depleted treasuries. These issues can have a major impact on utility finances and the return on your investments.

It's important that public officials and those who elect them understand the relationship between utility companies and the economic and environmental arenas in which they exist. As an investor, it's important to understand the issues that impact your investment.

We work best in this country when policies are made with input from all concerned parties. There are currently 41 state-funded utility consumer agencies operating across the country. Regulators and legislators should also hear from the individuals whose investments make utility services possible. With AUIA, Arizona joins 10 other states in providing a voice for utility investors to balance consumer and regulatory positions.

AUIA's Objectives

AUIA will work to provide a favorable environment for the competitive and profitable operation of utilities in Arizona, including recognition of the importance of utility services to economic development and the need for an appropriate return on invested capital. AUIA will give high priority to public education regarding utility economics, service choices, new technologies and the impacts on consumers and investors.

AUIA will focus on these activities:

- Develop a grass roots organization which can function throughout Arizona;
- Make sure the investor's voice is heard at legislative and regulatory hearings;
- Educate new regulators and legislators;
- Issue newsletters, legislative alerts, bulletins and position papers;
- Organize public forums and seminars;
- Develop and execute strategies that address vital issues;
- Provide news media with the investor's point of view;
- Participate in shareholder meetings of investor companies when appropriate;
- Act as a clearing house for information that will benefit utility investors.

How do I join?

No dues are required of individual investors, but contributions to offset operating expenses are important. All you need to do is fill out the attached card and mail it in to AUIA. Whether or not you choose to make a contribution at this time, your membership in AUIA is important. Make your voice heard and increase your clout. Join AUIA today!

YES!

I want my interests protected as a utility investor. Sign me up for AUIA.

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I have investments in these utility companies that operate in Arizona *(Check all that apply)*:

- ❑ Pinnacle West Capital Corp.
- ❑ Citizens Utilities Company
- ❑ Southern California Edison
- ❑ Salt River Project
- ❑ San Diego Gas & Electric
- ❑ Public Service of New Mexico
- ❑ PacifiCorp
- ❑ El Paso Electric
- ❑ El Paso Natural Gas
- ❑ Tucson Electric Power
- ❑ Southwest Gas Corporation
- ❑ US WEST
- ❑ AT&T
- ❑ Other ____________

I own (Check all that apply):
____ common stock ____ first mortgage bonds
____ preferred stock ____ mini-bonds
____ other ____________

Mailing Address:

Name ____________

Street ____________ Apt ____

City ____________

State ____________ Zip ____

Home or office telephone number: (____) ________

__ I want to help offset operating expenses and I'm enclosing a contribution of $10, payable to AUIA.
__ I prefer not to make a contribution at this time, but sign me up as a member.

I am registered to vote in Arizona: Yes ____ No ____
I usually vote in state and local elections: Yes ____ No ____
I am interested in financial information about utilities:
Yes ____ No ____

"Increase Your Clout as a Utility Investor."

Arizona Utility Investors Association
P.O. Box 34805
Phoenix, Arizona 85067-4805
Ph: (602) 230-0428

(AUIA is applying for recognition as a 501 (c)(6) non-profit organization. However, contributions to AUIA are _not_ deductible as a charitable contribution for federal income tax purposes.)

PLACE
STAMP
HERE

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P.O. Box 34805
Phoenix, Arizona 85067-4805