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BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000-94-0165

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Rebuttal Testimony of Richard Rosen on the Stranded Cost portion of the above-referenced Docket.

RESPECTFULLY SUBMITTED this 4th day of February, 1998.

Deborah R. Scott, Chief Counsel
Teena Ingram Wolfe, Attorney

AN ORIGINAL AND TEN COPIES
of the foregoing Notice and Testimony
filed this 4th day of February, 1998 with:

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SERVICES THROUGHOUT	)	
THE STATE OF ARIZONA	)	
	)	

REBUTTAL TESTIMONY OF

DR. RICHARD A. ROSEN

Submitted on Behalf of
The Residential Utility Consumer Office

February 4, 1998

Summary of Rebuttal Testimony of Dr. Richard Rosen

This testimony is offered as a rebuttal to direct testimony filed by many parties in Arizona Corporation Commission (ACC) Docket No. U-0000-94-165. Generally, I agreed with many of the policies supported by other parties, especially the points raised by the ACC Staff regarding the need for the use of a retail market price rather than the wholesale market price in the calculation of stranded costs, the need to share positive stranded costs, the usefulness of a price cap, and the need for incentives to ensure the mitigation and reduction of uneconomic costs. However, I disagreed with those parties supporting the use of the Dow Jones Palo Verde Index for estimating market prices, for advocating the securitization of stranded costs, and freezing rates. I disagree that a bottom-up or asset-by-asset approach to computing stranded costs conflicts in any way with a top-down or net system approach. I also disagree with arguments for full recovery of stranded costs based on the existence of a regulatory compact. I counter the argument that stranded cost recovery charges create barriers to exit and entry in competitive markets. I believe that there will be no change in the value of the transmission and distribution system that can be used to mitigate stranded generation costs. Finally, although I do not oppose divestiture, I believe it is an acceptable method for stranded cost recovery only if accompanied by a true-up mechanism based on a net system approach.

Tucson Electric Power Company (TEP) advocates the use of Dow Jones Palo Verde Index (PVI) for estimating market prices. I strongly disagree that the PVI will provide the best estimate of the type of market prices that are necessary for computing stranded costs. The PVI is a short-term spot market wholesale price. The use of a short-term spot market wholesale price for computing stranded costs may unjustifiably increase the magnitude of stranded costs. The market prices that should be used to calculate costs that might become stranded due to retail competition must be the market price for retail generation services. Thus, projections of those retailing costs, which make up what I call the "retail margin," should be added to long-run projections of competitive wholesale prices in order to derive a more accurate market price for retail generation services for computing stranded costs.

I disagree with TEP's position that securitization should be used as a method for stranded cost recovery. Based on my initial estimates of TEP's strandable costs, they are too uncertain for securitization to be a prudent approach for recovering any of these stranded costs. The use of a non-securitized competitive transition charge ("CTC") with opportunity for true-up provides for more flexibility in stranded cost recovery given the inherent uncertainty in estimating stranded costs. Thus, the ACC should not securitize any level of TEP's strandable costs in order to prevent the problem of ratepayers inadvertently over-paying for these costs if market prices turn out to be higher than currently anticipated. Second of all, as I stated in my direct testimony, TEP should not be allowed to recover its stranded costs after January 1, 2003, even if this implies the need to write-off more stranded costs than it otherwise would have to. TEP ratepayers should have to pay only the market price for generation after full-scale retail access begins.

In this rebuttal testimony I demonstrate how, on average, TEP would likely over-collect its stranded costs if a rate freeze were in place. Thus, I oppose TEP's proposal for a rate freeze. I recommend capping the rate, as opposed to freezing rates, for the standard offer generation service at either the generation rate that would have been charged to each customer class if regulation had continued, or at the market price for retail generation services appropriate to that customer class, whichever is lower.

Regulators have always balanced the customer's right to adequate service at reasonable rates with the investor's opportunity to earn a fair return. The notion of risk-sharing is not new—in fact, I describe decisions made by public utility commissions as far back as 1980 which prove that regulators have often allocated the burden of uneconomical excess costs between utility investors and ratepayers. That balancing of ratepayer vs. investor interests does not support the notion of a compact or claims of entitlement to full recovery of prudent investments under the Constitution. Therefore, I disagree with the notion that a "regulatory compact" has existed in the past.

Even though I am strongly in favor of Dr. Rose's arguments in favor of the sharing of stranded costs, I do not agree with Dr. Rose's arguments on behalf of the ACC Staff which attempt to show that any level of the recovery of stranded costs will have a negative impact on the development of a competitive generation market. The existence of a non-bypassable stranded cost recovery charge will not create barriers to exit and entry in a competitive market. After rates are unbundled, all customers in each rate tariff will pay the same stranded cost recovery charge whether or not they stay on the standard offer. As long as all customers pay the same stranded cost recovery charge based on their usage of the distribution system, all generation suppliers including the standard offer providers are on an equal basis. Thus, no barriers to exit or entry can be created by collecting this charge. I discuss self-generation as a possible exception where stranded cost recovery could lead to uneconomic bypass.

I disagree with the statement that a rise in the value of the transmission and distribution system should be used to mitigate stranded costs on the generation side. In a restructured environment, transmission and distribution systems will remain regulated. Therefore, no change in value of the transmission and distribution system will be possible, since there will not be a free market in transmission and distribution ("T&D") services.

Finally, divestiture as a method of stranded cost recovery was raised by several parties in this docket. Although RUCO does not advocate that divestiture of utility generation assets be required, RUCO does not oppose divestiture. However, parties should be aware that a market valuation approach to stranded costs may yield auction, spin-off, or sale prices that are either too low or too high relative to actual long-run market prices for generation at the wholesale level. An artificially low sale price received for generation assets would, of course, increase stranded costs above the level they should be if market prices reflecting a more competitive market were utilized for their determination. Thus, divestiture or market valuation is not necessarily a more accurate way to determine stranded costs than an administrative evaluation approach. From a consumer protection perspective, divestiture can be an acceptable method for estimating stranded generation costs only if it is accompanied by a true-up mechanism that incorporates a "net system" perspective. A net-system true-up approach under an administrative valuation stranded cost determination method would take the sale price of divested generation assets into account as <u>partial</u> evidence of market price <u>in addition</u> to other data on current and projected prices for retail generation services.

Q. ARE YOU THE SAME RICHARD A. ROSEN WHO FILED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes, I am.

Q. DO YOU AGREE WITH MANY OF THE POSITIONS HELD BY OTHER PARTIES IN THIS DOCKET?

A. Yes, I generally agree with many of the policies supported by other parties in this docket, especially the points raised by the Arizona Corporation Commission Staff regarding the need to use a retail price rather than the wholesale market price in the calculation of stranded costs, the need to share positive stranded costs, the usefulness of a price cap, and the need for incentives to ensure the mitigation and reduction of uneconomic costs. Therefore, I also agree with Dr. Mark Cooper's belief, stated in his direct testimony on behalf of the Arizona Consumers Council, that there should be a sharing of stranded costs between ratepayers and shareholders, and particularly that ratepayers should not be responsible for more than 50 percent of that recovery. I also agreed with the general line of argument Dr. Cooper raised against the securitization of stranded costs and against the existence of a regulatory compact. Carl Dabelstein's testimony also raised salient arguments supporting the use of the administrative approach for the quantification of stranded costs and the need for a true-up mechanism. Both are positions I support.

REBUTTAL TO FILINGS OF AFFECTED UTILITIES

Q. WOULD YOU LIKE TO RESPOND TO ANY OF THE TESTIMONY FILED BY AFFECTED UTILITIES IN THIS DOCKET?

A. Yes, I would like to respond to just a few points regarding the proper stranded cost calculation methodology that were made in TEP's testimony.

Q. DO YOU HAVE A RESPONSE TO TEP'S COMMENT ON THE USE OF THE DOW JONES PALO VERDE PRICE INDEX AS THE BEST ESTIMATE OF THE MARKET PRICE FOR THE PURPOSE OF COMPUTING STRANDED COSTS?

A. Yes, I would like to respond to Mr. Bayless' comment on page 14 of his testimony on behalf of TEP where he states, "TEP proposes using the Dow Jones Palo Verde Price Index ("PVI") as a market price estimate." I strongly disagree that the PVI will provide the best estimate of the type of market prices that are necessary for computing stranded costs. First, the PVI is a short-term spot market wholesale price which reflects the current situation of excess capacity. Therefore, it tends to be a low wholesale price and does not reflect the higher prices of long-term contracts for firm capacity purchases.

