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AZ CORP COMMISSION
DOCUMENT CONTROL

April 22, 2002

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

RE: ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. R14-2-1606
ACC DOCKET NO's. ~~E-00000A-02-0051~~, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069 and E-01933A-98-0471

REBUTTAL TESTIMONY

Dear Sir or Madam:

Pursuant to the Procedural Order dated February 8, 2002, in the above referenced Dockets, Arizona Public Service Company is hereby filing the rebuttal testimony of Mr. Jack E. Davis, Dr. John H. Landon, Dr. William H. Hieronymus, Mr. Cary B. Deise and Mr. Charles J. 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: Docket Control (Original, plus 18 copies)
Service List

Arizona Corporation Commission
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REBUTTAL TESTIMONY OF JACK E. DAVIS

On Behalf of Arizona Public Service Company

Docket No. E-01345A-01-0822, et al.

April 22, 2002

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REBUTTAL TESTIMONY OF JACK E. DAVIS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-01-0822)

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 DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In response to the Arizona Corporation Commission ("Commission") Utilities Division Staff's ("Staff") recommendations concerning a "stay" of divestiture and other elements of the Company's 1999 Settlement Agreement ("1999 APS Settlement Agreement"), I will provide some background on the status of electric restructuring in Arizona and more specifically, on the steps taken by APS in furtherance of and in reliance on the Commission's restructuring rules (A.A.C. R14-2-1601, et seq., hereinafter called the "Electric Competition Rules") and orders. Second, I will reassure this Commission that restructuring can and should proceed subject to the "safety net" provided by the proposed purchase power agreement ("PPA") between APS and Pinnacle West Capital

Corporation's Marketing & Trading Division ("PWM&T"). In contrast, Staff and Intervenors advocate what is nothing less than a dangerous and largely irreversible experiment based on nothing more than conjecture and wishful thinking. Their recommendations threaten the very foundation of what has to date been a rare, and perhaps unique success story regarding electric industry restructuring in this country, namely the 1999 APS Settlement Agreement between this Commission and APS, and more globally the Company's continued ability to provide reliable and reasonably-priced service to its nearly 900,000 Standard Offer service customers. Finally, I will rebut the many incorrect or misleading statements made by Staff and Intervenors about both the intent and the terms of the proposed PPA. In that regard, I propose several changes to either reinforce that intent or clarify the specific language of the proposed PPA.

Q. **WILL APS PRESENT OTHER REBUTTAL WITNESSES?**

A. Yes. Both Dr. William Hieronymus and Dr. John Landon will respond to the criticism of their direct testimony in this proceeding and to certain of the Staff and merchant plant Intervenors' recommendations. In addition, Mr. Cary Deise, the Company's Director of Transmission Operations and Planning, discusses the APS transmission system and provides a critique of the analyses and recommendations of Staff witness Jerry Smith, among others. Finally, APS has asked Dr. Charles Cicchetti, former head of the Wisconsin Public Service Commission and a widely known and respected expert on both regulation in general and the electric utility industry in particular, to address Staff's position on divestiture of APS generation and adherence to the 1999 APS Settlement

Agreement, the claims concerning merchant plant reliability, as well as certain criticisms of the proposed PPA.

Q. WILL ANY OF THE COMPANY WITNESSES DIRECTLY DISCUSS COMPETITIVE BIDDING PROCEDURES AND OBJECTIVES IN THEIR REBUTTAL TESTIMONY?

A. No. This proceeding on the requested variance to A.A.C. R14-2-1606(B) ["Rule 1606(B)"] is not the forum to discuss, let alone decide, the details of any required competitive power procurement program. It is clearly premature to anticipate the results of either this proceeding or the Generic Docket, where Staff has indicated that it will address this very issue. APS is, however, appreciative of the suggestions and observations on competitive bidding made by the various Intervenor witnesses, but finds them either to be too generalized to require a specific response or to represent an effort to direct the competitive bidding process in a way that might favor individual bidders but not APS customers. As the Company noted in its Motion filed on April 19, 2002 in the Generic Docket, it intends to evaluate these Intervenor suggestions and observations, along with receiving input from Staff and consumer representatives such as the Residential Utility Consumer Office ("RUCO") and Arizonans for Electric Choice and Competition ("AECC"), and will issue an RFP or RFPs by September 1, 2002.

II. <u>SUMMARY</u>

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. Staff's essential premise, which is that we are at the beginning of the restructuring process with little or no accountability for the past, is fatally flawed for two reasons. First, it is historically inaccurate. And second, it is fundamentally unfair to APS and its affiliated companies. Arizona is not on the "verge" of restructuring or at a "crossroads" in restructuring. It is well down the path, and with few exceptions it has been the same path for some four years. APS has given up literally hundreds of millions of shareholder dollars and countless hours of effort to get to this point.

It must likewise be recognized that all of the assets included in the proposed PPA were constructed or acquired to assure reliable and reasonably priced service to the Company's Standard Offer customers. This includes the new units at West Phoenix, Saguaro and Redhawk 1 and 2 every bit as much as the Four Corners units or the PacifiCorp agreement. These assets are and will be needed by APS customers for reliable service in the years to come. To assure this reliable production and delivery of electricity to its customers, the Company's generation affiliate, Pinnacle West Energy Corporation ("PWEC"), and parent corporation, PWCC, have committed to a billion dollar construction program in reliance upon the Commission's regulations and express promises regarding restructuring and most specifically divestiture. APS itself is spending another billion dollars on transmission and distribution infrastructure.

The reorganization of APS to form PWEC, PWM&T, APS Energy Services and PWCC's Shared Services departments all reflect the Company's undertaking to make restructuring a reality in this state. Yet now, when APS has fulfilled every obligation imposed upon it by either the Electric Competition Rules or the 1999 APS Settlement Agreement, Staff would have this Commission renege on its own commitments or even fail to acknowledge their existence.

Staff and Intervenors either choose to ignore the lessons of California, Nevada, Oregon, Washington, etc., or they attempt to explain them away. For the merchant plant Intervenors, this can be explained by simple and quite understandable self-interest. As to Staff and consumer intervenors such as AECC, their trust in the wholesale power market prior to the implementation of the very structural reforms and infrastructure upgrades cited by Staff as essential to the efficient working of that same market is misplaced and premature. The proposed PPA provides an alternative to those APS customers who either lack Staff's optimism or doubt the merchant generators' concern for their welfare. It is a conservative and stable alternative for a group of consumers who are risk adverse and for whom price stability is most important. On the other hand, if APS is wrong and the others right about the long-term competitiveness of the proposed PPA, then the Company will suffer the loss of increasing numbers of customers to Direct Access service. Thus, consumers have effectively a free "put" on their electric supply options.

Staff and Intervenor witnesses have done everything possible to portray the proposed PPA in the worst light possible, to dismiss its obvious benefits, and to minimize the risks of their own unproven alternatives for Standard Offer service customers. Their assessments are is based almost entirely on a misunderstanding or misstatement of the terms of the proposed PPA or on a preconceived bias against any PPA between APS and an affiliate. To the extent such criticisms have any foundation, the Company will propose changes to the language of the proposed PPA to better effectuate its original intent.

III. COMPETITIVE VISION AND THE STATUS OF RESTRUCTURING IN THE APS SERVICE AREA AS EXPRESSED IN STAFF AND INTERVENOR TESTIMONY

Q. DO THE VARIOUS PARTIES IN THIS CASE SHARE A COMMON VISION WITH REGARD TO THE DIRECTION AND END OBJECTIVES OF RESTRUCTURING?

A. I believe we do, with the possible exception of Staff and perhaps RUCO's witness, Dr. Rosen. It is largely timing and speed that separate the various recommendations. And while these are quite important issues to both the Company and its Standard Offer customers, they should not detract from the equally important fact that a common vision of reaching a workable competitive wholesale generation market is supported by witness after witness in this proceeding, whether he or she is an APS witness or one of the many merchant generator witnesses. Indeed, as noted in my Direct Testimony, both the merchant generators as a class and the competitive wholesale market as an institution will be vital to the Company's long-term future, because even under the proposed PPA, APS will be the largest purchaser by far of competitive wholesale power in Arizona. And that dependency will only grow over time. I say this lest my criticism of this or that witness' specific testimony or proposals obscure the common thread that runs throughout this proceeding.

I believe as firmly as ever that the Company's variance request and the associated PPA present a reasoned and logical transition from a vertically-integrated monopoly to a market-based system, which transition has been the essence of this Commission's competitive vision since at least 1996 – a vision which was most perfectly manifested in the 1999 APS Settlement Agreement. More importantly, the variance and the PPA are in the best interests of APS customers. Obviously, the merchant Intervenors and Staff disagree, and unfortunately conjure up "boogie men" in every conceivable sentence and clause of the proposed PPA in an attempt to persuade this Commission that it is better to entrust Standard Offer customers to what to date has been a very unpredictable and most unforgiving wholesale market. They seem to forget or ignore the fact that as a regulated utility, APS (unlike the merchant plant Intervenors) is accountable directly to this Commission for all its actions. I would never attempt to defend some of the devious contractual shenanigans hypothesized by these witnesses. Eventually, the Commission will have to decide which of the many competing proposals in this proceeding best protects Standard Offer customers and be accountable for its choice.

However, I must take strong issue with those who suggest that we are not well along the road towards accomplishing the aforementioned transition to a restructured and more competitive electric industry here in Arizona. More specifically, I interpret Staff's position in this case to represent a significant retreat from the vision of the past six years or, perhaps more accurately, as one that is premised on the assumption that we are at the very beginning of this process with little in the way of "sunk costs" from previous Commission actions to be considered.

Q. DOES STAFF ACTUALLY CONTEND THAT ARIZONA HAS NOT INITIATED AN ELECTRIC RESTRUCTURING PROCESS?

A. No. But, the Staff's testimony in this proceeding cannot be separated from the "Staff Report in the Generic Electric Restructuring Docket" (Docket No. E-00000A-02-0051). In such report, the message is clear that Arizona has not seriously begun the monumental work of restructuring, and that the relative lack of retail competition in electricity as a commodity (there is considerable competition going on in retail energy services of all kinds) has somehow left the Commission a "clean slate" upon which to reinvent the restructuring process without the troublesome baggage of previous actions or prior commitments. Alternatively, the Report would leave the reader to conclude that Arizona is at some strategic "fork in the road" – one allowing any of a number of future paths from which the Commission may choose independent and unmindful of the steps taken thus far. In either case, Staff has chosen the issue of the Company's impending divestiture of generation assets to PWEC as the focus of its attempts to reinvent both retail electric competition and the 1999 APS Settlement Agreement.

Well, the past several years have been far more than an interesting academic exercise. The traditional vertically integrated utility known as APS, which through itself or a predecessor has provided reliable service to the State for some 100 years, has been significantly transformed, and even more changes are coming. It has been reorganized in a manner dictated by both this Commission and the Federal Energy Regulatory Commission ("FERC"). Entire new lines of business have been initiated while others have been terminated or reassigned to newly created affiliates. To now suggest that the Company simply "stand down," go back to its pre-1999 status, and await further orders of the Commission is clearly unnecessary; it will likely be counter-productive, and it is certainly unfair to both APS and its affiliates.

Q. WHAT SPECIFIC STEPS HAVE APS AND THE COMMISSION TAKEN TO DATE TO EFFECTUATE ELECTRIC RESTRUCTURING?

A. This story goes back over a year prior to the 1999 APS Settlement Agreement. In Decision No. 61071 (August 10, 1998), the Commission, at Staff's urging, added a mandatory divestiture provision to the Electric Competition Rules. Although originally proposed as a California-style divestiture to merchant plant developers, APS and Tucson Electric Power successfully argued for a third option – divestiture to an affiliate. *See* A.A.C. R14-2-1615. That provision was later reaffirmed not once but twice. *See* Decision Nos. 61272 (December 11, 1998) and Decision No. 61969 (September 29, 1999). Moreover, in Decision No. 60977 (June 22, 1998) the Commission assured APS full stranded cost recovery, including 100% of the costs of <u>voluntary</u> divestiture.

The Company subsequently entered into a settlement in 1999 covering, among other things, stranded costs and divestiture. Despite the Commission's previous decisions on these same subjects, that settlement, as modified by Decision No. 61973, required the Company to write off $234 million, did <u>not</u> allow 100% recovery of the costs of what was now a <u>mandatory</u> divestiture of its generation, and called for five consecutive price reductions for both Standard Offer and Direct Access customers. These price reductions were in stark contrast to other western electric utilities that have received one or more double-digit rate increases during that same period or to jurisdictions such as Pennsylvania where only direct access customers received rate decreases. APS made yet additional concessions both in the negotiation of the settlement and as a result of Decision No. 61973. These include the funding of low-income programs, the implementation of a code of conduct more stringent than required by the Electric Competition Rules, the deletion of certain provisions in the negotiated settlement favorable to the Company (e.g., certain waivers of Commission rules and statutory conditions), and the withdrawal of all then-pending litigation against the Commission over the Electric Competition Rules.

Decision No. 61973, did however, reaffirm for now the fourth time that divestiture of the Company's generation to an affiliate was "in the public interest" and thus granted "all requisite Commission approvals for . . . the creation by APS or its parent of new corporate affiliates. . . and the transfer thereto of APS' generation assets…" *See* 1999 APS Settlement Agreement at §§ 4.2 and 4.4.

