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AZ CORP COMMISSION
DOCUMENT CONTROL

June 11, 2002

Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, Arizona 85007

RE: ARIZONA PUBLIC SERVICE COMPANY'S REBUTTAL TESTIMONY ON "TRACK A" ISSUES UNDER THE GENERIC DOCKET
DOCKET NUMBERS: [redacted], E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069, E-01933A-98-0471

Dear Sir or Madam:

Pursuant to the Procedural Order dated May 2, 2002, for the above referenced Docket Numbers, Arizona Public Service Company "(APS") is hereby filing the rebuttal testimony of Mr. Jack E. Davis, Dr. William Hieronymus, Mr. Cary Deise and Mr. Charles Cicchetti.

If you or your staff have any questions, please feel free to call me.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
State Regulation

Attachment

JVN/srm

Cc: Original (plus 18 copies)
Service List

Arizona Corporation Commission
DOCKETED

JUN 11 2002

DOCKETED BY

REBUTTAL TESTIMONY OF JACK E. DAVIS

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, *et al.*

June 11, 2002

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REBUTTAL TESTIMONY OF JACK E. DAVIS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000A-02-0051, *et al.*)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Jack E. Davis. My business address is 400 North Fifth Street, Phoenix, Arizona 85072. I am President of Energy Delivery and Sales for Arizona Public Service Company ("APS" or "Company"). I am also President of Pinnacle West Capital Corporation ("PWCC").

Q. DID YOU PREVIOUSLY SUBMIT WRITTEN TESTIMONY IN THIS GENERIC PROCEEDING?

A. Yes. I submitted written testimony to the Arizona Corporation Commission ("Commission") on "Track A" issues in Docket No. E-00000A-02-0051 ("Generic Docket") on May 29, 2002. I have also filed both Direct and Rebuttal Testimony in Docket No. E-01345A-01-0822 ("Variance Docket"), which had previously been consolidated with the Generic Docket.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS GENERIC PROCEEDING?

A. My primary purpose is to relate to the Commission the potentially devastating impact of Utility Division Staff's ("Staff") recommendations as set forth in its May 29th testimony – devastating to the Company, to its customers and to the hopes for a competitive retail and wholesale market in Arizona. I also address the efforts of the merchant generator intervenors ("Merchant Intervenors") to both interject "Track B" issues into this "Track A" phase of the proceedings and to at the same time hobble their most formidable competition – the generation comprising the "Dedicated Units" under the proposed purchase power agreement ("Proposed PPA"), which PPA is currently pending Commission consideration in the Variance Docket.[1] Finally, I will respond to specific contentions made by Staff and Intervenor witnesses.

Q. WILL APS PRESENT OTHER REBUTTAL WITNESSES IN THIS GENERIC PROCEEDING?

A. Yes. Dr. William Hieronymus will address the analyses of market power presented by Staff and Intervenor witnesses as well as the economic and policy flaws in Staff's recommendations. Dr. Charles Cicchetti will also address the latter, but from the special perspective of a former regulator. Finally, Mr. Cary Deise will rebut certain allegations against the Company's transmission system planning and operation made in Staff witness Jerry Smith's May 29th testimony and respond to allegations of "transmission market power" made by both Staff and Intervenor witnesses.

II. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. Procedurally, the adoption of Staff's recommendations will prevent the Commission from resolving any of the threshold issues identified by the Company in its Motion of April 19th prior to year's end, let alone within the time established by both the Commissioners themselves at the April 25, 2002 Special Open Meeting and by the Chief Administrative Law Judge's Procedural Order dated May 2, 2002. Many of the recommendations could not even be

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[1] These consist of APS' present generation plus those Pinnacle West Energy Corporation ("PWEC") units constructed or being constructed to serve APS customers.

implemented in this docket because they would necessitate separate rulemaking proceedings.

Substantively, Staff would have this Commission undo virtually every provision and reverse virtually every finding from the 1999 APS Settlement Agreement ("1999 APS Settlement" or "Settlement"), excepting, of course, the rate reductions, the $234 million write-off and other concessions made by the Company in the course of such Settlement. Indeed, the very existence of the 1999 APS Settlement is barely acknowledged. As noted in my Rebuttal Testimony in the Variance Docket, this Settlement involved the Commission itself as a party and has been characterized as a binding contract with the Commission by the Arizona Court of Appeals. And in the place of the very Settlement that has allowed Arizona to move forward towards a restructured and competitive electric industry without the sort of economic disruptions that have erupted almost everywhere else in the Western United States, Staff proposes a bizarre and oppressive form of "regulated competition" that is neither competition nor traditional regulation and which will utterly fail to provide consumers the benefits of either regime. It is premised on a "lower of cost or market" philosophy that this Commission and others have repeatedly rejected and which is inherently unreasonable, inequitable and unsustainable.

Taken in combination with the suggestions of the Merchant Intervenors, Staff's recommendations are more likely to lead to a repeat of California than to the reliable service at just and reasonable rates that Staff professes to be its objective. This is because Staff's position represents a complete failure to recognize the essentials of a competitive market or to acknowledge the regulatory bargain inherent in traditional cost-of-service regulation.

Furthermore, Staff has ignored the practical aspects of efficiently and reliably planning and operating an electrical system, as is discussed at length in Mr. Deise's Rebuttal Testimony.

Staff's testimony is all the more puzzling to the Company because the very Proposed PPA that Staff has spent so much effort opposing would, in fact, answer many if not most of Staff's stated concerns. And although I am aware that the Commission has stayed proceedings in the Variance Docket, I would be doing the Company's customers a great disservice if I did not point this paradox out to the Commission in my Rebuttal Testimony.

While Staff's testimony was, to put it mildly, greatly disturbing, that of the Merchant Intervenors was, for the most part predictable, self-interested and procedurally inappropriate. The "Track A" issues about which they originally expressed no opinion back in December of 2001 now become a new source of leverage in "Track B." The PWEC that they bravely challenged to open competition in December 2001 now becomes some form of market "superpower" that must be restrained from meaningful competition with the Merchant Intervenors. Rather than support the Company's original request to resolve "Track A" and "Track B" issues in a single proceeding or acquiesce to the Commission's decision to address them separately, the Merchant Intervenors apparently want two turns at bat, once in this proceeding and another in the "Track B" proceeding. What is new is the Merchant Intervenors new-found interest in delay, since many of their proposals are so radically different than anything heretofore proposed in this jurisdiction that they could likely not be in place even by the summer of 2003. This is in stark contrast to a group that as recently as April of this year urged the Commission to immediately order APS to begin competitive bidding.

Staff's continued disregard for the 1999 APS Settlement is obviously contagious. Residential Utility Consumer Office ("RUCO") witness Dr. Richard Rosen would have the Commission abandon competition and return to traditional regulation if the Commission is unwilling to consider a long-term buyback from the Dedicated Assets similar to that already before the Commission in the form of the Proposed PPA. Although a principled position in the abstract, it ignores that fact that Dr. Rosen's client is bound by the 1999 APS Settlement, which itself imposed no requirement for a PPA of any sort, let alone one as favorable to consumers as the Proposed PPA. Dr. Rosen also expresses concern that PWEC or Pinnacle West Marketing & Trading ("PWM&T") might engage in "capacity withholding" or "bid gaming" if unrestrained by a long-term PPA with APS. Although the Proposed PPA is in the interests of APS customers, a fact recognized by Dr. Rosen, even in its absence there is no reason to believe that APS affiliates would engage in such activities or that regulators, state and federal, would tolerate them.

Arizonans for Electric Choice and Competition ("AECC") witness Kevin Higgins generally presents a balanced recommendation that both recognizes AECC's responsibility to uphold the 1999 APS Settlement and urges appropriate vigilance regarding the wholesale electric market. While APS and the AECC will apparently continue to have disagreements over the particulars of the proposed PPA, we do not appear to have major disagreements in this phase of the Generic Docket, and thus I will not further address in any detail the AECC's testimony in the body of my Rebuttal Testimony. (Dr. Hiernoymus will, however, discuss the new market power test proposed in Mr. Higgins' testimony.)

III. THE STAFF RECOMMENDATIONS

1. Lower of Cost or Market

Q. WHY DID YOU STATE IN YOUR SUMMARY THAT THE STAFF'S POSITION WAS PREMISED ON A "LOWER OF COST OR MARKET" PHILOSOPHY?

A. Staff's testimony is full of statements and recommendations that can only be characterized as promoting a rate-making philosophy that limits APS' recovery of power supply costs to the lower of (an undefined) cost-of-service or (an equally undefined) market price, regardless of the prudence of the Company's power supply acquisition policies. For example, in Staff witness Matthew Rowell's testimony at page 4, lines 6-7, Mr. Rowell states:

> Staff believes it is important to ensure that consumers are no worse off under the restructured environment than they were under traditional cost-of-service regulation. [Emphasis supplied.]

Of course, such assurance is impossible under a regulatory regime based on market pricing. Indeed, the most ardent supporter of competitive electric markets would not predict and could not promise that competitively-based electric prices would at all times and under all circumstances be below prices based on traditional utility cost-of-service principles.

Staff witness Barbara Keene is even more direct. She urges the Commission to adopt an expanded Code of Conduct that would require:

> for ratemaking purposes, sales or transfers from an affiliate should be priced at the lower of cost or market [emphasis supplied]."

See Testimony of Barbara Keene at page 8, lines 17-19. Ms. Keene would apparently include sales of power under this restriction because she criticizes the

FERC code of conduct for not encompassing such transactions. *Id.* at page 5, lines 21-23.

Q. WOULD STAFF LIMIT THIS APPLICATION OF A "LOWER OF COST OR MARKET" TO PURCHASES OF POWER FROM AN AFFILIATE SUCH AS PWM&T OR PWEC?

A. No. Mr. Rowell expands on the application of Staff's "lower of cost or market" philosophy at page 6, line 26 through page 7, line 13:

> Regardless of the provisions of rule 1606(B) the Commission Should consider measures that ensure that consumers are no worse off because of competitive procurement than they would have been under cost of service regulation. Specifically, during this transition period, the established cost of service should be used as both a standard for UDC [cost] recovery and as the price to beat for any competitive solicitation process. Staff recommends that prudence reviews of purchases by UDCs from their affiliates or others should use the already established cost of service of the assets the utility has chosen to transfer as the baseline for the prudence evaluation. Also, the established cost of service for the utilities' existing generation units should be used as the price to beat during competitive solicitations whether the utility has transferred its generation assets or not. Generally, Staff does not believe it appropriate for a UDC to procure power at a higher price than its own cost of service before transfer or its affiliate's cost of service after transfer. [Emphasis supplied.]

This passage appears to indicate that whether APS transfers its existing generation to PWEC or not, it will be limited to recovering the lower of those generating assets' "already established cost of service" (whatever that means) or the cost of procuring an equivalent amount of power in the market. In the divestiture case, this means that APS would not recover all its purchase power costs even if the latter was prudently acquired in conformance with Rule 1606(B) and fairly represented the then market price of power. Were APS to retain its existing generation, this means that APS would not recover its cost-of-service unless market prices were continually above such cost-of-service for the entire remaining life of these generation assets.

Q. HOW LONG WOULD THESE COMMISSION-IMPOSED PRICE CAPS ON WHOLESALE POWER PRICES BE IN PLACE?

A. At page 7, lines 1-2, Mr. Rowell appears to limit the duration of these caps to some sort of unspecified "transition period," the length of which the Commission will determine through some unspecified process using some unspecified criteria. *Id.* at page 5, lines 17-20. However, Ms. Keene's testimony uses no such temporal limitation, and thus it would appear that affiliates of APS such as PWM&T and PWEC could be under permanent price caps as regards their sales to APS, or for so long as the current APS generation is in service.

Q. DOES STAFF PROVIDE ANY INSIGHT INTO HOW THIS "MARKET TO COST" COMPARISON WOULD BE MADE IN ACTUAL PRACTICE?

A. No. In fact, it looks like the comparison will be somewhat of a moving target. No guidance is given as to the time frame of the comparison, how disparate products will be compared, or how (in the generation asset retention case) market prices will be discovered. With the present lack of a consistent and developed market structure in the West, including Arizona, these questions, along with the determination of the "already established cost of service" (of the existing APS generating assets post-divestiture) will be - constant sources of debate and controversy.

Q. ARE SUCH PRICE CAPS CONSISTENT WITH A COMPETITIVE WHOLESALE MARKET?

A. No. Under a competitive price regime, the individual seller is entitled to the market price irrespective of its or any of its competitor's cost-of-service. There are neither price caps nor price floors. When market prices are high, producers (especially low-cost producers) earn higher profits. When market prices are low, earnings suffer and in the case of individual producers, may disappear altogether. It is precisely that earnings volatility that makes the cost-of-capital higher for competitive firms in competitive industries.

Q. DOES STAFF'S POSITION REPRESENT THE TRADITIONAL COST-OF-SERVICE REGULATION THAT ELECTRIC CONSUMERS AND UTILITIES HAVE OPERATED UNDER FOR THE PAST 90 YEARS?

A. No. Under such traditional regulation, utility producers are entitled to receive cost-of-service irrespective of market prices. Even when the market price is high, producers earn only their cost-of-capital. On the other hand, producers are protected from losses otherwise attributable to low market prices. In other words, regulation provides both a price floor and a price cap based on prudently incurred costs.

Q. DIDN'T FERC IMPOSE OR APPROVE PRICE CAPS ON MARKET-BASED RATES TO PROTECT CONSUMERS AGAINST PRICE VOLATILITY AND MARKET FAILURE?

A. Yes, and the wisdom of those decisions is a matter of considerable debate. All price caps in a competitive market are likely to disincent new investment and encourage uneconomic consumption. However, short to intermediate-term price caps for peak periods or when transmission is constrained and which are set well above the production costs of most market participants, which is what FERC has endorsed, are a far cry from what Staff is proposing, even assuming the Commission had the authority to impose wholesale price caps of any sort. Moreover, these FERC "price caps" do not apply to wholesale sellers under traditional cost-of-service pricing, another important distinction from Staff's seeming position in this proceeding.

Q. ISN'T WHAT STAFF PROPOSES THE SAME AS THE OLD LEAST COST PLANNING REGULATION OF THE 80'S AND EARLY 90'S?

A. No, far from it. Least cost planning or integrated resource planning ("IRP") as it was sometimes called, was merely a regulatory tool for implementing traditional cost-of-service regulation. It was prospective rather than retrospective. IRP gave the regulator before-the-fact input, sometimes even final decision-making authority in the planning for new supply or demand-side resources. It also allowed regulators to require that such decisions be made in a specified fashion or that it incorporate specific types of resources (e.g., renewable generation, demand-side programs, etc.). IRP required the utility and the regulator to evaluate resource alternatives in terms of their <u>expected</u> present-value costs over the entire the planning horizon, usually 10-20 years. It was not a year-by-year after-the-fact comparison. Under IRP, once a specific resource decision was made, whether it be to build a new power plant of a certain type, or construct new transmission, or implement a demand management program, the prudent costs of that decision were recovered in rates even if the decision turned out to be more costly than some alternative course of action. IRP never guaranteed outcomes to electric customers, i.e., that the agreed upon resource decisions would be in fact least cost, only that the process by which such resource decisions were made was prudent and rational.

Q. DOES STAFF CITE ANY AUTHORITY OR PRECEDENT FOR THE LIMITATION OF RATE RECOVERY TO THE "LOWER OF COST OR MARKET?"

A. No. I am not aware of any jurisdiction in the United States, or for that matter, anywhere else that would suggest such a patently unfair and destructive form of confiscatory regulation. It would destroy the incentive for the new investment necessary to provide safe and reliable service under either a competitive or traditional regulation price regime. Since all power procurement decisions will result in a penalty to the UDC if anything at any time goes wrong for any reason ("wrong" being defined as being at a cost above some after-the-fact determination of "market"), decision-making itself will be paralyzed. Because retail prices under the "lower of cost or market" philosophy will, on average, always be below cost, uneconomic consumption of electricity will be inevitable and systemic. Just as certain is the ultimate destruction of the UDC's financial viability, unless of course, it abandons Standard Offer service altogether.

Q. HOW WILL SUCH A PRICING PHILOSOPHY DESTROY THE UDC'S FINANCIAL VIABILITY?

A. That should be obvious. If you go to Las Vegas and make a series of bets with only the prospect of getting your bet back when you win, but absorbing all losses when you lose, you will eventually go broke no matter what game you play or what betting strategy you employ. The only way to even beak even or cut your losses is to not play, which in the context of Staff's recommendation means to not offer Standard Offer service.

Let me give you a specific hypothetical example. APS enters into a PPA either with an affiliate or with one of the Merchant Intervenors for a five-year period. In four of the five years, PPA costs are anticipated to be below the "benchmark" cost of the Company's existing generation. (I have put aside for purposes of this hypothetical the difficulty in making such a comparison unless the products being acquired through competitive bidding are comparable to the products to be provided from the existing generation portfolio.) The anticipated PPA costs are also lower on average for the entire five-year period. I interpret Mr. Rowell's testimony to mean that APS could only recover the actual cost of the PPA during the four years it was below the cost of the existing generation, but would be penalized during the fifth year. Worse yet, even when the PPA was anticipated to be below the cost of the existing generation for every year of this hypothetical five-year period, if (on an after-the-fact basis) the PPA ever turned out to be above such "benchmark" cost for any period of time, the Company would be likewise penalized. The same penalties would seemingly apply if the Company determined that it would retain its existing generation, and it later turned out that market prices were below the "benchmark" cost-of-service for any period of time during either the "transition period" or the remaining life of the retained generation.[2]

Such a punitive system of regulation would be inappropriate even if applied only prospectively, let alone to APS generating assets that have already been found to be prudent, to be used and useful and to have a "fair value" well in excess of cost. You don't have to be either a lawyer or an economist to label this scheme for what it is – the systematic confiscation of the value of the Company's property.

Q. DOES STAFF PURPORT TO ADDRESS THE POTENTIAL IMPACT OF THIS PROPOSAL ON THE FINANCIAL VIABILITY OF THE UTILITY DISTRIBUTION UTILITY ("UDC")?

[2] I say "seemingly" because Mr. Rowell's responses to the Company's data requests on this issue were somewhat confusing, ambiguous, and contradictory.

A. No. Similar to its later position on the Settlement, there is less than a sentence in all of Staff's testimony concerning the financial health of the UDC, and no analysis of the impact of its proposals on the ability of the Company to attract and retain capital or fund operations in a safe and reliable manner.

Q. HOW WILL STAFF'S "LOWER OF COST OR MARKET" PHILOSOPHY AFFECT THE COMPETITIVE WHOLESALE MARKET?

A. It will impede and most likely prevent the development of such a market for the foreseeable future. Since the "price cap" applies to both affiliates and non-affiliates, there is actually an incentive to keep market prices as high as possible. This will assure a greater likelihood that both affiliated and non-affiliated generators will recover at least their cost-of-service. Because building either new transmission or new generation is likely to have a depressing effect on market price, Staff has now created a disincentive to do anything about transmission constraints. This disincentive not only affects the incumbent UDC and its affiliates, but all other market participants because they are effectively subject to the same price caps. Additionally, such Standard Offer "price caps" would discourage customers from even trying Direct Access service, making Staff's dire predictions about the pace of retail competition something of a self-fulfilling prophecy.

Q. THIS ALL SEEMS SOMEHOW FAMILIAR. HAS ANY OTHER JURISDICTION EXPERIENCED THESE PROBLEMS?

A. Yes. UDCs caught in a regulatory price squeeze, demand responses divorced from market forces, new investment in infrastructure discouraged - these are all reminiscent of California. Although the means of destruction are different, the likely result will be the same.

Q. HAVE THIS COMMISSION AND OTHER REGULATORS PREVIOUSLY CONSIDERED AND REJECTED THE LOWER OF COST OR MARKET PHILOSOPHY EMBODIED IN STAFF'S RECOMMENDATION IN THIS PROCEEDING?

A. Yes. Although nobody in Arizona, or to my knowledge anywhere else, has ever proposed anything of the scope of Staff's recommendations, some aspects of this "heads I win, tails you lose" version of regulation was proposed during an APS fuel and purchase power adjustment proceeding in 1986. At that time, RUCO proposed that APS generating unit performance be measured against some historical measure of performance, with an automatic disallowance if performance fell below the standard but no potential for reward above the units' cost-of-service if performance exceeded the standard. RUCO's scheme was not strictly a "lower of cost or market" proposal. Yet it was one in which cost-of-service was a rate cap but not a rate floor, and one where the prudence of APS' actions would not prevent a disallowance, and thus it had many of the flaws and inequities inherent in Staff's present proposal. The Commission rejected the RUCO proposal as "inherently biased against APS." Decision No. 55118 (July 24, 1986) at Finding of Fact No. 37. The Commission also labeled a companion RUCO suggestion to automatically disallow costs above some specified level (analogous to Staff's suggestion of a *per se* cap of the lower of cost or market) "an unreasonable and draconian position." *Id.* at 13.

In large part the Commission's analysis was similar to the discussion of "economic excess capacity" in Docket No. U-1345-85-367, a seemingly endless rate proceeding filed in 1985 but not finally decided until the Spring of 1988. In that proceeding, Staff proposed to subject Palo Verde to a "market cost" test while at the same time constraining the value of the Company's other generating plants to original cost. Thus, as in Staff's current proposal, APS cost recovery for generation would be the lower of cost or market. But unlike Staff's present recommendation, Staff was at least willing to compare the present value of Palo Verde's life cycle costs to the present value of the market alternative for a comparable period of time rather than a year to year spot analysis. Then, as in this case, Staff contended that its standard for cost recovery would be "reasonably applied," similar to Mr. Rowell's admonition that "the financial health of the UDCs cannot be forgotten." Testimony of Matthew Rowell at page 4, lines 15-16. At the time, the Company was honored to present as a rebuttal witness Dr. Alfred E. Kahn, former head of the New York Public Service Commission and former Chairman of the Civil Aeronautics Board, and almost literally the father of modern utility regulation. His response to this "lower of cost or market" scheme was eloquent, if somewhat blunt:

> I am honestly uncertain whether this [Staff's] response is properly characterized as disingenuous or meaningless; but at least one of the two or some combination of them seems to me inescapable. It will not do for [Staff witness] Dr. Yokell to set up an admittedly unattainable standard of perfection; recommend that departures from it will be subjected to a substantial penalty; and then assure us that his intention is, however, to have it applied "reasonably." The standard is itself unreasonable; it is a standard for expropriation; and "reasonable expropriation" is an oxymoron.