Regarding this very point, on page 15 of his testimony Mr. Bayless was asked, "Shouldn't the market price used for calculating stranded costs include long-run capacity costs?" He replied, "Yes, to the extent that such costs are recovered in the competitive market. Further, as excess capacity is depleted and the market for capacity becomes tighter, the PVI price will more fully reflect capacity costs." This may be true, but it does not change the fact that the PVI price will be a short-term price. A more appropriate estimate of a wholesale market price for power to meet a certain type of load, such as peaking, cycling, or baseload, should be no less than the unit cost of financing, constructing, and operating those plants needed to meet that load in the least-cost way over the long run. Ancillary service costs and the impact of transmission and distribution ("T&D") losses must also be taken into account.

The use of a short-term spot market wholesale price for computing stranded costs may, therefore, unjustifiably increase the magnitude of stranded costs. As Dr. Rosenberg, testifying on behalf of Arizonans for Electric Choice and Competition, et al., also stated in his testimony, "Because spot energy prices are typically lower than the prices of other competitive power contracts, the exclusive use of spot energy to measure market prices is likely to increase the magnitude of stranded costs. A spot market wholesale price is not indicative of the price that customers realistically will be able to obtain if they desire intermediate to long-term retail firm service (pages 16-17)."

Q. WHAT TYPE OF MARKET PRICES DO YOU BELIEVE SHOULD BE USED TO CALCULATE STRANDED COSTS?

A. As discussed at length in my direct testimony, a <u>wholesale</u> market price, as advocated by Mr. Bayless, is not the appropriate <u>type</u> of market price for computing stranded costs. Mr. Higgins, testifying on behalf of Arizonans for

Electric Choice and Competition, et al., stated, "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." I believe Mr. Higgins is partially correct, but he does not adequately portray the amount and components of the non-wholesale components of the market price for retail generation services. The market prices that should be used to calculate costs that might become stranded due to retail competition must be the market price for retail generation services. Dr. Kenneth Rose, testifying on behalf of the Arizona Corporation Commission, stated on page 19 of his direct testimony, "...Price scenarios must reflect the projection of a retail price that end-use customers will likely see. It should not be based on a projection of wholesale prices that wholesale and other large customers face in the spot market." To use a wholesale market price to calculate a utility's stranded costs significantly underestimates the appropriate market price, and, thus also overestimates strandable costs. (My response assumes that the market price is being compared to the unbundled generation component of required revenues when computing stranded costs, as in a "top-down" approach.) Of course, this same point applies to many other witnesses in this case, such as Mr. Dick Minson, who states that stranded costs should be computed using long-term marginal prices, but who forgets to say that these prices should be retail prices.

In addition to the cost of buying power at wholesale, the types of costs that competitive alternative generation suppliers will incur to provide retail generation services fall into the following categories: generation-related customer services, ancillary services, marketing and advertising, generation-related administrative and general services, profits and income taxes on profits, and other taxes. Each type of cost just listed should be reflected in the estimated market price for retail generation services used to compute stranded costs. Each type of cost will be incurred by retail generation suppliers, regardless of whether they provide each and every service from in-house resources or whether they contract out certain services. Thus, projections of these retailing costs, which make up what I call the "retail margin," should be added to projections of competitive wholesale prices in order to derive a more accurate market price for retail generation services for computing stranded costs. (Please see Section 4 on the market price of retail generation services in my direct testimony for a more complete discussion of this issue). Thus, it is the total market price for retail generation services as determined by alternative suppliers to the utilities, not spot wholesale prices such as those in the Dow Jones Palo Verde Index, that will determine the revenue that the existing utilities will be able to earn in the future retail market.

Q. DO YOU HAVE A RESPONSE TO TEP'S PROPOSAL TO SECURITIZE 75 PERCENT OF ITS STRANDED COSTS WITH REPAYMENT OVER 10-15 YEARS?

A. Yes, I would like to respond to Mr. Bayless' proposal on page 17 of his testimony. He stated, "The Company's proposal requires rates to be fixed at some level to recover stranded costs via the CTC through 2004 and securitization of up to 75 percent of stranded costs with repayment over 10-15 years."

First of all, I disagree that securitization should be used as a method for stranded cost recovery. Based on my initial estimates of TEP's strandable costs, they are too uncertain for securitization to be a prudent approach for recovering any of these stranded costs. My estimates range from a low of $257 million to a high of $770 million in 1998 present value dollars. Securitizing even a portion of the low estimate of $257 million in strandable costs locks TEP's ratepayers into this recovery mechanism at a fixed level. It could be that even this low estimate will prove too high, and therefore 75 percent of this low level will also prove to be too high. The use of a CTC that is not securitized would enable the utility to cope with changes in the estimates of stranded costs over time due to the true-up process. The use of a non-securitized CTC provides for more flexibility in stranded cost recovery given the inherent uncertainty in estimating stranded costs. Thus, the ACC should not securitize any level of TEP's strandable costs in order to prevent the problem of ratepayers inadvertently over-paying for these costs if market prices turn out to be higher than currently anticipated.

Second of all, as I stated in my direct testimony, TEP should not be allowed to recover its stranded costs after January 1, 2003, even if this implies the need to write-off more stranded costs than it otherwise would have to. TEP ratepayers should have to pay only the market price for generation after full-scale retail access begins.

Q. DO YOU AGREE WITH TEP'S PROPOSAL FOR A RATE FREEZE?

A. No, I do not agree with TEP's proposal for a rate freeze. To again quote Mr. Bayless' comment on page 17 of his testimony, "The Company's proposal requires rates to be fixed at some level to recover stranded costs via the CTC through 2004..." I believe that a price cap is more appropriate than a rate freeze, as discussed in my direct testimony. A rate freeze may provide the opportunity for Affected Utilities to make greater profits than are likely under normal ratemaking practices by accelerating the recovery of stranded costs. In fact, my calculations indicate that if TEP had a rate freeze from 1998-2002, they would over-collect their strandable costs by $268 million in the high market price scenario and under-collect their stranded costs by $126 million in the low market price scenario in 1998 present value dollars.[1] Therefore, on average, TEP would likely over-collect its stranded costs, and thus I oppose a rate freeze. I recommend capping the rate for the standard offer generation service at the lower of the generation rate that would have been charged to each customer class if regulation had continued, or the market price for retail generation services appropriate to that customer class. This approach would provide a much fairer and more objective basis for setting a rate cap during the transition period than just freezing rates at today's level.

Q. WHAT IS YOUR POSITION REGARDING THE EXISTENCE OF A REGULATORY COMPACT BETWEEN UTILITY COMPANIES AND REGULATORS OR RATEPAYERS?

[1] This estimation of stranded cost collection in the case of a rate freeze is based on my high and low estimates of stranded costs for TEP (See Exhibit__(RAR-8), p.1 of my direct testimony). The high market price scenario yielded total stranded costs of $257 million and the low market price scenario yielded total stranded costs of $770 million in 1998 present value dollars. The stream of stranded costs between the years 1998-2002, in 1998 present value dollars, yielded $526 million in stranded cost recovery in the high market price scenario. In the low market price scenario, that stream of stranded costs yielded $644 million in 1998 present value dollars. The difference between the two defines how much TEP would over- or under-collect in stranded cost recovery.

A. First I would like to say that issues regarding the "regulatory compact" involve legal issues, and are, therefore, most appropriately addressed in legal briefs. However, because TEP's witnesses, Charles Bayless and Daniel Fessler, have addressed these issues at length in their testimony, I will rebut their positions. Please note for the record that I am not an attorney. However, I have testified many times over the past 15 years before public utility commissions all over the U.S. on the issues of the prudency of utility investments, and the sharing of uneconomic utility costs as a policy witness. In fact, my testimony on the sharing of canceled utility plant in Pennsylvania was the basis for the well-known U.S. Supreme Court case Duquesne Light Co. v. Barasch.