Unlike most settlements before the Commission, the 1999 APS Settlement Agreement provided for the Commission itself to become a party to the settlement by virtue of its approval of that settlement in Decision No. 61973. The legality of the 1999 APS Settlement Agreement, including the Commission's inclusion as a party to the settlement, and Decision No. 61973 survived unscathed through two separate judicial appeals, the last of which was finally decided in December of 2001. In upholding the 1999 APS Settlement Agreement, the Arizona Court of Appeals stated:

> The agreement requires APS to divest its generation assets by December 31,2002, and requires the Commission approve the formation of an APS affiliate to acquire those assets at book value. [Opinion at ¶ 8.]
>
> . . .
>
> Section 6.1 [of the Settlement] makes the Commission a party to the agreement, and section 6.2 precludes the Commission from taking or proposing any action inconsistent with the agreement and requires the Commission to actively defend it. [Opinion at ¶ 33.]
>
> . . .
>
> The general rule, however, is that a contract that extends beyond the terms of the members of a public board is valid if made in good faith and if its does not involve the performance of personal or professional services for the board. [Citation omitted.] The [Arizona Consumers] Council has not alleged that the [settlement] contract was not entered into

> in good faith, and the <u>contract</u> does not involve personal services for Commission members. <u>The [settlement] contract can therefore bind future commissions</u>. [Citation omitted.] [Emphasis supplied.] [Opinion at ¶ 38.]

While these appeals were pending, the Company, as mentioned above, wrote off some $234 million dollars in previously recognized (in APS rates) and prudently-incurred costs as required by the settlement, reduced rates by some $120 million as required by the settlement,[1] and spent literally tens of millions of additional dollars to otherwise comply with the settlement and the Electric Competition Rules, many of which costs were directly related to the divestiture of APS generation assets to PWEC.

More specifically, APS or its parent corporation, PWCC, have taken the following specific steps in regard to divestiture of APS generating assets to PWEC:

1) forming PWEC and subsequently obtaining a financial credit rating (contingent upon transfer of the APS generating assets) for PWEC from major credit rating agencies;

2) reorganization and reassignment of APS personnel to PWM&T and PWEC and the retention by PWEC of new personnel to both operate APS generation and to engage in the construction of new generation;

3) PWEC's initiation of over $1 billion dollars in new generation construction to serve APS retail customers, which decision was wholly dependent upon the ability to acquire existing APS generation under the provisions of the Electric Competition Rules and the 1999 APS Settlement Agreement;

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[1] This does not count the two remaining rate reductions or the continuing favorable impact on APS customers of the first three rate reductions.

4) provision of interim financing by PWCC for PWEC's construction of new generation to serve APS load, which financing has placed an extreme burden on PWCC without the ability to collateralize the APS generating assets;

5) development of a comprehensive "buy-back" agreement whereby APS generating assets could remain dedicated to APS retail customers at essentially cost-of-service prices;

6) notice to or consents from some 3500 co-participants, fuel suppliers, government entities, creditors, etc., for transfer of the APS generation and related contracts, permits, rights-of-way, letters of credit, etc;

7) preparation of requests for and the securing of several private letter rulings from the IRS addressing the transfer of APS generation to PWEC and the continued tax-advantaged status of the Palo Verde Nuclear Generating Station ("PVNGS") decommissioning trust;

8) preparation of legal documents of transfer (deeds, bills of sale, assignments, etc);

9) preparation of the data required by Decision No. 61973 to be included in the 30-day notice of transfer; and,

10) submission of an application to the Nuclear Regulatory Commission ("NRC") for the transfer of the Company's operating license at PVNGS.

The last two critical path events prior to the actual transfer are: 1) securing NRC approval of a license transfer for the operation of the PVNGS; and 2) securing approval from the owners of or (more likely) a buyout of the secured lease obligation bonds ("SLBs") associated with the previously authorized sale/leaseback of PVNGS Unit 2. APS has already submitted its application for operating license transfer to the NRC. Approval is expected within no more than six months. Also, buyout of the SLBs will be initiated by the Company in the next few months. This buyout will be an extremely expensive proposition and will significantly increase the divestiture-related expenditures incurred by APS to date.

Q. ARE DIVESTITURE AND COMPETITIVE BIDDING UNDER RULE 1606(B) OR THE PROPOSED PPA LINKED?

A. Absolutely, both in the historical context of the Electric Competition Rules and in the practical sense. I say historical context because the two provisions [Rule 1606(B) and Rule1615)] arose at the same time and have always been synchronized in their starting date. Even during the approval process of the 1999 APS Settlement Agreement, the variance granted to Rule 1606(B) was referred to as a "corresponding delay," that is, "corresponding" to the delay in implementation of Rule 1615. Moreover, the competitive bidding and other power procurement provisions of Rule 1606(B) refer only to "Utility Distribution Companies," which in the parlance of the Electric Competitions Rules is used only to describe Affected Utilities such as APS in their post-divestiture state of restructuring. Practically speaking, it would make little sense for a still vertically-integrated utility to bid for resources it already owns, a concession that even merchant generators such as Sempra have acknowledged in response to the Company's data requests. Thus, Staff's seeming suggestion that APS be required to bid more than its shortfall from the Dedicated Assets is illogical under the construct of the Electric Competition Rules as they have existed for the past four years. And it would be an impractical, even wasteful, means of securing resources to reliably and economically serve the Company's Standard Offer customers.

Q. ARE STAFF'S RECOMMENDATIONS TO BOTH STAY THE DIVESTITURE WHILE AT THE SAME TIME PROCEEDING WITH

MANDATORY COMPETITIVE BIDDING ALSO INCONSISTENT WITH THE ORIGINS OF RULE 1606(B) AND A.A.C. R14-2-1615 ("RULE 1615")?

A. Yes. As I have noted above, these provisions are inexorably linked. And although divestiture was officially proposed by Staff in the Spring of 1998, it had been a topic of considerable debate and analysis since the original consideration of the Electric Competition Rules in 1996. Unlike the 50% competitive bidding requirement, divestiture was fully subject to the review and comment process of Arizona rulemaking. In conclusion, the Commission found that: "only through the divestiture of competitive services or the transfer of competitive services to an affiliate would the subsidization and crossovers between monopoly and competition be prohibited." Decision No. 61272 at Appendix C, p. 33. Nearly a year later, the Commission again concluded after yet another rulemaking proceeding that: "separation of monopoly and competitive services by the incumbent Affected Utilities <u>must</u> take place in order to foster development of a competitive market in Arizona" and "the <u>requirement</u> that competitive generation assets and Competitive Services be separated to an unaffiliated party or to a separate corporate affiliate or affiliates, will provide greater protection against cross-subsidization than would separation to a subsidiary." Decision No. 61969 at 60-61 (emphasis supplied).

Q. **IS STAFF'S PRESENT RECOMMENDATION TO "STAY" THE DIVESTITURE OF APS GENERATION TO "AN AFFILIATE OR AFFILIATES" ALSO INCONSISTENT WITH THE ORIGINAL 1999 APS SETTLEMENT AGREEMENT?**

A. Yes. Again, unlike the 50% competitive bidding requirement, divestiture of APS generation was at the very heart of the 1999 APS Settlement Agreement from the time of its original submission to the Commission in May 1999. It was an express part of the Company's bargained-for consideration in the agreement.

Q. DID STAFF OPPOSE THE DIVESTITURE PROVISIONS OF THE 1999 APS SETTLEMENT AGREEMENT?

A. Not at all. In fact, no participant in the proceeding resulting in approval and adoption of the 1999 APS Settlement Agreement was opposed to divestiture. The Commission itself, in addition to adopting the Settlement, specifically stated: "[T]he Commission supports and authorizes the transfer by APS to an affiliate or affiliates of all its generation and [other] competitive electric service assets as set forth in the Agreement no later than December 31, 2002." Decision No. 61973 at 10. The Commission also adopted the following language as set forth in the Agreement:

> The Commission has determined that allowing the Generation Assets to become "eligible facilities," within the meaning of Section 32 of the Public Utility Holding Company Act ("PUHCA"), and owned by an APS EWG ["Exempt Wholesale Generator"] affiliate (1) will benefit consumers, (2) is in the public interest, and (3) does not violate Arizona law.

Id. at Attachment 1, p.7.

Q. WON'T DIVESTITURE OF APS' GENERATION TO PWEC RESULT IN THE FERC HAVING JURISDICTION OVER APS PURCHASES OF ELECTRICITY?

A. FERC has had that jurisdiction since the 1930s. The transfer of APS generation to PWEC or, for that matter, to anyone else, would not change that fact. Without significant owned-generation, however, APS will obviously have to purchase most of its Standard Offer service requirements from wholesale suppliers. This too has always been understood since the first additions of Rule 1606 and Rule 1615 to the Electric Competition Rules back in 1998. It would likewise be true under the recommendations of the merchant plant Intervenors and to a large extent, those of Staff.

Q. EVEN THOUGH DIVESTITURE DOES NOT CHANGE THE HISTORIC JURISDICTIONAL SEPARATION BETWEEN STATE AND FEDERAL REGULATORS, SHOULDN'T THE COMMISSION BE CONCERNED THAT FERC HAS ALLOWED CERTAIN SELLERS, INCLUDING PWM&T, TO CHARGE MARKET-BASED RATES THAT MAY BE WELL IN EXCESS OF WHAT THIS COMMISSION WOULD HAVE ALLOWED BASED ON COST-OF SERVICE?

A. That depends on one's guess about future market prices. To the extent APS must obtain power from non-affiliated sources, it is a risk the Commission has already decided to accept under the competitive-bidding or other market-based power acquisition strategy contemplated by Rule 1606(B). In the Staff Report dated March 22, 2002, the need for Commission monitoring of and participation in FERC market proceedings is addressed in some detail. The proposed PPA, however, gives the Commission the authority to review and approve the rate-setting formula on the front end – a formula premised on traditional cost-of-service principles. It also provides customers with the same resource, fuel and geographic diversity as the Company's existing bundle of generating assets. More to the point, it directly addresses Staff's apparent concern with APS purchasing so much of its Standard Offer requirements in the wholesale market, which is necessarily under FERC supervision, and it does so in a way that does not effectively gut the 1999 APS Settlement Agreement and which supports the original vision of the Commission's Electric Competition Rules.

Q. WHAT IF, AS IS ALLEGED BY SOME OF THE PPA OPPONENTS, MARKET PRICES ARE BELOW THE LEVEL OF THE PPA PRICES FOR MOST OR ALL OF ITS TERM?

A. A significant portion of the power provided APS under the proposed PPA would come directly from that market, and thus will, by definition be at the market price – no higher and no lower. Assuming the question refers to only the Dedicated Energy Products under the proposed PPA, I find the assumption somewhat implausible. The competitive market may or may not produce lower prices than traditional cost-of-service regulation over the long haul assuming a common starting point. But in the Dedicated Assets, we are talking about power plants and power agreements that were, for the most part, built and/or negotiated decades ago. Nevertheless, if the Dedicated Assets prove uncompetitive on average over the proposed PPA term, APS will be at a significant competitive disadvantage to competitive Electric Service Providers ("ESPs") and will likely see a steady deterioration of its Standard Offer service customer base. If, on the other hand, market prices spike in the future (perhaps more than just occasionally) as unexpectedly and severely as they did in 2000 and early 2001, APS Standard Offer service customers would be insulated from a very significant portion of that volatility.

IV. <u>IMPACT ON THE COMPANY OF STAFF AND INTERVENOR RECOMMENDATIONS</u>

Q. IN ADDITION TO ABROGATING THE 1999 APS SETTLEMENT AGREEMENT PROVISION ON DIVESTITURE, WHAT OTHER ASPECTS OF THAT AGREEMENT WOULD BE NEGATED BY STAFF'S RECOMMENDATIONS?

A. There are several. First of all, the 1999 APS Settlement Agreement allows APS affiliates to provide power to APS for Standard Offer in the same manner as non-affiliates. *See* Agreement at Section 4.4. The only restriction is that such affiliate have no "automatic privilege." Staff's recommendation (to allow PWM&T to participate only through competitive bidding) would automatically make PWM&T ineligible to serve up to 50% of APS' Standard Offer service requirements. Second, Staff's seeming proposal to require competitive bidding at those hubs where APS has substantial competition while constraining it to cost-of-service at illiquid hubs creates a "lower of cost or market" scenario never contemplated by the 1999 APS Settlement Agreement or the Electric Competition Rules. It is a scenario that can only lead to the financial crippling of either APS or PWEC, if not both. Finally, and although not in Staff's pre-filed testimony on the requested variance, the Staff Report discussed above, which is a part of the same consolidated docket, also appears to be suggesting a reconsideration of the very rate adjustment mechanisms approved in principle by the 1999 APS Settlement Agreement and upheld by the courts on appeal.

Q. WERE YOU SURPRISED BY THE STAFF REPORT AND THE SUBSEQUENT STAFF TESTIMONY IN THIS PROCEEDING?

A. Surprised and then deeply disappointed. Nowhere does Staff even acknowledge, let alone suggest honoring the regulatory commitments made to the Company or recognize the tremendous sacrifices the Company has made to keep up its end of the bargain. It's as if they never existed. I realize that Staff was not a signatory to the 1999 APS Settlement Agreement, but it was present during most of its negotiation, and Staff did not oppose a single one of the provisions in that Settlement it now seeks to eviscerate. In fact, Staff's chief witness on the 1999 APS Settlement Agreement testified:

> Q. What major changes do we need to make to the regulation and organization of the electric industry in order to allow competition to flourish?
>
> A. In order to have competition in the electric industry, we need the following:
>
> - to give customers the opportunity to purchase electric services from a supplier of their choice;
> - to inform customers of what they pay the utility for each service, so they can compare different providers
> - to give other suppliers fair access to the wires and to customers

- to avoid the subsidization of unregulated services by regulated services, which would give the utility an unfair advantage over competitive suppliers.