Rebuttal Testimony of Alfred E. Kahn in Docket No. E-1345-85-367 at 3. After later characterizing Staff's proposal as "pie in the sky" (*Id.* at 4), Dr. Kahn went on to state:

> In other words, just as his [Staff's] basic proposal would have the Commission play "heads we win/tails you lose" by allowing utility companies to recover <u>only the costs</u> (including the cost of capital) associated with their <u>successful plants</u> and something less than that on the unsuccessful ones, even though the associated investments were prudent, so similarly he [Staff] would allow them recovery of costs and <u>only</u> of costs <u>only during the period</u> when the Commission <u>assesses those investments as meeting</u> the standard of perfection, but not during the period of its [the Commission's]

> erroneous and later withdrawn assessment that they fell short of the standard.
>
> In short, under Dr. Yokell's [Staff's] regulatory scheme, the utility company would be penalized not just for its own lapses from omniscience but also those of its regulators!

Id. at 7-8 (emphasis in original). Needless to say, Staff's recommendation was not adopted by the Commission.

In Commission Docket No. U-1345-90-007, the Commission was again faced with the issue of "economic excess capacity." This time it was RUCO that proposed "capping" cost recovery of Palo Verde at some calculation of the market cost of an alternative resource, in those days a coal plant. Once again the concept was utterly repudiated.

Other jurisdictions have also repeatedly rejected the selective use of market value in setting rates, which is essentially what Staff's "lower of cost or market" philosophy embraces. These include New York, Oregon, Illinois and North Carolina.

2. What 1999 APS Settlement?

Q. YOU HAVE REPEATEDLY CRITICIZED STAFF'S FAILURE TO OBSERVE THE TERMS OF THE 1999 APS SETTLEMENT AGREEMENT. DO STAFF'S PROPOSED LIMITATIONS ON BOTH PWM&T AND PWEC VIOLATE THE SETTLEMENT?

A. Yes, and I know some may think I'm a broken record on this topic. But I am continually puzzled and confounded by the fact that the 1999 APS Settlement apparently means so little to Staff. Whether you accept the Court of Appeal's pronouncement about this Settlement being a binding contract or believe it just part of another order of the Commission, the 1999 APS Settlement deserves more consideration and deference than has been repeatedly evidenced by Staff's recommendations in this proceeding as well as in the Variance Docket. The 1999 APS Settlement specifically found that APS could transfer the power marketing function, which of necessity includes power acquisition. *See* 1999 APS Settlement at Section 4.2. Yet Staff now is recommending that either this function be retained at APS or worse yet, that APS and PWM&T have redundant power marketing functions. *See* Testimony of Matthew Rowell at page 7, lines 15-18. The 1999 APS Settlement specifically held that the Company's new generation affiliate would not be placed under any different regulatory scheme on account of its affiliation with APS:

> The APS affiliate or affiliates acquiring APS' generating assets will be subject to regulation by the Commission, to the extent otherwise permitted by law, <u>to no greater manner or extent than that manner and extent of Commission regulation imposed on other owners or operators of generating facilities</u>.

1999 APS Settlement at Section 4.4 (emphasis supplied). Yet Staff proposes both limiting the ability of APS affiliates to compete for sales of power to APS in a manner not applicable to non-affiliates and requires nonsensical affiliate pricing rules for such sales that would likewise not be applicable to non-affiliates. *See* Testimony of Barbara Keene at page 8 lines 13-20.

Q. WHAT ABOUT STAFF'S RECOMMENDATION THAT RELIABILITY MUST-RUN ("RMR") UNITS BE RETAINED BY APS?

A. This would encompass Ocotillo, Yucca, the non-PWEC units at West Phoenix, and perhaps the Douglas CT. Retention by APS of this small amount of generating capacity would also violate the 1999 APS Settlement, which specifically listed these units as among those to be divested (1999 APS Settlement, Exhibit C), and would be unwise and unnecessary in any event.

It is not economic for APS to retain a small redundant generation infrastructure when the overwhelming majority of its generation will reside at PWEC. I discuss this at pages 29 and 30 of my Rebuttal Testimony in the Variance Docket as well. The Company's Open Access Transmission Tariff ("OATT"), the Arizona Independent Scheduling Administrator ("AISA") protocols, and the WestConnect protocols before the Federal Energy Regulatory Commission ("FERC") address RMR, and Rule 1609(I) requires that there be a contract or other legal assurance of RMR prior to divestiture. A FERC-approved contract or tariff (or both) will suffice in lieu of continued APS ownership of these units, which after all are RMR only a limited number of hours each year. (West Phoenix Units 4 and 5, which are PWEC units, as well as SRP's planned San Tan and Kyrene Units are much more efficient than the Ocotillo and older West Phoenix facilities and will largely if not completely displace them for RMR service.) And once the WestConnect protocols are approved and WestConnect becomes operational, RMR issues will be handled through that organization.

Q. DOES STAFF'S TREATMENT OF THE 1999 APS SETTLEMENT AFFECT YOUR CONSIDERATION OF ITS PRESENT RECOMMENDATIONS IN THIS DOCKET?

A. Absolutely. For example, Staff witness Jerry Smith is suggesting an acceleration of transmission projects and a general substitution of transmission for generation. Both these recommendations will be exceedingly expensive to implement. APS has already spent hundreds of millions to comply with the 1999 Electric Competition Rules and the 1999 APS Settlement, both of which are now being dismantled or ignored by Staff. Staff is recommending a whole new code of conduct when APS has already formally trained over 2000 employees on the existing Code of Conduct that Staff itself helped to draft just two years ago and concerning which there has not been even one alleged violation. Staff is recommending that APS get back into the generation business when it has already devoted millions of dollars to get out of it in compliance with divestiture provisions in the Electric Competition Rules drafted and promoted by Staff and with the divestiture provisions in the 1999 Settlement Agreement that were supported by Staff and which were indistinguishable from the divestiture provisions insisted upon by Staff in the ill-fated 1998 settlement also discussed in my Rebuttal Testimony in the Variance Docket. Aside from the Company's many and profound substantive disagreements with most of Staff's positions, there is the quite legitimate question whether any or all of Staff's recommendations are likely to be completely changed or abandoned altogether within a few short years, if not sooner.

Q. DOES STAFF OFFER ANY EXCUSE FOR ITS TREATMENT OF THE 1999 APS SETTLEMENT?

A. No Commission employee has a word to say on the subject. Staff outside consultant witness Neil Talbot offers the "change of circumstances" excuse at page 31, line 21 of his testimony. I find it more than curious that these "changed circumstances" justify changing those portions of the 1999 APS Settlement bargained for by the Company but not those portions of the Settlement, such as the guaranteed rate reductions and the write-off of $234 million in prudently-incurred costs, which were bargained for by the various consumers groups that joined in that 1999 APS Settlement and apparently welcomed by the Commission. That aside, the changes in circumstances since 1999 have generally been towards a more competitive wholesale market, especially in Arizona. We have far more merchant generation and merchant generators in Arizona than in 1999 or than were anticipated in 1999 to be in Arizona today.

We are closer to having a working RTO than in 1999. We have a more proactive FERC than in 1999. We have a cost-based PPA on the table, which is again something we did not have in 1999. Rather than being a document that time and events have passed, the 1999 APS Settlement has proven an even better deal for consumers than first anticipated (just ask people in California and Nevada). Moreover, the rationale stated by the Commission for each of its major provisions is more salient than ever before.

3. The Proposed PPA Would Resolve Most of Staff's Stated Concerns

Q. HOW WOULD THE PROPOSED PPA RESPOND TO STAFF'S STATED CONCERNS?

A. As I noted in my Summary, it is ironic that the very Proposed PPA that Staff seemingly rejected out of hand in the Variance Docket would go a long way towards meeting many if not most of Staff's stated concerns. This is especially true given the clarifications and amendments to the Proposed PPA discussed at pages 36-51 of my Rebuttal Testimony in the Variance Docket. Below is a listing of the concerns or issues raised by Staff in this Generic Docket along with the Proposed PPA's treatment or resolution of each such concern or issue:

> ***Market Power*** – The Proposed PPA completely eliminates even the potential exercise of market power by APS affiliates against APS or its customers. And Staff's own analysis demonstrates that neither APS (pre-divestiture) nor PWEC (post-divestiture) can exercise any significant market power on a regional basis.
>
> ***Affiliate Transactions*** – The Proposed PPA gives the Commission prior-approval authority for most of APS' purchases from PWM&T. The balance of the Company's needs would come from a transparent and open competitive bidding process under the direct control of APS. Except as regards its responsibilities under the PPA, PWM&T will undertake no other significant affiliate transactions with APS. The same is true as regards PWEC. As it is, those transactions are already subject to Commission review in both rate proceedings and as a result of the Affiliate Rules (A.A.C. R14-2-801, *et seq.*).
>
> ***Code of Conduct*** – Approval of the PPA moots most potential code

of conduct issues identified in Ms. Keene's testimony. Moreover, the Commission should await final FERC action on this same issue So as to avoid potentially conflicting or duplicative requirements.

Just and Reasonable Rates - The Proposed PPA gives APS customers the greatest possible assurance that they will be no worse off than if restructuring had never taken place. It does so without confiscatory "lower of cost or market" schemes but through incentives to maximize performance from the Dedicated Units and by fixing a return component during today's period of historically low capital costs. Because the PPA imposes no restrictions on customers' ability to chose retail access, such customers can play the "lower of cost or market" game themselves without making the Company's shareholders unwilling and uncompensated participants in that game.

Reliable Service – The Proposed PPA gives APS customers the same reliability benefits of fuel, geographic and operational diversity as heretofore enjoyed.

Long-Term Promotion of Wholesale Competition – The PPA gradually phases in market resources through a combination of mandatory procurements and significant purchases of Supplemental and Replacement Energy Products under the PPA. Although the Merchant Intervenors naturally would be enriched by an acceleration of both, it is clear that the PPA, even as drafted, would not impose the sort of draconian price caps and create the sort of disincentives for open market development as are part and parcel of the Staff's recommendations.

Please note that the above analysis does not purport to "solve" the "jurisdictional issue." If by "solve," it is meant a means by which the Commission can wrest jurisdiction over wholesale power transactions from FERC or by which the Commission can arrest FERC's progressive stranglehold over transmission issues, I can offer no "magic bullet." Only Congressional enactment can serve those purposes. But I can say that the Commission's influence over wholesale market participants such as PWM&T and PWEC, both because of their affiliation to APS and their status as Arizona-centered businesses rather than a collection of Delaware LLCs, is and will remain far greater than the influence it believes it can exercise through the occasional power plant siting proceeding or even by the Merchant Intervenors' participation in this proceeding.

4. Procedural and Timing Issues

Q. DOES STAFF INDICATE IT WISHES TO DELAY THE DIVESTITURE OF GENERATION ASSETS IN VIOLATION OF THE SCHEDULE AGREED TO IN THE 1999 APS SETTLEMENT?

A. Staff's position is confusing at best, and disingenuous at worst. At page 12, lines 16-19 of his testimony, Mr. Rowell states that Staff's recommendations are not "designed to delay the asset transfers provided in the settlement agreements." Yet at page 9, line 12 of that same testimony, he states "that the timing of the asset transfers is problematic." And at page 10, lines 2-9, Mr. Rowell sets up a gauntlet of prior conditions to any transfer that could not possibly be achieved by year's end. Some of these prior conditions would not even be initiated, let alone resolved, until 90 days after the conclusion of this proceeding, which means a start date of late November at the earliest.

It's not as if Staff has made any specific proposals that could be easily implemented without further controversy. For example, Mr. Rowell states:

> The [required] market power study should consider any and all factors that could adversely impact the ability of new or alternative suppliers to enter the Arizona retail or wholesale markets. The market power study shall examine horizontal and vertical market power, the effect on competition of distribution and transmission pricing, contractual arrangements, and other potential barriers to entry into the Arizona wholesale and retail market. The analysis of horizontal market power should be consistent with the U.S. Department of Justice and Federal Trade Commission's Horizontal Merger Guide-Lines, as revised April 8, 1997 ("DOJFTC Merger Guidelines"). The DOJFTC Merger Guidelines, standards, and methods, which are designed to apply [only] to mergers, should be adapted and modified as necessary to the circumstances specific to the deregulation of generation and the introduction of retail open access. The analysis should also be consistent with current FERC market power tests such as the pivotal supply test and analytical methods such as

> strategic behavioral analysis. The horizontal market power analysis for retail and wholesale products should include analyses of market concentration and barriers to entry for non-affiliated providers for each customer class. The vertical market power analysis should demonstrate that the functional separation, codes of conduct, affiliated transactions, and interconnection and open access policies and tariffs are or will be structured and implemented to assure that all wholesale and retail competitors have access to the competitive markets equal to that of the utility and its ESP affiliates. If the results of the above described analysis reveal areas of concern the Commission may require that additional analysis be conducted such as strategic behavioral analysis. The Arkansas Public Service Commission's Minimum Filing Requirements for Market Power Analysis approved on June 27, 2000, provides additional detail on The content of market power studies.

Testimony of Matthew Rowell at page 11, lines 2-25 (emphasis supplied). This is not a study – it's a lifetime endeavor for a "think tank" full of market power and market structure experts. Or at least it would be if the confusion of retail and wholesale issues in the above-quoted passage and the continuous use of ambiguous qualifiers such as "consistent with," "as necessary," "any and all," "such as," etc., did not make Staff's precise recommendation indecipherable. Mr. Rowell then goes on to prejudge the outcome of his own mandated mega-study by requiring that the utility (APS) submit a "market power mitigation plan for Commission approval." *Id.* at page 10, line 4. I have to assume this prejudgment is a by-product of the so-called "rebuttable presumption" theory espoused by Mr. Talbot at page 17 of his testimony. Mr. Talbot neither provides or cites any proof for this theory nor do the potential concerns of the Arkansas Public Service Commission about multi-state giant Entergy constitute such proof.

The same problem exists with Ms. Keene's recommended "code of conduct" filing. She references a number of other jurisdictions' codes of conduct, most of which are irrelevant to the issue at hand. But Ms. Keene makes no specific recommendations other than the "lower of cost or market" mantra previously discussed and the suggestion that the code should address in some unspecified manner a host of other issues. For the most part, each of these issues is already addressed in the existing Commission-approved APS Code of Conduct and/or FERC Code/Standards of Conduct or was an issue (e.g., shared office space) already considered and rejected by Staff and the Commission. If Ms. Keene had simply and straightforwardly recommended that the existing Commission-approved APS Code of Conduct needed this or that additional provision, this would be the sort of recommendations to which the Company and others could rationally respond.

Combined with Mr. Rowell's never-ending market power analysis, I am led to the inescapable conclusion that, contrary to Mr. Rowell's assertion, the whole point of Staff's recommendation is to delay the transfer of assets indefinitely. And yet Staff cynically maintains that the decision to divest or not will be, in Mr. Rowell's own words "at the utilities' discretion." Testimony of Matthew Rowell at page 10, line 7.

Q. DID STAFF RAISE THESE ISSUES IN 1999?

A. Vertical market power concerns were one of the stated reasons why Staff proposed divestiture of the Company's generation in the first instance and why, as I noted in my May 29th testimony, the Commission specifically held that such divestiture was "in the public interest." Code of Conduct was also an issue, resulting in the present Commission-approved APS Code of Conduct. Horizontal market power was not raised. In fact, in the ill-fated 1998 settlement agreement between APS, TEP and Staff, Staff agreed to allow APS (and thereafter its affiliate) to acquire even more generation. That never took place, and since 1999, the generation market share of APS generation has dropped significantly.

In point of fact, APS and its affiliates have already passed every known form of recognized market power test I have ever heard of, and thus no "market power mitigation plan" is either necessary or possible. FERC has repeatedly found that APS and its affiliates have no market power and perhaps more to the point, that the transfer of APS generation to PWEC "will not adversely affect competition." FERC Docket Nos. EC00-118-000 and EC00-118-001 (November 24, 2000) at 5. I must note that the referenced FERC proceeding included this Commission as an intervening party, and that FERC went on to note in its order: "no intervenor disagrees" with the Company's assertion that "the proposed transaction will not have an adverse effect on competition in the generation or transmission markets."

Aside from the amorphous nature of the preconditions (to divestiture) themselves, which require significant further definition before they could possibly be adopted and implemented, Staff also assumes completion of an as of yet uninitiated rulemaking proceeding to amend Rules 1615, 1616 and 1606. This is easier said than done, and once you begin pulling on the essential threads of restructuring, you don't know how much of the cloth will unravel. Even if such a proceeding were begun immediately and conducted concurrently with the market power and code of conduct proceedings contemplated by Staff's recommendations, something Staff has been most reluctant to do, completion prior to December 31, 2002, or any time remotely close to such date, is impossible.

Q. COULD THE COMMISSION JUST PROCEED TO INSTITUTE STAFF'S VARIOUS RECOMMENDATIONS IN THIS PROCEEDING, THUS SHORTENING THE PROCESS?

A. Perhaps if back in January, when this Generic Docket was conceived, Staff had initiated the process of completely reinventing regulation in this state or had opened up a new rulemaking docket, there might be the procedural vehicles in place. However, there would still be no evidentiary basis for any of these Staff proposals, which I believe will inevitably lead to the same sort of chaos that gripped California and other Western states in 2000-2001.

Q. DIDN'T STAFF PROPOSE AND THE COMMISSION AGREE THAT THE DIVESTITURE ISSUE WAS TO BE RESOLVED, YEA OR NAY, BY AUGUST OF THIS YEAR?

A. Yes. I do not understand how Staff can possibly reconcile its current suggestion of some open-ended and ill-defined code of conduct proceeding or an equally ill-defined and unprecedented set of market power analyses with goal of getting this threshold issue resolved by August.

IV. THE MERCHANT INTERVENORS

Q. DOES APS OPPOSE CONSIDERING "TRACK B" ISSUES SUCH AS HAVE BEEN RAISED IN VIRTUALLY ALL OF THE MERCHANT INTERVENORS' TESTIMONY IN A SINGLE PROCEEDING?

A. No. APS does oppose considering them in two proceedings. Both Reliant and Panda/TECO opposed a one-track proceeding. They should not now be allowed two bites at the apple. Nor should they be permitted to use this "Track A" proceeding as additional leverage to further their pecuniary interests in "Track B" at the expense of APS and its customers.

Q. WHAT SPECIFIC RECOMMENDATIONS OF THE MERCHANT INTERVENOR PANDA/TECO DO YOU OPPOSE?

A. Panda/TECO witness Dr. Craig Roach would condition asset transfer on the denial of the Proposed PPA. Although asset transfer is directly linked to the requirement and need for competitive power procurement under Rule 1606(B), the Proposed PPA and asset transfer are largely independent of each other. Although PWM&T could not fulfill the terms of the Proposed PPA without the portfolio of generating assets that PWEC will acquire from APS, APS would effectuate divestiture as called for in Rule 1615 and the 1999 APS Settlement with or without approval of the Proposed PPA.

Dr. Roach also suggests that APS not be permitted to divest its generation in accordance with the 1999 APS Settlement until APS established a short-term energy market in Arizona. Testimony of Dr. Craig Roach at page 4, lines 6-7. While I appreciate the vote of confidence, neither APS nor any other single market participant can establish such a market. In California, it took a concerted effort by all market participants and the state over many months to establish a liquid short-term market, and even it eventually failed.

In point of fact, APS will need significantly less competitively procured power if it is forced to retain its generation than would be acquired under the Proposed PPA, and thus Dr. Roach's suggested denial of the Company's generation asset transfer is hardly in the interests of Panda/TECO and the other Merchant Intervenors. Panda/TECO appears to be raising these issues largely in an effort to use divestiture as a carrot to induce the Company to abandon the Proposed PPA.

I also disagree with Dr. Roach's assertions at page 15, lines 1-5, and thus further disagree that there is anything this Commission can and should do to "mitigate" alleged APS "transmission market power." The first two assertions made by Dr. Roach to support his recommendation are simply wrong, both factually and legally. The third is partially true in that FERC does regulate APS transmission. It is not true that FERC grants APS any monopoly. The fourth is true in the sense that WestConnect is not fully operational, but the implication that APS is somehow in violation of some FERC order or regulation is completely false. FERC is presently reviewing WestConnect's protocols, and APS expects a positive response from FERC prior to any significant competitive procurement process being implemented in Arizona. Even if they were not, the type of competitive procurement presently favored by the Company, an open and transparent auction-type process, with the winners becoming designated network resources on an equal footing with those covered under the Proposed PPA or any variant of such agreement, when combined with the Company's OATT and the AISA, would satisfy any fair-minded individual that APS ownership of transmission is a non-issue in these proceedings.

Finally, Dr. Roach suggests using an RFP process followed by private negotiations, with PWEC and PWM&T being excluded from this process, as a "mitigation" measure for non-existent market power. Whatever merit there is in Dr. Roach's recommendation, it has nothing to do with mitigation of market power. In fact, as we saw in California, the use of the RFP process and private bilateral negotiations magnified the market power of the merchant generators to the considerable detriment of consumers. To the extent that "Track B" issues are in any way related to market power, this is just another argument in favor of having as open and transparent a competitive procurement process as is feasible. Also, eliminating or handicapping the merchant generators' major competitors

(PWEC and PWM&T), or requiring APS to competitively procure power without the assistance of its most experienced and knowledgeable power traders (PWM&T) is just the ticket for driving up prices to consumers.

Q. ARE YOU SAYING THAT APS WOULD DO AS POOR A JOB AS THE CALIFORNIA DEPARTMENT OF WATER RESOURCES ("CDWR") IN HANDLING AN RFP/BILATERAL NEGOTIATION PROCUREMENT PROCESS?