Thus, based on my long experience with these issues, I disagree with the notion that any kind of a "regulatory compact" has existed in the past that goes beyond the state utility code in any way. Arizona utilities claim that state utility commissioners are bound by a long-standing compact which requires that they be assured at the outset that they will recover all investment not previously disallowed as imprudent. Such assurance is required, they claim, on the grounds of constitutional right, fairness and symmetry. Mr. Bayless, on page 6 of his testimony stated, "The operations of public utilities, since shortly after their inception, have been based on the Compact. In Arizona, electric utilities were given a Certificate of Convenience and Necessity and were <u>required</u> to build facilities to serve <u>everyone</u> in their respective service territories and were allowed the opportunity to earn a reasonable return on their investment." But the argument supporting the existence of a regulatory compact is not sound. Dr. Kenneth Rose, testifying on behalf of the Arizona Corporation Commission, stated in his direct testimony,

> "The Rules and the method of stranded cost recovery that is suggested elsewhere in this testimony do not break or violate the regulatory compact, but rather redefine and modify it as a matter of state public policy during a transition period to greater competition in the electric industry. ...the opportunity to recover costs and earn a reasonable return on and if its investments still exists under the Rules. We must be clear that the social compact is not now, nor has it ever been a contract guaranteeing the utility a perpetual monopoly, freedom from competition or full cost recovery. No argument can be made that there is now or was in the past a contract obliging the people of Arizona to pay for uneconomic costs (pages 2-3)."

I agree with Dr. Rose.

Q. HAVE OTHER UTILITY EXPERTS REJECTED THE EXISTENCE OF THE REGULATORY COMPACT?

A. Yes, many utility experts reject the idea that there has ever been a regulatory compact that dictates 100 percent recovery of stranded costs. For example, in testimony before the State of New Jersey Office of Administrative Law, ex-PUC Commissioner Peter Bradford stated,

> I have found no discussion of such a compact before the early 1980s. ...I make the following points (regarding the notion of a regulatory compact):
> 1) Courts have never endorsed the notion of a compact.
> 2) Courts have rejected the argument that if an investment is prudent, the shareholders are entitled to full recovery.
> 3) The franchises created early in the industry's history did not establish an ongoing regulatory compact; in fact, they were displaced for most purposes by regulation precisely to avoid the

contract-like inflexibility which the utilities now seek to attribute to regulation itself.
4) The concept of "regulatory compact" or "regulatory bargain" plays no role in the considerable economic literature on regulation.
5) State commissions today are rejecting the notion of a compact.[2]

The review of relevant regulatory literature performed by Mr. Bradford indeed found that prior to the 1980s, there was no discussion of a regulatory compact. He explains how before that time, he found only general arrangements that varied from state to state and from time to time, arrangements that might give rise to investor hopes but not to the constitutionally protected claims commonly asserted by utilities in restructuring hearings.

Q. IS THERE ANY HISTORICAL PRECEDENT FOR THE POSITION THAT YOU ADVOCATE IN FAVOR OF RISK-SHARING BETWEEN RATEPAYERS AND STOCKHOLDERS?

A. Yes, there is. We should not forget that risk-sharing of uneconomical generating capacity and investments is not a new issue. Two fairly old regulatory decisions — the Kansas Corporation Commission-Wolf Creek case (1985) and Massachusetts Department of Public Utilities-Millstone 3 case (1986) — illustrated that many regulatory commission believed that investments in new capacity must be economically justified and that risk-sharing must apply to the portion of those investments deemed to be uneconomic. (Please refer to *Risk Sharing and the*

[2] Direct Testimony of Peter A. Bradford, previously Chairman of the Maine and New York public utility commissions, before the State of New Jersey Office of Administrative Law. BPU Docket No. EO97070462, OAL Docket No. PUC-7347-97, BPU Docket No. EO97070461 and OAL Docket No. PUC-7348-97. Filed November 26, 1997. Pages 5-7.

'Used and Useful' Criterion in Utility Ratemaking by Dr. Stephen Bernow and myself, attached as Exhibit RAR-13, for a more lengthy discussion of this issue.)

In particular, the Massachusetts Department of Public Utilities (DPU), in Docket No. 85-270, most directly applied the approach of measuring economic value as the appropriate test of when a utility investment is "used and useful," and accepted the need for risk-sharing in the regulatory treatment of excess costs in their rate treatment of Millstone 3. With respect to the "used and useful" standard, the DPU stated,

> The used and useful standard requires the Department to determine whether the utility investment is needed and economically desirable. Need for a new electric utility production plant is established if it can either be shown that the investment in question can provide either capacity or energy which is required by the utility, at a new cost which is lower than the cost of the capacity and/or energy which it displaces. Once need for capacity and/or energy savings has been established, the Department must then determine the extent to which an investment is useful and thus the extent to which a return should be allowed on the investment. Even if it could be shown that a utility had an immediate need for additional capacity, such a demonstration in and of itself would not be sufficient to justify a particular generating unit; the Company still must demonstrate that the generating unit it had constructed to meet capacity need was the most cost-effective (Order, pp. 64-65).

In its order, the DPU established the economic value of the unit by calculating the estimated cumulative net present value of revenue requirements associated with the least-cost alternative generation expansion plan that would have been followed had Millstone 3 not been built. The analysis indicated that the revenue requirements of the optimum alternative generation scenario was 24 percent lower than the present value of revenue requirements that resulted because

Millstone 3 was built. The result of this analysis was a significant sharing of the excess costs between ratepayers and investors.

Similarly, in Docket Nos. 142,098-U and 142,099-U, the Kansas Corporation Commission examined the requests of Kansas City Gas and Electric and Kansas City Power and Light to include in their rate base their investment in the Wolf Creek nuclear plant. The Kansas Commission implemented the traditional prudence test by determining that a portion of the construction cost was "inefficiently and imprudently incurred." Secondly, <u>over and above this imprudency disallowance</u>, the Kansas Commission identified a portion of Wolf Creek as excess capacity, finding that "reserves in excess of 20 percent should be justified from an economic perspective." Finally, the Commission accepted the concept of economic risk-sharing I advocated in the case.

Q. WERE THESE TWO DECISIONS THE FIRST OR PRECEDENT-SETTING DECISIONS ON RISK-SHARING IN CASES OF EXCESS CAPACITY THAT LED TO THE EXISTENCE OF UNECONOMIC COSTS?

A. No, there were several regulatory commission decisions made previously which also supported risk-sharing. Back in 1980, the Pennsylvania Commission, in a decision involving the Philadelphia Electric Company, found the Company in possession of excess capacity (Docket No. 79060865). The Commission found that the excess capacity was not due to errors or mismanagement on the part of the Company. Rather, unanticipated events such as lower than expected demand growth had caused some of the Company's generation capacity to become "excess," as new generating units were added. The Commission adjusted the Company's rates to apportion some of the cost of the excess capacity to investors in the Company. In discussing this decision in a speech before the Pennsylvania Bar Association, Chairman Shanaman of the Pennsylvania Utility Commission stated:

> Prior to making its rate base adjustment, the Commission made the explicit finding that the burden of excessive plant investment was not the fault of Philadelphia Electric or its investors, but neither was it the fault of the ratepayers. We found that, under the circumstances, there must be some sharing of the risk associated with maintaining plants on-line. [Emphasis in the original.]

Another decision took place in Kentucky in 1983, when the Kentucky Public Service Commission removed 50 percent of a new water treatment plant from the ratebase of the Kentucky-American Water Co. (Case No. 8571). The Commission found that excess capacity of water treatment facilities existed on the Kentucky-American system, and that an equal sharing of the risk (50/50) was appropriate under the circumstances.

The four decisions mentioned above illustrate that the rate treatment of that portion of the investment which is found to be uneconomical, i.e. not "used and useful," has most equitably been handled through the application of the prudent investment test in combination with "risk sharing." This is the approach regulators have used to allocate the burden of uneconomical or excess costs between the utility's investors and ratepayers in reasonable proportions, based on the facts responsible for the existence of the costs and the circumstances under which they were incurred, thereby balancing ratepayer vs. investor interests.

Q. COULD YOU ELABORATE ON WHY YOU BELIEVE THAT THE BALANCE STRUCK BY REGULATORS BETWEEN FAIR RATEMAKING AND INVESTORS' OPPORTUNITY TO EARN A FAIR RATE OF RETURN DOES NOT NECESSITATE THE EXISTENCE OF A REGULATORY COMPACT?