Q. Has the APS Settlement Agreement contributed toward these changes?

A. Yes. The APS Settlement Agreement has provided us with these basic building blocks for a competitive system. It also provides additional benefits to both customers who choose a competitive supplier, as well as standard offer customers.

Testimony of Dr. Lee Smith in Docket No. E-01345A-98-0473, *et al.*, at 2

Q. WHAT DO YOU THINK HAS CHANGED TO SO RADICALLY ALTER STAFF'S CURRENT PERCEPTION OF THE 1999 APS SETTLEMENT AGREEMENT?

A. I don't really know. The only factor they cite is the so-called loss of jurisdiction issue. Yet, that issue was decided by the Commission nearly four years ago. And as I discussed above, there is really no "loss" of jurisdiction, just the increased application of pre-existing FERC jurisdiction, which as to the Dedicated Assets, is addressed by the proposed PPA and which as to purchases from non-affiliates is unavoidable under <u>any</u> of the proposals before the Commission in this proceeding.

Q. ASIDE FROM THE ABROGATION OF THE 1999 APS SETTLEMENT AGREEMENT, ARE THERE OTHER IMPACTS ON APS AND ITS CUSTOMERS THAT FLOW FROM THE RECOMMENDATIONS OF STAFF AND INTERVENORS?

A. Yes. Though APS has been pilloried by most of the parties for even requesting a variance to Rule 1606(B), I find it most interesting that the majority of even the non-Company witnesses in this proceeding believe Rule 1606(B) cannot or should not be implemented as written. Certainly Staff and all of the consumer group Intervenors such as RUCO and AECC support some manner of variance. Many of the merchant plant Intervenor witnesses acknowledge the need to either delay or phase-in implementation of the full 50% requirement or to better specify the parameters of any mandatory competitive bidding proposal. In response to our data requests of Staff, RUCO, AECC and the merchant plant Intervenors, it appears nobody has done a study or other analysis that would support the practicality or desirability (from the consumers' point of view) of this 50% requirement. I must also reiterate the point made in my Direct Testimony that the requirement itself was subjected to no analysis or study when it was first adopted in 1999. As is noted by Mr. Deise in his Rebuttal Testimony, the Staff's "interim" proposal is nearly as flawed as was the original last-minute addition of the 50% competitive-bidding provision in Rule 1606(B). Staff and the merchant plant Intervenors have ignored or glossed over the shallowness of the market in respect to access to APS system delivery points and the inherent limitations of the transmission system circling the Valley, where some 77% of the Company's load is located. What they propose is nothing less than a dangerous experiment at APS' and its customers' expense.

Q. YOU NOTED THAT THE PROPOSED RESTRICTION ON THE ABILITY OF PWEC/PWM&T TO COMPETE FOR APS LOAD WAS INCONSISTENT WITH THE COMMISSION'S OWN FINDINGS IN THE 1999 APS SETTLEMENT AGREEMENT. WOULD SUCH A RESTRICTION OTHERWISE BE PRACTICAL?

A. No. PWEC is one of two entities locating new local generation within the Valley and the only one that has completed construction of such generation. This new generation will almost certainly be "must-run" for part of the year, which makes competitive bidding impractical unless you believe a single bidder provides for a meaningful bid.

Q. COULD YOU CITE ANOTHER EXAMPLE OF HOW APS IS HARMED BY THESE PROPOSALS?

A. Yes. It is often acknowledged that fuel and resource diversity considerations, combined with the low operating costs of the Company's existing coal and nuclear generation, give facilities such as Palo Verde, Four Corners, etc., a competitive advantage in any prudent resource acquisition by APS. Yet it is argued that the new gas-fired facilities constructed or under construction by PWEC are indistinguishable from those of the merchant plant Intervenors. Thus, it is argued, a "gas on gas" competition is both possible and likely to produce advantages to both the merchant plant Intervenors and APS customers. These claims ignore the scope and purpose of these new PWEC investments as well as the economic balance struck in the proposed PPA.

Redhawk, West Phoenix 4 and 5, and the Saguaro CT, all of which were constructed or are being constructed by PWEC, were not sized, sited or constructed by happenstance or on speculation. They were expressly built to serve APS load, and were planned and begun at a time when it looked as if nobody was willing to build for the Arizona, or more specifically, the APS market given the lucrative possibilities in California. In fact, I personally took part in discussions of whether PWEC should itself sell all or a portion of Redhawk's output forward to California. Despite the tremendous profit potential from such a transaction, I was unwilling to gamble that an unidentified "somebody else" would then meet APS' needs here in Arizona. Thus, Redhawk was kept off the market, which I believe was an act of commitment to our customers deserving of commendation rather than the derision heaped upon it by Sempra witness William Engelbrecht. (Engelbrecht at 2.) Moreover, to this day, no merchant plant has been built or is planned to be built within the Phoenix load center. Had PWEC not stepped to the plate with both its West

Phoenix 4 unit and the trailer-mounted temporary units referenced in my Direct Testimony, Phoenix would have likely faced blackouts last summer. The general shortage of peaking capacity among the merchant plant Intervenors is also well known. Aside from PPL's Sundance facility, only PWEC is constructing combustion turbines, and only the latter is building them solely for APS customers. To now toss this billion dollar commitment aside in favor of "playing the field" is clearly inequitable and quite possibly foolish.

Q. WHY DO YOU BELIEVE IT "QUITE POSSIBLY FOOLISH" TO ATTEMPT CARVING OFF THE GAS-FIRED GENERATION FROM THE PROPOSED PPA?

A. The proposed PPA is a package. It is obvious that low cost plants such as Four Corners could earn more than their cost-of-service in the competitive market. It would not make economic sense for PWEC to accept only cost-of-service for such valuable assets without receiving something in return. That "something" is the stable revenue stream covering PWEC's newer and higher cost assets embodied in the proposed PPA. If these latter assets were to be removed from the PPA, it would fundamentally alter the economics of the deal, thus forcing PWEC to reprice the remaining assets. Even if a uniform "slice of the system" were cleaved off the proposed PPA, it is likely that PWEC would have to reprice the remainder since the PPA reflects, in effect, a volume discount precisely because it covers all of the PWEC assets constructed on the Company's behalf.

It is also far from obvious that on a stand-alone basis, APS customers do not benefit in the long run from a commitment of PWEC's gas-fired resources to them at cost-of-service prices. As discussed by RUCO witness Dr. Richard Rosen, future gas-fired generation is likely to be more expensive in real terms than today's gas-fired generation, thus leaving existing units such as Redhawk with long-term cost advantages. In a competitive market that means higher profits for PWEC, while under the proposed PPA it would mean better prices for APS customers. Moreover, the Redhawk units have advantages unique to themselves, such as the ability to reuse effluent from the Palo Verde treatment facility. Finally, several of the gas-fired plants are in load pockets. Although such units will not be allowed to exercise the market power they possess during "must-run" hours by virtue of their location, it is more than possible that in the future they will receive prices set above cost-of-service (or at least the cost-of-service level inherent in the proposed PPA) as an incentive for both merchant plant construction within the load pocket and the construction of new transmission to and from the load pocket.

Q. DO THE STAFF OR MERCHANT PLANT INTERVENOR PROPOSALS RESOLVE THE ISSUE OF SUPPLY RELIABILITY IDENTIFIED IN YOUR DIRECT TESTIMONY?

A. No. They would still leave APS exposed to and dependent upon the vagaries of the market. No entity would possess both the responsibility to ensure adequate supplies of power and the ability to fulfill that responsibility. Sure, APS could put together a portfolio of merchant contracts promising reliability, but with little assurance that the promised capacity and energy would not be simultaneously sold to someone else or that future capacity necessary to meet the promises of future firm delivery would ever be built. These are not idle or hypothetical concerns – just ask California.

It is also true that these proposals do nothing to resolve what Staff terms the "loss of jurisdiction" issue. Neither Staff nor the merchant plant Intervenors have suggested that the Commission will have the same ability to review and approve purchase power agreements between APS and these same merchant plant as has been offered in the case of the proposed PPA. No non-affiliate has indicated any willingness to make the terms of its prospective agreements with APS a matter of public record and debate, as APS and PWM&T have done through the proposed PPA. I further strongly suspect that none of the merchant plant Intervenors would be willing to cap their rate of return at regulated levels for up to thirteen years. In fact, in response to APS discovery, the merchant plant Intervenors refused to even discuss possible terms and conditions to any agreement. Some even refused to acknowledge whether they had power they were able or willing to sell to APS at any price.

Q. DO STAFF AND INTERVENOR WITNESSES ACKNOWLEDGE THE RELIABILITY AND STABILITY BENEFITS OF THE PROPOSED PPA?

A. No. They either ignore or seriously undervalue these benefits. For example, Staff witness Schlissel states: "APS could develop a fuel diverse portfolio of baseload, intermediate and peaking resources using its own facilities and the resources obtained through a competitive bid process." Schissel at 19. First of all, the only "resources" APS is presently authorized to own after December 31, 2002 are relatively minor amounts of solar and other renewables. Outside of PWEC, the only entities in Arizona or surrounding states that have a remotely similar "fuel diverse portfolio of baseload, intermediate and peaking resources" are vertically integrated utilities such as SRP. I seriously doubt they would ever be willing to meet APS' needs to the exclusion of their own, and I know they presently lack sufficient excess capacity to do so and that such excess capacity as they do own is not by any stretch a "fuel diverse portfolio of baseload, intermediate and peaking resources." Even if I were to assume away the 1999 APS Settlement Agreement and Rule 1615, thus allowing or requiring APS to keep its existing portfolio of assets, APS load cannot be reliably served without the PWEC generation at West Phoenix, and the competitive market for peaking power would consist of only two suppliers, PWEC and PPL – hardly a situation favorable to consumers absent the price protection offered by the proposed PPA.

The merchant plant Intervenors' proposals do not allow for the hedge from existing APS generation hypothesized by Mr. Schlissel. They ask for all APS needs to come from the competitive market, and in the Southwest, that means from gas-fired generation. The fact that Duke might own a coal plant in North Carolina or Panda/TECO one in Florida does not mean they will be able to provide that power to APS, and it certainly doesn't mean they would price their contracts based on coal-fired generation. It also doesn't change the fact that they own no facilities northeast of Phoenix, which are essential to the physical operation of the APS system.

These same witnesses discount the price stability benefits either by claiming that the proposed PPA encompasses significant gas-fired generation or that gas price volatility can be contracted away. As to the former, it is true that roughly 30% of the Dedicated Units output would be from gas-fired generation. The remainder of the Dedicated Energy Products come from the two Dedicated Contracts – one with SRP that is partly unit-contingent on gas-fired generation and partly a system sale backed by the full diversity of the SRP generation portfolio, and the other with PacifiCorp which is basically a "winter coal for summer hydro" seasonal exchange. If one believes that 30% (or less) price volatility is more or less the same as 100% price volatility, then I would have to concede my critics' point. It is also true that price volatility can be contracted away for some period of time and for a price. But for how long and for what price? My read of the merchant plant Intervenors' testimony doesn't provide even a clue as to what premium they would demand or for how long they would be willing to limit any price adjustments under any agreements with the Company.

Lastly, Staff witness Schlissel opines that the Dedicated Units' availability and efficiency may decline over time, given the age of some of the units. In point of fact, power plants don't wear out like an old pair of shoes. Critical components are constantly maintained, repaired and replaced with newer, more efficient equipment. Although facilities can become economically or technologically obsolete, their physical life and mechanically efficient operation can be maintained more or less indefinitely. Thus, I can say virtually without exception that the availability and operating efficiency of the older generation to which Mr. Schlissel refers are comparable to or greater than that achieved twenty years ago.

Q. **YOU TESTIFIED EARLIER THAT YOU WERE SURPRISED AT THE SHORT SHRIFT GIVEN BY STAFF TO THE COMMITMENTS MADE TO APS BY THE COMMISSION IN THE 1999 APS SETTLEMENT AGREEMENT AND THE COSTS INCURRED BY APS IN RELIANCE UPON THAT AGREEMENT. EVEN ASIDE FROM THE SETTLEMENT, ARE YOU SURPRISED BY STAFF'S POSITION IN THIS CASE?**

A. Yes. APS expected the merchant plant Intervenors to take exactly the positions they have. Their motive in these proceedings is quite naturally financial gain, and phrases like "fair competition," "public interest" and "consumer welfare" are just a part of the sales pitch. They have no legal responsibility to APS customers and no accountability to this Commission. Theirs are the same arguments previously made in California, Nevada, etc. Indeed, some of their witnesses attempt to explain away or rationalize the events in California (Hall and Ruff).

Staff, on the other hand, is charged with balancing the interests of consumers with those of the regulated utility, not with the promotion of unregulated competitors. It must recognize both the financial commitment of the utility and the regulatory commitments of the institution of which it is a part. Staff's recommendations do neither. They would leave APS in the position of receiving the lower of cost or market for some $3.1 billion in generation investment. Staff would similarly leave PWEC, itself a creation of the 1999 APS Settlement Agreement, twisting in the wind with neither the promised portfolio of APS generating assets nor the proposed PPA. APS customers, on the other hand, will increasingly see their rate stability and service reliability treated as just another commodity to be bought and sold on the trading floors of a group of LLCs they never heard of or would not recognize if they had.