A. No, and I'm also not in a position to criticize CDWR. For all I know CDWR did the best it could with the weak hand it had been dealt. I do believe, however, that any procurement process that is based on RFPs and private bilateral negotiations will, because of the tremendous degree of subjectivity involved and the lack of proper oversight and accountability, potentially lead to claims of "foul" by the losers (claims that may and have resulted in prolonged litigation), invite "second guessing" by regulators, and result in higher prices to end-users.

Q. WHAT ABOUT RELIANT'S PROPOSAL?

A. Reliant witness Curtis Kebler presents the unusual scenario wherein APS or PWEC generation is first sold to merchant entities and then resold with some undisclosed markup back to APS. Although I don't know how long it would take to set up what would be in effect a second auction, I would agree that this would allow parties without uncommitted generation in Arizona to participate in providing generation for Standard Offer customers, but I fail to understand why this is particularly desirable. One of the things APS, and I believe the Commission, wish to encourage is the construction of new generation in Arizona, not a proliferation of "asset-less" power marketers. From a reliability point of view, the proposal may have some merit since it allows others to purchase APS' and PWEC's then existing reliable portfolio of generation, but I again struggle to see how essentially adding a "middleman" (and a "middleman's" profit) to the Proposed PPA benefits the Company's customers or enhances Arizona's future energy supplies.

Q. BOTH THE MERCHANT INTERVENOR WITNESSES AND STAFF WITNESSES HAVE SUGGESTED THAT MANY ADDITIONAL STEPS NEED TO TAKE PLACE BEFORE WE CAN HAVE RESTRUCTURING AND REALLY EFFECTIVE WHOLESALE COMPETITION. DO YOU AGREE?

A. I certainly agree that implementation of WestConnect, the creation of a liquid spot market, and the construction of more transmission would each facilitate more efficient wholesale competition. I do not agree that the first steps toward that more efficient wholesale competition, which are divestiture of APS generation in conformance with the 1999 APS Settlement and the Electric Competition Rules and the beginning of a rational competitive procurement process, should be delayed pending the other institutional and infrastructure changes described above. If we wait to move forward until we have perfect conditions in place for wholesale competition, we will be waiting a long time, if not forever.

Q. WHY DO YOU BELIEVE THE MERCHANT INTERVENOR WITNESSES ARE MAKING PROPOSALS THAT WILL SIGNIFICANTLY DELAY, PERHAPS INDEFINITELY, THE BEGINNING OF COMPETITIVE PROCUREMENT OF POWER BY APS?

A. I don't really know. It was just this past April that Panda/TECO was filing a Motion asking an "Order to Show Cause" because the Company was not immediately proceeding to competitive bidding. All the other Merchant Intervenors supported Panda/TECO in this request. The scheduled hearing on the Company's request in the Variance Docket was cancelled so that we could get on with the bidding. Now, just as suddenly, the Merchant Intervenors are the co-proponents (with Staff) of delay. Maybe they simply are hoping that market conditions will improve before they have to commit any resources to Arizona. Maybe some of them don't believe their plants will be done in time for 2003. Or it may be that getting a competitive edge vis-a-vis APS and its customers by structuring the procurement process in "Track B" to their liking is more important to them than getting the procurement process started on time.

V. RUCO AND AECC

Q. DO YOU HAVE ANY COMMENTS ON THE RECOMMENDATIONS OF EITHER RUCO WITNESS DR. ROSEN OR AECC WITNESS HIGGINS?

A. I indicated in my Summary that APS did not disagree with most of Mr. Higgins observations or recommendations, and I will not belabor that point. As to Dr. Rosen, I agree with his observations about the benefits of the Proposed PPA or some similar buy-back agreement premised on the assets, old and new, constructed by APS and its affiliate to serve APS customers. I do not agree that the absence of this or any other PPA would result in PWEC or PWM&T engaging in the sort of market activities described in Dr. Rosen's testimony. APS did not conduct itself that way in California (and in fact reported to authorities others that did), where market rules actually encouraged that sort of behavior, and it certainly would not do so in its own back yard even if there were not the sort of increased Commission and FERC market monitoring and oversight we are now experiencing. If Arizona goes the way of California, it most likely will not have market manipulators to blame, but only the sort of bad regulatory policies urged by Staff and some of the Merchant Intervenors in this proceeding as well as in the Variance Docket.

VI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS IN REBUTTAL?

A. Yes. It was no pleasure having to be so critical of Commission Staff in these proceedings. But I honestly believe their recommendations, if adopted, could only lead to the financial destruction of the Company and send us down a path that although different in both design and intent, would lead to the same end result as California, Nevada and other Western states. You can have competition and surrender the safety of traditional regulation. You can keep traditional cost-of-service regulation and forego the potential benefits of competition. You can hedge your bet with devices such as the Proposed PPA. But you can not insure that the outcome of any of these choices will always be the best for consumers all of the time. And you cannot reasonably expect the Company to provide such assurance without inviting financial disaster and denying to it the opportunity to make a reasonable return either under competition or regulation. Even insurance companies, and Staff has certainly not proposed paying APS any premium to provide the price insurance Staff is essentially seeking, do not cover every hazard all of the time.

Aside from the substance of Staff's recommendations, I continue to be dismayed by the lack of deference, or even consideration, afforded the 1999 APS Settlement. Reinventing regulation every two to three years is certainly not in the best interests of customers. I see no reason to give Staff's proposals in this Generic Docket any greater consideration since if I wait a year or two, they too will likely be rescinded or significantly modified.

No party has demonstrated why the current provisions on affiliate transactions and code of conduct are not sufficient with perhaps a tweak here or there.

Similarly, APS has already passed every legitimate market power test, and there is no need to attempt to keep coming up with ever more complex and time consuming studies or to prepare mitigation plans to address a non-existent market power.

The Proposed PPA is still in the best interests of our customers. It actually addresses most of Staff's stated concerns and allows for greater development of the wholesale market than would retention of generation by APS.

Q. DOES THAT CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY IN THIS GENERIC PROCEEDING?

A. Yes, it does.

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, *et al.*

June 11, 2002

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REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

INTRODUCTION

Q. Please state your name and business address.

A. My name is William H. Hieronymus. My address is Charles River Associates Inc., 200 Clarendon Street T-33, Boston, MA 02166.

Q. Have you testified previously in this proceeding?

A. Yes. I filed direct testimony on May 29, 2002. My credentials are attached as Exhibit WHH-1 of that testimony.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. APS has asked me to comment on the testimony of various intervener and ACC Staff witnesses, primarily on the subject of market power associated with the transfer of generating assets.

Q. Can you summarize your rebuttal testimony in this proceeding?

A. Yes. While a number of witnesses talk about market power, none demonstrates, or even makes a serious attempt to demonstrate, that PWEC would have unmitigated market power after transfer of the assets. Moreover, these witnesses studiously ignore the fact that the intermediate to long term contracts that are a near certain outcome of this group of proceedings will (to the extent that customers are served under contracts priced independently of future market prices) protect Standard Offer customers from the exercise of market power by PWEC or anyone else. Similarly, to the extent that a substantial proportion of PWEC's energy is sold under long-term contracts, any plausible concern that it could exercise market power with respect to any customer will be mooted.

Staff proposes a "lower of cost or market" means of pricing the wholesale component of Standard Offer service that is certain to trap costs within APS no matter what purchasing strategy it employs. If it buys from the market, including by competitive bidding for long-term contracts, it will face disallowance if the market price exceeds what would have been a cost of service price for PWEC or APS. If it buys on a cost of service-type contract, it will face disallowance if the market price is lower. This proposal would replicate, and in some respects be still worse than, some of the bad regulatory policies that led directly to the California fiasco with bankrupt and near-bankrupt utilities unable to buy power for their customers and the state having to take over procurement. Further, Staff's procedural proposals, including in particular its proposal for a smorgasbord of market power studies, inevitably and needlessly will delay Arizona moving forward along the path of restructuring that has been the Commission's firm policy for the past several years.

REBUTTAL TO PANDA WITNESS ROACH

Q. At page 5, Dr. Roach is asked whether his "concern about market power [would] persist even if the transfer entailed a contract to sell back at cost-plus rates." He responds, "Yes, absolutely." Do you agree?

A. No, absolutely not. His response makes no sense whatsoever. The purported basis for this conclusion is his assertion in the variance proceeding that Standard Offer customers would pay higher prices, face higher risks and have lower reliability than if served by competing suppliers. In my rebuttal in that proceeding I explained the total invalidity of his conclusions, to the extent that they had any basis beyond bald assertion. However, that is not the point I wish to make here. The point that is relevant to my testimony in this proceeding is that the PPA of which he complains is not, and could not be, the result of "market power".

Market power is the ability to profitably sustain an above-competitive price in the marketplace. APS never has contended that the PPA is a contract arrived at in the market, although it does believe that the contract is at least as favorable as a contract originated in the market would be. Moreover, since the contract is cost-based it is just and reasonable and will only allow a reasonable return on investment. PWEC cannot use "market power" to impose this contract on its affiliate, APS. APS is before this Commission to seek its approval for the PPA. The PPA also would be subject to FERC jurisdiction, since it is a wholesale contract. If this Commission believes that the contract is not in the best interests of APS's Standard Offer customers, it presumably will reject it. FERC similarly can act in appropriate circumstances to reject the contract. Nothing in this approval process suggests that the contract can possibly be the product of market power, either arising from the transfer of assets or from other causes.

Q. **Dr. Roach argues that APS's supposed market power requires mitigation and asserts that the asset transfer should be approved only if APS acquires 100 percent of its standard offer requirements from a competitive market prior to asset transfer. Do you agree?**

A. No. Setting aside, for the present, the question of whether APS might have market power in some circumstances, it is manifestly untrue that any such market power requires procurement of 100 percent of Standard Offer requirements from the competitive market. I do agree that were I to assume that PWEC would have market power over APS it would be good policy to insulate APS's customers from the potential abuse of that market power. However, I very much doubt that 100 percent contract cover would be necessary. Any market power that PWEC might have would arise from the fact that, at least at present, competitors likely could not meet 100 percent of APS's customers' loads. However, there clearly is or soon will be sufficient competition available to discipline prices for a substantial portion of such loads.[1]

The main point, however, is that <u>any</u> intermediate to long term contract covering a substantial proportion of APS's customers' loads would insulate them from PWEC exercising market power against them under even the most pessimistic scenario. The key attribute of such a contract is that its pricing terms are not affected by the market price that PWEC allegedly could increase using its hypothetical market power. The PPA that APS has proposed in the variance proceeding clearly meets that objective, as would a range of alternative contractual arrangements, assuming that they are feasible (and, hopefully, reliable and economic). Certain types of contracts entered into in the "competitive market" would meet this objective. Others would not. So, the key point about insulating customers from any market power PWEC might have, or indeed, that any other

[1] Customers are insulated from the market though at least mid-2004 by the rate plan agreed as part of the

provider might have in the future, is to cover a substantial portion of the customers' load with contracts that insulate them from it.

Q. **Dr. Roach presents an SMA analysis, as did you. Have you reviewed his analysis?**

A. Yes. While there are material differences between his analysis and mine, these appear to relate primarily to what capacity is considered to be inside or outside of the control area, not to the total amount of competing capacity. Both Dr. Roach and I find that APS (and PWEC post-transfer) pass the SMA test by a wide margin.

Q. **Did Dr. Roach construct a test similar in form to the SMA that APS fails?**

A. Yes. However, he does so by assuming away the competing capacity that FERC would count and that disciplines prices.[2] There are three categories of competing capacity that FERC counts in the SMA: in-area merchant generation, in-area shares of power plants that are owned by utilities other than APS, and imports. In Dr. Roach's Table Two, in which APS fails the test, he assumes both in-area merchant generation and the joint units away in their entirety. Unsurprisingly, by changing the FERC test to eliminate the competition, he is able to construct a version of the test that PWEC will fail.

Q. **Do you agree with his basis for zeroing out in-area merchant capacity and the shares of other utilities in jointly owned facilities?**

APS Settlement. Between now and mid-2004, substantial additional merchant generation is scheduled to come on line.

[2] *AEP Power Marketing, Inc., AEP Service Corporation, CSW Power Marketing, Ind., and Central and Southwest Services, Inc.; Entergy Services, Inc.; Southern Company Energy Marketing L.P.,* Order on Triennial Market Power Updates and Announcing New, Interim Generation Market power Screen and Mitigation Policy, 97 FERC ¶ 61,219 (2001).

A. No. His sole argument appears to be that the proposed PPA denies the merchants an opportunity to compete. This misses the point entirely. The SMA test inquires whether a seller is pivotal over the control area load. A traditional vertically integrated utility may be pivotal and hence fail the SMA test despite the fact that the load to which its capacity is dedicated is, in fact, served under state-regulated rates. The fact that the load is not served from the market is not deemed to be relevant for the SMA. Even if the bulk of APS's load were served under contracts with other sellers that insulate it from market prices, PWEC still could be pivotal and fail the test. The two concepts (the PPA and the SMA test), therefore, are wholly unrelated. As noted below, this lack of relationship is a flaw in the SMA test. However, correcting the flaw to take the PPA into account would support rather than attack the PPA. In fact, the PPA would fully moot any conceivable concern that PWEC could possess market power.

The SMA test is designed to determine whether a supplier faces sufficient competition that it cannot be pivotal with respect to the control area load, irrespective of that load's contractual arrangements. This has been criticized by utilities that fail the test despite the fact that most of their capacity is dedicated to native load.[3] However, the fact that competitors' capacity is not, in fact, serving the native load of the control area utility hardly means that it should be ignored, as Dr. Roach proposes. If anything, the presumed fact that their capacity is not dedicated

[3] Note that if the supplier's capacity were contracted away to another wholesale supplier who in turn served the load (or sold its output off-system), the capacity would be counted as competing rather than owned capacity. Hence, the SMA test's failure to take native load responsibility into account treats serving native load as a less "real" responsibility than meeting wholesale contracts.

to APS's standard offer load means that it is fully available to compete for any sales in the competitive market with delivery points in APS's control area.

Q. **What basis does Dr. Roach offer for zeroing out the capacity owned by non-APS owners of jointly owned plants in its control area?**

A. Dr. Roach suggests two reasons. The first is identical to his argument about the merchants, i.e., the PPA means that the capacity somehow goes away. The argument is wrong for identical reasons. His second argument, that the owner is a load-serving utility means that the capacity should be ignored, also lacks merit. It depends on very unusual factual circumstances, which simply do not exist.

Q. **What do you mean by "very unusual" facts??**

A. The key fact question is whether the joint owners must use their capacity to serve their native loads or whether such capacity could be sold in competitive markets to serve load at delivery points in the APS control area. I emphasize the point of delivery, because the SMA treats the control area as transmission constrained. It almost certainly is true that the jointly-owned capacity can be sold within the APS control area. For example, El Paso Electric owns a portion of the Palo Verde nuclear plant, a plant that is included by Dr. Roach in the control area. However, if APS/PWEC were to seek to exercise locational market power in the APS control area, El Paso could sell its Palo Verde output into the hypothetically high-priced market and buy power elsewhere at prices not affected by this local market power. So the mere fact that an owner whose load is outside the control area also has native load, or even that its native load requirements equal or exceed its capacity, does not mean that its capacity in the APS control area does not and would not discipline APS/PWEC's hypothetical market power.

Q. Doesn't Dr. Roach also cast doubts that 3,900 MW of imports could compete?

A. Yes, though this appears to be a throwaway argument made solely for completeness. He points to market conditions in 2000 for the proposition that there is no uncommitted capacity that could be made available. However, this clearly is not relevant. Indeed, if Panda truly believed that 2000 market conditions would prevail in 2003 and beyond, they would not be in this proceeding fighting so vigorously.

Q. Beginning at Page 13 Dr. Roach performs an SMA-type analysis for the Phoenix area (the "Valley Market"), and finds that APS fails the test. Does this result surprise you?

A. No. All that Dr. Roach is seeking to demonstrate is that the valley is a load pocket and that generation inside the valley (all of which are owned by SRP, PWEC or APS) is needed during the peak hour. APS has never denied that the valley is a load pocket and that, in consequence, the prices charged by in-valley generators must be mitigated for a few hours per year. As I noted in my Direct Testimony in this proceeding, APS has filed mitigation protocols, as have AISA and WestConnect that doubtless will be in effect when the latter becomes operational.

Q. What mitigation does Dr. Roach propose?

A. He suggests, first, that competitors should be given full access to the transmission capability into the valley market. Second, he suggests that APS should have a competitive procurement for new capacity inside the valley interface.

Q. Do you agree with his first mitigation?

A. No. First of all, it is inherent in the definition of a load pocket that imports cannot fully discipline prices because they cannot be delivered into the load pocket in sufficient quantity to meet load. So the proposal cannot be effective in replacing the usual forms of mitigating prices in a load pocket. Beyond this obvious failing, it is not entirely clear what he is proposing. On page 18, lines 7-11, he appears to argue that all merchant generation that "competes in the APS Market" should be designated as network resources. It simply is not feasible for all such capacity to be network resources In support for this proposal, he cites a FERC order requiring that all new interconnections have the right to be studied as if they were network resources. This order is only germane for utilities that fail the SMA test (which APS and PWEC do not) and only for new connections (which Panda is not). Moreover, if I understand the proposal, it means that transactions through the valley to external destination points, or to SRP destination points would have access to the transmission system on a par with the use of the system to serve APS's native load. This could reduce reliability to, and/or increase the cost of, serving APS's customers, both Standard Offer and Direct Access.

On the other hand, at page 18, lines 13-15 he recommends that APS be required to designate as network resources all winners of any competitive procurement. This is not the same thing as he appears to have said in the immediately previous answer. This latter recommendation is, at least in concept, reasonable. I understand APS's proposal to be that any resource contracted to it to meet Standard Offer load would be treated as a network resource.

Q. Do you agree that APS should be required to issue a competitive RFP for new facilities to be built in the Valley?

A. No. It sometimes, indeed often, is cheaper to rely on must run facilities than either relieve transmission constraints or buy power from new facilities. APS's existing must run units at Ocotillo and West Phoenix are old units. While they are less efficient that modern peaking facilities, they also are heavily depreciated from a relatively low historic book value. Dr. Roach has not even attempted a showing that replacing these units with new capacity, whether owned or purchased competitively, is cost effective, and there is no particular reason to believe it would be. Further, there are absolutely no legal or other prohibitions against merchant generators building new generation in the valley to compete against the must run in-valley generation – they simply have chosen not to do so. Dr. Roach's proposal would require that APS contract for, and subsidize, generation that his client and other merchant generators have not found to be commercially feasible.

Q. Dr. Roach also proposes that APS's must run price should be set based on the operating and capital costs of a new peaker. Would this benefit ratepayers?

A. I very much doubt it, though I have not analyzed the matter. Since West Phoenix and Ocotillo have such low rate base costs, such a pricing scheme almost certainly would increase costs to APS and its ratepayers.

Q. At Page 18, Dr. Roach seeks to rebut portions of your rebuttal of Dr. Ruff in the variance proceeding. Do you agree with his "clarifying points"?

A. While I am not sure of whether this portion of Dr. Roach's testimony is procedurally proper, I will respond. His first point is that market power is not just a spot market issue, but also can affect longer-term markets. I agree. However, this is not valid rebuttal since I made no statement to the contrary. His second point is that a long-term contract mitigates market power only if the contract itself was arrived at through a competitive process. He is not correct, at least in the context in which I address the role of long-term contracts. If a seller contracts away its output at rates that do not vary with the market price, its incentive and ability to exercise market power is essentially eliminated. Similarly, a buyer covered by a long-term contract that does not float with the market is subsequently insulated from the market (to the extent that it has contracted), including both the exercise of market power and any other source of price changes. Dr. Roach makes the point that contract terms may themselves be affected by the seller's market power. I agree that this could be so. However, it does not follow that any contract not arrived at through a competitive solicitation is infused with market power. Nor, for all that, is a contract arrived at through a competitive solicitation necessarily free of market power. While I am not opining on their merits, the regulatory filings whereby the California Department of Water Resources and other buyers of power in the Western power markets are seeking to overturn the contracts that they entered into in competitive RFP procurements allege that these contracts are not "competitive." In any event, as I have stated earlier, this Commission is in the midst of a process of determining whether the PPA is in the interests of customers. Presumably it would not accept a contract that it believes is over-priced as a result of PWEC exercising market power.

His third point is that the exercise of market power is not necessarily confined to withholding supply. He asserts that market power also can be exercised by APS "pushing competitors away" to sign the PPA. I have two responses. First, the "market power" that he asserts is not PWEC's post-transfer market power that is docketed here, but rather the power inherent in the agency role that APS plays as the buyer of power for Standard Offer service. This agency function is inherently exclusive, hence "monopoly", even if the agent wholly lacks power in the energy market which, parenthetically, would be monopsony power, not monopoly power. In any event, a Standard Offer provider's decision to contract with one supplier inherently excludes other suppliers. The question in the relevant docket (not here) is whether APS is justified in signing this particular agreement – an issue this Commission already has been asked to address.

Finally, he objects to my statement that whether PWEC might or might not be in a position to exercise market power over APS is frankly irrelevant, contending that this is the key issue in Track A. While I do not presume to tell the Commission what it deems to be the key issue in Track A, I can explain my statement. The PPA is not a contract arrived at in the market. Hence, whether APS might have had market power in a market for such contracts is irrelevant. The Commission can, and presumably will, determine the merits of the proposed contract based on its content, not the means by which it was negotiated. The full sentence in my testimony from which Dr. Roach abstracts his quotation is, "APS does not contend that this is an arms-length transaction, so that the issue of whether PWEC might or might not be in a position to exercise market power over sales to APS is frankly irrelevant." This statement was and is true.