A. Regulators have always balanced the customer's right to adequate service at reasonable rates with allowing the investors' an opportunity to earn a fair return. That balancing of ratepayer vs. investor interests does not support the notion of a compact or claims of entitlement to full recovery of prudent investments under the Constitution. Therefore, I disagree with Mr. Bayless's comment on page 6 of his direct testimony that,

> "...the continued existence of the Compact (is shown) as earnings are limited on prudent investments to a regulated rate of return. If a utility builds a plant or transmission line which operates at a cost far below the current market, the company is only allowed to earn a regulated return on its actual cost. The utility is never allowed to charge a market rate and hit a "home run" for investors as non-regulated entities do. ...The requirement for TEP to sell its products at a below-market price, in my view, constitutes an unconstitutional "taking" for a public purpose without just compensation. In the past, the Company did not, however, complain about the unconstitutional taking."

I also disagree with the assertion of a legal entitlement to recover stranded costs from ratepayers. Daniel Fessler, testifying on behalf of TEP, commented on page 26 of his direct testimony that,

> ...It is fully appropriate that existing ratepayers on whose behalf the assets were constructed and liabilities assumed should bear the costs. I support the principle that net uneconomic generation assets, above-market purchase power contract obligations and regulatory assets remain the obligation of ratepayers and that restructuring not

be used as an opportunity to attempt to shift them to utility shareholders.

Assuming that ratepayers, on whose behalf the assets were constructed, should bear the full costs of those assets under all conditions is far too simplistic. Some of the uneconomic costs on a utility's system that will become stranded costs under competition are due to bad or questionable management decisions and/or poor resource planning practices. Prudency approvals should not necessarily protect utilities from later having to write-off portions of their uneconomic costs if they do not turn out to be used and useful. Even if decisions to acquire generation-related assets were deemed prudent at the time, there is ample justification in regulatory theory for sharing stranded costs between utility stockholders and ratepayers now, given that there always has been some risk that management decisions were not the most economically efficient. Kevin Higgins, testifying on behalf of Arizonans for Electric Choice and Competition, et al., stated in his rebuttal testimony in this docket that,

> Mr. Bayless' view (on the existence and rationale of a regulatory compact) 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...(page 2)"

I agree with Mr. Higgins that Mr. Bayless' view is unreasonable. Mr. Higgins raises the important point that deregulation of generation services may increase opportunities for shareholders to realize greater rates of return on their investments.

REBUTTAL TO FILINGS OF OTHER PARTIES

Q. WOULD YOU LIKE TO RESPOND TO ANY OF THE TESTIMONY FILED BY NON-UTILITIES IN THIS DOCKET?

A. Yes, I would also like to respond to some of the testimony filed by non-utilities by topic or issue, as I have done above for the affected utilities.

Q. DO YOU SUPPORT MOST OF DR. ROSE'S ARGUMENTS IN FAVOR OF THE NEED TO SHARE STRANDED COSTS BETWEEN RATEPAYERS AND STOCKHOLDERS?

A. Yes, I support most of Dr. Rose's arguments in favor of the need to share stranded costs, but I only support sharing stranded costs if they are positive. If a negative stranded cost recovery charge were to be put into place for APS and SRP, then I would not be in favor of sharing stranded costs between ratepayers and stockholders. In such a case, the ratepayers should get the full benefit of the negative stranded cost recovery charge. The reason for my position is the inherent and appropriate asymmetry in the regulation of electric utilities in the past, as Dr. Rose describes on pages 5-6 of his testimony. Under traditional cost-of-service regulation, utilities should be allowed a maximum rate of return on equity which includes a risk premium to cover various business risks. They should not be allowed to recover extraordinary profits above and beyond a reasonable allowed return on equity if they have negative stranded costs, and if retail competition is implemented in Arizona. All the benefits of the investments in power plants that ratepayers have funded in the past should be flowed through to ratepayers in the future to the extent that negative stranded costs exist. That is because, by definition, the calculation of negative stranded costs assumes a reasonable allowed rate of return on utility assets as a baseline.

One particularly strong reason for sharing stranded costs cited by Dr. Rose, aside from the basic equity in doing so, is that sharing will provide a very strong incentive for utilities to mitigate stranded costs. I, too, have often cited this advantage of sharing in my written testimony and reports about stranded costs. Sharing provides a strong incentive to mitigate stranded costs because the utility will save the proportion of the sharing that it would otherwise have to pay for each dollar of stranded costs actually mitigated. For example, if there were a 50/50 percent sharing of stranded costs, the utility would save $0.50 of each dollar actually mitigated by not having to write-off that $0.50 against its profits.

Q. DO YOU ALSO AGREE WITH DR. ROSE THAT ANY LEVEL OF RECOVERY OF UNECONOMIC OR STRANDED COSTS FROM CUSTOMERS WILL HAVE A "NEGATIVE IMPACT ON THE DEVELOPMENT OF A COMPETITIVE MARKET," AS DR. ROSE STATES ON PAGE 9 OF HIS TESTIMONY?

A. No. Even though I am strongly in agreement with Dr. Rose's arguments in favor of the sharing of stranded costs, I do not agree with Dr. Rose's arguments which attempt to show that any level of the recovery of stranded costs will have a negative impact on the development of a competitive generation market, with one exception. The one exception is self-generation, which in fact, is the one issue that Dr. Rose dismisses as a possible exception, prematurely in my view. I believe that the possibility of uneconomic bypass via the use of self-generation as discussed by Dr. Rose on pages 10-12 of his testimony is the one case in which the recovery of stranded costs, even through a non-bypassable wires charge, is a problem.

The reason that I believe that uneconomic bypass could be a problem is that a so-called "non-bypassable" wires charge is bypassable in one and only one way, namely if a customer decides to self-generate on-site and not use the T&D wires for delivering a certain amount of power to the site. That means that a high stranded cost recovery charge would work as an incentive to self-generate in order to avoid paying the stranded cost recovery charge. If uneconomic bypass occurs, namely if self-generation has higher marginal costs than to continue buying from the utility, then this would lead to a less than perfectly competitive generation market, by definition. Of course, avoiding paying any transmission and distribution charges is also an incentive to self-generate, but this factor has always existed independently of a stranded cost recovery charge.

Perhaps Dr. Rose dismisses the significance of the incremental impact of stranded cost recovery on the likelihood of uneconomic bypass through self-generation because he realizes there is already a strong incentive for large customers to self-generate in order to avoid T&D system charges. However, in my view there is nothing a public utility commission can or should do to try to prevent uneconomic bypass due to self-generation. It is an issue that has always confronted the regulatory world, and it is an issue that will continue to exist under retail competition. Little has changed with regard to this issue, and I believe we need to live with this limited imperfection in generation markets due to the need to regulate the T&D system.

Q. WITH THE EXCEPTION OF SELF-GENERATION, WHY DON'T YOU AGREE WITH DR. ROSE THAT THE RECOVERY OF A STRANDED COST CHARGE AS A NON-BYPASSABLE WIRES CHARGE CAN CREATE BARRIERS TO ENTRY AND EXIT IN THE GENERATION MARKET?

A. The reason I disagree with Dr. Rose that the existence of a non-bypassable stranded cost recovery charge can create barriers to exit and entry is that Dr. Rose seems to have mis-characterized the structure of rates for the standard offer service that should be established after unbundling occurs. He does not seem to recognize that after rates are unbundled, all customers in each rate tariff should pay the same stranded cost recovery charge whether or not they stay on the standard offer. This is what makes the stranded cost recovery charge non-bypassable. As long as all customers pay the same stranded cost recovery charge based on their usage of the distribution (or transmission) system, all generation suppliers, including the standard offer providers, are on an exactly equal basis. Thus, no barriers to exit or entry can be created by collecting this charge, no matter how big it is.

Dr. Rose may have come to the wrong conclusion about barriers to entry and exit because his illustration of the problem discussed on lines 18-27 of page 11 of his testimony has a critical flaw. In this example, Dr. Rose seems to forget that, according to his example, once rates are unbundled for all customers, including those in the standard offer, the customer who is paying the utility's marginal cost of 3.5 cents per kWh will also have to pay the uneconomic cost charge of 2.0 cents per kWh, for a total of 5.5 cents per kWh. This implies that this customer will choose the alternative supplier's power at 4.5 cents per kWh, which, indeed, has the lowest marginal costs. Thus, under the conditions discussed, there will be no uneconomic bypass, the generation market will be competitive, and there will be no barrier to entry for new generation owners into the market due to the collection of stranded costs.