Q. HAVE THE OTHER PARTIES TO THE 1999 APS SETTLEMENT AGREEMENT SOUGHT TO ABROGATE THAT AGREEMENT AS WELL?

A. RUCO has been exemplary in its recognition that divestiture of APS generation to an "affiliate or affiliates" was at the heart of the 1999 APS Settlement Agreement. Although I have some issues with Dr. Rosen's specific written recommendations, they do not threaten either the economic viability of the proposed PPA or the continued vitality of the 1999 APS Settlement Agreement. AECC's position is less clear. Although Mr. Higgins expresses great concern about the supposed reliance on Rule 1606(B) by the merchant plant Intervenors, a claim they themselves have now largely abandoned and refused to confirm when confronted by APS requests for proof, there is not a word about APS' reliance on either Rule 1615 or the 1999 APS Settlement Agreement. Also, Mr. Higgins eagerly accepts PWM&T's offer of the older low cost APS generation at cost-of-service prices but would sever the new PWEC units from the proposed PPA with apparently no regard to the resulting impact on the Company or its affiliates. For the reasons I have already testified to at length, this is neither reasonable nor acceptable to PWM&T without a reworking of the other elements of the proposed contract with APS.

Q. HAVE STAFF AND THE MERCHANT PLANT INTERVENORS OVERSOLD THE BENEFITS OF COMPETITIVE BIDDING AND MINIMIZED OR IGNORED THE DIFFICULTIES AND RISKS?

A. Absolutely. Although there are allusions to impliedly "successful" competitive bidding programs in other states, the definition of "success" appears to be no more than the amount of load competitively bid. We are told nothing about the price as compared with what customers were paying under traditional cost-of-service regulation, nothing about the length of the agreements, nothing about the reliability or diversity of the winning bidders, and nothing about the availability of better alternatives to competitive bidding – in essence nothing that would give this Commission any assurance that a competitive bidding program of the magnitude suggested by the merchant plant Intervenors or even Staff would succeed in Arizona or that such success would hold up over the long haul.

Staff witness Smith acknowledges that "there are risks and uncertainties associated with the achievement of these [Staff's] competitive bidding objectives." Smith at 19. These "risks and uncertainties" are magnified because they revolve around entities and organizations (e.g., the merchant plant Intervenors, interstate gas pipelines and Regional Transmission Organizations or "RTOs"), that are outside the Commission's jurisdiction and control and may require actions by FERC that this Commission has limited power to influence. Other factors cited by Staff witness Smith as critical to a widespread competitive bidding program are transmission improvements not even scheduled for completion until the latter part of this decade (Smith at 13-14) and which have yet to face the firestorm of "NIMBYism" routinely encountered by such projects – an experience Mr. Smith innocently refers to in his testimony and the Staff Report as "the rigors of the state line siting process" (Smith at 13) or the implementation of RTO protocols that Staff witness Smith agrees "will likely take several years." Smith at 15.

Even if all the "risks and uncertainties" referenced by Staff were resolved and resolved favorably (from Arizona's perspective) overnight, it would not change the fact that the merchant plants upon which Staff is willing to stake the future of APS customers lack both fuel and geographic diversity. It also ignores the reality that both for economic and reliability reasons, any competitive bidding program must either encompass or recognize the portfolio of generation constructed by APS and PWEC. I use both these entities in my answer because it is impossible to discuss APS' existing generation without understanding its relationship to the new generation constructed or under construction by PWEC. Both are required if PWM&T is to be a viable bidder in such a program.

Q. WHY IS THAT?

A. It is critical that a single entity own and control both sets of generation because the burden on PWCC of the continued interim financing of PWEC's construction of units dedicated to serve APS is becoming increasingly difficult to obtain and expensive to maintain. Indeed, PWCC's credit integrity could be threatened by the continued burden of supporting both PWEC and PWM&T (the latter, although profitable, requires extensive credit support). And yet PWEC cannot assume that financing burden without receiving the Company's existing generation (which the rating agencies have established as a pre-condition to PWEC's credit rating). Moreover, APS has repeatedly represented to employees, to Wall Street and to those that deal with PWEC that divestiture will take place as soon as practical but certainly prior to year's end. PWEC was never intended to be a "start from scratch" merchant generation business and no doubt would never have undertaken the responsibility of building Redhawk, West Phoenix, etc., without the assurance that the balance of APS' generation portfolio would follow as agreed to in the 1999 APS Settlement Agreement. Staff's proposals would burn the Company's candle to the quick from both ends. By suggesting that divestiture be stopped, PWEC is left without the imbedded financial base on which it was premised. By leaving it without the proposed PPA, PWEC potentially loses the market for which it was created.

V. <u>THE CLAIMED IMPACT OF THE PPA ON THE MERCHANT PLANT INTERVENORS</u>

Q. HAVE ANY OF THE MERCHANT PLANT INTERVENORS DEMONSTRATED ANY ADVERSE IMPACT ON EITHER THEMSELVES OR THE COMPPETITIVE WHOLESALE MARKET THAT WOULD OCCUR AS A RESULT OF THE PPA?

A. No. There are the usual general pronouncements about more competition being better than less and testimonials about the many claimed successes of competitive bidding (without either defining "success" or sharing with us important details such as price, terms, etc.), but no hard evidence of any kind that the proposed PPA will have any adverse affect on themselves or the competitive market as a whole. This was hardly surprising. When APS specifically asked each of the merchant generators to provide even one piece of tangible evidence to support their claims about the damage APS was doing to competition, they first objected to the question and then, when pressed, admitted they had no such evidence. Below is a sampling of the responses:

Duke Energy North America/Duke Energy Arlington Valley

Q.1-20 Please provide a copy of any analyses conducted by or on behalf of Duke, or of which Duke is otherwise aware, of the impact on the wholesale market (in Arizona or anyplace else) of the proposed PPA during each or any of the years 2003-2015.

Response: Objection. May require the disclosure of proprietary, confidential and competitively sensitive information to a competitor of Duke, and is overbroad, unduly burdensome, and irrelevant, particularly as it may relate to information about studies of markets outside of Arizona and insofar as it seeks "any analyses…of which Duke is otherwise aware."

Subject to the objection, none.

Harquahala Generating Company (a.k.a. PG&E):

Q.1-20 Please provide a copy of any analyses conducted by or on behalf of PG&E, or of which PG&E is otherwise aware, of the impact on the wholesale market (in Arizona or anyplace else) of the proposed PPA during each or any of the years 2003-2015.

Response: HGC does not intend to introduce into evidence or refer to in any testimony or cross-examination any documents relevant to this response.

Panda Gila River:

Q.1-20 Please provide a copy of any analyses conducted by or on behalf of Panda, or of which Panda is otherwise aware, of the impact on the wholesale market (in Arizona or anyplace else) of the proposed PPA during each or any of the years 2003-2015.

Response: Panda objects to this question because it requests disclosure of highly confidential, commercially sensitive information. Qualification of the impact of APS' variance request would necessarily involve Panda's projections of future market prices, potential transactions, and marginal costs of Panda's facility (along with speculation regarding costs of other wholesale generators' facilities). In addition, quantitative analysis requires an understanding of the cots of power under the PPA and the generating facilities used to supply such power. As discussed in Panda's objection to Question 1-3, it is impossible for Panda to determine future costs under the PPA. In addition, disclosure of such analyses could require disclosure of material legally protected from disclosure, including studies produced under confidentiality agreements or material prepared in anticipation of litigation, which material is therefore protected by the attorney work product doctrine.

Notwithstanding the foregoing and without waiving any of these objections, Panda anticipates that evidence will demonstrate that removing APS' approximately 6000 MW of Standard Offer load from wholesale competition will qualitatively harm the wholesale market, even if Panda is unaware of specific studies quantifying such harm.

Reliant Resources:

Q.1-20 Please provide a copy of any analyses conducted by or on behalf of Reliant, or of which Reliant is otherwise aware, of the impact on the wholesale market (in Arizona or anyplace else) of the proposed PPA during each or any of the years 2003-2015.

Response: See response to question 1-19.

[The response to Q.1-19 refers solely to the direct testimony of Curtis Kebler filed in this proceeding along with its responses to the Commissioners' Questionnaires on Restructuring this past February. Neither is directly responsive to the Question.]

Sempra Energy Resources:

Q.1-20 Please provide a copy of any analyses conducted by or on behalf of Sempra, or of which Sempra is otherwise aware, of the impact on the wholesale market (in Arizona or anyplace else) of the proposed PPA during each or any of the years 2003-2015.

Response: See response to Q.1-19.

[The response to Q.1-19 refers to attached documents and the response to Q-1-7, which in turn refers to pages 5-7 of Sempra's responses to questions posed by Commissioner Mundell, none of which address any specific harm to competition.]

Southwestern Power Group (including Toltec and Bowie power stations):

Q.1-20 Please provide a copy of any analyses conducted by or on behalf of SWPG, or of which SWPG is otherwise aware, of the impact on the wholesale market (in Arizona or anyplace else) of the proposed PPA during each or any of the years 2003-2015.

Response: See our response to Q.1-7 and Q.1-9 above. [The responses to Q.1-7 and 1.9 states that to date, no such studies have been conducted.]

Q. HAVE ANY OF THE MERCHANT PLANT INTERVENORS DEMONSTRATED THAT THE DECISION TO BUILD THEIR FACILITIES IN ARIZONA WAS PREMISED ON EITHER RULE 1606(B) OR THE 1999 APS SETTLEMENT AGREEMENT?

A. No. None of the merchant plant Intervenors were parties to the 1999 APS Settlement Agreement or even entered an appearance in that proceeding. In response to an APS data request, they had to admit that they did not have a single scrap of paper to back up their earlier contention that Rule 1606(B) had been a consideration, significant or otherwise, in the decision to locate or site a generating facility in Arizona. In fact, the only party that presented the Company with any documentation of a specific intent to serve load in the APS service area was Southwestern Power Group, and only from the planned Toltec facility, which subsequently failed to receive siting approval from this Commission. Again a sampling of their responses:

Duke Energy North America/Duke Energy Arlington Valley

Q.1-15: Please provide any documents issued by or on behalf of Duke that specifically mention any of the Arizona Corporation Commission's Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*)

Response: Objection: Vague, irrelevant, overly broad and unduly burdensome with respect to any documents that may mention the Electric Competition Rules; may require, at least in part, the disclosure of proprietary, confidential and competitively sensitive information to a competitor of Duke.

Harquahala Generating Company (a.k.a. PG&E):

Q.1-15: Please provide any documents issued by or on behalf of PG&E that specifically mention any of the Arizona Corporation Commission's Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*)

Response: Other than documents submitted by HGC in connection with the consolidated docket (Docket Nos. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069, E-01933A-98-0471), HGC has no documents responsive to Q.1-15. With respect to documents filed by HGC in the above-mentioned dockets, such information is equally available to APS from the Arizona Corporation Commission Docket Control.

Suppl. Resp. HGC has not issued any documents that specifically mention A.A.C. R14-2-1606.

Panda Gila River:

Q.1-15: Please provide any documents issued by or on behalf of Panda that specifically mention any of the Arizona Corporation Commission's Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*)

Response: Panda objects to this question because it seeks information not calculated to lead to the discovery of admissible evidence. Panda's internal communications regarding the Arizona Corporation Commission Rules are not relevant to determining whether APS' requested variance is in the public interest. In addition, it would be unduly burdensome to require Panda to search for irrelevant information, absent some showing by APS that the likelihood of discovering admissible evidence outweighs the substantial burden.

Panda also objects because the question seeks privileged information legally protected from disclosure, including confidential attorney-client communications and material prepared in anticipation of litigation, which material is therefore protected by the attorney work product doctrine.

Reliant Resources:

Q.1-15: Please provide any documents issued by or on behalf of Reliant that specifically mention any of the Arizona Corporation Commission's Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*)

Response: At the present time, the only documents known to be issued by or on behalf of Reliant that specifically mention Rule 1606(B) are Reliant's direct testimony of Curtis Kebler filed in this proceeding along with its Comments to the Commissioner's Questionnaires on Restructuring.

Sempra Energy Resources:

Q.1-15: Please provide any documents issued by or on behalf of Sempra that specifically mention any of the Arizona Corporation Commission's Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*)

Response: Documents attached, see general discussion of Rules in response to Q.1-7. [The response to Q.1-7 refers to pages 5-7 of Sempra's responses to questions posed by Commissioner Mundell and are not remotely contemporaneous with Sempra's decision to build in Arizona]

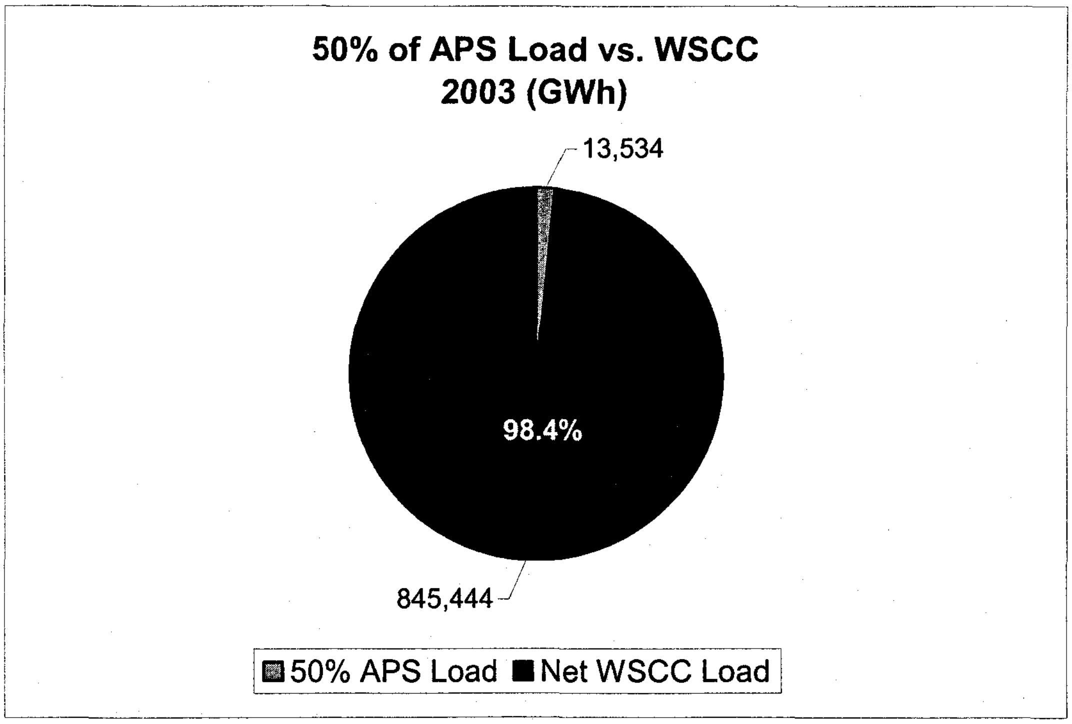
Southwestern Power Group (including Toltec and Bowie power stations):

Q.1-15: Please provide any documents issued by or on behalf of SWPG that specifically mention any of the Arizona Corporation Commission's Electric Competition Rules (A.A.C. R14-2-1601, *et seq.*)

Response: Copies of pleadings filed by SWPG in connection with the APS Request for Variance from the electric competition rules have been previously provided to APS as a party to docket E-01345A-01-0822.