Q. What do you conclude concerning Dr. Roach's testimony?

A. Dr. Roach's key conclusion is that PWEC possesses, or would possess, market power and that, hence, the asset transfer should be approved only if 100 percent of APS's Standard Offer load is contracted. However, he fails to demonstrate that PWEC would have market power. He fails to demonstrate that allowing APS to contract with PWEC for all or a substantial portion of its load outside of the competitive procurement that he advocates would expose APS's customers to any PWEC market power. He fails even to demonstrate that a competitive procurement would insulate such customers from market power. In fact, a substantial long-term contract between APS and PWEC would serve to insulate APS's Standard Offer customers from market power in the post-transfer market, irrespective of by whom such hypothesized market power is exercised. It also moots any conceivable concern that PWEC would exercise market power over any wholesale power buyer after the assets are transferred.

REBUTTAL TO ACC STAFF

Q. How have you organized your rebuttal to ACC Staff witnesses?

A. Because Staff's testimony is inter-related and cross-referenced, rebuttal is somewhat hard to organize. Since Mr. Rowell summarizes Staff's positions, I will begin with him and deal with other Staff witnesses relevant to the issues I am addressing in turn, to the extent that relevant testimony has not been covered in my rebuttal to Mr. Rowell.

Q. Mr. Rowell begins by discussing retail competition and its role in Staff's recommendations concerning the wholesale market. He asserts that UDC customers have no alternative to buying from the UDCs, so that the Commission must scrutinize the UDC's procurement practices. Do you have any comment on this?

I agree that since Standard Offer Service is a retail tariff service, the Commission has a valid interest in the prudence and reasonableness of the costs included in it. I would, however, point out one oddity of Mr. Rowell's position. It simply is not true that customers have no alternatives. It is true that few retail providers are actively trying to sell to APS's customers and that few customers have switched. This does not mean that customers have no alternatives, merely that retailers cannot successfully compete against APS's retail rates. There is a simple reason for this: retailers buying power in the competitive market and adding their costs of operation cannot sell profitably at prices that attract consumers. This does not mean that competition fails to discipline the prices charged by APS, but rather that APS's current prices are below a competitive level. If APS's prices were to rise above the competitive level, I have little doubt that retail service providers would flock to Arizona. So long as retail choice remains an option for consumers, APS's prices, and hence the amount that it can pass through from its wholesale purchases, will be disciplined by competition.

Q. Mr. Rowell states that the goal of Staff's recommendations is to ensure that Standard Offer consumers will receive reliable electric service at just and reasonable rates. He goes on to state that, "Staff believes it is important to ensure that consumers are no worse off under the restructuring environment than they were under traditional cost-of-service regulation." Are these goals achievable?

A. The first goal is. Mr. Rowell concludes that cost of service rates are just and reasonable. My understanding of the PPA is that it is intended to deliver power at prices wholly consistent with cost of service ratemaking. Therefore, this goal can be achieved via the PPA.

The second goal is inherently unachievable. Once one embarks on a market-based procurement of wholesale power, there is no feasible way to assure that prices will be no higher than under regulation. Indeed, market prices on an hour-by-hour, day-by-day or even year-by-year basis will sometimes be above, and sometimes below regulated prices. Staff surely cannot truly believe that customers are entitled to, or could get, the "lower of cost or market" on this pick-and-choose basis.

Even on a wholly *ex ante* basis, evaluating the PPA relative to hypothetical or even real competitive market offers can be difficult and will necessarily be based on projections of costs and contract terms that are inherently uncertain. This comparison seems to be what he has in mind in saying, at Page 5, that the Commission can use cost of service rates as a benchmark for evaluating competitive rates.

At page 7 Mr. Rowell puts a little more flesh on the bones of Staff's proposal. He says that the established cost of service should be used as both the standard for UDC cost recovery and the price to beat for any competitive solicitation. With respect to an affiliate PPA, he states Staff's position that the UDC should pay no more than its pre-transfer cost of service or the affiliate's post-transfer cost. He notes, that this does not apply to load growth beyond the capability of the utilities' current capacity.

First of all, a critical caveat is that this standard must be applied prospectively in approving the prudence of contracts, including affiliate contracts that APS enters into <u>before</u> they are signed. This is especially true if the Commission rejects the PPA in whole or in part in favor of APS buying from the merchant market. If the Commission requires that APS turn down a cost-based contract, one based on its affiliates cost of service, and requires that it buy instead from the market, it cannot ethically or in all likelihood legally, subsequently disallow resulting costs as "imprudent".

However, Staff does not appear to be thinking only in terms of an *ex ante* determination that APS is pursuing a strategy that will result in just and reasonable rates. What Staff appears to have in mind is absolutely inappropriate. While the language used by Staff is a bit imprecise, I am especially concerned by the question and answer on Page 14 of Mr. Rowell's testimony. The question asked is, "<u>After a utility transfers its generating assets to an affiliate,</u> how should the UDCs recover the cost of power purchased from that affiliate?" He assets that the prudence of purchases from any of "its affiliates <u>or for any other wholesale provider</u> should be evaluated based on (1) the costs of other competitive alternatives and (2) the costs the UDC would have borne had the transfer of assets not happened" [emphasis supplied]. This smacks of the worst sort of after-the-fact, lesser of cost or market regulation. Purchases from an affiliate made on a cost of service basis would be judged based on costs of competitive alternatives. When lower, they are recoverable. When higher, they are not. Similarly, the cost of purchases from the competitive market is recoverable only if they are less than the cost of service alternative. Indeed, the comparison of competitive purchases to cost of service does not exhaust risk. The Nevada Commission recently disallowed nearly half a billion dollars of the power purchase costs of Nevada Power Company, enough to put the company on the verge of bankruptcy, on the theory that it should have entered into a different market contract at an earlier time.

Mr. Rowell professes concern for the financial health of UDCs. His proposal assures that the UDCs would not be credit-worthy and poses a high risk of bankruptcy even if their procurement decisions are uniformly reasonable and prudent. At a minimum, lenders would impose a substantial risk premium on APS, as would equity investors. Vendors, including merchant sellers of wholesale electricity, would sell to APS, if at all, only at prices that reflected the substantial risk of default.

If this indeed is Staff's proposal, it is repeating the worst of the policy errors committed by the state of California. When the power shortage developed and prices went sky-high, there was no impact on Edison's and PG&E's retail prices. They remained at levels based on historic cost of service, a ceiling that Staff proposes here. With no pass through of cost and hence no demand response, the California shortage persisted. Once a material increase in retail prices was allowed to occur, demand fell substantially. This substantially eased the supply-demand imbalance eliminating the shortage wherein any major supplier was "pivotal". And, of course, this ill-conceived policy bankrupted a utility with far deeper pockets than the Arizona UDCs and nearly bankrupted another. An end result was that a state agency ended up having to contract for power to meet Standard Offer loads and, having paid what is believed (with hindsight) to be too much, retail access had to be suspended so that these above market contract costs could be imposed on all consumers, including Direct Access.

If I understand Staff's proposal correctly, were energy prices to spike again, rates would be held at a fictitious "cost of service" level. I find it astounding that Staff would propose repeating this crucial California policy error. Conversely, if Staff were to support the PPA it could have cost-of-service level prices (themselves locking in a cost of capital at historically low levels), irrespective of the market price, without embarking on an inherently unworkable attempt to trap unrecovered power costs in APS.

The imprecision of Staff's proposal with regard to which costs serve as a benchmark also gives me pause. Staff references both the UDC's cost of service and the affiliates' post-transfer cost of service. At least for APS, these are not the same, but Staff does not indicate which of the two benchmarks it would support. Since PWEC's cost of service includes the new plants required to meet load growth, and Staff explicitly exempts purchases to meet load growth from the benchmark tests, the distinction should not matter, but Staff's language suggests otherwise.

If, as I hope (but doubt) the prudence test that Staff has in mind is an *ex ante* test, conducted prior to APS signing contracts, the proposed benchmark still is difficult.[4] The APS PPA has many of the same cost of service provisions as traditional ratemaking, for example, the pass-though of fuel and purchased power costs. It also is a requirements contract shaped to APS's load. Competitive offerings will, if some of the merchants have their way, have quite different forms. Intermediate and long-term merchant contracts typically are gas price and inflation indexed. Several of the merchants likely would offer power that is not load shaped, but in 7X24 or 6X16 blocks, either firm or unit contingent. It is, of course, possible to gerrymander both the PPA and competitive offerings to be directly comparable. For example, each could be required to be for a slice of load (as Reliant recommends) and fixed price over identical time periods. However, this is standardization would come at a price, quite possibly a high one. Moreover, it is quite inconsistent with Staff's insistence that the UDC should be given full latitude to procure power in whatever matter it deems appropriate.

Q. At page 6, Mr. Rowell relates Staff's recommendation that UDCs be allowed to not transfer their assets if they so choose but that they would still need to

[4] This interpretation of what Staff is proposing is consistent with Mr. Rowell's statement that "As part of their ongoing procurement planning process, the UDCs should be required to perform an assessment or analysis that demonstrates that they are obtaining and/or producing reliable power for Standard Offer customers at the best price." He earlier had defined best price in terms of a combination of price and risk. Since risk is *ex ante* (after the fact outcomes are no longer risky) this suggests that the prudence review is before the fact. Unfortunately, he may mean that prudence must be demonstrated before the fact, and then confirmed based on after-the-fact outcomes.

comply with Section 1606(B) or seek a variance. What is your view of these positions?

A. Regarding the transfer issue, I think that there are valid reasons for many state legislatures and commissions to have required such transfer. However, the issue is moot for APS, as it intends to transfer its generating assets.

Regarding 1606(B), Staff's position is confusing. Staff accepts that UDCs that do not transfer assets would be unlikely to be able to comply with these competitive procurement provisions. This surely is correct. Since non-transferred assets remain in rate base, procuring 50 percent of power from an auction and the balance from a competitive market are not consistent with retention of assets in the regulated UDC. However Staff also says that a variance from 1606(B) should be backed by a demonstration that the UDC tried to comply but could not procure the requisite power at just and reasonable rates. For the non-transferring utility, this makes little sense, since even a partially successful procurement would result in a combination of retained and contracted capacity far in excess of load requirements. For transferring utilities, Staff is silent on what demonstration is required. Staff appears to be suggesting that the utilities should proceed with the competitive bid auction, but stand ready to supply power to the extent to which the auction does not match the "price to beat". I already have discussed the difficulty of such comparison. Moreover, Staff's proposal smacks of yet another form of the "lower of cost or market" theme that permeates Staff's recommendations. Further, the whole variance process raises serious questions about timeliness, in view of Staff's response to the variance requests made earlier this year by APS and TEP.

Q. Beginning at page 7, Mr. Rowell addresses Staff's market power concerns regarding the transfer of assets. Please comment.

A. Much of what Mr. Rowell says is derivative from other Staff witnesses and I will address it in that context. However, I will make a few comments. Staff begins by simply assuming that the UDC's have market power – with no analysis whatsoever. Mr. Rowell focuses primarily on the possibility of affiliate abuse – PWEC inflating costs then passing them on to ratepayers. This "strategy" has nothing to do with market power. It arises from unbundling a utility into a regulated entity and a competitive entity. This decision, I had thought, was settled in Arizona.

In any event, Mr. Rowell's stated concern, arising from the loss of jurisdiction over wholesale rates, ignores two key facts. The first is that any affiliate sales will be by contract. APS is before this Commission for approval of the contract. The Commission has power to accept or reject its terms. Second, FERC is particularly vigilant concerning affiliate dealing. It too will have jurisdiction over the contract. While the prudence and reasonableness of APS's purchase costs now are subject only to ACC oversight, any affiliate contract will be subject to challenge in both State and Federal venues after the assets are transferred.

Second, any local market power that PWEC might have hypothetically will be constrained by contract provisions, market oversight and, in the future, RTO monitoring. Moreover, as I have discussed at length, PWEC will not be in a position to exercise market power with respect to APS's customers to the extent that their needs are covered by contracts or with respect to anyone to the extent that its power is sold into the larger regional market or that its sales are under contracts that pre-exist the period of alleged concern.

Q. **Beginning at page 10, Mr. Rowell discussed the market power studies that he proposes that UDC's be required to file. Do you have any comment on these recommendations?**

A. Yes. Mr. Rowell proposes a laundry list of every imaginable and unimaginable type of market power study. This includes the DOJ/FTC Merger Guidelines analysis, presumably as adapted by the FERC, the FERC Supply Margin Assessment Test, and an amorphous category that he terms a strategic behavior analysis. He also proposes a vertical market power analysis and an analysis of entry barriers.

Let me begin by noting that much of this already has been done. Both Dr. Roach and I have provided SMA analyses in this proceeding, and APS passes. In 1999, I provided the Commission with an analysis based on the Merger Guidelines; APS also passed. Market changes since then have been clearly pro-competitive. The vertical issue is not new and is not exacerbate by the transfer of assets. Indeed, the greater remoteness from transmission that is a consequence of the transfer should reduce market power concerns. APS already has a regulation-imposed code of conduct governing affiliate dealings, and FERC has imposed restrictions intended to eliminate the potential use of vertical market power. I am unaware of any allegations that APS has exercised such power. An analysis of entry barriers seems an empty exercise in view of the very substantial entry that has occurred in Arizona.

I would not recommend the "strategic behavior analysis" that Mr. Rowell asserts should be done. I have reviewed a number of such analyses, all of which assume forms of tacit collusion among market participants. I have yet to see one in any electric market that did not conclude that the market structure would not support competition. Indeed, some of Mr. Talbot's colleagues performed a study of the PJM market that concluded that 30 firms, each of whom owned identical plants, were required before the market would be acceptably competitive. Thus, a market with concentration index of 300 (30 times 3.33 squared) is necessary to achieve workable competition, according to their analysis. In contrast, the DOJ/FTC Merger Guidelines that Mr. Rowell also proposes regard a concentration index of 1,000 (ten identical firms) as so competitive that the effects of a merger do not matter, and an index of 1,800 as only moderately concentrated and presumptively still workably competitive.

Q. Does Mr. Rowell provide any guidance on how the Commission should use these analytical tools?

A. No. This is unfortunate, because the tools themselves, having been written for general application, ignore facts that are knowable in the Arizona context. The two FERC tests – merger guidelines and SMA, have been used often and have well-known limitations. I have performed, or had performed under my direction, more such tests than anyone else in the country. I am very familiar with them and how they operate. A major problem with both tests is that they are presumptive of what the relevant geographic market is and of what share of the capacity that the utility owns is available to sell at market prices in the relevant market. The core presumption of both SMA and the Merger Guidelines-related delivered price test is that all of the load in a control area is uncontracted and must buy in the competitive market and that none of the local utility's capacity is sold under regulated tariffs. Both assumptions are patently false for APS today, for APS if the PPA is signed, or under any other plausible outcome of these proceedings.

As I have stated in my Direct Testimony and in other testimony before the Commission, any assessment of market power must take into account the contracts that will result from this series of proceedings. A good example is the PPA. If it is in place, all of PWEC's capacity will be under contract and it will have nothing that it could sell to APS that is not covered by the contract. Under these circumstances, it is silly to even attempt to analyze PWEC's post-transfer market power over customers in the APS control area. Manifestly, it will have none.

The portfolio of market power studies that Mr. Rowell proposes be required as a post-transfer condition will take a very long time to prepare and considerably more time for Staff and others to comment on and for the Commission to review and accept. Given that the Commission has the opportunity to mandate the existence of contracts that insulate APS customers from the exercise of market power, including but not restricted to accepting the PPA, this is a waste of time. Moreover, the fact that the Staff cannot even agree on which market power test to use, but instead wants all tests performed, does not signal that Staff is prepared to play a resolute role in the timely resolution of any market power issues.

Q. On pages 12 and 13, Mr. Rowell discusses Staff's recommendations regarding reliability must run generating units. He proposes that they be retained under

ACC rate regulation (presumably, owned by APS) until they no longer are must run. Is this a good policy?

A. Frankly, it doesn't matter, at least from a market power perspective. Energy from must run units is provided on a cost of service basis today, and would be under the AISA protocols or under the proposed PPA. Moreover, the Commission will not retain jurisdiction over must run pricing for long, no matter who owns the units. Once there is an RTO, Must Run power is provided pursuant to a contract between the owner and the RTO. This is a FERC jurisdictional contract, whether PWEC owns the units or APS.

Thus, the only real issue about the must run units is which ownership is likely to minimize costs. If the expertise for running generating units resides primarily in PWEC, my presumption is that costs would be minimized if the units were transferred. Finally, I should note that with the completion of West Phoenix 4 and 5, the largest portion of costs, and the bulk of must run power, likely will come from units that are not ACC jurisdictional.

Q. Please turn now to Mr. Schlissel's testimony. At pages 4-8 he discusses an SMA analysis of APS, focusing on the load pockets in the valley and Yuma. Please comment.

A. My only substantive comment is that APS can properly resent his discussion of various APS "admissions" concerning market power. This terminology suggests an inadvertent disclosure of something that APS is seeking to hide. APS always has voluntarily acknowledged the need to regulate the pricing of units that are must run as a result of these constraints. FERC policy similarly insists that such prices be mitigated. There is no dispute that when these areas are constrained for a few hours each year, market power mitigation is warranted.

Q. At page 9, Mr. Schlissel disputes your statement that FERC would assure that must run units could not exercise market power, pointing to FERC's supposed dilatory mitigation of market power in California. Can you respond?

A. Yes. FERC has been quite active in controlling prices for reliability must run (RMR) units in California and elsewhere. In pointing a finger at FERC lapses in proactively solving the California mess, he does not provide any evidence whatsoever that the failings had anything to do with the pricing of output supplied by must run units under RMR conditions.

Q. Please turn now to Mr. Talbot's testimony. What in his testimony do you choose to comment upon?

A. There is little to comment upon. Mr. Talbot primarily summarizes Staff's recommendations, effectively duplicating Mr. Rowell's testimony. In terms of what is new, there is a commentary on the western regional market and on market power supposedly exercised in them. The discussion is backward looking, and his market power conclusions are wholly unsupported in his testimony. Frankly, there is nothing there to aid the Commission in determining whether the market in which Arizona will buy power after the rate freeze ends will be competitive. There also is a discussion of local market power that duplicates several other discussions of load pockets in Arizona. The existence of load pockets and need to discipline pricing of RMR units are not in dispute.

Next, there is a discussion of the "rebuttable presumption" that the traditional utilities have market power. I will leave to lawyers the import of the term "rebuttable presumption" but will note that if it has the meaning that I believe it has, it puts the utilities in the position of proving the negative. This is a generally insurmountable burden of proof, since interveners always can hypothesize a case that has not been examined.

He also quotes at length from a New York Public Service Commission Order in 1998 relating its vertical market power concerns. I will note simply that, as a consultant to a party participating in that proceeding, I know that the NYPSC had decided to order the divestiture of generation and the hypothetical vertical abuses that are in the cited section of the order were designed to justify that conclusion. In any event, those concerns did not arise from a transfer of assets such as is contemplated by this Commission's competition rules, but from the retention of generation by a vertically integrated regulated utility.

He next discusses the motive for doing analyses of "strategic behavior" noting that such analyses "reveal opportunities for market manipulation by large sellers" even when market concentration is low. As I have discussed earlier in this testimony, it is this ability to find such "opportunities" by assuming collusive behavior that is the most serious flaw in such studies. I can state categorically that the methodology he is discussing would not find that any U.S. power market is competitive.

He then discusses jurisdictional issues, noting that the ACC would lose authority over wholesale pricing. He accepts that a buyback agreement or PPA could overcome this problem. He notes that APS has proposed such a PPA but also notes that Staff opposes it. He provides no information, useful or otherwise, concerning the basis for that opposition.

Lastly, in his "Concluding Remarks", he begins by expressing his concern with the competitiveness of the wholesale market in the context of the asset transfer. He asserts that this concern can be assuaged if the UDCs file market power studies. Of course, filing studies does not in and of itself resolve anything, and Mr. Talbot and Staff witnesses generally provide precious little insight as to what the Commission should do on the basis of those studies. In general, the whole tone of this section is an apologia for Staff's "go slow, if at all and take no substantive positions" stance. This, frankly, is disappointing. One would hope that Staff and its consultants would provide the Commission with a basis for action rather than non-action. Arizona is now some six years into restructuring. Policy makers need to make policy decisions and move on.

Q. **Please turn now to Mr. Peterson's testimony. What is the first point on which you would like to comment?**

A. In his summary, he urges caution in view of the recent problems in the industry and the in-progress status of various regulatory initiatives concerning the wholesale market. He concludes by supporting Staff's recommendation that "if APS is confident that the transfer of its assts is in best course of action at this time, then it is appropriate to assign to APS the financial risks associated with such a decision." This statement of Staff's position is an egregious distortion. Staff is not merely asking that APS take on the risks of the asset transfer. Indeed, the proposed PPA fundamentally eliminates those risks by putting all jurisdictional assets under a long-term contract. Staff's "lower of cost or market" proposal demands that APS take on a wholly new risk that it did not have pre-transfer; the risk that cost of service will be, from time to time, above market.

Indeed, the more of Staff's testimony one reads, the more one is convinced that Staff doesn't know what it wants. Mr. Rowell appears to be saying that the 1606(B) auctions must go forward and that utilities should be free to transfer assets. Mr. Peterson comes quite close to saying that the time is not right for asset transfer and the utilities should bear the consequences of any costs incurred on other than a cost of service basis – including any purchases from the competitive market.

Q. Mr. Peterson has an extensive discussion of Market Rule 17 of the New England ISO and recommends the adoption of something like in Arizona. Do you have any comment?

A. I was the primary author of Market Rule 17 and the witness that sponsored it. I therefore am unlikely to oppose its adoption elsewhere under appropriate circumstances. However, Market Rule 17 depends on certain institutional conditions that do not exist in Arizona, notably the existence of an explicit, hour-by-hour unconstrained price for the region. Market Rule 17 cannot exist without an ISO or RTO, at least as it is written.

Mr. Peterson also describes the level of congestion that has occurred in New England and surmises about the causes. While not particularly relevant to this proceeding, I disagree with his diagnosis. The main reason why congestion increased in New England after the ISO was formed was that the formerly-integrated utilities had dispatched around congestion. The Arizona analog to the congestion that did not exist previously but that has occurred in Connecticut and greater Boston after ISO formation would concern the Arizona load pockets. I am confident that, historically, the Tucson and Valley transmission is rarely congested (i.e. loaded to their limits). What is unsaid is that it is not congested because RMR units are run, despite costs that exceed those of external units, before the inbound transmission is exhausted fully. APS does not pretend, as did some NEPOOL utilities, that these areas are not load pockets within which generation must be run even when their costs exceed external units' costs.