Q. DOES DR. ROSE'S DISCUSSION OF STATIC VS. DYNAMIC EFFICIENCY CHANGE YOUR CONCLUSIONS IN ANY WAY?

A. No. Dr. Rose's rather lengthy discussion of static vs. dynamic efficiency does not change my conclusion that self-generation aside, the collection of a properly structured, non-bypassable, stranded cost recovery wires charge will not impede the economic efficiency of the generation market. This is true whether the stranded cost recovery charge is positive or negative. The basic reason for this conclusion is that any charges included as part of the <u>regulated</u> T&D rates of the utility do not impact on the efficiency of the <u>unregulated</u> markets, as long as similarly situated customers have to pay similar T&D and stranded cost rates. Whether or not the T&D and stranded cost recovery rates are fair or are properly structured is another issue entirely.

Q. DO YOU AGREE WITH THE STATEMENT IN DR. COYLE'S TESTIMONY, ON BEHALF OF THE CITY OF TUCSON, THAT A RISE IN VALUE OF THE TRANSMISSION AND DISTRIBUTION SYSTEM DUE TO THE EXISTENCE OF RETAIL COMPETITION SHOULD BE USED TO MITIGATE STRANDED COSTS ON THE GENERATION SIDE?

A. No, I do not agree with this statement because I do not believe that it makes sense to say that the value of the T&D system will change due to restructuring. Dr. Coyle stated:

> Restructuring changes the value of the generation assets, and the change is generally assumed to be downward. ...Restructuring changes, at the same time, the value of the transmission system and, separately, the value of the distribution system. Both these changes we can be confident will be an increase in value.

Dr. Coyle attributes the increase in value to a drop in the cost of capital for transmission and distribution, and less risk on the part of investors. In the deregulated environment, generation is unbundled from transmission and distribution, and the different returns on equity become apparent by the rate of return on equity required by the market. But in a restructured environment, transmission and distribution systems will remain <u>regulated</u>. Thus, even if the required rate of return on equity for the T&D system decreases due to restructuring, no change in value of the transmission and distribution system will be possible, since there will not be a free market in T&D services. The "value" of the T&D system could only increase if the return on equity decreased and the total revenues from the T&D rates stayed roughly the same. However, since no rise in the value of the T&D system will occur due to continued regulation, I can not agree with Dr. Coyle's statement that "the increase in value (of the T&D system) should be used to mitigate stranded costs..." I do, however, agree that the return on equity may be lower due to a difference in risk, which could lower the revenue requirement for T&D services. Therefore, I conclude that transmission and distribution rates may actually be lower in the future due to restructuring than they would have been otherwise. This would be an indirect benefit for ratepayers of restructuring, and one which would indirectly help to mitigate or reduce the net impact of stranded cost recovery on ratepayers.

Q. IS DIVESTITURE AN APPROPRIATE METHOD FOR ESTIMATING STRANDED GENERATION COSTS, AS SUGGESTED BY DR. ALAN ROSENBERG AND MS. MONA PETROCHKO?

A. RUCO does not advocate that divestiture of utility generation assets be required, though RUCO does not oppose divestiture. However, parties in this docket should be aware that a market valuation or divestiture-based approach to determining stranded costs may yield auction, spin-off, or sale prices that are either too low or too high relative to actual long-run market prices for generation in a truly competitive wholesale market. A low sale price received for generation assets would, of course, increase stranded costs if this sale price were used as the sole basis for their determination. Divestiture or market valuation is therefore not necessarily a more accurate way to determine stranded costs than an administrative evaluation approach. That is why I disagree with Alan Rosenberg's statement on page 38 of his direct testimony on behalf of Arizonans for Electric Choice and Competition where he states, "...market based approaches for determining strandable cost are superior to administrative ones, with divestiture being the optimal method."

Divestiture does not ensure that retail customers will not be overcharged for stranded costs, in part because market prices are likely to be volatile. If the prices at which generation assets are sold are below the sale prices that a truly competitive market would yield, a utility's stranded costs will be directly affected. If the ACC were to mandate that divestiture in Arizona occur quickly, the regional generation asset market would be flooded, and bidders for the assets would likely see an increase in their bargaining power to obtain generation assets at below competitive market sale prices. However, in the long run, the new owners of the generation assets would presumably sell their output at full competitive market prices. They would not sell their output at below-market prices just because they initially bought the assets at below-market prices. Therefore, in this scenario, consumers would end up paying more than they should in stranded cost recovery changes while not experiencing any compensating reduction in market prices for generation. They would pay twice for some stranded costs, an unacceptable result.

Q. WHAT SHOULD THE RELATIONSHIP BE BETWEEN THE SALE PRICE DUE TO DIVESTITURE AND STRANDED COSTS RECOVERY?

A. From a consumer protection perspective, divestiture can be an acceptable method for initially estimating stranded generation costs only if the recovery process includes a true-up mechanism. Furthermore, any reasonable true-up methodology must be done on a "net system" basis, whereby generating resources having negative strandable costs are netted against generating resources which have positive stranded costs. This would be possible if stranded costs were determined using an administrative net-system valuation approach which took the sale price due to divestiture into account as partial evidence in determining a competitive market price. (Please refer to page 23 of my direct testimony for more explanation of this point.) I prefer the net system approach as opposed to the asset-by-asset approach because the net system approach calculates the stranded costs of a utility's whole system. It is by far more difficult to do this on an asset-by-asset basis. Following an administrative net-system valuation stranded cost determination, a utility may voluntarily divest itself of generation assets. Regulators could then true-up initial stranded cost estimates to reflect actual market prices for generation assets, actual retail market prices for generation services, as well as forecasts of the future retail market prices. Until a fully competitive and mature generation asset market develops, the asset sale prices should not be relied upon as the sole indicator of market value for purposes of calculating stranded costs simply because sale prices currently appear to be highly volatile, and may tend to be too low. If a true-up mechanism is adopted by the ACC based on actual market prices, at least through 2002 as I have recommended, then divestiture could occur at the risk of the utility as to whether or not the sale price was reasonable. In this way, ratepayers would be protected from the risk of over-paying stranded costs.

Q. DO YOU AGREE WITH BETTY PRUITT'S COMMENT, IN HER DIRECT TESTIMONY ON BEHALF OF THE ARIZONA COMMUNITY ACTION ASSOCIATION, THAT "ONLY THOSE CUSTOMERS IN THE COMPETITIVE MARKET SHOULD PAY STRANDED COSTS, SINCE CAPTIVE CUSTOMERS ARE ALREADY PAYING THESE COSTS AND SHOULD NOT BE SUBJECT TO DOUBLE DIPPING?"

A. Generally, I agree with the gist of her comment that ratepayers never be required to pay twice for stranded costs. However, I do wish to clarify her point that only customers in the competitive market should pay stranded costs. First, for competition to occur most efficiently, all utility tariffs should be unbundled so that all customers of retail generation services, regardless of whether they have a competitive supplier or stay on standard offer service, contribute equally (within each tariff) to stranded cost recovery. This is best accomplished through a non-bypassable, nondiscriminatory wires charge which ties the collection of stranded generation costs to the continued use of transmission or distribution service, as I have discussed previously.

Utilities must, then, estimate their potentially strandable costs as part of the unbundling process for the purpose of establishing the stranded cost recovery mechanism. The standard offer rate for those customers who stay with their default supplier should be set to approximate the retail market price for generation services, plus a stranded cost recovery charge, plus the cost of transmission and distribution service. This approach to unbundling, which I also recommended in my direct testimony, will imply that customers on the standard offer service and customers who purchase from alternative suppliers will both pay the same stranded cost recovery charge. The same market price assumptions used to estimate stranded costs should be used to determine the standard offer rate. In this way, customers on default service will not be in danger of paying twice for stranded cost recovery, and customers will not be penalized for seeking retail generation services from alternative suppliers. Ms. Pruitt's point, I believe, was just to argue that in the event that the current rate were to be used as the rate for the standard offer as allowed by the current version of the restructuring Rules, the stranded cost recovery charge should not be added to the current rates.

Q. DO YOU AGREE WITH BETTY PRUITT'S COMMENT THAT "A TRUE-UP MECHANISM IS ACCEPTABLE ONLY IF IT IS LIMITED TO BEING DOWNWARDLY FLEXIBLE (DIRECT TESTIMONY, PAGE 1)?"