Q. WILL APS EXERCISE MARKET POWER UNDER THE PROPOSED PPA AS ALLEGED BY STAFF AND INTERVENOR WITNESSES?

A. No. In response to one of the Company's data requests, Staff indicated that that "market power is the ability to influence price prevailing in a given market." APS Data Request 2-21. With or without the proposed PPA, APS or (post-divestiture) PWEC is a very small fish in a very big ocean. The chart below shows 50% of the Company's entire load as a percent of the total market. No doubt for this reason, Staff went on to state in the same response that "Staff is not claiming that APS or PWEC has market power at the regional level." Staff



then erroneously concludes that the relevant "market" is the just the APS service area, despite the strong interconnections between that service area and the balance of the Western United States.

Now California showed us that relatively small market participants can affect market price, but contrary to Staff's apparent belief, that alone is not indicative of market power. To benefit from market power, a participant must be able to both move the market and thereafter benefit from the price movement. That requires very significant amounts of reserve capacity, which is something neither APS nor PWEC has or will possess, even within the APS service area. In fact, the existence of a full-requirements obligation such as is represented by the proposed PPA would make it impossible for PWEC to even move the market price, let alone benefit from the movement, thus putting PWEC in even a worse position to ever exercise even the most localized of marker power.

VI. STAFF AND INTERVENOR WITNESSES HAVE MISINTERPRETED OR MISREPRESENTED THE SPECIFIC TERMS AND OVERALL INTENT OF THE PROPOSED PPA WHILE AT THE SAME TIME UNDERESTIMATING OR IGNORING ITS BENEFITS TO APS STANDARD OFFER CUSTOMERS

Q. HAVE STAFF WITNESS DAVID SCHLISSEL, RUCO WITNESS DR. RICHARD ROSEN, AND INTERVENOR WITNESS DR. LARRY RUFF PROVIDED CRITIQUES OF THE PROPOSED PPA?

A. Yes. I will specifically address Mr. Schlissel's, Dr. Ruff's and Dr. Rosen's criticisms, not because they are more or less valid than those of the other witnesses or because I wish to pick on Staff, RUCO, and Sempra, but because the three of them provide perhaps the most extensive criticisms, albeit from two totally different points of view. By discussing them in detail, I will cover the great majority of the points raised by the other Intervenor witnesses. However, my failure to mention any specific criticism of the proposed PPA should not be interpreted as representing my agreement with that criticism or as any "concession" by the Company on a particular issue.

Q. STAFF WITNESS SCHLISSEL AND OTHERS HAVE POINTED TO THE MINIMUM CAPACITY AND ENERGY PROVISIONS OF THE PROPOSED PPA AND EXPRESSED CONCERNS THAT THERE MAY BE INSUFFICIENT INCENTIVES FOR AVAILABILITY OR WORSE YET, UNINTENDED OPPORTUNITIES FOR PWM&T TO "GAME" THE AGREEMENT TO THE DETRIMENT OF APS AND ITS CUSTOMERS. WHAT IS YOUR RESPONSE TO THOSE CONCERNS?

A. I too would be concerned if these criticisms were valid. Fortunately, they are not. For example, Mr. Schlissel states that APS customers are not entitled under the proposed PPA to the entire 5618 MW of Dedicated Assets (sum of the Dedicated Units and the Dedicated Contracts)[2] or to 100% of the output from these assets if such capacity and energy are required to serve Standard Offer customers. Schlissel at 10-16. This is simply untrue, and let me make this unmistakably clear. APS customers have first call on 100% of the capacity and energy from the Dedicated Assets, subject only to one or more of the Dedicated Assets being physically unavailable for reasons excusable under the contract. I do agree, however, that the language in the proposed PPA may not be sufficiently clear on this point. Attached to my Rebuttal Testimony as Schedule JED-1R is revised language to Section 3.2.3 of the contract that I believe will clarify what was always the intent of the PPA.

Q. DOES THAT MEAN PWM&T COULD NOT PURCHASE SUPPLEMENTAL ENERGY PRODUCTS FOR APS IF ANY OF THE 5638 MW OF DEDICATED ASSETS REMAINED UNUTILIZED TO SERVE APS STANDARD OFFER LOAD?

A. No. As Mr. Schlissel correctly notes, the proposed PPA implicitly includes some 898MW of reserves in 2003. As APS Standard Offer load increases to the point where more than the 4720 MW minimum capacity is required to meet that

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[2] Mr. Schlissel uses the figure 5638 MW in his testimony. APS has been unable to determine the source of that figure and the reason why it is slightly different than what is set forth in the proposed PPA. I would also note that the capacity of the Dedicated Units will increase slightly once the new steam generator is installed for Palo Verde Unit 2 in 2004.

load, the reserve margin built into the proposed PPA would necessarily begin to deteriorate. That doesn't mean PWM&T would have *carte blanche* to run out and obtain Supplemental Energy Products (in this case, Supplemental Capacity) to fully and immediately restore the implicit reserve margin. PWM&T is required to follow good utility practices, and no utility would go out and acquire additional resources just because its reserves fell, say, from 16% to 14% for a couple of hours. Moreover, even if reserves fell below what everyone would agree is a prudent level, PWM&T could only purchase sufficient Supplemental Capacity to restore reserves to a level prudent under the circumstances, and not necessarily to the full level implicit in the PPA. This Supplemental Capacity would be the most economical available at the time, and because the full energy output of all 5618MW (2003) of Dedicated Assets would still be available to APS, little Supplemental Energy would be required under such circumstances. This is exactly how APS manages its resources today, and absolutely nothing would change under the proposed PPA.

Q. COULD PWM&T BOTH BE MAKING OFF-SYSTEM SALES FROM THE DEDICATED ASSETS AND PURCHASING SUPPLEMENTAL OR REPLACEMENT ENERGY RESOURCES FOR APS AT THE SAME TIME?

A. In the sense hypothesized by Mr. Schlissel and others, the answer is no. However, this could occur under an unusual circumstance but only to the benefit of APS and its Standard Offer customers. I go back to that same example used in the prior answer where APS load required more than the 4720 MW minimum capacity from the Dedicated Assets, and circumstances were such where it would have been prudent for PWM&T to acquire additional <u>capacity</u> to replenish, at least in part, the reserves standing behind the agreement. PWM&T could, nevertheless, make non-firm sales of <u>energy</u> from the Dedicated Assets.

This would not require that additional Supplemental Energy Products be acquired for APS because the energy from all the Dedicated Assets would remain fully available to serve APS customers on a firm basis, as would all the capacity. APS would, however, receive its share of the margins earned from these non-firm sales from Dedicated Assets.

Q. IS PWM&T "GUARANTEED" A REASONABLE RETURN ON THE DEDICATED ASSETS AS ALLEGED BY MR. SCHLISSEL AND OTHERS?

A. No. The overall return used to calculate the Facilities Charge is fixed for the initial term of the proposed PPA. Whether PWEC actually realizes that contract return depends largely on its ability to keep the Dedicated Assets available to APS without unexcused outages. PWM&T is also required to use good utility practices in all "practices, methods, and acts . . . which could be expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition." Proposed PPA at 32. Even if both PWM&T and PWEC fully satisfy the terms of the two contracts, the fixed return established in the proposed PPA may or may not be "reasonable." It was determined during a low point in the cost of capital cycle. In fact, it's the lowest equity return I can remember ever being awarded the Company. During past periods of time comparable to the initial term of the proposed PPA, APS' allowed equity returns have been as high as 16.15% and debt costs as high as 10.5%. I would presume that virtually every merchant plant Intervenor anticipates average equity returns over the next 13 years that are well in excess of 11.25% and expects debt costs to exceed 7.5% for all or a large portion of that period. The rate of return in the proposed PPA was also established for the proposed PPA before the recent demise of Enron and the difficulties experienced by other merchant generators such as Williams and Calpine, all of which have resulted in demands by creditors for higher equity ratios and less debt. And, of course, the portions of the Dedicated Assets that are comprised of the Dedicated Contracts include no return component for either PWM&T or APS.

Q. DOESN'T THE PROPOSED PPA PLACE ON APS MUCH OF THE RISK OF FUEL PRICE FLUCTUATIONS, PURCHASE POWER COSTS, INCREASED ENVIRONMENTAL COSTS, UNANTICIPATED (BUT REASONABLE) O&M INCREASES AND CAPITAL IMPROVEMENTS?

A. To the extent PWM&T and PWEC act prudently, the answer is yes. Many of these same risks may also be passed along to APS in a competitively-bid agreement or assumed by the seller only in exchange for a substantial premium in the base price, but that misses the point. The goal of the PPA is to provide Standard Offer customers most (but not all) the benefits of cost-of-service pricing. This means they ought to bear most (but not all) of the risks inherent in such a pricing scheme. It is unrealistic and unfair to expect PWM&T (and by extension, PWEC) to agree to a capped regulated rate of return but be required to assume the same risks as unregulated enterprises.

The same is true as regards the pass-through of costs attributable to Supplemental and Replacement Energy Products. APS has always included purchased power costs in rates on a dollar-for-dollar basis. This would also be the case under the competitive-bidding regime suggested by Staff and the Intervenors. Under the latter, there will be instances in which contracted-for power is not delivered or contracted-for power turns out to be less than what is actually required by the Company, thus necessitating the acquisition of the analogs to Supplemental and Replacement Energy Products. Now APS would agree that it must (through PWM&T) demonstrate to the Commission that both the decision to obtain Supplemental and Replacement Energy Products and the source from which they are obtained represent good utility practice if it reasonably expects to receive recovery in rates of such costs from its Standard Offer customers through an adjustment mechanism of some sort. But that is again no different than the situation today. Similarly, if PWM&T or PWEC fail to fulfill their contractual obligations, APS could be held liable by this Commission for failing to take reasonable steps to enforce its rights. Thus, to suggest that there is materially less opportunity for Commission oversight of purchased power costs under the proposed PPA than exists today or would exist under the massive competitive-bidding program recommended by Staff and the merchant plant Intervenors is simply inaccurate and misleading.

Q. MR. SCHLISSEL ALSO CONTENDS THAT THE PROPOSED PPA WOULD NOT GIVE THE COMMISSION OVERSIGHT OVER VARIOUS ASPECTS OF THE AGREEMENT. WHAT IS YOUR RESPONSE TO THESE CRITICISMS?

A. On the subjects of Competitively-Bid, Supplemental and Replacement Energy Products, the Commission will retain precisely the same oversight as is presently the case with purchased power and arguably more oversight than it would under the proposals of Staff and the merchant plant Intervenors. I say that because both Staff and these Intervenors are recommending significantly more mandatory competitive bidding than is required under the proposed PPA and also seem to be suggesting far more Commission involvement in the bidding process itself. Obviously, to the extent the Commission dictates specific resource acquisition strategies and procedures, it will have less discretion on an after-the-fact basis to question the outcome of these strategies and procedures.

As to the Dedicated Assets, the PacifiCorp and SRP agreements have been previously reviewed and approved by the Commission for inclusion in APS rates. The same is true of most of the Dedicated Units, and I would presume if Staff had any questions about the prudence or need for the Dedicated Units, it would have presented testimony on this issue. Both Commission rule and Commission precedent grant APS a presumption that such investments and costs are prudent absent "clear and convincing evidence" to the contrary. *See* A.A.C. R14-2-101 (A)(3)(l) and Decision No. 55228 (October 9, 1986). I would hasten to add that in the long history of APS, the Commission has never found that APS has been imprudent in the construction of any of its gas-fired generating units, and there is no reason given by Mr. Schlissel, let alone "clear and convincing evidence," to suggest a different result in this case. As to "used and useful," APS' current peak load is already in excess of the Dedicated Assets without regard to any reserve margin. Its load for 2004, the first year for which any of the new PWEC units would be reflected in rates, is expected to be some 520 MW higher. Thus, there is no credible issue as to whether these units will be "used and useful" in the traditional regulatory sense discussed by Mr. Schlissel.