Lastly, Mr. Peterson discusses, generally positively, recent developments in FERC RTO policy and initiatives being undertaken by the California ISO. However, he remains cautious about the ability to "game" the market despite these initiatives and points to studies indicating that markets other than California have not had fully competitive prices. This, and other references to studies showing above-competitive prices in non-California markets, motivates a comment about standards for determining whether markets behave competitively.

Economists, of which I am one, tend to hold to a short run marginal cost concept of competitive prices. However useful this is as an analytical device, it is not a good description of competitive market behavior. My local grocery store does not sell me milk at its marginal cost. If I buy a car, I do not expect to get it at the dealer's actual cost of buying one more car from the factory. Moreover, it is well established that marginal cost energy pricing is not compensatory of the full cost of new facilities, what economists call long-run marginal costs. Studies, such as those that Mr. Peterson cites, purport to demonstrate that market prices are above short run marginal costs. In itself, this does not demonstrate that prices are not competitive.

REBUTTAL TO RELIANT RESOURCES' WITNESS KEBLER

Q. What is the focus of Mr. Kebler's testimony?

A. Mr. Kebler has a quite specific proposal that PWEC be required to auction off entitlements to approximately one-third of its capacity to other bidders in a competitive auction. The successful bidders would be required to bid the capacity into a Section 1606(B) auction. The auction price would determine the competitive price that also would serve as a benchmark price for any PPA.

Q. Mr. Kebler begins by asking himself what market power issues are raised by the transfer of assets and answers that the main issue is the concentration of assets in a single entity. Is this in fact an issue arising from the transfer?

A. No. Pinnacle West companies own the same amount of assets pre- and post-transfer. The asset concentration and purported problems that it creates for allowing multiple bidders to access the market are not at all related to the transfer. Indeed, absent the transfer, the auction of 50 percent of load requirements under 1060(B) clearly would not occur.

Q. What purpose, then, is served by the auction of output from PWEC's capacity?

A. From Reliant's perspective, it serves the purpose of creating the possibility that it would have something to sell to APS. My understanding is that Reliant's Arizona generation is fully pre-sold to SRP. If PWEC were required to auction one-third of its capacity, Reliant would be better positioned to compete.

Such an auction also would make the form of competitive purchase auction that Reliant is proposing more feasible. Reliant proposes a load-slice auction. Serving a load slice economically requires access (by contract or otherwise) to baseload, cycling and peaking resources. Mr. Kebler's proposal would compel APS to sell its capacity to PWEC competitors in order to enhance such competitor's ability to compete for the type of load auction product that Reliant is supporting in Track B.

Q. What risks does this proposal imply for PWEC?

A. Reliant proposes that PWEC be compelled to auction one-third of the output of the transferred facilities. It is silent on the term (time-length) of the auction. Pinnacle West companies would not be allowed to participate in the auction. From this, I infer that PWEC would not be allowed to set a reservation price. PWEC would be at risk that the resulting price would be below both its opportunity cost and its cost of service.

Q. If the auction proceeds are below cost of service, what happens to the shortfall?

A. Mr. Kebler does not say. These costs would be "stranded". Whether he would support stranded cost recovery is not clear.

Q. Do you believe that auction proceeds would be below cost of service?

A. I don't know. Entitlement to the transferred capacity would be valuable, particularly since it could be packaged with the available merchant combined cycle capacity. Indeed, a buyer such as Reliant might be able to strike a very attractive deal to buy merchant combined cycle output that otherwise would have difficulty competing in a load slice auction if it acquired a major share of the APS capacity. Competition for this favorable position could cause the price for the PWEC capacity to be bid up, perhaps to above cost of service.

Q. If you were certain that the capacity auction would cover at least PWEC's embedded cost for the sold capacity entitlements, would you support the proposal?

A. This depends on what hat I am wearing. Clearly PWEC would like a high price for its capacity. However, the successful bidder would be unlikely to offer the capacity into the Section 1606(B) auction at less than its acquisition cost. Hence APS could end up paying more for the capacity than it would under the PPA. Note that this also could be true if the successful bidders paid less than cost of service for PWEC capacity.

Q. Mr. Kebler proposes that the successful bidder would be required to bid the capacity into the Section 1606(B) auction. Does this moot your concern about the effects on APS and its customers?

A. No. Mr. Kebler doesn't say that the capacity would have to be offered at the price that the successful bidder paid for it. Indeed, such a requirement would not be enforceable since the purchased capacity would be commingled with other capacity for which no cost basis is established or jurisdictionally enforceable.

REBUTTAL TO AECC WITNESS HIGGINS

Q. What is the subject matter of Mr. Higgins testimony?

A. Mr. Higgins discusses market power. Primarily, his testimony does two things. First, it cites approvingly the various market power mitigation measures that have been included in existing AISA and WestConnect protocols and in more general FERC policies. These include, in particular, measures to mitigate market power in load pockets. He urges the Commission to take notice of what has been accomplished so as not to "reinvent the wheel". He also offers his opinion that FERC is strongly focused on vertical market power and that, in a post-California environment, horizontal market power is also on the "front burner" at FERC. Second he proposes using the California ISO's Residual Supply Index (RSI) in lieu of the FERC SMA test as a measure of market power. It is on this latter issue that I would like to focus.

Q. What is the RSI?

A. The RSI is a measure developed by the California ISO to look at whether there are pivotal suppliers in the real time market. The test looks at the amount of capacity offered into the market in a particular hour. In looking at whether a large supplier is pivotal, it then compares 110 percent[5] of load offered into the real time market to the capacity offered into the market by participants other than the supplier being studied. If the competing supply exceeds 110 percent of load, the supplier being analyzed is not pivotal and "passes" for that hour.

Q. Is the RSI as originally formulated applicable to the prospective analysis of market power in a manner similar to the SMA?

A. No. Not as originally formulated. Since the RSI deals only with the real time market and supplies offered into the real time balancing market, it cannot be used prospectively since the amount of supply and demand that will be bid into the real time market is not knowable. Moreover, the SMA is not merely concerned with the real time balancing market, but power markets more broadly.

In the April 24, 2002 filing that Mr. Higgins cites, the California ISO has proposed a form that can be used prospectively. In concept, this could be used for the same purposes as the SMA.

Q. What does the California ISO propose?

A. The RSI still would be applied on an hour-by-hour basis. However, it would utilize total load and total capacity (both on a prospective basis), not just capacity and load in the real time balancing market.

Q. What are the key differences between RSI and SMA as proposed as a prospective test?

A. In addition to the hour-by-hour provision, one difference is use of 110 percent of load. However, this distinction is more apparent that real. The RSI permits a failure of the test in 5 percent of hours. Given the needle peaks in desert region loads, the tolerance of failure in 5 percent of hours using 110 percent of load is roughly equivalent to the SMA's 100 use percent of peak load with no tolerance of failure. I note also that except under quite atypical conditions, modeling markets

[5] I.e., load plus a 10 percent allowance for operating reserves.

hour-by-hour on a prospective basis will not uncover "pivotal suppliers" that are not also found with the SMA.[6]

The other and more important difference is that the RSI excludes from the capacity of the supplier being analyzed any capacity used to serve native load or that is under long term contract to other parties. This is an important difference. The SMA makes no native load allowance; the applicant supplier's total capacity is counted even though it may be wholly dedicated to native load. In this respect, I agree with Mr. Higgins that the RSI is superior. It recognizes that what can be sold into the market does not include that which has been presold or is dedicated to native load. Failure to make that adjustment has been a major criticism of SMA.

This having been said, the SMA is FERC's test until it is changed. Nothing that happens in this proceeding will change this.

Q. If the Commission were to adopt the RSI and require that APS demonstrate compliance with it, would a post-transfer PWEC pass?

A. Yes. Since PWEC passes the SMA test by a wide margin, it also would pass RSI. Further, under any reasonable expectation of the outcome of these proceedings, a substantial proportion of PWEC's capacity will be under long or intermediate term contracts. I have testified repeatedly that contracts mitigate market power. This is recognized explicitly by the RSI. Since the RSI takes native load responsibility or equivalent contract responsibility into account, PWEC would pass the RSI by amounts still greater than the amount by which it passes the SMA. The amount of

[6] Since load is less in non-peak hours, but competing capacity is more or less the same, a supplier that passes the RSI for the peak hour almost certainly will pass in other hours. The possible exception that I have in mind relates to systems in which competing capacity is predominantly hydroelectric, with sufficiently severe energy limits that such capacity does not discipline off-peak prices. This does not apply to Arizona.

PWEC's capacity covered by contracts will determine the margin by which it will pass the RSI, but it will pass in any event.

Q. Does this complete your prepared rebuttal testimony?

A. Yes, it does.

REBUTTAL TESTIMONY OF CARY DEISE

On Behalf of Arizona Public Service Company

Docket No. E-00000A-02-0051, et al.

June 11, 2002

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Rebuttal Testimony of Cary Deise

DOCKET NO. E-00000A-02-0051, et al.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Cary Deise. My business address is 502 South Second Street, Phoenix, Arizona 85003. I am Director of Transmission Operations and Planning for Arizona Public Service Company ("APS" or "Company").

Q. ARE YOU THE SAME CARY DEISE THAT FILED REBUTTAL TESTIMONY SUPPORTING APS' REQUEST FOR A PARTIAL VARIANCE IN DOCKET NO. E-01345A-01-0822?

A. Yes.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS, PROFESSIONAL BACKGROUND, AND YOUR RESPONSIBILITIES AT APS.

A. I have a Bachelor's Degree in Engineering from California State University–Long Beach, and I am a registered Professional Engineer in the state of Arizona. I have over 32 years of experience in transmission planning and operations, and I have worked for APS in numerous different positions relating to transmission and system planning and operations continuously for the last 30 years. I am Chair of the WestConnect Interim Committee, the WestConnect representative on the Seams Steering Group-Western Interconnection ("SSG-WI"), and I serve on the Western Electricity Coordinating Council's Reliability Compliance Committee, Planning Coordination Committee and Operation Transfer Capacity Policy Group.

In my current capacity as Director of Transmission Planning and Operations, I am responsible for 10-year and general transmission system planning for APS, as well as the overall operation of APS' transmission system. Among other activities, I oversee all technical study work on APS' system, all scheduling over the APS system, the operation of APS' Open Access Same-Time Information System ("OASIS"), merchant generator interconnections, and the preparation of the Company's Ten-Year Transmission Plans.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will respond to Staff's suggestion that APS' transmission system is somehow "inadequate." I will also respond to the assertion in Staff witness Jerry Smith's testimony that reliance on local generation or "must run" is inappropriate for the Valley. In conjunction with that discussion, I will explain how Staff's proposal to significantly overbuild transmission, while largely ignoring local generation, load-related opportunities, and accepted utility planning practices, is both unprecedented in nature and unwise from a policy standpoint. Specifically, Staff's proposal ignores the significant costs (economic, environmental, social and opportunity) associated with overbuilding transmission and dismisses the institutions that are emerging to effectively deal with transmission planning in a competitive marketplace. Finally, I will respond to the claims of Staff and some intervenors, such as Panda witness Roach and RUCO witness Rosen, that APS can exercise market power in transmission or inappropriately control network transmission service in a manner that favors APS or affiliated generation.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Without offering any actual system study or detailed analysis, Staff has taken the position that "generation and transmission in Arizona is presently inadequate to ensure reliable service to the consumers of Arizona." At least as to APS, Staff's conclusion is totally incorrect. APS' transmission system and load-serving capability are adequate today, and we continue to plan prudent, timely and appropriate additions to the system.

Staff's analysis of the role of local generation, which at times is considered "reliability must run" or "RMR" generation, is also flawed. As I discussed in my rebuttal testimony in the APS Variance Docket, local generation and transmission investments are trade-offs that largely depend on the circumstances prevailing at the time the choice of investment is made. Often, installing local generation that may operate as "must run" at limited times during the year makes more sense than siting and building a largely unused or significantly more expensive transmission line through an urban area. Additionally, local generation provides needed reliability to the local system, such as voltage support, that cannot be provided by a more remote generator, no matter how "cheap." Staff's must-run analysis misses many of the significant issues in this trade-off between local generation and new transmission investment. Correcting the flawed assumptions in Mr. Smith's cost-benefit analysis shows that additional, unplanned transmission lines are not warranted at this time. Also, Staff ignores the point that merchant generators voluntarily decided to build their facilities outside the Valley; APS has not prevented any merchant plant from siting generation inside any constrained area or from agreeing to fund new transmission.

Staff's proposal wrongly urges the Commission to require jurisdictional utilities—but not SRP, the Western Area Power Administration ("WAPA"), or merchant generators—to embark on overbuilding transmission in an uneconomic, fractured, and likely futile effort to relieve all existing or potential transmission constraints in Arizona under all conceivable generation marketing patterns. This would be poor policy anywhere, but in the Desert Southwest, where load centers are both relatively concentrated and widely separated from each other, it makes absolutely no sense. In fact, I know of no jurisdiction that has taken the position or even suggested that all transmission constraints should be remedied by constructing more transmission. Staff also vastly underestimates the costs, including economic, environmental, social and opportunity costs, associated with a policy focused on so overbuilding transmission. Further, the suggested "reliability" standards associated with this policy—standards which were unilaterally developed by Staff without a rulemaking process—are substantively deficient and far too vague to ever realistically implement.

Staff also appears to disregard, or at least marginalize, the developing institutions that are intended to facilitate system planning appropriate for a competitive market. The WestConnect RTO, the WECC, FERC and the Western Governors' Association ("WGA") are all appropriately advocating or developing an integrated, regional approach to system planning recognizing the potentially different planning needs of a competitive market. Unlike Staff's go-it-alone proposal, these institutions can embrace all affected entities, including public power, federal power marketing agencies, and merchant plants and can actually resolve issues such as cost allocation and cost-benefit trade offs.

Lastly, Staff and some intervenors have alleged that because APS or its affiliates would own both transmission and generation, there is the potential for the exercise of vertical market power. For a FERC-jurisdictional transmission owner such as APS, that is incorrect. In Orders 888 and 889, FERC required non-discriminatory access to transmission and imposed restrictions on the inappropriate sharing of information between those involved in transmission and generation. Pinnacle West and its affiliates' FERC-mandated Standards of Conduct also would prohibit the exercise of such market power. Panda witness Roach asserts that the designation of generation as a network resource has "market power" implications for APS and its affiliates. This is simply incorrect—transmission, network transmission service and network resource designation are all related to load and are driven by load. They are unaffected by transmission ownership. If a generator (whether or not affiliated with APS) is serving APS' loads, it will be given the appropriate network designation and have the appropriate network transmission rights. However, simply calling a power plant a "network resource" will not change physical transmission limits. So, for example, all of the new capacity being constructed at Palo Verde could still not simultaneously serve all of APS' load requirements regardless of whether all were designated as "network resources" or have network transmission service.

Q. BEFORE YOU DISCUSS THESE POINTS IN MORE DEPTH, ARE THERE PARTS OF MR. SMITH'S TESTIMONY WITH WHICH YOU AGREE?

A. Yes. I am not suggesting that APS won't need additional transmission and access to load-serving resources. As our 2002-2011 Ten-Year Plan indicates, APS will be siting and constructing over $750 million of new transmission upgrades and additions, and we intend to continue to work closely with Staff on these projects. So I agree with Mr. Smith when he states that "there has certainly been a good faith demonstration by Arizona utilities of their commitment to respond favorably on a forward looking basis." (J. Smith Test. at p. 22.) I also agree that transmission planning needs to be a broadly collaborative process, and that the Central Arizona Transmission Study ("CATS") was a good example of such collaboration.(J. Smith Test. at p. 24.) And, I further agree that system planning is more challenging in a competitive environment, and that RTOs will be important institutions in that process. Mr. Smith also has acknowledged that there are trade-offs between using local generation and constructing additional transmission especially considering that must-run generation is only required for limited times during the summer. (J. Smith Test. at p. 13.) But my agreement with Staff on these issues does not change my conclusion that Staff's analysis and recommendations are neither correct nor appropriate.

III. LOAD SERVING ADEQUACY AND RELIABILITY

Q. DO YOU AGREE WITH STAFF'S CONCLUSIONS ON GENERATION AND TRANSMISSION ADEQUACY?

A. No. One of the conclusions that Mr. Smith reached in his direct testimony was:

> that generation and transmission in Arizona is presently inadequate to ensure reliable service to the consumers of Arizona. Utilities are presently dependent upon [the] use of reliability must-run generation and load tripping schemes to meet local load requirements due to local transmission import constraints.

(J. Smith Test. at p. 3).

As noted in my summary, as to APS, that "reliability" conclusion is neither supported by evidence nor factually accurate. Electric system reliability, as defined by the North American Electric Reliability Council ("NERC"), the national body responsible for electric system reliability, involves two core concepts—adequacy and security. "Security" refers to the ability of the interconnected electric system to withstand contingencies, such as the sudden loss of a transformer or the unexpected tripping of a generator. Security focuses largely on the operation of the electric system, and there are detailed operating requirements for member systems (including APS) in the Western Electricity Coordinating Council's ("WECC")[1] published Minimum Operating Reliability Criteria. "Adequacy" looks to whether there are sufficient

[1] The WECC was formerly known as the Western Systems Coordinating Council or "WSCC."

generation and transmission resources to serve expected load. As with security, there are detailed NERC and WECC planning standards to ensure adequate and reliable interconnected electric systems.

APS meets these and other accepted, industry-standard requirements for system adequacy and security, and thus satisfies all applicable reliability requirements. The transmission projects already identified in APS' Ten-Year Plan will allow us to meet both adequacy and security requirements in the future. Mr. Smith, on the other hand, cites no recognized reliability standard that APS has violated, and he does not present any study or analysis showing how APS' system is "inadequate" or "unreliable." Neither does he identify any specific transmission project or upgrade that must be constructed to address a reliability or adequacy issue on APS' system.

Mr. Smith's discussion of the APS' "load-tripping" scheme as evidence of a reliability deficiency is incorrect as well. The load-tripping scheme that APS and SRP jointly developed is not necessary for single contingency outages under system normal conditions, but rather it is a second line of defense, a "safety net" if you will, should load ever be higher than anticipated when multiple generating units are out of service. Since it was developed, APS has not had to arm the load-tripping scheme even once. Considering a prudent emergency planning and operating measure like this load-tripping scheme as evidence of a deficient transmission system is like characterizing a driver as "reckless" just because he purchases car insurance.

Mr. Smith also asserted that on July 4, 2001, "APS was within one-half hour of activating rolling blackout procedures due to unavailability of several generating units…." (J. Smith Test. at p. 18.) This too is incorrect. On July 2, 2001, there was a multiple contingency on the system, but APS was within one-half hour of initiating a public request to voluntarily curtail electricity use, not to commence "rolling blackouts." This voluntary curtailment effort was to maintain adequate operating reserves under a multiple contingency situation. It was ultimately avoided by a wholesale purchase, and is not evidence of any system-wide adequacy or reliability problem.

Q. MR. SMITH STATES THAT THE ENTIRE WESTERN GRID MAY BE PLACED AT RISK IF TOO MUCH GENERATION IS INTERCONNECTED WITHOUT THE ABILITY TO DELIVER TO LOADS. ISN'T THAT A RELIABILITY ISSUE?

A. No. Mr. Smith states: "interconnecting such plants to the grid without a demonstration of the ability to reliably deliver to a market can result in placing the entire Western grid at operational risk." (J. Smith Test. at p. 21.) Generators must have transmission rights to dispatch generation over the grid, they must satisfy minimum reliability criteria when interconnecting to the grid, and they are monitored by transmission system operators for compliance. If there is not enough transmission capacity available, all of the generators cannot simultaneously dispatch energy into the grid, and some will have to be offline or operate at reduced capacity. Certainly, generator output cannot be sold as "firm" without firm transmission rights, and generation without such rights will not depended upon for reliability purposes. While this may be a financial concern to those generators, <u>it is not nor can it be a reliability concern to the system</u>. And it certainly doesn't suggest that APS or other UDCs should be required to construct additional transmission to address non-reliability related commercial concerns of merchant generators simply because they decided to site their plant in a location without sufficient transmission.

Q. DOES THE USE OF LOCAL GENERATION, AS MR. SMITH SUGGESTS, INDICATE THAT APS' SYSTEM IS INADEQUATE OR UNRELIABLE?

A. No. The use of local generation (whether "reliability must run" or otherwise) is not a reliability defect or evidence of an "inadequate" system. No accepted reliability standard (i.e., those of the NERC or the WECC) holds that the use of local generation is either "inadequate" from a system planning or operational standpoint or is evidence of "inadequacy." Local generation actually contributes to the reliability of a system. In fact, when it adopted the Electric Competition Rules, the Commission specifically recognized that a UDC's obligation to provide reliable electric service "depends upon the adequacy of its distribution, local generation and interconnections with the bulk transmission system..." (emphasis added). Decision No. 61969 (Sept. 29, 1999).

IV. LOCAL GENERATION AND "MUST RUN" REQUIREMENTS

Q. HAVE YOU REVIEWED MR. SMITH'S TESTIMONY AND ANALYSIS REGARDING "RELIABILITY MUST RUN" GENERATION?

A. Yes.

Q. DO YOU AGREE WITH MR. SMITH'S ASSERTION THAT MUST-RUN "GENERATING STRATEGIES" ARE "SAFETY NETS" FOR THE SYSTEM?

A. No. In his testimony, Mr. Smith claimed that:

> Utilities have traditionally used RMR generating strategies as an operational safety net when siting or construction of new transmission facilities was impeded, delivery of new equipment was delayed, capital financing was constrained, or to restore service following a transmission outage.

