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Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

Re: Kevin C. Higgins Direct Testimony of January 21, 1998 -- Missing Pages

Dear Sir or Madam:

Enclosed are an original and ten copies of pages 13 through 33 which were inadvertently omitted from the Direct Testimony of Kevin C. Higgins, which was filed on January 21, 1998. We apologize for any inconvenience this may have caused.

If you have any questions, please don't hesitate to call me at 916-5332.

Very truly yours,

FENNEMORE CRAIG

Marc H. Lamber

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Enclosures
cc: Service List Docket No. U-0000-94-165
PHX/MLAMBER/816636.1/23040.041

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. Should there be a limit on the time frame over which stranded costs are calculated? (Question 4)

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. Should there be a limitation on the recovery time frame for "stranded costs"? (Question 5)

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. <u>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)</u>