Q. WHAT ABOUT FUTURE CAPITAL ADDITIONS, O&M AND FUEL COSTS INCURRED FOR THE DEDICATED UNITS?

A. (Sempra witness) Dr. Ruff posits a hypothetical where PWEC spends an additional $1 million in maintenance to presumably increase availability or efficiency to the extent that PWEC can make additional off-system sales producing $2 million in gross margins. Ruff at 17. He then compares the $1 million in additional O&M charged to APS under the proposed PPA with the Company's share of the increased margins, $500,000, to somehow conclude that this is a bad deal for APS Standard Offer customers. His hypothetical is simply wrong and consequently draws an improper conclusion. First of all, if the $1 million dollar cost is a one-time expense bringing in a $500,000 return every year to APS, this would be one heck of an investment for APS customers. Secondly, APS customers would have first call on the posited increased availability and/or efficiency. Thus, rather than making increased off-system sales from the Dedicated Units, these Dedicated Units would be available and operate more often to produce Dedicated Energy Products for APS customers. Under the situation assumed by Dr. Ruff in his hypothetical, this would result in a reduction in purchase power or fuel costs to APS somewhat in excess of $2 million, or a 100% plus annual return to APS customers for the original $1 million O&M investment, which would be an even better deal for APS customers than under the assumptions in Dr. Ruff's hypothetical.

Aside from the flaws in Dr. Ruff's specific hypothetical, and as I noted earlier, the operation of the Dedicated Units, and indeed, PWM&T's whole administration of the two agreements (one with APS and the other with PWEC) is limited by the notion of "good utility practice" under the proposed PPA. It would hardly be anyone's definition of "good utility practice" to knowingly make an uneconomic investment based solely on the belief that the imprudent expenditure could be passed off to the counter-party to the agreement. And if APS refused to take reasonable steps to enforce those standards against PWM&T or PWEC, I believe the Commission to be far from powerless in such circumstances. That being said, the Company is not opposed to providing some additional safeguards against even this hypothetical possibility of overreaching on the part of PWM&T and PWEC. Attached as Schedule JED-2R to my

Rebuttal Testimony is revised contract language that gives APS the power to audit capital additions and O&M costs, as well as the fuel costs of the Dedicated Units every three years at the same time as the new Facilities Charge is determined. These audit results would be available to the Commission and non-competitors of PWEC/PWM&T on a confidential basis. If an audit turned up any unexplained irregularities that failed the standard of good utility practice (which I believe is indistinguishable from the Commission's traditional prudence standard), APS would again have to demonstrate its own prudent efforts to enforce its rights under the contract.

Q. DOES THE PROPOSED PPA CONTAIN ANY PERFORMANCE "GUARANTEES" OR INCENTIVES RELATIVE TO THE DEDICATED UNITS?

A. There are no absolute guarantees of anything in either life or business, and I have not seen a purchase power contract that had no *force majeure* provision. However, I do believe that provision in the contract should be clarified to remove the possible interpretation wherein a default by PWEC on its agreement with PWM&T could be claimed as a *force majeure* by PWM&T with regard to the PPA. Although in such an instance I believe APS would insist that PWM&T take action against PWEC or that APS could even take such action itself as a third-party beneficiary of the PWEC/PWM&T agreement, it is better to just eliminate this unintended issue from these proceedings. A revised *force majeure* provision to the proposed PPA is attached as Schedule JED-3R.

The proposed PPA does have minimum capacity and energy requirements, and the sharing of off-system sales margins gives PWEC/PWM&T a powerful incentive to have the Dedicated Units available as often as possible. Indeed, as noted above, Intervenor witness Dr. Ruff suggested that this may "over-incent" the parties to make what would be for APS uneconomic improvements to unit efficiency and availability [Ruff at 17], which was one of my motivations in suggesting that APS have the right to audit major capital additions or major O&M increases.

Q. MR. SCHLISSEL AND OTHER WITNESSES ARE CRITICAL OF THE TERM OF THE PROPOSED PPA. WOULD APS AND PWM&T CONSIDER AN AGREEMENT WITH A SHORTER TERM?

A. That depends on how much shorter. As APS noted to the parties in response to discovery, it considered both longer and shorter terms during the course of developing the proposed PPA. As a general proposition, APS was opposed to the shorter term because it was looking for long-term reliability and stability. PWM&T was opposed to a longer term for precisely the reasons identified in RUCO witness Rosen's testimony. As to the allowed extensions of the proposed PPA, APS would agree to seek to exercise its right of termination under Section 11.2 of the proposed PPA if the Commission determines that continuation of the proposed PPA for another five-year term is not in the best interests of APS Standard Offer service customers.

Q. DO YOU BELIEVE THAT MR SCHLISSEL HAS ALSO UNDERESTIMATED THE BENEFITS OF THE PROPOSED PPA?

A. Yes. In addition to those non-price factors discussed earlier in my Rebuttal Testimony, as well as in my Direct Testimony, Mr. Schlissel (among others) has criticized my calculation of customer benefits of between $400 million and $1.5 billion for the following reasons:

1) my calculation essentially assumes all the Dedicated Assets' output would be replaced by power acquired at long-run market prices;

2) my calculation assumes that all the power used to replace the Dedicated Units would come from gas-fired plants; and,

> 3) it is impossible to know precisely how much power from the PPA will cost, specifically the cost of Supplemental and Competitively-Bid power and the fuel and non-fuel operating costs of the Dedicated Units.

Schlissel at 22-23. Mr. Schlissel goes on to state that the underlying assumption of my analysis can only be proven by actually competitively bidding and seeing what happens.

The first two points raised by Mr. Schlissel are really the same point. Since the alternative to the PPA is purchasing the Company's Standard Offer service requirements for a comparable period of time entirely from the competitive market, comparing the PPA price to the long run competitive market price is hardly a criticism – its an essential part of what you're trying to measure by the analysis. Second, I don't assume that all the generation will come from gas-fired generation (although it might). I do assume that sellers will expect to get market prices for all the generation they sell to APS, irrespective of fuel source. Thus, if gas-fired generation drives the market price, and on that I don't believe there is much dispute, all market generation will be priced at gas irrespective of its actual fuel source.

Mr. Schlissel's third criticism ignores the fact that my analysis claimed no savings attributable to Supplemental or Competitively-Bid power. That was assumed to come at the long-run market price. Similarly, I used the same gas price assumptions for both the long-run market price and the portion of the Dedicated Energy Products that are themselves generated from gas generation. Thus, whether my projections were right or wrong, they would cancel out for some 30% of the MWHs analyzed. As to coal prices, those long-term agreements are fairly easy to project with a high degree of accuracy. Non-fuel

O&M costs could vary from forecast, but that could go either way. Although I cannot discuss specific numbers in a public forum given the presence of so many competitors of APS/PWM&T/PWEC, we have given these numbers to Staff and RUCO, and I believe they would agree that they are conservatively high for purposes of my calculation of future Dedicated Unit costs under the proposed PPA.

I do agree that if APS could competitively-bid load and energy equivalent to the Dedicated Energy Products for the equivalent period of time and at the same delivery points, we would know more about whether the prices so bid were below or above the projected prices of the Dedicated Energy Products. However, no party, including Staff, has suggested such a comparable bid. And even if they had, we still wouldn't know for certain, both because the competitively acquired power would itself likely be subject to variable price escalation provisions and because a contract for delivery is no better than the counterparty to the contract. However, at that point it really wouldn't matter since the Company would be stuck with the bids, for better or worse. And that still won't resolve the Company's concerns about fuel diversity, geographic diversity, and overall responsibility for supply reliability

Q. **COULDN'T APS CONDUCT A NON-BINDING BID?**

A. We could, but it wouldn't tell you anything useful. If the bids are not binding, then you will not get serious bids. It will be like the "expressions of interest" that gas pipelines solicit when considering constructing a new pipeline. Everyone sends in their "expressions of interest" quoting fantastic volumes of gas they want to transport on the proposed line, but when it comes time for taking binding orders for specific capacity, they're all staring at the floor and sitting on their hands.

Q. DR. ROSEN ALSO HAD SOME CRTICISMS OF THE PROPOSED PPA. WOULD YOU PLEASE RESPOND.

A. Yes. Dr. Rosen expresses concern that "APS might try to raise the required rate of return on all of APS' existing generating capacity, either in its next ACC rate case, or in a case at FERC, above the level being requested here." Aside from the fact that APS (as contrasted with PWM&T or PWEC) would have no reason to wish an increase in the rate of return on the Dedicated Units, the proposed PPA fixes the return for the initial term of the contract. And for the reasons I discussed earlier in my Rebuttal Testimony, this is a positive feature from the perspective of APS and its customers because the fixed return was established during a period of relatively low capital costs.

Dr. Rosen is also concerned about the term of the proposed PPA, albeit for precisely the opposite reasons as posed by Staff, AECC, and the merchant plant Intervenors. All I can say is that you obviously can't please both sides on this issue. I can add little to what I previously said about the competing concerns that APS and PWM&T had relative to the term of the Agreement.

Finally, Dr. Rosen is opposed to a mandatory competitive-bidding requirement of any kind and believes all future resource acquisition should be administratively determined through a more or less traditional resource planning process. He further believes that such a process should allow for a "self-build" option by the UDC. The first of these suggestions would go further than APS has proposed and further than it could support at the present time. APS believes that "trying the water" in the competitive wholesale market through a measured and consistent phase-in of competitive bidding is appropriate and continues to stand by its original proposal. As to maintaining a UDC "self-build" option, that would require yet another variance to the Electric Competition Rules, and the Company has quite enough on its hands trying to secure one variance without trying to get another. Also, it is just not practical for APS to maintain two generation-owning and generation-building organizations – one at APS and another at PWEC.

Q. SEMPRA WITNESS DR. RUFF ALSO CLAIMS THAT THE PROPOSED PPA COULD LEAD TO A "DEATH SPIRAL" EFFECT IF APS LOSES SIGNIFICANT AMOUNTS OF LOAD TO RETAIL COMPETITION. DO YOU AGREE?

A. No, and I really doubt Sempra is overly concerned with the Company's loss of Standard Offer load. However, this hypothetical is more likely to occur when high market prices for the Competitively-Bid Energy Products drive up the average cost of the PPA rather than because of the impact of Dedicated Energy Products themselves. Nonetheless, Dr. Ruff himself posits some of the solutions should significant APS Standard Offer customers leave for Direct Access. These include resale of portions of the Dedicated and Competitively-Bid Energy Products and/or renegotiation of the deal with PWM&T. PWEC could also reduce the costs of the Dedicated Units by eliminating or deferring maintenance on the assumption that the units now have less demanding duty cycles. PWEC could even retire or mothball one or more of the units, thus further reducing the Facilities Charge component. Yet another option, and one APS would likely propose if at the time of this hypothesized loss of retail load the cost to consumers of Dedicated Energy products was or was anticipated to be below those obtained through competitive bidding (again the most likely situation under the facts posited by Dr. Ruff in his hypothetical), is to request the

Commission for relief from the continued mandatory competitive bidding requirements of the proposed PPA.

Q. DR. RUFF ALSO CHARACTERIZES THE RENEWAL OPTIONS AS "A HEADS-PWCC WINS-TAILS-PWCC WINS" PROPOSITION. IS HE CORRECT?

A. No. I have previously discussed modifications to the optional renewal procedure to address those who are concerned that APS would renew the PPA even if not in the best interests of Standard Offer customers. Mr. Ruff now seems concerned that APS will not renew the PPA and would instead be forced to buy from his client and the other merchant plant Intervenors at higher prices. It should be obvious that the only viable solutions to Mr. Ruff's concerns would be to lengthen the initial term of the proposed PPA or to make the renewal options unilateral in the Company's favor. Both would alter the economics of the package represented in the proposed PPA and would not be fair to PWM&T and, I doubt, neither change would be supported by the merchant plant Intervenors.

Q. DOES DR. RUFF AFFIRMATIVELY SUPPORT IMPLEMENTATION OF RULE 1606(B) AS WRITTEN?

A. No. He states: "There are many possible alternatives to APS' interpretation of Rule 1606(B), including what the Commission probably had in mind all along: A prudent phase-in of competitive contracting over time." Ruff at 23. Putting aside the issue of what the Commission had in mind during the entire 10-15 minutes it deliberated on the 50% competitive bidding requirement, Mr. Ruff's proposal of "[A] prudent phase-in of competitive contracting over time" is precisely what the Company is attempting to accomplish through the proposed PPA, the only remaining issue being what manner of phase-in the Commission finds most "prudent" given present and anticipated market conditions in Arizona and the nature of Standard Offer service.

VIII. CONCLUSION

Q. WOULD YOU SUMMARIZE YOUR CONCLUSIONS?

A. Yes. The proposed PPA was a package deal covering both the existing APS generation units scheduled to be transferred to PWEC pursuant to Rule 1615 and the 1999 APS Settlement Agreement and certain new facilities specifically constructed by PWEC to serve APS load. Attempts to divide the agreement either by refusing to allow APS to transfer its generation to PWEC or by slicing PWEC's units off fundamentally and fatally destroy the economic foundation of the proposed PPA. In my Rebuttal Testimony, I have proposed certain changes to the contract either in response to some of the points raised herein or to better effectuate the original intent of the agreement. Each of these changes is beneficial to APS and detrimental to PWM&T, but they do not undermine the essential economics of the deal.

Competitively bidding the portion of APS Standard Offer load suggested by Staff and the merchant plant Intervenors is neither practical nor desirable. APS has proposed a measured and practical way for competitively acquired power to be phased-in for the Company's Standard Offer service requirements while preserving the advantages of cost-service-regulation for much of those requirements. All the while, those APS customers who believe they have better opportunities in the market can avail themselves of Direct Access service. In doing so, they will have a direct means of comparing those opportunities to the cost of power under the PPA. There will be no doubt as to the appropriate "market generation credit."