(J. Smith Test. at p. 8.) Such a characterization of the role local generation, even when it is required to run for system reliability purposes, is simply not correct. Local generation was, and is, a central and essential component of resource planning, not "an operational safety net." In many cases in the past, and I would expect in the future as well, the construction of local generation rather than new transmission lines is the most efficient solution for meeting the resource needs of a utility's customers.

In addition to economic trade-offs between new transmission line investments and local generation investments, there are significant system operation and reliability reasons that justify local generation. For example, local generation offers critical voltage support, particularly to large load centers like the Valley, and is absolutely necessary to provide a dynamic reactive reserve margin, as reactive power cannot be transmitted over long distances. Local generation is also important as contingency support for the Valley. By that, I mean that such generation is available to meet local load requirements when, for example, there is a disturbance on or loss of a transmission line outside of the local area that trips remote generation. I would never recommend relying solely on importing remote power over transmission lines to support the entire Valley system at peak load. Finally, local generation (and generation located near load centers) minimizes transmission line losses.

Mr. Smith also appears to ignore the environmental and non-economic costs associated with transmission line construction. For example, in his testimony he refers to the "environmental merits" of transmission capacity in providing access to "more environmentally friendly generation external to the constraint." (J. Smith Test. at p. 8.) This assertion misses several key issues. First, is a remote coal-fired generator "more environmentally friendly" than a local gas-fired plant? And, how does one quantify the difference? Second, local generation is not necessarily less efficient than remote generation and is often subject to more stringent air permitting requirements and emission offset requirements than remote generation, which may actually make it "more environmentally friendly." Third, while local generation may only run several hundred hours per year, transmission lines are permanent and have their own environmental impacts. Fourth, transmission lines may directly impact more people and their property than local generation due to the right-of-way requirements for such lines. Fifth, the premature or unwarranted construction of transmission has significant opportunity costs, both in terms of the finite resources that APS can devote to such construction and in foregoing possible future developments in advanced transmission technologies. This list is not exhaustive; there are undoubtedly other non-economic costs that should be considered when balancing the need for transmission or local generation.

Q. HAVE YOU REVIEWED MR. SMITH'S ECONOMIC ANALYSIS OF RMR GENERATION?

A. Yes. He concluded that APS and TEP "may find it difficult" to justify the economics of deferring transmission investment to reduce the need for local generation. (J. Smith Test. at p. 13.)

Q. DO YOU AGREE WITH THAT ANALYSIS?

A. No. But before getting to the specifics of his analysis, let me put the "must run" issue in context and make sure that certain terms I will use are understood. APS' Valley local generation was considered "reliability must run", in other words, required to operate for reliability reasons and "out of market" in terms of economic dispatch, for only 9 hours in 2001—1/10th of one percent of all hours that year—and for only 6 hours in 2000. When local generation is considered "reliability must run," its price is capped at demonstrable cost. This cost-based price cap means that, contrary to the arguments of some intervenors, "reliability must run" generation cannot exercise market power. Transmission import limitations did exist for more than 9 hours, but during virtually all of the time the dispatch cost of local generation was less than the market price at the Palo Verde hub.[2] Given this context, it obviously makes no sense to spend hundreds of millions of dollars on a 365-days per year transmission "solution" to address a nine-hour-a-year generation "problem" costing far less than a million dollars.

A correct cost-benefit analysis would compare "reliability must run"—that is, when local generation is both required and out of the market—with the cost of

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[2] At page 10 of his testimony, Mr. Smith has misapplied the concept of "reliability must run" to the concept of the Local Generation Requirement that I included in Schedule CD-3R in my Rebuttal Testimony in the APS Variance Docket. In that testimony, I noted that Local Generation Requirements for the Valley were around 400 hours per year, or roughly 5 percent of all hours in a year.

additional transmission line investment. However, Mr. Smith's analysis addressed not just "reliability must run," but all times that local generation was required whether it was economically dispatched or not. Even using this broader analysis, there is no economic case for new, unplanned transmission investment because many of the assumptions Mr. Smith used are incorrect. As a result, even using Mr. Smith's methodology applied to all local generation requirements and even without considering the unquantified environmental, social and opportunity costs that I just discussed, his conclusions are not supported or supportable.

Q. PLEASE DISCUSS THE MORE SIGNIFICANT ERRORS IN MR. SMITH'S ANALYSIS.

A. Let me start with Mr. Smith's formula for determining avoided costs associated with transmission line investment. In general, the assumed transmission line capital cost of $1 million per mile is significantly understated, particularly if part or all of a project will be constructed in urban or suburban areas. For monopole construction, the cost of facilities, excluding right-of-way, is approximately $1.6 million per mile of 345 kV/500 kV transmission line. Lattice towers cost approximately $1.2 million per mile. Right-of-way costs will add at least $1 million to $2 million per mile for construction. A conservative analysis would use a blended cost assuming 15 miles of monopole with the remainder using lattice tower construction, and $1 million per mile for right-of-way costs. Also, Mr. Smith's assumed transmission termination costs for a new transmission line of $4.5 million is significantly lower than APS' experience. Recently planned source and sink terminations on APS' system average approximately $18 million. However, adding new bulk power feeds into the Valley system also will likely require additional upgrades on the APS and SRP local system, the costs of which are not even captured in that $18 million figure.

Additionally, Mr. Smith's analysis incorrectly omits the carrying costs associated with new transmission lines. Carrying costs are determined by FERC using an annual fixed charge factor that takes into account O&M, A&G, allowed rate of return, depreciation, taxes, general plant, cash working capital, and other accounting costs. The fixed charge factor is applied to the capital costs of the facilities to give an annual carrying cost for a transmission line. APS' current annual transmission fixed charge factor is 14.22 percent. Therefore, the cost for a 50-mile transmission line would be roughly $19 million <u>per year</u>. These annual cost calculations for hypothetical transmission lines of 50, 100 and 150 miles are shown Schedule CD-GD-1R.

Q. WOULD YOU DISCUSS MR. SMITH'S CALCULATION OF RMR GENERATION COSTS?

A. Yes. That calculation also has faulty inputs. Perhaps most significant is Mr. Smith's assumption that the marginal market price for "alternative" generation will be $35/MWh. Because local generation is only required on peak in the June through September period, it is inappropriate in the context of the Mr. Smith's analysis to assume an annualized market price for "alternative" generation of $35/MWh. A more appropriate but still conservative benchmark for such power during June-September peak hours is approximately $56/MWh at the Palo Verde hub. This is conservative because truly "alternative" generation from Palo Verde needed to meet load would be a non-standard product which would add to the $56/MWh figure.

Q. HAVE YOU CONDUCTED A COST-BENEFIT ANALYSIS OF LOCAL GENERATION VERSUS NEW TRANSMISSION INVESTMENT USING MR. SMITH'S GENERAL METHODOLOGY BUT CORRECTING THE ASSUMPTIONS DISCUSSED ABOVE?

A. Yes. Schedule CD-GD-1R is an analysis using two scenarios—427 MW of local generation in 2003 for 400 hours at a 65 percent load factor, and 1034 MW in 2007 for 400 hours at a 65 percent load factor. The cost-benefit was then tested using a $56/MWh price for generation at the Palo Verde hub and a $75/MWh cost for local generation. I did not use hypothetical local generation costs above $75/MWh because it is unreasonable to assume that local generation costs will significantly increase, due to higher natural gas prices for example, without a corresponding increase in the price of "alternative" generation from Palo Verde. In other words, what is important is not the absolute cost of local generation but the difference between local generation and "alternative" generation. The result is then compared to the same three transmission line length alternatives (50, 100 and 150 miles) used by Mr. Smith in his analysis. Attached as Schedule CD-GD-2R is a graphical summary of this analysis in the same format used by Mr. Smith.

Q. WHAT DID YOUR COST-BENEFIT ANALYSIS SHOW?

A. APS' analysis shows that the economic costs associated with local generation do not warrant building significant new, unplanned transmission lines. Additionally, Mr. Smith incorrectly concluded that APS' hourly operating costs for RMR generation are "in excess of $75/MWh." In fact, the cost for RMR generation in 2001 was slightly less than $75/MWh ($73.11/MWh). Further, new combined cycle units, such as West Phoenix 4 and 5, are expected to have lower per-MWh costs than existing local generation. So I expect the cost of local generation, let alone RMR generation, after 2002 to decrease and it will be significantly less than $75/MWh. Thus, a cost-benefit analysis does not support the construction by APS of additional, unplanned transmission into the Valley—even without considering the other significant environmental, social and opportunity costs that I discussed earlier.

V. STAFF'S "ACCELERATED DEVELOPMENT" PROPOSAL IS FUNDAMENTALLY FLAWED

Q. IS STAFF PROPOSING A DIFFERENT STANDARD FOR PLANNING AND CONSTRUCTING TRANSMISSION IN ARIZONA?

A. It certainly appears so from Mr. Smith's testimony and recommendations. Having concluded without study or analysis that Arizona's transmission and generation resources are inadequate, Staff is apparently advocating a vastly expanded transmission system from that currently planned by APS and from any system that would be required by the applicable NERC and WECC standards. This is proposed by Staff in its recommendation for the "accelerated development" of transmission solutions. As part of that expanded system, Staff apparently establishes the goal of removing all transmission constraints from the various permutations of generation dispatch and power flows, presumably including the construction of non-reliability related transmission to allow merchant generators to serve out-of-state markets.

Q. WHAT DOES STAFF'S RECOMMENDATION FOR "ACCELERATED DEVELOPMENT OF TRANSMISSION SOLUTIONS" APPEAR TO MEAN FOR APS?

A. It is somewhat difficult to say, because I am aware of no other jurisdiction that has taken or even considered a position remotely similar to that recommended by Staff, so there is nothing to compare it to. As I discussed earlier in my testimony, APS' transmission system and load-serving resources meet all applicable planning and reliability criteria. So an "accelerated development" of transmission solutions is not necessary from a reliability standpoint.

To the extent that Staff is looking beyond a reliability-driven transmission system to economic factors associated with transmission planning for a competitive energy market, they have not proposed a reasonable or practical alternative by calling for the "accelerated development" of unspecified "transmission solutions" to relieve all transmission constraints. For example, although Mr. Smith noted the illustrative discussion from my rebuttal testimony in the APS Variance Request on resource selection and least-cost planning for the Yuma area, the remainder of his testimony still appears to take the position that UDCs should be responsible for alleviating all transmission constraints (regardless of cause, cost, duration or impact), and that such constraints are something that generally need to be remedied by building more transmission. This is an inappropriate and overly-simplistic conclusion. In the recently issued National Transmission Grid Study, the Department of Energy noted that:

> [R]emoving bottlenecks is not simply a matter of finding "congested" transmission paths and then reinforcing existing transmission facilities along those paths or constructing new facilities. Because the system is a network, reducing congestion on one part of the system may shift it to another (the next-most-vulnerable) part. Congestion also tends to move around the system from year to year and in response to weather and other seasonal factors.

(National Transmission Grid Study at p. 20.)

Q. IS STAFF'S PROPOSAL BASED ON AN ACCEPTED RELIABILITY STANDARD?

A. It appears to be partly based on the standard that Staff proposed during the last Biennial Transmission Assessment—a standard that appears to require that all loads (local and regional) must be capable of being served without limiting access to an undefined "more economical or less polluting" generation resource. This is not a reliability standard used anywhere in the United States, it has not been adopted as Commission policy, it has not been subject to notice and comment rulemaking, and it is far too vague to allow meaningful compliance.

Q. DOES MR. SMITH IDENTIFY WHAT TRANSMISSION PROJECTS HE BELIEVES WOULD HAVE TO BE BUILT TO SATISFY THIS REQUIREMENT?

A. No.

Q. IS IT REASONABLE TO DESIGN A TRANSMISSION SYSTEM TO MR. SMITH'S APPARENT STANDARDS?

A. The existing transmission system was not planned or constructed to accommodate some vague concept of "least cost" wholesale power trading, where any generator can dispatch its power to any customers in this state or beyond. Such a transmission system would have to be massively overbuilt from a reliability standpoint, and require literally billions of dollars of new transmission investment that would have to be recovered through customer rates. It also would be an impossible moving target. Staff acknowledged as much in response to a data request, by stating that "new transmission constraints may emerge as [UDCs] attempt to take delivery from different generation resources."

Such a system, even if designed as a "best guess" of future loads and resources, and their timing and location, would certainly not be practicable because merchant generators will likely serve multiple customers at different locations over the life of any given power plant. For example, it would be inappropriate for APS to construct several new transmission lines from Palo Verde into the Valley, and also upgrade all necessary Valley facilities to accommodate the new lines, just to allow more generation the <u>opportunity</u> to sell from Palo Verde, when five years from now these same generators may be serving loads in California over a new Arizona-to-California transmission line. In fact, much of the new transmission required by Staff would likely do little more than facilitate merchant generators selling their capacity out-of-state at the expense of Arizona consumers. After all, based on Mr. Smith's testimony, over 19,000 MW of merchant generation is being constructed in or proposed for Arizona. Much of that capacity is obviously intended for out-of-state loads.

To overbuild the transmission system to accommodate all of this capacity would also eliminate any incentive or price signals to merchant generators on where to appropriately site local generation. This is contrary to existing Commission policy. When the Electric Competition Rules were adopted in 1999, the Commission specifically recognized that "ideally market forces, and not UDC decisions, should drive plant-siting decisions by new market entrants or merchant generators." (Decision No. 61969, Concise Explanatory Statement, at p. 41.)

Q. ARE THE COSTS THAT WOULD BE ASSOCIATED WITH STAFF'S "ACCELERATED DEVELOPMENT" PROPOSAL JUSTIFIABLE?

A. No. As I discussed earlier, Staff's focus on overbuilding transmission, including its proposal to eliminate the need for any local generation, ignores many of the costs that need to be considered when making resource decisions between transmission lines, power plants, and even load-based alternatives such as load reduction or demand response. The analysis that I provided earlier shows that a cost-benefit analysis does not warrant the construction of significant new, unplanned transmission capacity for non-reliability related purposes. Further, the addition of transmission has ripple effects on the system, which means that there will most likely be costs on the local 230 kV and 69 kV systems if additional bulk power terminations are added in the Valley. Not all of these costs will occur on APS' system, and there may be impacts to the interconnected systems of WAPA and SRP or even others.

Apart from the increasing costs of permitting, obtaining right-of-way, constructing, and operating transmission lines, there are also costs in building new transmission lines that are difficult to quantify. For example, transmission lines sited in urban and suburban areas may require the condemnation of residential or commercial properties. While such action is often necessary for the good of our society, I expect that people evicted by unneeded or prematurely-constructed transmission lines would object to Staff's proposal. Also, there is significant progress being made in new advanced transmission technologies, including high-voltage direct current ("HVDC"), energy storage, superconductor technologies, and new higher-capacity conductor materials. Prematurely constructing transmission using current technology may limit the ability of utilities to take advantage of these new advanced transmission technologies when they become available, or at best the deployment of these technologies will strand transmission investments that become no longer necessary.

Q. ARE THERE OTHER SIGNIFICANT FLAWS IN THE PROPOSAL?

A. Yes. Staff appears to underestimate the time commitment necessary to develop more transmission in Arizona, and the uncertainty inherent in a competitive market. Mr. Smith suggests that "transmission system adequacy" will be achieved in the last half of this decade, but then suggests that Arizona cannot wait "several years" for RTOs to develop. However, any transmission project identified today would require at least three years to site, permit and construct. Projects that involve federal lands (over 45 percent of Arizona is federal land) often require significantly longer lead times to allow compliance with the National Environmental Policy Act ("NEPA"), particularly if the underlying federal action is appealed to a federal court and a stay issued. Thus, APS focuses on what transmission investments are needed over the long-term to provide adequate and reliable service to its customers. Any notion that an "accelerated development" program will result in significant short-term differences in the integrated transmission system is overly optimistic.

Q. DOES STAFF'S PROPOSAL ADDRESS COST RECOVERY FOR THE "ACCELERATED DEVELOPMENT" PROPOSAL?

A. No, and that is another significant flaw. Because so much of Staff's proposal affects non-jurisdictional entities such as merchant generators, public power, and federal entities, all that Staff can propose is "collaboration" and building on existing industry-driven efforts like the CATS program. Cost-recovery issues have been recognized by virtually all commentators as a significant barrier discouraging the coordinated development of transmission in a competitive market. However, without a specific mechanism or specific authority to address cost recovery, it is unrealistic to think that through collaboration merchant generators or other parties will volunteer to make significant transmission investment—particularly if they believe that a UDC will ultimately be forced to "ante up" if they don't contribute. The Southeast Valley Project is a good example, in that several merchant generators expressed interest in the early project scoping, but when it came time to make a financial commitment only APS, SRP, Tucson Electric Power Company and a group of public power districts actually committed dollars to the project.

I also do not believe that the Commission's siting authority over merchant plants will, as Staff suggests in its Recommended Action No. 5, significantly support Staff's proposal. Most of the new merchant plants that will be constructed in Arizona in the foreseeable future already possess Certificates of Environmental Compatibility ("CECs") and, apart from some limited investment by Duke, no significant new transmission line construction has been funded through the generator CEC process. In any event, merchant generators could avoid any Commission-imposed requirement by either siting a facility on Indian land or just outside Arizona. Also, I would note that while the Commission may attempt to place restrictions on merchant generator interconnections, APS and other FERC-jurisdictional transmission owners cannot enforce these restrictions. In fact, FERC has made it clear that generators may request "interconnection-only" service without making any request for transmission service from the underlying transmission owner. Thus, for example, APS could not require any merchant plant to demonstrate its ability to deliver to a market without as a condition of interconnection. Finally, even if the Commission could address these issues among Arizona utilities, it would not address seams issues or interstate transmission that are significant for regional transmission planning.

VI. TRANSMISSION PLANNING IN A COMPETITIVE MARKETPLACE

Q. WILL SYSTEM PLANNING BE DONE DIFFERENTLY IN A COMPETITIVE WHOLESALE ENVIRONMENT.

A. It is certainly possible, if not likely, that transmission planning will begin to include more projects that might not be justifiable for a single utility or which could offer economic rather than reliability advantages to one or more load serving utilities. As Mr. Smith recognizes, APS is at present planning appropriate transmission additions well into the future that are driven by the needs of its system. He noted that:

> It is Staff's opinion that Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions...

(J. Smith Test. at p. 22.) I would not be surprised, however, if additional long-term transmission projects are ultimately identified or pursued by the WestConnect RTO, merchant transmission owners, or jointly pursued by utilities to take advantage of competitive wholesale power opportunities or added interconnection of regional markets. Such efforts, however, must be broadly coordinated (including for example multiple states, public power, federal power marketing agencies, utilities, and other market participants) and still need to address significant issues such as cost recovery for non-reliability related transmission projects.

Q. DOESN'T THE RECENT NATIONAL TRANSMISSION GRID STUDY AND THE WESTERN GOVERNORS' ASSOCIATION TRANSMISSION REPORT SAY THAT THERE NEEDS TO BE MORE TRANSMISSION?

A. Yes, but both the Department of Energy's May 2002 National Transmission Grid Study and the August 2001 Report to the WGA were primarily focused on regional transmission interconnections, not an uneconomic effort to relieve every local transmission constraint on utility systems. For example, the principles outlined in the August 2001 WGA Report recognize that transmission expansion can and should have regional as well as local benefits, and should be coordinated on as broadly-based a level as possible. Similarly, the National Transmission Grid Study emphasizes the importance of coordinated regional efforts to address inter-regional transmission constraints.

While the National Transmission Grid Study did recognize the need for additional transmission to better accommodate regional transmission in a competitive market, that study concluded that:

> Building new transmission facilities or undertaking other strategies to address transmission bottlenecks should depend first and foremost on market participants responding to business opportunities.

(National Transmission Grid Study at p. 8 [emphasis added].) In stark contrast, one of Staff's conclusions in recommending the accelerated development of transmission by UDCs in Arizona is that:

> The West simply cannot wait on FERC and RTOs to address this transmission need via market driven solutions.

(J. Smith Test. at p. 23 [emphasis added].) One of my major concerns with Staff's recommendation, if adopted, would be that Arizona and Commission-jurisdictional utilities will find themselves far "out-of-sync" and even at cross-purposes with more rational, collaborative, and regionally-based efforts addressing transmission infrastructure issues that are being pursued by everyone else.

Q. IS THERE AN ADEQUATE PLAN TO RESOLVE, AT LEAST FROM A TRANSMISSION PLANNING PERSPECTIVE, WHAT MR. SMITH REFERS TO AS THE "CHAOS OF ELECTRIC RESTRUCTURING"?

A. Absolutely. As I noted earlier, I agree with Mr. Smith that planning in a competitive environment may be more difficult than in a vertically-integrated environment. But I don't agree that we are "playing chicken" with reliability for Arizona consumers. (J. Smith Test. at p. 24.) One of the most significant concerns in the current debate over transmission planning in a competitive environment is the problem of coordinating among varying jurisdictions, regions and interests. However, Staff's proposal to require UDCs on an intrastate basis to commence a "crash course" in new transmission investment within a single control area within a single state threatens simply to add to the fractured nature of system planning when there are so many different constituents.

APS is working hard to help develop the WestConnect RTO, an institution that will have authority to engage in regional planning efforts and plan for non-reliability related investment. WestConnect will be able to provide for prudent and appropriate cost allocations for such non-reliability related investment. Additionally, the regional interconnection of markets is likely more significant on a long-term basis than the resolution of specific local transmission constraints. The Seams Steering Group-Western Interconnection, of which I am the WestConnect representative, is working to address these regional interconnection issues. This regional focus is also evidenced in the National Transmission Grid Study, which concluded that "robust and reliable <u>regional electricity transmission systems</u> are the key to sustaining fair and efficient competition in wholesale markets." (National Transmission Grid Study at p. 8 [emphasis added].) And, the WGA has proposed a regionally-coordinated planning process for transmission system expansion.