A. No, I disagree. The point of the true-up mechanism is to ensure maximum flexibility and accuracy in determining the amount of stranded costs that ratepayers must pay. If stranded costs were set at a capped level, the true-up mechanism would no longer be fully adjustable, and therefore estimates of stranded costs made in this modified true-up process would not reflect actual market prices. Once stranded costs have been calculated accurately and a percentage of sharing between ratepayers and stockholders has been decided on, the flexibility of the true-up mechanism both upwards and downwards must be maintained for fairness and equity towards both ratepayers and stockholders. A "downward only" flexible true-up mechanism should not be used as a second mechanism for implicitly accomplishing a sharing of stranded costs. Instead, the degree of sharing should be determined and implemented by the ACC explicitly.

Q. IN RESPONDING TO ISSUE NO. 3 ON PAGE 3 OF HER TESTIMONY, MS. PRUITT STATES THAT "ACAA RECOMMENDS THAT THE BOTTOM-UP, ASSET BY ASSET APPROACH BE USED" FOR COMPUTING STRANDED COSTS. DO YOU AGREE?

A. I do not oppose using an asset-by-asset approach to computing stranded costs, as long as such an approach is made entirely consistent with the administrative "top-down," or differential revenue requirements approach, that I recommended be used by the ACC in my direct testimony. I believe that Ms. Pruitt's discussion of these two approaches for computing stranded costs on page 3 of her testimony is somewhat over-simplified, however and I do not agree with her when she says "top-down, revenue lost methods should not be used." (page 3).

One reason why I disagree with her criticism of top-down administratively determined calculations of avoided costs is that she is wrong in concluding that "they do poorly in estimating the amount of stranded costs if utilities lose sales." In fact, the strandable costs or uneconomic costs of utility generation resources exist whether or not utilities lose sales due to retail competition. It is only through losing sales that these strandable costs actually may become stranded, as I discuss in my direct testimony. Ms. Pruitt does not acknowledge that important distinction in her testimony.

Secondly, the administrative "top-down" approach to computing strandable costs is so valuable precisely because it provides the quick means for computing a "control total" for strandable costs. Namely, it yields very directly a total value for all of a utility's strandable costs on a net system basis taking all generation resources and generation-related costs, assets, and liabilities into account. If a "bottom-up" asset-by-asset approach to valuing strandable costs does not yield the same total once other generation-related assets and liabilities are added in, then a mistake has been made. This is because the total net system strandable costs for a utility must equal the sum of the strandable costs for all of its generating assets, by definition. Thus, if done correctly, there is no contradiction or conflict at all between a top-down methodology and a bottom-up methodology for computing strandable costs.

Q. MS. PRUITT ALSO RECOMMENDS THAT ONLY THOSE COSTS INCURRED BY UTILITIES PRIOR TO DECEMBER 1996 SHOULD BE CONSIDERED FOR STRANDED COST RECOVERY. DO YOU AGREE?

A. Yes, I do agree with Ms. Pruitt if by "costs incurred prior to that time" (page 4) she means decisions to invest in new generating assets or decisions to sign purchased power contracts prior to December 1996. In contrast, I do not agree with her recommendation if taken literally that utilities should not be able to recover as stranded costs any costs incurred after December 1996. This is because the calculation of stranded costs needs to be made over a long time period, and many, if not most, of the costs during this time period like fuel and O&M expenses have yet to be incurred. Thus, unless no stranded cost recovery is allowed, some future costs will necessarily be part of any recovery of stranded costs.

Again, what I agree with is what I believe Ms. Pruitt meant to say, which was that a utility should be held 100 percent responsible for any strandable costs that resulted from any investment or contracting decisions made after December 1996.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

RISK SHARING AND THE 'USED AND USEFUL' CRITERION IN UTILITY RATEMAKING

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I. INTRODUCTION

The fact that public utility investments can involve substantial economic risks has been discussed extensively in the financial press and in the utility regulatory literature over the last decade. This discussion has been stimulated by the economically disastrous consequences of many utility investments that have been made over this time period.

Probably the most prominent examples of economically risky investments within the electric utility industry have been those made in nuclear power plants, many of which have ultimately been either cancelled after incurring substantial costs or completed at costs several times above their initial budget. In these situations, regulators have been faced with the problem of determining how the costs associated with these new facilities should be treated for rate making purposes. However, application of the traditional "used and useful" and "prudence" tests have proven to be difficult and controversial, due in part to the lack of precise definitions of, and measures for, these tests, and in part to the potentially serious financial implications for the utility associated with their application.

The common position of utility management with respect to investments in new capacity has been, and continues to be, that unless an investment is proven to have been imprudent, traditional ratemaking procedures should be followed. According to this perspective, a utility should be given a return of, and on, prudently made investments, so long as they are "used and useful" which, in its typical application, has meant completed and operating. This implies that ratepayers should be responsible for one-hundred percent of the costs that result from a prudent investment, no matter how uneconomical it may be. Historically, most public utility commmission rate orders have reflected the position of utility management in this regard.

Those representing the interests of electricity consumers have begun to present an opposing viewpoint in an attempt to obtain more equitable and appropriate rate treatment for uneconomical investments. These groups have argued convincingly that stockholders must share in the financial risks deriving from investments made by utility management, but until recently they have been less than successful in having commission orders reflect this position. Part of the reason for this lack of success has been the absence of a single and consistent methodological framework for determining what costs are unreasonable, and how such costs should be shared between ratepayers and stockholders.

Over the past several years Energy Systems Research Group (ESRG) has developed and presented a functional definition of the "used and useful" criterion which is structured to allow one to assess the economic usefulness (or value) of an investment in new capacity. This approach permits a determination of that portion of an investment which is "used and useful" and, correspondingly, that portion which embodies "excess costs". In addition, ESRG has advocated using the concept of risk-sharing for determining the appropriate rate treatment of the excess costs associated with such facilities. Others, particularly the Massachusettts DPU, have developed and proposed similar approaches, but ESRG witnesses have presented this methodology most extensively in utility hearings throughout the U.S.

This article describes ESRG's approach to the "used and useful" test as applied to investments in new capacity, and to the use of risk-sharing in determining the rate treatment of such investments. It describes how these approaches both subsume and retain the traditional prudent investment test. It also describes recent cases where this approach has been implicitly or explicitly adopted in commission orders.

II. CAPACITY PLANNING OBJECTIVES

In deciding whether or not to construct new capacity, utility management must evaluate and choose between various alternatives - e.g. purchasing versus building capacity, installing peaking versus base-load units, selecting coal versus nuclear capacity. In general, this involves the development of a plan which embodies a mix of both supply and demand-side options characterized by their magnitude, type, and timing. In this selection process, the planners must balance between three sometimes conflicting objectives, and choose the alternatives which best satisfies all three - i.e. the alternative that will result in a <u>reliable</u>, <u>economic</u> and <u>flexible</u> generation plan.

To meet system <u>reliability</u> requirements the utility must have sufficient capacity in place to serve firm peak demand as loads grow. Guided by forecasts of peak demand, capacity additions are planned and constructed so that adequate capacity will be available at the appropriate time to ensure reliable service. The level of capacity required for adequate reliability must be greater than firm peak demand in order for the utility to satisfy this demand when generating units suffer outages, either forced or planned. This reliability requirement is usually referred to as a required "reserve margin" and is measured in terms of the percentage by which generating capacity exceeds firm peak demand. Required reserve margins vary according to the characteristics of specific utility systems and their degree of interconnection with neighboring systems, but are generally in the range of 15 to 20 percent.

From the standpoint of meeting reliability requirements alone, it would be appropriate for a utility to simply build peaking facilities such as combustion turbines or small oil/gas steam-electric plants. Such plants could be built quickly in response to load growth, and could provide quick response to hourly load variation with relatively low forced outage rates. These plants typically have low capital costs and high operating costs.

A system composed solely of such peaking units, however, would not enable the utility to satisfy its second major planning objective, i.e. to generate electricity in an economical manner over the long term. To meet that objective the generation mix must also include large base-load plants which take longer to place into operation and which are less reliable. Compared to peaking units these plants have higher capital costs but much lower operating costs, so that their total costs per unit of output are typically lower. Of course, these capital intensive base-load plants may require many years before the savings from their lower operating costs outweigh their higher initial capital costs, i.e. before cumulative net economic benefits are achieved. For this reason choosing the appropriate mix of peaking and base-load plants to achieve an optimum balance between system reliability and generation economics requires a long-term perspective.