The proposed PPA will provide stable, reliable and reasonably priced power for the Company's Standard Offer customers for all the reasons I discuss in my Direct Testimony. These include: fuel diversity, geographic dispersion, operational characteristics and history, and transmission availability. It also results in putting some entity in charge of supply reliability – something overlooked by the Electric Competition Rules.

Finally, the proposed PPA and the competitive bidding requirements of Rule 1606(B) have one thing in common. Both are premised on the divestiture of the Company's generation as called for in Rule 1615 and the 1999 APS Settlement Agreement. I cannot emphasize too much that the path upon which APS and its affiliates find themselves was one taken entirely in reliance upon this singular promise. Whether or not the Commission finds the requested variance and the proposed PPA to be in the public interest, I urge the Commission to reject the recommendations of those who would now urge a repudiation of this and other regulatory promises.

Q. DOES THAT CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes, it does.

3.2.3 Minimum Availability of Dedicated Units.

3.2.3.1 Capacity. APS' Full Load Requirements Capacity needs shall have the first call rights on one hundred percent (100%) of the Capacity from the Dedicated Units, unless one or more of the Dedicated Units is physically unavailable. However, ~~A~~at a minimum, PWCC shall make Capacity from the Dedicated Units available as follows: (a) for 2002, prior to the transfer of Palo Verde Nuclear Generating Station Assets, the lesser of 3440 MW at system peak or actual load at system peak; and (b) for 2003 and later, after the transfer of Palo Verde Nuclear Generating Station Assets, the lesser of 4720 MW at system peak or actual load at system peak, subject to adjustment as Dedicated Units are retired

3.2.3.2 Energy. APS' Full Load Requirements Energy needs shall have the first call rights on one hundred percent (100%) of the Energy from the Dedicated Units, unless one or more of the Dedicated Units is physically unavailable. However, ~~A~~at a minimum, PWCC shall have available Energy from the Dedicated Units in the amount of: (a) for 2002, prior to the transfer of Palo Verde Nuclear Generating Station Assets, 15,370 GWh annually; and (b) for 2003 and later, after the transfer of Palo Verde Nuclear Generating Station Assets, 21,090 GWh annually, subject to adjustment as Dedicated Units are retired

13.12 Audit Rights/Retention of Records.

(A) Each Party shall maintain records of all transactions under this Agreement for a minimum of 3 years from the billing date of the transaction.

(B) Each Party may require the other Party to produce the other Party's records to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement.

(C) If the records produced under Section 13.12(B) reveal any inaccuracy in any invoice or similar statement, a refund shall issue to the Party owed money plus Interest, except that if the invoice or statement resulting in the refund is over 12 months old, no refund shall issue.

(D) APS shall have the right to conduct an audit of PWCC's Dedicated Units Annual Operating Expenses, Net Dedicated Units Assets, Base Fuel Charges and/or Fuel & Purchase Power Adjustments, as such terms are used in the Service Schedules to this Agreement, once every three (3) years and in a time period concurrent with the determination of the revised Facilities Charge, as such term is used in the Service Schedules to this Agreement. APS must provide PWCC twenty (20) days written notice of the intent to conduct an audit as described herein, and the commencement of the audit is subject to the execution of a mutually agreed upon confidentiality agreement between the Parties.

[EXHIBIT A]

[Definitions]

"Force Majeure" means an event that: (a) is not anticipated on the date the Agreement is signed; (b) is not within the reasonable control of the Party claiming Force Majeure; (c) could not, in the exercise of reasonable diligence and Good Utility Practice by the Party claiming Force Majeure, have been prevented or avoided; and (d) renders the Party claiming Force Majeure unable to carry out, wholly or in part, its obligations under this Agreement. Subject to the foregoing, Force Majeure includes, but is not limited to, the following events: (1) act of God; (2) act of public enemy, war, terrorism, blockade, insurrection, civil disturbance, disobedience or riot; (3) strike, lockout, material shortage or other industrial disturbance; (4) epidemic, landslide, earthquake, fire, storm, lightning, flood or other natural catastrophe; (5) failure of the transmission or distribution grid, including third parties' transmission facilities, to transmit or distribute Energy; (6) reductions or interruptions in services which may be required by the control area operator or regional transmission organization; (7) material failure of performance (a) by any non-PWCC Affiliate acting as a PWCC supplier, including failures as a result of Force Majeure, which results in a shutdown or material reduction of any of the generation capacity or output owned or controlled by PWCC or a PWCC Affiliate or (b) by any PWCC Affiliate acting as a PWCC supplier which is a result of a force majeure in the agreement between PWCC and such supplier; (8) shutdown or reduction by the Nuclear Regulatory Commission of a material portion of the generation capacity or output which is owned or controlled by PWCC or a PWCC Affiliate; (9) act, omission, failure to act, or order of a civil, judicial, regulatory or government authority, if the Party claiming Force Majeure has acted to the fullest extent reasonable to prevent or correct the act, omission, failure to act or order; and (10) any other act or omission similar to the foregoing examples which by the exercise of a Party's reasonable diligence cannot be overcome. Force Majeure specifically excludes PWCC's ability to sell Dedicated Energy Products at a more advantageous price.

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

On Behalf of Arizona Public Service Company

Docket No. E-01345A-01-0822, et al.

April 22, 2002

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Rebuttal Testimony of William H. Hieronymus

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, Massachusetts 02116.

Q. Are you the same William H. Hieronymus who filed direct testimony on behalf of Arizona Public Service Company earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. Arizona Public Service Company (hereafter, APS) has requested that I respond to comments made by witnesses for various intervenors and ACC Staff. I will focus substantially on the testimony of Dr. Roach, a witness for Panda Gila River, L.P. because his testimony most directly seeks to rebut my conclusion that granting the variance and executing the PPA are in the best interest of APS's customers. However, I also will comment on other intervenor testimonies as well.

Q. Based on your review of these testimonies, have you changed your conclusions?

A. No. I reached two fundamental conclusions in my direct testimony. The first was that the PPA was in the best interests of APS's customers. While criticisms of my analysis that compared the PPA to benchmark contracts, which analysis partly underwrote that conclusion, have caused me to make minor adjustments to the comparison, the fundamental conclusion is unaffected. Indeed, the revisions I have made actually improve the case that the PPA is cheaper than the benchmark contracts. My second conclusion was that the variance to the competition rules that APS requested to permit the PPA to be signed would not materially impact competition in wholesale markets. That conclusion was not seriously rebutted by Dr. Roach or any of the other Staff or intervenor witnesses and likewise remains unchanged.

Q. Dr. Roach criticizes your benchmark analysis on several grounds. Have you reviewed his criticisms?

A. Yes. Dr. Roach makes what he characterizes as four criticisms. These relate to my alleged failure to document assumptions that I made in creating a comparison of the PPA to the other contracts, a "failure" that he uses as a jumping off point for substituting his own assumptions; my comparison of the PPA to the individual contracts rather than to his "optimal portfolio" of such contracts; the fact that I did not compare the PPA to the affiliate contract offered by PG&E; and my alleged failure to take into account the non-price terms of the benchmarking contracts.

Q. What is the substance of Dr. Roach's first criticism?

A. Dr. Roach asserts that I have "failed to document" my analysis of the cost of the PPA relative to the cost of the benchmark DWR contracts. However, as his very criticisms make clear, it is simply incorrect that he cannot tell how the calculation was made. In fact, Dr. Roach appears to have had no difficulty understanding either the method or the inputs to it. Rather, his criticisms go to the inputs to the calculation and to what he believes is a lack of sufficient discussion of their basis. In some cases he disagrees with these inputs; in all cases he presents an alternative input or mode of analysis. On the basis of his inputs, he concludes that the cost of the PPA on a levelized nominal basis is between $62.04/MWh and $64.54/Mwh, which is up to 28 percent above the estimate that I presented.

Q. Do you agree with Dr. Roach's criticisms?

A. Generally, no. However, I have taken the criticisms seriously and have gone back and sought other data to determine whether the assumptions I made are reasonable and supportable. In some cases I have modified my assumptions. The new analysis is shown in Exhibit WHH-1R, and is discussed further below.

Q. Dr. Roach asserts that you erred in using 25,531 gWh instead of the contractually guaranteed 20,090 gWh in calculating the cost of power under the contract. Do you agree?

A. Certainly not. The contract is akin to a tolling agreement, in that APS gets to nominate the amount of power to be dispatched on the basis of its hourly load, subject to a) the size of its load less its small amount of renewable assets, what it takes from certain pre-existing third party contracts, and also the amount to be procured at competitive auction and b) the amount of capacity available from the Dedicated Units. APS is not limited to the contractual minimum energy, any more than it is limited to the contractual minimum capacity. In arriving at these minimums, APS and PWEC took into account a conservative margin of non-availability; in the case of capacity, it is based on a 16 percent reserve margin.

The 25,531 gWh that I used was derived in APS's analyses of the ability of the units to produce energy, taking potential outages into account, and the ability of APS to use the energy, given its load and the other contractual sources of power. The figure that I used is the result of this calculation for 2004. In future years, the amount could be more or less. The key driver of whether the amount goes up or down is the relationship between load growth and the 270 MW of projected load growth per year to be served by third party generation acquired under competitive bidding. If load grows faster than 270 MW (or APS's load factor improves to more than 51 percent), the amount of power from dedicated resources likely will exceed 25,531 MWh; conversely if load grows by lesser amounts, the amount of power that APS could take is reduced. Yet another factor will be whether SRP exercises its right to cancel its long-term agreement with

APS, which SRP is free to do with 3 years' notice. If it does so, this would increase APS's need for power from the Dedicated Units.

In forecasting the future, it is important to use expected, not extreme outcomes. The calculation that I have made relies on a reasonable and conservative estimate of the power that would be produced from the dedicated units under the PPA, even assuming the continued availability of the SRP power. The calculation that Dr. Roach espouses and upon which he relies in computing the cost of power from the PPA assumes the extreme result that PWC will not be able to produce (or APS could not use) anything above the contractual minimum that it is required to produce, in each and every year of the contract. PWC has no incentive for such a poor level of performance. Indeed, the fact that it gets a share of profits from off-system sales, sales that only can be made once the dispatch request of APS is met fully, gives PWC a strong incentive to maximize the availability of the dedicated units.

Q. Dr. Roach also disagrees with your use of coal prices from the mountain region, arguing that you should use prices for the Arizona-New Mexico sub-region, which show a higher rate of escalation. Why did you use mountain region prices?

A. The EIA forecasts the price of coal delivered to electric utilities for the Mountain Region, but not for sub-regions. Hence, the Mountain Region was the smallest relevant region for which a delivered coal price was available. I regarded delivered prices to utilities as a more relevant basis for price escalation than the mine-mouth prices that are available on a narrower regional basis.

Q. Have you further considered what forecast series is most appropriate for APS's coal units?

A. Yes. Approximately 65 percent of APS's coal-fired capacity is minemouth, whereas 35 percent is delivered by unit train to Cholla. A review of the EIA forecasts indicates that the escalation rate difference between regional delivered prices and minemouth prices relates to transportation, which indeed has fallen substantially in real terms in recent years. In view of the mix of coal deliveries for APS coal units, I used the escalation rate that Dr. Roach recommends for 65 percent of the coal, and the delivered price escalator for the Mountain Region for the remaining 35 percent.

In calculating a new fuel cost, I used the weights for the mix of energy from Mr. Davis's testimony that was used by Dr. Roach. However, I weighted the escalation on a dollar rather than kWh basis, as is correct. Because the highest cost fuel in the mix, gas, has the highest rate of escalation, this increases the escalation rate for the PPA fuel charge relative to the method used by Dr. Roach.

Q. Have you made any other changes in your fuel prices?

A. Yes. Recall that in my original analysis I used the fuels escalators to increase fuels costs from a base charge of 1.74 cents per kWh in 2003. Dr. Roach does the same. In discussing the fuel cost issues with personnel at PWCC, I discovered that the 2003 fuel cost forecast incorporated gas hedges that are at above current market prices. This also is true of 2004. As these hedges unwind, fuels costs will fall, not rise as I had assumed. APS forecasts that the 2004 actual nominal fuel cost will be 1.71 cents/kWh and that the 2005 cost, after the above-market hedges fully expire, will be 1.60 cents/kWh.

Hence, by simply escalating the 2003 base fuels price, I was making the inadvertent assumption that the existing out-of-market hedges would continue year after year throughout the period of my analysis. That is incorrect and in order to correct that error, it is necessary to shift from a base year of 2003 (since the fuel cost for that year is not at market) to a base year of 2005. In so doing, however, I have not simply adopted APS's 2005 forecast of 1.60 cents per kWh.

Because the EIA gas prices that I am using are somewhat higher than those in the APS analysis, I have instead used a 2005 price of 1.66 cents per kWh in order to be conservative.

The effect of the change in escalation that I have made is to increase fuel costs, whereas the effect of taking the out-of-market hedges out of the base fuels costs as the hedges expire is to reduce them. The net effect is to reduce the fuel costs that I use in Exhibit WHH-1R relative to the analysis in my direct testimony.