We need to let the institutions that have the necessary jurisdiction and authority to coordinate transmission planning in a competitive environment do their jobs and evolve as institutions. Such an outcome is established Commission policy, which has recognized that "eventually, the obligation to ensure adequate transmission import capabilities should rest with the ISO." (Decision No. 61969 at p. 41 and Rule R14-2-1609(B).) Certainly, the Commission will have an important role in this process. But the Commission should reject Staff's recommendation to develop a separate "go it alone" transmission plan for Arizona, which will be limited to Commission-jurisdictional UDCs (apart from any informal collaboration by non-jurisdictional entities). At best, Staff's recommendation would be a massive misallocation of resources. At worst, it could actually interfere with efforts to coordinate regional and inter-regional transmission planning.

VII. TRANSMISSION "MARKET POWER"

Q. DOES STAFF'S TESTIMONY ALSO DISCUSS MARKET POWER ISSUES INVOLVING TRANSMISSION?

A. Yes. Staff witness Matt Rowell and Mr. Smith in his recommendations note that part of the market power study that APS is to submit prior to divestiture should address how transferring generating units to PWEC will affect "other market participants' use" of constrained transmission paths.

Q. IS THIS SOMETHING THE COMMISSION SHOULD BE CONCERNED ABOUT AS A PRECONDITION TO APS' GENERATION ASSET TRANSFER?

A. No, for several reasons. Under FERC Order 888 and Order 889, and the FERC-approved Standards of Conduct, APS is required to provide non-discriminatory open access to its transmission system. Those orders and the Standards of Conduct prevent APS from favoring PWEC or any other merchant generator in providing transmission service. Also, network transmission rights to serve APS' native load will follow that load. Thus, if Duke or Panda provide service to APS' native load, they would have network transmission rights. If PWEC provides such service, it would have network transmission rights.

Of course, the physical configuration of APS' system necessarily impacts transmission. For example, all of the generators at Palo Verde could not simultaneously dispatch to serve APS' native load (even assuming APS' load was high enough to require that) because the capacity from the Palo Verde/Hassayampa switchyard into the Valley is limited. But if network transmission service had to be allocated, FERC rules would require that it be allocated on a non-discriminatory basis and would prevent APS from favoring PWEC or any other merchant generator.

Also, as I discussed in my rebuttal testimony in the APS Variance Request, APS has a solid record of working proactively to interconnect merchant generators to its transmission grid. APS obtained rapid and efficient siting approval, including federal NEPA review, for the Panda Interconnection Project and is completing that project on time. APS also reacted quickly to address issues discovered on WAPA's transmission system that affected Reliant's Desert Basin plant. We developed a pro forma generator interconnection agreement that was approved by FERC prior to the initiation of the Generator Interconnection NOPR in May 2001. APS also actively participated in having the Hassayampa Switchyard designated as part of a "common bus" with the Palo Verde switchyard, which allows merchant generators to reach the Palo Verde market hub without having to pay for wheeling over the Palo Verde transmission system. This proven track record should further allay any concerns that APS will act inappropriately on issues affecting merchant generators.

Q. **DOES THIS SAME EXPLANATION APPLY TO COMMENTS MADE BY OTHER INTERVENORS.**

A. Yes. Dr. Rosen noted that transmission rate "pancaking" gives rise to transmission market power. Although this is an issue that RTOs and appropriate seams policies are intended to address, APS already has shown its proactive response to "pancaking" issues both by its efforts with the Palo Verde/Hassayampa common bus and its support for WestConnect. With respect to Dr. Rosen's discussion of the trade-offs associated with constructing local generation and new transmission, I agree that constructing local generation is often cheaper than building new transmission lines. However, because must-run local generation is capped at cost-based prices when it is "out of the market", this trade off does not result in transmission market power. Also, merchant generators could always construct their own generation within the constraint or build transmission to relieve the constraint.

Staff witness Talbot stated that the Commission should ensure that APS is not restricting transmission access in a way that favors PWEC generation. However, he then suggests that another code of conduct may be necessary to address this. There already is a code of conduct in the form of the FERC Standards of Conduct that prevents the discrimination to which Mr. Talbot refers. The Commission should not attempt to re-regulate what FERC already covers with its Standards of Conduct.

Panda's witness, Dr. Roach concludes that APS has transmission market power because it is a "transmission monopoly" and recommends that the Commission ensure that competitors have "full access to the 3,685 MW of import transmission capacity into the APS Valley market" and be treated "comparably to APS' own generation." (C. Roach Test. at p. 15.) Because I am not an economist, Dr. Hieronymus will address in his rebuttal testimony the economic aspects of Dr. Roach's testimony. However, Dr. Roach's testimony seems to ignore that transmission, network transmission service and network resource designation are all related to load and are driven by load. If a merchant generator (whether or not affiliated with APS) is serving APS' loads, it will be given the appropriate designation and have the appropriate transmission rights. Also, APS is not a transmission "monopoly" in that merchant transmission could certainly construct into the Valley or elsewhere on APS' system.

VIII. CONCLUSION

Q. WHAT CONCLUSIONS HAVE YOU REACHED BASED ON YOUR REVIEW OF THE INTERVENOR AND STAFF TESTIMONY?

A. Staff's conclusion that APS' transmission system is inadequate to reliably serve APS' customers is simply not true. Staff's analysis regarding the economics of local generation versus transmission line construction is also incorrect, and by a very large margin. A more reasonable analysis currently does not support the "accelerated development" of additional transmission lines, as Staff recommends. Moreover, such a plan ignores the developing regional and inter-regional planning institutions, such as RTOs, that should effectively address any new planning required in the transition to a competitive marketplace. Thus, the Commission should decline to adopt any of Staff's recommendations regarding transmission and local generation. Finally, the assertions in Staff's testimony and that of some intervenors that APS can exercise market power in transmission ignores applicable FERC rules and APS' FERC Standards of Conduct. The intervenor recommendations that are premised on this assertion should also be rejected.

Q. DOES THAT CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY IN THIS GENERIC DOCKET?

A. Yes.

1194932.1

ANNUAL COST OF NEW TRANSMISSION FACILITES

Estimated Cost of New Transmission Facilities:

50 Mile Line = (50 Mi * $2.32M/Mi) + $18M = $134.0 M
100 Mile Line = (100 Mi * $2.26M/Mi) + $18M = $244.0 M
150 Mile Line = (150 Mi * $2.24M/Mi) + $18M = $354.0 M

Annual Carrying Cost of New Transmission Facilities:

AC = OC * FCF

Where:

AC = Annual economic cost for new transmission facilities
OC = Original cost of new transmission facilities
FCF = Annual fixed charge factor for transmission facilities (14.22%)

Length of Line	Annual Cost
50 Miles	$19.05 M
100 Miles	$34.70 M
150 Miles	$50.34 M

Annual Cost for Acquiring Market Price Power In Lieu of RMR Generation

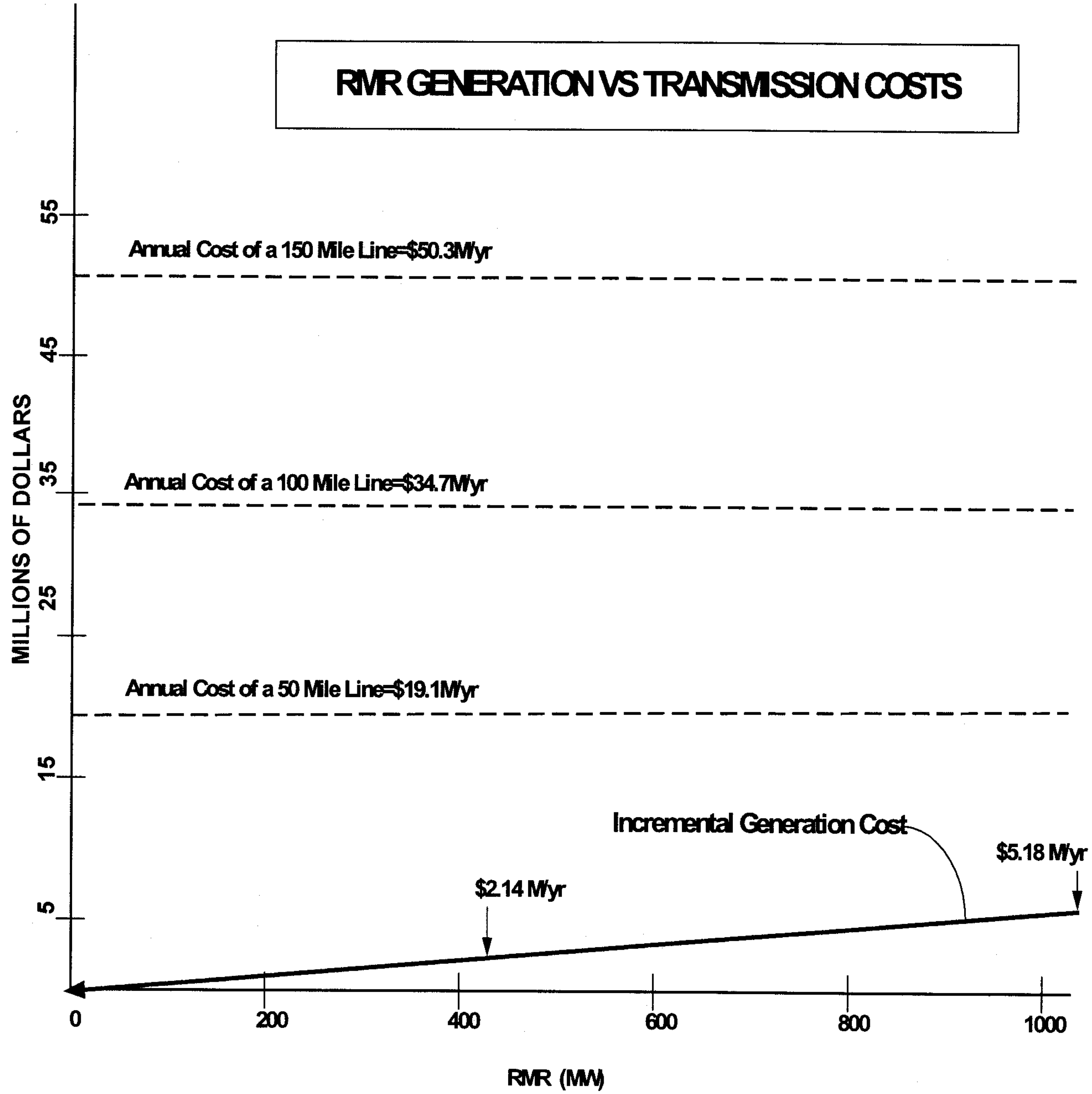
Incremental Generation Cost:

IGC = (AC-MKT)*T*MW*LF

IGC = Annual incremental cost of generation.
AC = Assumed cost of RMR generation.
MKT = Market price for generation.
T = The number of hours such purchases are needed annually (400 hours).
MW = The number of peak MW needed in lieu of RMR generation.
427MW for 2003, 1034MW for 2007
LF = The load factor during constraint period (.65).

427MW = $2.14M/yr

1034MW = $5.18M/yr


RMR GENERATION VS TRANSMISSION COSTS
MILLIONS OF DOLLARS
55
45
35
25
15
5
Annual Cost of a 150 Mile Line=$50.3M/yr
Annual Cost of a 100 Mile Line=$34.7M/yr
Annual Cost of a 50 Mile Line=$19.1M/yr
Incremental Generation Cost
$2.14 M/yr
$5.18 M/yr
0
200
400
600
800
1000
RMR (MW)

BEFORE THE

ARIZONA CORPORATION COMMISSION

Rebuttal Testimony of

Charles J. Cicchetti, Ph.D.

Docket No. E-00000A-02-0051, et al.

On Behalf of

Arizona Public Service Company

June 11, 2002

TABLE OF CONTENTS

SECTION I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME, BUSINESS AND ADDRESS.

A. My name is Charles J. Cicchetti. My address is Pacific Economics Group, L.L.C. (PEG) 201 South Lake Avenue, Suite 400, Pasadena, California 91101.

Q. WHAT IS YOUR POSITION WITH PACIFIC ECONOMICS GROUP?

A. I am a Co-Founding Member of PEG.

Q. WHAT ARE YOUR DUTIES AS A MEMBER OF PEG?

A. I actively consult with clients on price, costs, environmental, natural gas and electricity market issues and antitrust policies, particularly as those policies relate to regulated industries.

Q. DO YOU HOLD ANY OTHER POSITIONS?

A. I hold the Jeffrey J. Miller Chair in Government, Business and the Economy at the University of Southern California.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I attended the United States Air Force Academy, and I received a B.A. degree in Economics from Colorado College in 1965 and a Ph.D. degree in Economics from Rutgers University in 1969. From 1969 to 1972, I engaged in post-doctoral research on energy and environmental matters at Resources for the Future.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I served as chief economist for the Environmental Defense Fund from 1972 to 1975, and was a faculty member at the University of Wisconsin from 1972 to 1985, ultimately earning the title of Professor of Economics and Environmental Studies. From 1975 through 1976, I served as the Director of the Wisconsin Energy Office and as Special Energy Counselor for the Governor. In 1977, I was appointed by the Governor as Chairman of the Public Service Commission of Wisconsin and held that position until 1979, and served as a Commissioner until 1980. In 1980, I co-founded the Madison Consulting Group, which was sold to Marsh & McLennan Companies in 1984. In 1984, I was named Senior Vice President of National Economic Research Associates and held that position until 1987. From 1987 until 1990, I served as Deputy Director of the Energy and Environmental Policy Center at the John F. Kennedy School of Government at Harvard University, and from 1988 to 1992, I was a Managing Director and ultimately Co-Chairman of the economic and management consulting firm, Putnam, Hayes & Bartlett, Inc. In 1992, I formed Arthur Andersen Economic Consulting, a division of Arthur Andersen, LLP. In late 1996, I left Arthur Andersen to co-found Pacific Economics Group.

Q. HAVE YOU PUBLISHED ANY PAPERS OR ARTICLES?

A. Yes. I have published a number of articles on energy and environmental issues, public utility regulation, competition and antitrust. A complete listing of my publications is included in Attachment 1.

Q. HAVE YOU EVER GIVEN EXPERT TESTIMONY IN A COURT OR ADMINISTRATIVE PROCEEDING?

A. Yes. A list of the proceedings in which I have provided expert testimony since 1980 is also included in Attachment 1. Much of my consulting work before and since the time I was the Chairman of the Public Service Commission of Wisconsin has involved regulated industries, specifically, electric, natural gas, telecommunication, and water. I have testified in the U.S. before most of the state public utility commissions, and various federal agencies. In Canada, I have testified before the Alberta and Ontario Energy Boards, as well as before the National Energy Board.

SECTION II. PURPOSE OF TESTIMONY

Q. WHO RETAINED YOU FOR THIS TESTIMONY?

A. I have been retained by Arizona Public Service Company (APS) to provide rebuttal to testimony in response to the Procedural Order dated May 2, 2002 (Procedural Order) entered by the Arizona Corporation Commission (ACC).

Q. WHAT IS YOUR UNDERSTANDING OF THE NATURE OF THIS PROCEEDING?

A. This is a generic proceeding that, as I understand matters, will involve issues related to the transfer of assets and associated market power issues, code of conduct issues, and Affiliate Interest rules. These issues arise from the ACC's Retail Electric Competition Rules that were intended to develop competitive markets for electricity in Arizona.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS GENERIC PROCEEDING?

A. I have had significant regulatory and restructuring experience in the electric utility business. APS has asked me to review the proposals set forth by witnesses for the ACC's Utilities Division (Staff) in this proceeding and to provide my perspective on the various staff proposals. This testimony represents my critical review and evaluation of what I find to be the most egregiously misdirected aspects of Staff's proposals in this matter

Q. CAN YOU BE MORE SPECIFIC?

A. Yes. Staff has simply and very surprisingly failed to "learn the lessons" of California's power crises and, most troublesome, the disastrous role that faulty regulatory designs and bad transition plans played in this financial catastrophe. Quite simply, California's failed attempt to manage competition had a lot more to do with a bad combination of regulatory failures and very unfavorable market forces than alleged Enron-style gaming or even, to a lesser extent, as yet unproven but frequently charged market power abuse. Failing to grasp the regulatory and institutional failures and design flaws in California, Staff is apparently making recommendations that will repeat these errors.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section II, I discuss the testimonies filed by three Staff witnesses. First, I discuss Matthew Rowell's testimony, which I find most troubling. In particular, I focus on Mr. Rowell's testimony with respect to: (1) standard offer service pricing and (2) enhanced prudence reviews of supply acquisition decisions.

Second, I explain that Erinn Andreasen's proposed Advisory Group structure and requirements are unnecessary and likely to be grossly ineffective.

Third, I explain that Barbara Keene's proposed treatment of utility affiliates virtually ignores the APS restructuring agreement with the ACC. Ms. Keene mostly creates phantom affiliate issues that, if they ever actually arose, could be readily addressed under current regulation. Ms. Keene's proposals effectively shift significant risk to APS and its affiliates without conferring corresponding benefits to APS and its affiliates, or even to APS' customers.

Fourth, I review Ms. Keene's code of conduct discussion. While I recognize this is a generic proceeding, I am troubled that Ms. Keene mostly ignores the existing strong regulatory tradition of affiliate and cost of service regulation In Arizona. Ms. Keene also appears to believe that a generic proceeding means that Staff should ignore existing regulatory agreements, affiliate regulation, and codes of conduct. She is quite wrong when she implies that this proceeding should evolve into a broad, full blown proceeding to solve non-existent, very speculative affiliate matters. In my experience, regulation needs to recognize preexisting precedents and principles, and build upon them to address new circumstances and contingencies.

SECTION III. STAFF WITNESSES

<u>Mr. Rowell's Testimony</u>

Q. PLEASE SUMMARIZE YOUR CRITICISM OF MR. ROWELL'S "STANDARD OFFER" PRICING PROPOSAL.

A. Beginning at page 5 of his Direct Testimony, Mr. Rowell seeks to improperly elevate the "Standard Offer" retail customer to an unattainable and counterproductive status under a misdirected guise of "regulatory bargain" protection. Under the traditional "regulatory bargain," Investor owned utilities are granted a service territory franchise in exchange for a "duty to serve." This is coupled with a real "opportunity" to recover reasonable expenses and earn a "fair return" on prudent investments.

Customers expect regulators to review the franchise utility's cost of service, prudence, rate of return, cost allocation, and tariff design. The stated regulatory goal is safe and reliable cost-based service that provides for the recovery of prudent utility investments. In Arizona, as is true throughout the United States, prudence review using twenty-twenty hindsight is eschewed by regulators who recognize that the future is uncertain and that economic and financial risks are unavoidable, although manageable over time through prudent management.

Mr. Rowell believes that new Standard Offer Service (SOS) should represent the "best" combination of "lowest" price and "lowest" consumer risk, significant terms that he leaves largely undefined. Such a standard would effectively cause Standard Offer customers to "have their regulatory cake and eat a free competitive price dessert." This is unnecessary and, as far as I know, it is a proposal that is totally without regulatory precedent. Worse, it would mean that no rational retail consumer would ever forgo such a "standard offer" because it would guarantee that retail consumers pay the "lesser of" cost of service prices (i.e., the regulatory default price) or a competitive market price – whichever turns out "best." I hope this asymmetric result is not what Staff is pushing here. I may be confused, but wish to err on the side of extreme caution because no regulator should seek to impose a "heads I win, tails you lose" retail pricing system.

Q. PLEASE REVIEW IN MORE DETAIL YOUR CRITICISM OF STAFF'S PROPOSAL TO CHARGE RETAIL CUSTOMERS THE "LESSER OF COST OF SERVICE OR MARKET PRICES?"

A. An example will help to explain what I believe Mr. Rowell is unreasonably seeking to do and why I think that this is a heterodox approach. Suppose a utility has a cost of service generation price of 7 cents per KWh, while market prices generally swing between 5 cents and 10 cents per KWh. As I understand Mr. Rowell's proposal, he would charge retail customers the "lesser of" the cost of service price (7 cents per KWh) or the lower market price (5 cents per KWh). Thus, when the market price was less than the cost of service price, consumers would pay the market price of 5 cents per KWh, even though the actual cost to serve those customers from dedicated generation was 7 cents per KWh. However, when market prices rose to 10 cents per KWh and were, therefore, above the cost of service price, customers would pay the cost of service price of 7 cents per KWh. Retail consumers would never pay 10 cents per KWh, even though wholesale prices in the Commission-desired competitive market would rise to this level. Thus, the regulated utility would systematically fail to recover its actual costs when market prices are low and would lose the opportunity to profit from the competitive market when market prices are high.

Mr. Rowell seeks to accomplish the impossible when he tries to resolve the inherent antimony between regulation and competition. Quite simply, consumers that opt for the 7 cent per KWh cost of service price because they eschew competitive risks cannot and should not expect to be able to reap the benefits that sometimes occur under a competitive market outcome when the competitive price dips below the cost of service price. Similarly, consumers that select a retail competitive market outcome cannot and should not expect a safe harbor (i.e., cost of service fixed prices) if and when market prices rise above the cost of service standard.

None of this means that energy service providers (ESPs), should be prevented from offering competitively priced retail contracts that permit customers to switch back and forth between a base charge and competitive market swings in prices. Most important, when retail suppliers offer such contracts, they recognize two facts. First, the base prices are established with respect to competitive market expectations, not on cost of service prices. Second, the greater risk of such retail option offerings increases the costs of suppliers and these costs would need to be recovered through an insurance-like surcharge that would be added to the expected value of the competitive market price.

Here, Mr. Rowell proposes an unorthodox and unsustainable pricing recommendation that purports to offer retail customers the "best" of these conflicting approaches. This is simply not possible.

Q. WHY DO YOU CONCLUDE THAT SUCH A SCHEME WOULD BE UNDESIRABLE? WOULDN'T MR. ROWELL'S PROPOSED "BEST" PRICE AND "LEAST RISK" BE GOOD FOR ARIZONA'S CONSUMERS?

A. No. Any notion of consumer benefits would be illusory. Mr. Rowell's proposal is hopelessly myopic. The long-run effects would be disastrous and include:

1. No one would build new generation or enter into long-term dedicated purchase power contracts if they would receive the "lesser of" cost of service or market prices.
2. No competitive retail supplier would be able or willing to enter the retail market in Arizona if Staff's standard offer service pricing requirements were imposed on the incumbent utility companies.
3. Retail consumers would not receive appropriate price signals to moderate consumption of electricity, and market prices would, therefore, not be disciplined.