Given the many factors which can change over the long term, for example between the initial justification of a new base-load plant and its commercial operation, flexibility becomes an important third planning objective of an optimum generation expansion plan. Many factors, such as capital or operating costs which have significantly exceeded planning budgets, or the unexpected availability of less expensive power from other sources, can render investments which initially appeared cost-justified, and therefore prudent at the time they were made, to be uneconomical at a later date. This potential problem can have deleterious consequences when the investment is very large. This has, in fact, occurred for many new nuclear units throughout the U.S. since 1980. Thus it is important that utility planners incorporate a considerable degree of flexibility in their generation expansion planning process and investment decisions,so that they can react appropriately to changing circumstancess in order to maintain the optimum balance between reliability and economics in the face of the options available to them at any point in time.

III. RATE TREATMENT OF INVESTMENTS IN NEW CAPACITY

In recent years, many electric utilities have found themselves with new base-load facilities coming on line at a time when the demand for power that they were expected to serve has not materialized. In addition, these facilities have often turned out to be much more expensive than planned, owing to cost overruns, and more expensive than other sources of power as a consequence of unanticipated changes in the relative economics of the various generation alternatives.

Commissions regulating these utilities have had to determine whether, or to what extent, their investments in such expensive new capacity should be placed in the ratebase. Unfortunately, regulators grappling with this issue have been hampered by a lack of clear principles to guide them in their determinations as to how they should apply the traditional "used and useful" and "prudence" tests. This is understandable, since the conditions under which electric utility regulators have operated have changed radically over the last decade -- previously the context was one of long-run decline in the real price of electricity, economies of scale in plant construction, and rapid load growth. The substantial diminution of load growth, and the advent of very high cost baseload facilities, especially nuclear plants with costs in the billions, have contributed to situations of excess costs.

Application of the traditional "prudence" and "used and useful" tests prior to the mid 1970s did not create any obvious problems, since large new facilities in that era were typically needed to meet rising demand within a reasonably short period of time, and they benefitted from increasing economies of scale in their construction costs. The situation today is, however, far different, and the regulatory approaches which served well in that earlier period clearly became more problematical in the new and complex environment of the 1980s. This change illustrates a general need for both the practical application of regulatory theory to be refined and adapted to meet changing circumstances, as well as the need for the theory itself to evolve in a manner that allows the goal of distributive justice to be more closely approached under new circumstances.

Most states require that investments in utility plant be both prudent and "used and useful" in order that they may be put into ratebase. In the case of <u>prudence</u>, the determination has not been one of "either/or" but, rather, a matter of degree. That is, Commissions have sought to determine what portion of an investment has been prudently incurred and what portion has been incurred as a result of imprudence (e.g. excessive costs resulting from construction mismanagement). Rate treatment has followed from such determinations, with the imprudent costs entirely excluded from rates. Unfortunately, the second test -- <u>used and useful</u> -- has not been clearly and consistently applied. Indeed, there has been considerable confusion and disagreement as to how this test is to be applied due to the lack of a clear definition. The lack of a systematic approach to this critical regulatory issue has sometimes led to contradictory applications of the "used and useful" test in different states, or even in the same state at different times.

Generally, to be "used" a particular facility must be operational. This is relatively easy to determine. The controversy arises in determining whether new baseload capacity is "useful". Many jurisdictions have approached measuring this aspect of new capacity by measuring its contribution to system reliability - i.e. does the plant contribute usefully to the utility's reserve margin or could it be expected to do so in the forseeable future, given the need to add new baseload capacity to most systems in fairly large increments. If the new capacity is not thereby useful in serving the needs of system reliability, the capacity would be deemed excess capacity.

ESRG has taken the position that the real question facing regulators in applying the "used and useful" standard in these situations is not whether the new facility contributes to excess capacity, but whether its net economic value is beneficial or detrimental to ratepayers. Defined in this manner the test is, in a sense, applied to the investment in the plant and not the plant itself. The genesis of, and theoretical support for, this distinction between plant and investment has been traced by Roger D. Colton in Excess Capacity: A Case Study in Regulatory Theory and Application, in The University of Tulsa Law Journal, Volume 20. He cites Justice Brandeis' dissenting opinion in the United States Supreme Court decision in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission, "the thing devoted by the investor to the public use is not specific property, tangible and intangible, but capital embarked on the enterprise." (p. 418)

Using this economic approach, the question of whether or not a new base-load plant creates excess capacity becomes irrelevant to the ratemaking disposition of its costs; what is relevant is its net impact on required revenues. This is true for all types of units, though it is especially true for nuclear power plants and the uniquely high costs and economic risks they present. It is important to recognize that this position forces a radical break between the concept of "excess capacity" and the "used and useful" standard, and conflicts directly with many recent Commission decisions that have led to partial ratebase exclusions, for new plant investment, which were based simply upon the "excess capacity" approach. The most controversial implication of this approach is that an investment in a new plant can fail the "used and useful" test if it is deemed to be uneconomical, even if it does not contribute to excess capacity on the system. Conversely, it could pass the "used and useful" test even if it does contribute to excess capacity.

To determine if an investment in new capacity is "useful", then, one must measure its economic value to the system over the long term. This is done by comparing, under current and anticipated conditions, the cumulative costs of the facility in question to its savings over an appropriate planning period, usually the lifetime of the plant. The costs are those required revenues associated with building and operating the plant, and the savings are the required revenues associated with the lowest cost alternative plan that could have been prudently pursued in its place. For example, such an evaluation could involve comparison of the total revenue requirement impact of a new nuclear plant with that of a coal plant which could have been built instead. Or it could involve comparison of a new nuclear or coal plant with a more optimal plan, if indeed one can be identified, which embodies a mix of conservation, load management, peaking capacity and, ultimately, new baseload capacity when needed. In making this comparison all considerations of adequate reserve margin and system reliability levels are automatically addressed, for these design criteria must be explicitly met by the alternative capacity planning scenario used as the economic baseline. If this economic analysis shows cumulative long-run costs in excess of savings on a present value basis, the new capacity is not the most economic or optimal alternative and is therefore not <u>fully</u> "used and useful".[1]

It is important to note that an analysis of the economics of a new facility relative to those of the least cost alternative is based upon current conditions and projections of the future. Thus the degree to which the investment is not fully "useful" may change over time with changes in the relative costs of generation alternatives and with changes in demand. For this reason regulators, in adopting economic value as the measure of "used and useful", should give the utility the option to reapply to have any initially excluded investment placed in rate base should conditions change in the future in a manner favorable to the new investment.

IV. RATE TREATMENT OF UNECONOMICAL NEW CAPACITY

Once regulators determine the extent to which an investment in new capacity is "used and useful" , this amount can be placed into ratebase. However, the regulator must then determine what rate treatment the "uneconomic" portion of the investment is to receive, namely who is to bear these excess costs - ratepayers, stockholders, or each to some degree?

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[1] For example, if it is found that a $2 billion investment will result in cumulative costs far in excess of benefits, while had the investment been only $1 billion the lifetime benefits would equal the costs (breakeven), it could be said that fifty percent of the investment is "used and useful."

Ratepayers can argue that traditional ratemaking practice requires complete exclusion from rate base of any investment that is not "used and useful". Utility management can argue that if a decision to invest in new facilities was prudent at the time it was taken, then the full value of the resulting investment should be placed in ratebase. ESRG maintains that a reasoned and equitable sharing of these costs usually lies somewhere between these two extremes at a point which can only be determined by the Commission examining the facts of the specific case. This determination can be accomplished through the application of the "prudence" test in combination with the concept of "risk sharing", with imprudence seen as an extreme form of risk-sharing.

Most Commissions are gradually coming to realize that the "prudence" test alone does not provide a realistic way to allocate the costs of uneconomic new capacity between shareholders and ratepayers. Strictly applied this approach maintains that the only costs which should be borne by the utility are those deemed to have been imprudently incurred. Determination of imprudence has had a demanding evidentiary requirement, and rightfully so, for imprudence in this sense implies more than mere error of judgement; the utility's action must be characterized by misfeasance or malfeasance. Yet, this is seldom the explanation for the bulk of the excess costs in the most common situations where new uneconomic capacity has been completed.