4. The financial effects on the incumbent utilities that would be forced to sell retail electricity at the "lesser or" cost of service or market price would be devastating. At best, stranded costs (i.e., the cumulative difference between cost of service and market prices when market prices are lower) could rise to significant levels. At worst, there would be an unfair (and to my way of thinking, clearly illegal) taking of utility assets that, to be blunt, would amount to systematic confiscation on a scale that has no place under either the doctrines of a capitalistic market driven economy or long-standing American regulatory principles and practices.
5. Bankruptcy of incumbent utilities would inevitably result. One need only look at the PG&E bankruptcy in California to realize that a utility cannot long afford to sell electricity at prices below those at which it must purchase the power. Buying high and selling low is not a practice that can be sustained for long. State regulators who impose such unreasonable constraints would nearly certainly find that they would cede significant jurisdiction to federal bankruptcy courts.

Q. ARE YOU SUGGESTING THAT RETAIL CONSUMERS ARE NOT TO BE GIVEN CHOICES?

A. No. A primary purpose of retail, as opposed to wholesale, electricity competition is consumer choice. Differences in price/risk preferences are what will drive the various retail consumer product choices under retail competition. Mr. Rowell seeks to establish a world in which retail consumers would falsely appear to be perfectly insulated from wholesale price risk, yet pay nothing for this "insurance." Compounding this difficulty, Mr. Rowell would guarantee that the load serving entity would not recover its conventional cost of service because the incumbent utility would also be required to sell electricity at lower competitively based retail prices when market prices beat cost of service based prices. Mr. Rowell's proposal is patently inequitable and does not conform to either reasonable competitive market or traditional regulatory practices. This outcome is unfair, unsustainable, and inefficient.

Q. ISN'T FIXED STANDARD OFFER PRICING OFTEN USED DURING TRANSITION PERIODS IN MOVING FROM A REGULATED TO A COMPETITIVE ENVIRONMENT?

A. Yes. APS has actually reduced its Standard Offer prices each year sine the Electric Competition Rules were first implemented in this jurisdiction in 1996, and has further decreases scheduled for 2002 and 2003. However, Mr. Rowell's proposed Standard Offer Service (SOS) is far from typical

As I understand Staff's proposal, Staff seeks to guarantee the "best" result to retail consumers that take the "Standard Offer," not one based on a fixed competitively set contract reference price, but one based on a fixed cost of service price. Retail consumers would expect to pay more for a fixed competitive price than the expected value of the competitive price because they could avoid price volatility and, in effect, hedge their retail purchase position. Here, Staff seems to propose that the base Standard Offer price would be a cost of service price and if, and only if, competitive prices are less than this cost of service price, retail customer would pay less, but never more.

Q. WHAT OTHER PROBLEMS ARISE FROM IMPLEMENTING MR. ROWELL'S PROPOSED "STANDARD OFFER"?

A. There are two problems that arise. First, if Staff wants to encourage a fixed competitive tariff offering for some retail customers that provides for an anchor or base price with options to purchase at lower competitive prices, the base price needs to be set by competitive energy service providers and *not* an historic cost of service approach. Second, power markets have volatility, as do all commodity markets. Some customers may seek to insulate themselves from price volatility in both directions or on the upside. Regardless, avoiding market price risks is a form of insurance, and premiums must be paid.

Staff's approach assigns *all* risk to the utility distribution company and provides the utility with no potential upside as an insurance provider. This means that retail consumers would be so much better off under Staff's best price Standard Offer that no competitive energy service provider (ESP) could ever compete for these customers. In other words, the Staff proposal would set back competition in Arizona.

Worse, Staff's proposal increases APS' costs and risks without any compensation for being forced to assume those costs and risks. Much worse, this approach is precisely one of the principal structural flaws that helped to bring on and worsen California's electricity crisis because regulators incorrectly believed that retail customers could, in effect, pay cost of service rates after wholesale markets jumped to more than twenty times their preexisting cost of service levels.

Q. WHAT IS WRONG WITH MR. ROWELL'S PROPOSAL FOR ENHANCED PRUDENCE REVIEWS?

A. Mr. Rowell applies the *coup de grace* when, at page 14 of Direct Testimony. Most important, Mr. Rowell seems to ignore the fact that APS' proposed PPA would be reviewed and approved by the ACC. This is a reasonable regulatory prudence review. That said, Mr. Rowell would seem to invite ongoing, *ex post prudence* review through his advocacy of a "lesser of" tariff standard.

This would mean a terrible trifecta and unfair *ex post* combination of: (1) retail consumers paying the "lesser of" cost of service or market prices with no consumer risk or insurance premium payment for such assurances; (2) all asymmetric risks and costs would be shifted to the incumbent utility distribution company; and (3) no competitive ESP could or would attempt to match such a one-sided Standard Offer, and retail competition would fail to materialize in Arizona.

I am advised that under traditional Arizona regulation, prudently incurred costs should be recovered. Arizona Administrative Code, Title 14, Chapter 2 defines "prudently invested" as those:

> "Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in

> the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made."

Mr. Rowell's "enhanced prudence" review is consistent with neither this regulation nor general regulatory precedent.

Q. HOW DOES MR. ROWELL FAIL TO GRASP THE "LESSONS" OF THE RECENT CALIFORNIA ELECTRICITY CRISIS?

A. I am the co-author of the California Bureau of State Audits' Report on the causes of the California electricity crisis.[1] A brief review of California, as Arizona moves towards competition, is important in the context of California's recent disastrous experiences. This will help to demonstrate how Staff is falling into some of the same traps that California did when it restructured its markets.

The ACC determined in 1996 to let, to a greater extent, competition regulate electric markets, and rely less on comprehensive cost-of-service regulation. This decision was reviewed in several subsequent proceedings until it was finally affirmed in 1999, both by the passage of the current Electric Competition Rules and by approval of historic settlement agreements with APS and Tucson Electric Power. At the time, Arizona's mammoth economic neighbor (California) had nearly two years of wildly successful competitive wholesale market results and a program for full-blown retail consumer choice. Indeed, in 1998 and 1999, California's average annual competitive wholesale prices were nearly half

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[1] Energy Deregulation: The Benefits of Competition Were Undermined by Structural Flaws in the Market, Unsuccessful Oversight, and Uncontrollable Forces, March 2001.

their former cost-of-service levels (2.5¢ to 3¢/KWH versus more than 5¢/KWH). I fondly recall a major forum in April of 1999 at the University of Southern California at which all stakeholder groups sang a chorus praising California's great restructuring and electricity deregulation successes.

As we look back, it is now apparent that the western United States in 1999 had an existing excess generation supply with more new power plant construction under way. Crude oil and natural gas prices were very low and, adjusted for inflation real energy prices were at levels that the nation had not seen for decades.

Q. WHAT WENT WRONG IN CALIFORNIA?

A. Unusual climate conditions occurred in the western United States. In the Northwest, the winter was cold and dry, and in the Southwest, the spring and summer were hot. Normally, dry winters mean cool springs. This did not occur in 2000. The unusual weather increased demand, and reduced supply. The last time this happened, the WHOOPS[2] fiasco was foisted upon the Pacific Northwest. Natural gas and crude oil prices also surged in 2000. Indeed, the average U.S. natural gas price in late 2000 was more than five times its 1999 level; and, in California in late 2000, spot natural gas prices jumped thirty times over the previous year, from about $2 per MCF to $60 per MCF.

Q. DID CALIFORNIA'S MARKET HAVE ANY DESIGN FLAWS THAT EXACERBATED THE SUPPLY SHORTAGE?

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[2] Washington Public Power Supply System. In the 1970s, the West experienced a similar climate anomaly and the western states embarked on a costly major nuclear construction plan.

A. Yes. California's new market design also suffered from structural flaws that combined with supply/demand and fuel related market forces to cause California's wholesale prices in 2000 to average more than three times the levels established under cost-of-service regulation (about $150 per MWH versus $50 per MWH), and more than five times 1999 price levels (about $30 per MWH). Furthermore, in December of 2000, wholesale electric prices jumped in the western region to more than $1,000 per MWH. Soon thereafter, California's state government through the California Department of Water Resources (CDWR) signed long-term contracts (seven to ten years) at prices typically equal to about $ 70 to $80 per MWH. The FERC, after several false starts and much political dancing, began to regulate wholesale prices through western states' market mitigation (soft caps), which remains in effect.

On the design flaw side, California made three fundamental mistakes. First, retail prices were totally insulated from competitive price volatility. Thus, when supply fell below demand, there were no retail consumer price signals to encourage demand side responses. Second, California put all its eggs in a "spot market" basket, effectively denying market participants access to long-term forward and futures contracts. (California is virtually alone in the jurisdictions that restructured in this respect.) Third, California had a myriad of markets and products, whose existence encouraged arbitrage. Yet, the California entities (ISO and CPX) failed to grasp the need to participate in and to coordinate their activities in these much too complex interdependent markets and products.

Q. HOW DOES CALIFORNIA'S EXPERIENCE AFFECT ARIZONA?

A. At present, there is great market and regulatory uncertainty, particularly related to the FERC's current market mitigation rules for western states. Also, current political and regulatory conditions cause much uncertainty related to the future FERC terms, conditions, prices, and structure of a new regional transmission organization (RTO). The lessons learned from California's experience show that it is important to get the new rules, institutions, and regulations right at the start. Fixing problems in the midst of a power crisis is not easy, and is often fraught with political and market peril.

Second, despite California, the ACC can be reasonably assured that it has protected Arizona's electricity consumers, while continuing to move toward competition. This can be done while retaining retail choice in Arizona. In my mind, the key is to encourage APS and other ESPs to enter long-term purchase power contracts for much of their retail needs.

Third, the ACC needs to continue to firmly embrace competition's merits over regulation without, as some have proposed, a strict adherence to an academic "spot market" model that fails to reflect current regional market supply and demand, federal regulatory mitigation, RTO uncertainty, and inside Arizona transmission network constraints and realities. This is simply not how free markets work.

Most assuredly, the "best price" and double dip prudence proposals set forth by Staff have no place in this transitional plan because they are unsustainable, unfair, and inefficient. They would, in my opinion, set APS on the path towards bankruptcy.

The California fiasco and the FERC's regulatory mambo demonstrate that both market conditions and regulatory policy uncertainty combine to mean that retail choice will not take hold voluntarily, at least in the very near term. Incumbent utilities that retain their duty to responsibly serve virtually their entire native retail load, which continues to grow, need to be encouraged by regulators to make the necessary investments and to sign prudent long-term contracts for new supplies. This is not the time to impose unsustainable and costly "best price" requirements and to otherwise undermine the incumbent utility distribution companies.

Q. DO MERCHANT GENERATORS HAVE THE SAME SUPPLY AND LEAST COST (OR PRICE) RESPONSIBILITY THAT APS WOULD CONTINUE TO HAVE? HOW DOES THIS AFFECT THE UNREASONABLE CONSTRAINTS THAT STAFF WOULD IMPOSE?

A. No. Merchant generators sell a wholesale commodity in either a short-term spot market or under some long-term contract. The latter can be "futures" contracts in which an organized market defines specific products in terms of size, location, timing, etc. (e.g., pork bellies or West Texas crude oil barrels) or a "forward" bilateral contract in which the merchant generator (seller) and buyer design a long-term contract that uniquely specifies the product sold.

Merchant generators have no duty to serve retail consumers. Indeed, unless bilateral forward contracts are used with direct retail users, merchant generators mostly have no retail customers or contracts. They sell their output in commodity markets that mostly ignore geography and political jurisdictions. Competitively generated and sold MWHs would flow toward higher prices and are constrained, if at all, only by transmission networks.

Some generators sell to electricity traders or merchants that translate the physical energy produced (MWHs) to a commodity that is traded as a financial instrument much like common stocks, pork or corn. Under these market-trading conditions, few retail consumers have sufficient scale or scope to become direct buyers. New entrants into the energy service business or the incumbent local distribution utility (here APS) need to assume this necessary market aggregation and portfolio function.

Distribution and retail service providers must take steps to obtain adequate supply and hedge against price fluctuations along with designing different retail products. As I understand the facts in Arizona, although retail choice is available and has sometimes been touted, at present there are no retail customers that are willing to bypass APS and seek retail services under either bilateral forward contracts or from new competitive retail energy service companies. These retail market results appear to be directly tied to the recent memories of severe wholesale price spikes in the

West and APS' declining retail prices. Through default and its traditional franchise responsibilities, APS is, for a significant part of the state, the sole electricity entity that has any responsibility for achieving the joint retail consumer objectives of supply reliability and least price in Arizona. As such, Staff's proposals to saddle APS with a higher burden than traditional regulation at a much greater cost through a "best" price offer are totally unnecessary and unwarranted.

Merchant generators produce a commodity that is traded like all commodities. Their sense of reliability is related to unit capacity factors, not a commitment to a specific geographic or regulated jurisdictional entity's need to keep the lights on at just and reasonable prices.

Merchant generators, often to their chagrin, are also highly influenced by political and federal regulatory matters. The FERC's shifting, stuttering, and changing forms of western states' market mitigation regulation are prime examples of how politics and federal regulation can and have affected reliability and prices in the wholesale electricity markets in the western United States. Merchant generators bristle at all of this because they quite reasonably do not think that guaranteeing retail reliability or bundled price stability is their responsibility.

Merchant generators neither owe nor have any geographic or jurisdictional allegiance to Arizona. More significantly, the FERC can exercise considerable sway over merchant generators to react to real and politically manufactured emergencies in California. The ACC cannot accept an academic version of a free, unfettered wholesale electricity market as long as California and the FERC combine to prevent such a market from evolving in the west. I conclude that APS needs to be encouraged to sign prudent long-term purchase power contracts without the risk of future *ex post* prudence reviews or some “best” price, “lesser of” pricing scheme in which APS must pay a higher contract price, while charging retail consumers a lower competitive spot market price.

Q. ARE THERE ANY OTHER RELIABILITY CONCERNS THAT STAFF’S PROPOSAL DRAW INTO THIS PROCEEDING?

A. Yes. Reliability is more than balancing generation supply with demand to establish relatively stable prices and avoid blackouts. Reliability also involves transmission, which must maintain voltage balances, frequency, and manage capacity. Congestion management on the electricity network or grid is also necessary to achieve system efficiency and grid protection.

Accordingly, a network operating entity must manage the power grid, coordinate transmission line construction and new generation location, serve various load pockets, and sustain system growth. Available transmission capacity may vary periodically and over time. It is also necessary to coordinate or account for generation outages, imports and exports, and more. These are all matters of system reliability that are traditionally the regulated, vertically integrated utility’s responsibility. These roles and responsibilities do not disappear under wholesale competition. Indeed, the FERC-led, some might say forced-fed, effort to form large RTOs is based on forming new organizations that will assume these transmission functions plus various scheduling coordinator or dispatch roles.

In addition, fuel diversity has been and still is important. Merchant generators mostly build or propose to build new natural gas fired units. There have even been suggestions to convert existing coal generation in the region to natural gas. California's fiasco in the late fall and winter of 2000 shows that a single fuel choice is problematic in the western United States.

Combining coal and nuclear generation with natural gas fired generation enhances price stability and system reliability. Merchant generators have no such system wide or jurisdictional concerns, although they may be expected to hedge their own narrow single fuel position.

When a merchant generator designs a hedging strategy in competitive energy markets, it would likely consider upside electricity prices in conjunction with, or as offsets to, high natural gas or fuel prices. This business tradeoff is not what most retail electricity consumers are prepared to accept or consider. Accordingly, retail service entities, such as APS, need to design supply portfolios with multiple fuels, purchase power contracts, and more to provide the very different and more complete retail hedges. Given what happened in California, most retail consumers will demand and expect such assurances.

Ms. Andreasen's Testimony

Q. WHY DO YOU CONCLUDE THAT MS. ANDREASEN'S ADVISORY GROUP PROPOSAL IS "INEFFECTIVE AND UNNECESSARY"?

A. Ms. Andreasen's proposals are unnecessary and most certainly will be ineffective because the advisory group she proposes has no responsibility or authority. It would become a representative stakeholder debating society. As was demonstrated in California, such stakeholder boards are unwieldy in size and provide a false notion that real market performance will be monitored. There is now widespread recognition that such stakeholder advisory boards provide no information about and no security against real market abuse. In virtually all situations, they are simply more trouble than they are worth.

California's experience is quite relevant here. Stakeholder groups can sometimes help resolve small technical differences in a collaborative manner. However, in a crisis and/or when large sums of stakeholder monies are involved, (i.e., precisely when clear communication, authority, and decisiveness are required) stakeholder groups freeze like "deer in the headlights." They cannot act and they will not or cannot communicate quickly and effectively to people who can take action. As shown conclusively in California, advisory groups like the one recommended by Ms. Andreasen are generally useless. Regulators who establish advisory groups can also expect to both be blamed when things go wrong and the press discovers and critically reports that so-called "special interests" dominate the regulators' advisory board.

Second, the FERC has made it very clear that stakeholder representative groups are not sufficient for most substantive tasks. More important, FERC requires that market monitors must be independent, not representative.

Thus, I conclude and recommend to the ACC that Ms. Andreasen's powerless stakeholder advisory group proposal should be rejected.

Ms. Keene's Testimony

Q. WHY DO YOU FIND FAULT WITH MS. KEENE'S AFFILIATE AND CODE OF CONDUCT PROPOSALS?

A. Ms. Keene engages in a "ready, fire and aim" approach to regulation. She fails to identify (i.e., "aim" at) any real target or problem. She simply asserts that "self-dealing" and "preferential treatment" are inevitable, and that "cross subsidies" surely will follow.

Ignoring the significant ACC regulation, FERC regulation, and SEC/PUHCA regulation, Ms. Keene creates problems after she "fires" her charges at Arizona's energy companies. This is not reasonable. Worse, she fails to assess current regulatory rules and ratemaking practices. Ms. Keene cites a litany of bad things that could ensue (e.g., predatory pricing), and unreasonably assumes that even though the "lights are on, no one is home." I have much more faith in existing ACC regulation, FERC regulation, competitive market disciplinary forces, and the track record of Arizona's incumbent electric utilities in controlling and regulating affiliate transactions than does Ms. Keene. The ACC and others do not condone and will prevent self-dealing and predatory practices, eschew cross subsidies, and reject unfair competition. Ms. Keene fails to address current responsibilities and facts. Instead, she speculates about potential problems and offers no remedies for these non-existing speculative problems, other than the implication that competitive markets need to be regulated. There is no need for her to conjure up problems and to speculate as she does.

Q. WHY DOES MS. KEENE THINK THAT EXISTING CODES OF CONDUCT ARE INSUFFICIENT?

A. Ms. Keene does not explain why the current rules and existing codes of conduct are inadequate. Ms. Keene uses her speculative allegations of self-dealing, cross subsidies, and predatory pricing as a ruse to suggest that utility misconduct is inevitable. In so doing, she misses the target widely. In my experience, utility companies and their affiliates seldom come even close to these excesses. Here, Ms. Keene's speculation does not justify her call for oppressive regulation.

Q. HOW DO YOU RESPOND TO MS. KEENE'S SURVEY OF WHAT OTHER STATES ARE DOING?

A. Ms. Keene's survey appears to consist of only three states. This review is cursory at best, and not particularly representative.

Q. DOES APS' CODE OF CONDUCT ADDRESS THE ISSUES COVERED IN THESE STATUTES?

A. Yes. Like the Massachusetts statute referenced by Ms. Keene, Sections IV(A)&(B) of APS' Code of Conduct prohibit APS from using or providing confidential customer information to any competitive electric affiliate or other third party. As is apparently required by the Maryland statute, cross subsidization is also prohibited by Sections VIII(A)&(B) of APS' Code of Conduct; affiliates are treated the same as non-affiliates (Section III); customer information and privacy is protected (Sections IV(A)&(B)); and services must be provided in a non-discriminatory manner (Section VII(D)). Similar to requirements in Kentucky, APS' Code of Conduct covers affiliate pricing rules (Sections VIII(A)&(B)) and separate accounting treatment is required (Section X(C)).

Q. DOES MS. KEENE CONSIDER FERC'S AUTHORITY WITH RESPECT TO WHOLESALE POWER TRANSACTIONS?

A. No. Ms. Keene fails to address federal regulatory authority with respect to wholesale electricity transactions. Her "arms' length" transaction reviews are ill-formed and wrongly based on gathering proprietary information without proposing necessary detail, specifics, and relief. Regulators have sufficient experience, expertise, and authority here. Ms. Keene uses the "code of conduct" and "affiliate interest" issues inappropriately and unnecessarily to force unregulated competitive firms and/or affiliates to disclose proprietary information.

Ms. Keene's "ready, fire and aim" approach and her conclusions should be rejected.

Q. DOES MS. KEENE DISCUSS AFFILIATE PRICING ISSUES?

A. Ms. Keene references Mr. Rowell for the proposition that "sales or transfers from an affiliate should be prices at the lower of cost of market." Earlier in this testimony, I discussed at length why I disagree with Mr.

Rowell's "lesser of" pricing recommendations. Those criticisms apply equally to Ms. Keene's adoption of Mr. Rowell's proposals.

SECTION IV. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE ACC.

A. I support competition. I continue to urge the ACC to encourage retail choice if practiced on a level playing field. Staff's "standard offer" or "best price" scheme is foolish. It is also dangerous and not sustainable. It would guarantee that Arizona would have its own electricity crisis. This should not and need not happen.

Staff should *not* think it can manage and direct specific "best" competitive outcomes. This is a false "god." Thus, I recommend that the Commission neither attempt to control or to regulate competitive markets nor follow Staff's draconian and misplaced advice. When left to their own devices, competitive markets will send appropriate signals to match supply and demand, obtaining the best price and one that will vary based upon the degree of risk allocation for different consumers in a competitive choice market. Attempts to micromanage competition combine the worst elements of cost of service regulation and competition and are a guaranteed recipe for a disastrous California-like result.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.