Most often new capacity, which at some point seemed cost-justified and prudent, ends up being uneconomical due to a variety of factors. Some of these factors, such as an inadequate planning and review process, could have been much better controlled by utility management; others, such as changing fuel prices or demand growth rates and interest rates, were clearly beyond its control. Moreover, some phenomena beyond the utility's control could reasonably have been anticipated (e.g. certain changes in load growth) or brought under control (e.g. by demand management), while others may have been extremely difficult or impossible to predict (e.g. the oil price increase of 1979). Under these circumstances equity demands that the allocation of the resulting excess costs between shareholders and ratepayers should either reflect the degree of responsibility of each party for the situation at hand, or should reflect a sharing of the risk that no party could control. Adoption of a "risk sharing" approach by regulatory commissions to allocate costs in these situations is based, then, on the notion that the utility management could have pursued a planning process and construction program that was more flexible and therefore one that entailed less economic risk.

As stated above, in applying the risk-sharing concept regulators must be governed by the specific circumstances of the case at hand. The degree to which excess costs should be borne by investors or ratepayers will vary from case to case according to the factors causing the resulting investment to be uneconomic. The types of questions that need to be asked are: What risk reduction strategies were taken or could have been taken by utility management? Did the economics of the project deteriorate suddenly near the end of the project due to external factors (e.g. sudden decline in oil prices) or did they grow gradually worse over the construction period (e.g. due to budget overruns)? Did a public agency approve the utility's construction plan or not, and at what stage in the utility's planning process? Making a decision regarding the appropriate allocation of economic losses between parties based on the degree of utility responsibility is made easier by dealing in terms of economic value, i.e. dollars, which are very amenable to being allocated in the appropriate manner.

The theoretical basis for the use of this "risk-sharing" approach is that all investments involve an element of economic risk, even those investments made by a regulated utility. In a non-regulated business, both rewards and risks are unlimited, and they accrue solely to the investor. In a regulated industry, both the rewards and risks to the investor are limited, but they are not eliminated. This limiting of rewards and risks to the investor is achieved in effect through a sharing of them between investors and ratepayers. Investors, in exchange for accepting the requirement to provide service, are guaranteed a reasonable opportunity to earn a fair rate of return on their investments. Customers, in exchange for the assurance that electricity will be provided, incur an obligation to share some of the economic risks associated with its production. In return for the risk premiums they receive as part of their total return on equity, investors must also bear some of the economic risk associated with their investments.

This argument in support of the need and justification for risk-sharing in the regulatory process has been advanced in some detail by Dr. John Stutz of ESRG in a recent article "Risk Sharing in the Electric Utility Industry", in <u>Public Utilities Fortnightly</u>, April 3, 1986. This perspective is, in large measure, supported by John Colton in "Excess Capacity : Who Gets the Charge from the Power Plant", in the <u>Hastings Law Journal</u>, vol.34, and most recently by a July 10, 1986 editorial in <u>Public Utilities Fortnightly</u>, "The Social Compact and the Sharing of Risk". It is also consistent with the position advanced by the National Regulatory Research Institute in its study entitled <u>Commission Treatment of Overcapacity in the Electric Utility Industry</u> (NRRI-84-10).

V. RECENT REGULATORY DECISIONS ON UNECONOMICAL CAPACITY

In a number of recent regulatory decisions dealing with new base-load units, some Commissions have at least implicitly found that investments in new capacity must be economically justified and that risk-sharing must apply to the portion of those investments which are deemed to be uneconomic. These conclusions are found in orders dealing with new high cost generating facilities completed in the last few years in the following states: Illinois (Louisa), Pennsylvania (Susquehanna 1 and 2), Michigan (Fermi 2), Missouri (Callaway), Kansas and Missouri (Wolf Creek) and Massachusetts (Millstone 3). The basis for two of these decisions, the Kansas and Massachusetts orders, provide clear support for ESRG's approach to determining whether an investment in new capacity is "used and useful" and to the concomitant use of "risk-sharing" in the ratemaking process.

<u>Kansas Corporation Commission - Wolf Creek</u>

In Docket Nos. 142,098-U and 142,099-U, the Kansas Corporation Commission (KCC) examined the requests of Kansas City Gas and Electric (KG&E) and Kansas City Power and Light (KCPL) to include in their rate base their investment in the Wolf Creek nuclear plant. The Kansas Commission implemented the traditional prudence test by determining that a portion of the construction cost was "inefficiently and imprudently incurred". Secondly, over and above this imprudency disallowance, the KCC identified a portion of Wolf Creek as excess capacity, finding that "reserves in excess of 20 percent should be justified from an economic perspective". Finally, the Commission accepted the concept of economic risk-sharing advanced by ESRG in the case.

Based on these findings, the KCC applied the following rate treatment to Wolf Creek. Depreciation and return were disallowed for costs incurred as a result of imprudence. Only a small fraction of the traditional return on investment was allowed for the portion determined to be physical excess capacity. The portion of Wolf Creek that did <u>not</u> represent excess capacity in the physical sense was to be economically "revalued" at the cost of a coal plant, and a full return was allowed on this amount. Here the value of a coal plant seems to have represented what the KCC believed was a reasonable economic baseline against which the cost of generation from Wolf Creek should be measured. At the same time, depreciation of the prudent portion of the nuclear plant investment was permitted in rates. Thus, by this set of measures, a risk-sharing of the excess costs was effected.

In a decision issued on June 13, 1986 the Kansas Supreme Court upheld all the decisions of the KCC against an appeal of its order. The Kansas Supreme Court ruling confirmed the KCC's finding that there is "economic excess capacity" even when overly expensive capacity is needed to meet reliability requirements, and that the excess costs of such capacity could be shared between ratepayers and investors.

Massachusetts Department of Public Utilities - Millstone 3

The one Commission which appears to have most directly applied ESRG's approach to measuring economic value as the test of "used and useful", and which appears to have accepted the need for risk-sharing in the regulatory treatment of excess costs, is the Massachusetts Department of Public Utilities. Their decision issued June 30, 1986 in Docket No. 85-270 explicitly applied these principles to the rate treatment of Millstone 3.

With respect to the "used and useful" standard, the Department stated :

> The used and useful standard requires the Department to determine whether the utility investment is needed and economically desirable. Need for a new electric utility production plant is established if it can be shown that the investment in question can provide either capacity or energy which is required by the utility, at a net cost which is lower than the cost of the capacity and/or energy which it displaces. Once need for capacity and/or energy savings has been established, the Department must then determine the extent to which an investment is useful and thus the extent to which a return should be allowed on the investment. Even if it could be shown that a utility had an immediate need for additional capacity, such a demonstration in and of itself would not be sufficient to justify a particular generating unit; the Company still must demonstrate that the generating unit it had constructed to meet capacity need was the most cost-effective (Order, pp 64-65)

In its order, the DPU established the economic value of the unit (Millstone 3) by calculating the estimated cumulative net present value of revenue requirements associated with the least-cost alternative generation expansion plan that would have been followed had Millstone 3 not been built. This analysis indicated that the optimum alternative generation scenario had revenue requirements 24 percent lower than the Millstone 3 plan. Based on this analysis only 76 percent of the costs of Millstone 3 were included in the Company's rate base. The remaining 24 per cent were to be amortized, without a return, thus resulting in a sharing of the excess costs between ratepayers and investors.

The DPU acknowledged the fact that that its determination of the useful value of the unit was based on the forecast of a number of parameters over the plant's expected operational lifetime. For this reason the Company was allowed to return for further rate relief in the future should one of the key parameter values used in the DPU's original order turn out to have been significantly in error.

VI. CONCLUSION

Must commissions allow recovery of and return on all utility investments that are prudently incurred, no matter how excessive or uneconomical they may be? In this paper we have answered, "No." We have shown here that commissions can and should apply economic tests to utility costs as a basis for their ratemaking decisions.

The correct ratemaking treatment for an investment in a new power plant must be guided by an analysis of the economic value of that investment. This analysis, based upon the best current information, must compare all costs associated with ratebasing and operating the new facility, with those of an alternative resource plan which is at or near the least cost that could prudently have been achieved. This approach implies that whether a new generating plant is "used and useful" is a matter of degree, the degree to which its overall economics compares favorably to the best alternative that could have prudently been pursued. Thus, it is not simply a matter of "yes" or "no" as to whether a new plant is "used and useful".

The rate treatment of that portion of the investment which is found to be uneconomical, i.e. not "used and useful", is most equitably handled through the application of the prudent investment test in combination with "risk-sharing". Using this flexible approach, regulators can allocate the burden of uneconomical or excess costs between the utility's stockholders and ratepayers in any reasonable proportion, based upon all the factors responsible for the existence of these costs and the circumstances under which they were incurred. Moreover, they can accomplish this allocation in a manner that intrinsically balances the interests of both groups.