Q. **Dr. Roach also criticizes your assumption that the facilities charge for the dedicated units would rise at the rate of inflation less 1.5 percent, stating that you had provided no basis for that assumption. He instead assumes that they will increase at the rate of inflation. What was your basis for assuming that the facilities charge would go down in real terms by 1.5 percent?**

A. The largest portion of the facilities charge relates to the capital cost of the Dedicated Units. Such capital cost consists of interest payments, equity returns and associated taxes, and depreciation. Inherently, the initial capital cost of the units (i.e. historic book cost) is fixed in nominal terms. Hence, it goes down in real terms at the rate of inflation. As a result, (given that the rate of return imbedded in the PPA is fixed) the return component of the facilities charge also declines in real terms. Moreover, as the "ratebase" is depreciated, the return and associated taxes and the interest component of the cost of capital also go down even in nominal terms. Hence, these components of the initial "ratebase" not only do not rise with inflation, but they also fall in nominal terms at the rate of depreciation of the initial (2004) investment.

The initial capital-related component of the facilities charge is approximately two-thirds of it. Thus, considering that two thirds of the charge will not increase with inflation and indeed should decrease even in nominal terms, it could have been reasonable for me to project that the facilities charge should go down even in nominal terms. However, I assumed that the facilities charge would rise in nominal terms, at the rate of inflation less 1.5 percent. This contrasts with Dr. Roach's assumption that the charge will rise at the full rate of inflation, an assumption for which he provides no basis whatsoever and which is inconsistent with the "cost-of-service" nature of the PPA.

Q. **Why didn't you assume that the facilities charge would be constant or decline in nominal dollar terms?**

A. The reason why I assumed that the facilities charge would actually rise in nominal terms despite a decline in its largest component was because of the two remaining main elements that make up the facilities charge. These are capital additions and O&M expense and related G&A costs. Capital additions, by increasing "rate base" increase capital-related charges. O&M and related general and administrative charges also should go up on a nominal basis. However, this should not fully offset the effect of declining capital related charges. Based on historic evidence, O&M charges for a fixed set of generating units should go down in real terms as a result of productivity improvements.

On balance, a reasonable expectation is that the mix of facilities charges should stay approximately constant or go up quite slightly in nominal terms. I conservatively assumed that such charges would go up in nominal terms at a rate that is 1.5 percent less than inflation. I say, "conservatively" because, given that three-quarters of the charge predictably will go down in nominal terms, the implied rate of increase in the remaining components is quite large by historic standards.

Q. Dr. Roach also criticizes you for levelizing the cost over only 10 years rather than over the 13 years for which you present data. Do you agree with this criticism?

A. No. The whole purpose of the levelized calculation is to create a metric that can be compared to the benchmark contracts. The benchmark contracts all are about 10 years, not 13 years. Even in my analysis in my direct testimony, nominal prices for power from the PPA are higher in years 11-13 than in the previous years. In Dr. Roach's "Corrected Hieronymous (sic) Exhibit WHH-3" they are substantially higher since he assumes that both energy and facilities charges increase at approximately the rate of inflation. Hence, a 13-year levelized nominal price is materially higher than the 10-year charge that is the only valid basis for comparison.

The invalidity of Dr. Roach's comparison can be demonstrated as follows: Suppose that one is deciding between two certificates of deposit. Certificate A, which we will use as the "benchmark" certificate, is a 10-year certificate. Certificate B, the "PPA" certificate, is a 13-year certificate. Suppose that in fact the interest rates on the two certificates are exactly the same. Now suppose that the person calculates the average amount of funds in the certificate over its life. For obvious reasons, the average would be higher for the 13-year certificate, leading to a false conclusion that the 13-year certificate is a better investment than the 10-year certificate.

Dr. Roach's "apples to oranges" comparison would be less misleading if we were comparing levelized real costs instead of levelized nominal costs. As shown on Exhibit WHH-1R, the out-year levelized real charges are quite similar to (indeed, lower than) those in the first 10 years. Most economists would use levelized real comparisons rather than levelized nominal. I used the levelized nominal comparison simply because it is what Mr. Meehan used. In turn, Mr. Meehan used it solely because it is consistent with FERC precedent.

Q. Dr. Roach also made the provisional criticism that you did not adjust the contract cost to reflect ancillary services costs. Can you explain this issue?

A. Yes. In Mr. Meehan's benchmark analysis he increased the cost of those benchmark contracts that did not include provision of ancillary services by his estimate of the market cost of purchasing ancillary services. This adjustment was necessitated by the fact that the PG&E PPA would provide ancillary services. Dr. Roach is unsure whether the APS PPA includes such services or not and provides a calculation that imputes the cost of ancillary services to the APS PPA of $2.50 per MWh.

Q. Is Dr. Roach's calculation correct?

A. Dr. Roach is correct that an adjustment for ancillary services needs to be made. He is incorrect regarding the amount of the adjustment.

Q. Why is an adjustment necessary?

A. PWCC will indeed provide ancillary services. However, they will be provided under a separate contract. As indicated in Attachment 1 to the Service Schedule of the PPA, all of PWCC's ancillary services revenues will be deducted from the facilities charge. Hence, whatever APS pays to PWCC via the separate ancillary services contract will be rebated to it via the facilities charge. Therefore, what it takes out of one pocket flows back to the other.

While APS will not make a net payment for ancillary services, it nevertheless is true that I need to increase the cost of the PPA for the current APS estimate of the cost of ancillary services. This is because the base year facilities charge number that both Dr. Roach and I use already reflects the offset for PWCC's anticipated revenues from sale of ancillary services. Since that same amount (or at least the bulk of it) will be charged separately to APS, it is necessary to add it back in order to arrive at a facilities charge that reflects contractual arrangements that provide the ancillary services associated with the dedicated facilities. Relative to the analysis I provided in my direct testimony, this adds $18 million to the facilities charge in 2003, with slowly increasing amounts thereafter. I have increased the base facilities charge that I escalate in my analysis to reflect this.

Q. Dr. Roach used a substantially higher ancillary services cost than the $18 million that you cited. Does this affect the net cost of power under the PPA?

A. No, not at all. The facilities charge that I now am using is based on APS's estimate of the non-fuel cost of the PPA with no offset for payments for ancillary services. If, as Dr. Roach assumes, the cost of ancillary services would be $52 million rather than the $18 million that APS forecasts, then APS would pay the $52 million and receive a full rebate of it via a dollar-for-dollar reduction in the facilities charge. Hence, it truly does not matter to APS what the market cost of ancillary services is.

Q. Moving on to the second of Dr. Roach's criticisms of your analysis, he argues that you should have compared the APS PPA to an optimum portfolio of the benchmark contracts rather than simply comparing it to the cost of the individual contracts. He asserts that the optimum portfolio cost in Mr. Meehan's analysis is $56.82/MWh. Please respond.

A. Even if Dr. Roach is correct that an optimum portfolio analysis is useful, which may or may not be true, he clearly has chosen the least valid of the portfolios that Mr. Meehan constructed. The more valid portfolio has a higher cost than the portfolio he has used.

Q. Why is the portfolio with a cost of $56.82/MWh invalid for comparison to the APS PPA?

A. In order to answer that question, it is necessary first to explain the role of the "optimum portfolio" that Dr. Roach would have me compare to the PPA in a benchmark analysis. Mr. Meehan was seeking to demonstrate conclusively that the PG&E PPA was materially cheaper than the benchmark contracts. In so doing, he made numerous assumptions that favored the economics of the benchmark contracts so that there could be no credible claim that his analysis was biased in favor of the PG&E PPA. (These are described at pages 57 to 59 of his testimony.) Because my benchmark analysis has the same goal, I have left all of those conservative (from the perspective of the relative economics of the PPA) assumptions intact.

Dr. Roach has a quite different objective, that of demonstrating that the PPA is <u>not</u> in the best interests of APS's customers. What is an attempt to be conservative from Mr. Meehan's and my perspective is merely self-serving opportunism for him. That is, the conservativisms in Mr. Meehan's analysis are already biases in favor of Dr. Roach's position. While I will not reiterate all of the conservativisms in Mr. Meehan's analysis, there is one that needs to be explained in the context of the "optimal portfolio" to which he refers.

In determining the cost of the contracts in his benchmark group, Mr. Meehan made the ultra-conservative assumption that the power that DWR must purchase under the "must take" provisions of the contracts, and which was not needed to meet the load that DWR would serve, could be resold in wholesale spot markets at its fully allocated cost. Most of the energy (88 percent) in the "optimal portfolio" to which Dr. Roach refers comes from a scaled-up version of the contract that DWR signed with Pacificorp. However, this contract is a unit firm baseload contract. DWR is required to take and pay for all of the energy supplied, effectively on a level 7X24 basis. The fully embedded cost of this power is $54.23 per MWh, the lowest cost power in the DWR portfolio. However, this price is valid for power actually <u>used</u> by DWR only if it can <u>sell all</u> the unneeded, off-peak power at a price of $54.23 per MWh. This price is above the price I have calculated for the PPA for load-following, fully reserved power at a 51 percent capacity factor. It simply cannot be the case that, on an internally consistent basis, the value of off-peak power dumped into the market will be more than the cost of requirements power.

The remaining 12 percent of power in the "optimum" portfolio that Dr. Roach would compare to comes primarily from dispatchable peaking contracts. Even for these dispatchable contracts, Mr. Meehan's cost calculations are very conservative, assuming that the units covered by the contract are dispatched at the contractual maximum levels and that, again, the unneeded power is sold at its fully allocated cost. This amortizes the "facilities charge" component of these contracts over the maximum quantity in computing the cost per MWh. These assumed wholesale spot market sale prices range up to nearly $100 per MWh, for power sold typically in the lower load times of the day.

The individual contract costs that I showed in my direct testimony, Exhibit WHH-4, all made this same heroic assumption concerning DWR's ability to sell off-peak and mid-merit power at fully embedded cost. One practical reason that Mr. Meehan made this clearly counter-factual assumption about the value of surplus power sold out of the contracts was that he could not, in simply looking at any single contract in isolation, determine how much of the power would actually be used to satisfy DWR's sales commitments. This is because the use of an individual contract could not be modeled in isolation without knowing what other contracts were in the DWR portfolio.

The "optimal portfolio" analysis that Dr. Roach references for his estimated cost of $56.82 per MWh is simply a combination of the <u>lowest</u> cost contracts signed by DWR, scaled up to provide as much capacity as it needed to meet the load that would me met by the resources in the PG&E PPA, retaining the unreasonable assumption that unneeded energy could then be sold at fully allocated cost. However, Mr. Meehan cautioned that this analysis is not fully valid and he also provided a more reasonable, albeit still conservative analysis. In this analysis, DWR was (within the dispatch limits of its contracts) free to buy from the spot market whenever it was cheaper. It also sold surplus power at the spot market price.

Accessing lower cost spot power reduces the cost of this more realistic optimization relative to the analysis that Dr. Roach would rely upon. However, the need to sell at market prices rather than at an assumed fully allocated price likely increases the cost of the optimal portfolio. As shown in Mr. Meehan's Exhibit GEN-2-15, relaxing the unreasonable assumption that all surplus power could be sold at fully allocated costs increases the cost of the optimum portfolio to $58.85. If, as Dr. Roach argues, I should have compared the cost of the APS PPA to the optimum portfolio in Mr. Meehan's analysis, this (rather than the $56.82 cited by Dr. Roach) is the appropriate price to compare.

Q. **Dr. Roach's third criticism of your analysis was that you failed to compare the APS PPA to the PG&E PPA, asserting that this would make it clear that "PG&E is offering a much better deal to its ratepayers"... Do you agree?**

A. No. First of all, the "much better deal" is based on Dr. Roach's inflated estimate of the cost of the APS PPA, not on my estimate. My estimate is that the cost of the APS PPA is lower than the PG&E PPA. Second, the PG&E PPA is not a valid benchmark. Indeed, the reason for Mr. Meehan's benchmark analysis is precisely because it is not an arms length market contract. Moreover, the principally hydroelectric assets upon which the PG&E contract is based are not replicable. Certainly, the price at which nuclear and hydroelectric generation is offered in Northern California is not relevant in evaluating the options available to APS. Given the positions of parties in the various hearings concerning the disposition of the PG&E assets that underlie its proposed PPA, there is no chance that they will be made available to serve APS load.

Q. Beginning at page 35 of his testimony, Dr. Roach used the indicative data on the long run marginal cost of peaking and combined cycle units that you provided in your direct testimony to seek to show that the cost of the PPA is above long run marginal cost. Is this analysis valid?

A. No, for many reasons. Let me begin with the cost of the PPA. Dr. Roach asserts that the 2004 fixed cost in my analysis is \$171/kW and the variable cost is 1.74 cents per kWh. He uses these values in all of his calculations. I have verified that he derives the fixed cost by dividing the facilities charge in WHH-3 by 4,720 MW. However, the contract does not provide 4,720 MW but 5,618 MW. Hence, his cost per kW is very much too high. He should have recognized that he had mischaracterized what was in my data when he computed that the cost of the PPA at a 50 percent load factor was \$56.21 per MWh, whereas on the face of my exhibit the cost of the PPA at a 51 percent load factor was only \$49.2 per MWh. Since all of his other comparisons contain this same error, none are valid.

Second, the peaker and combined cycle costs that I used in my example were levelized real costs, which he compares to the first year nominal cost of a front-loaded cost-of-service-like cost stream for the Dedicated Units. The appropriate comparison would be to the levelized real cost of the PPA. This nowhere appears on my exhibit, but could have been computed readily to be about \$45 per MWh. Merely making these first two corrections is sufficient to reverse Dr. Roach's conclusions. At the 50 percent load factor that is most relevant, because it approximates APS's load factor, the PPA is cheaper than the combined cycle unit, the peaker, and Dr. Roach's optimal combination of the two.

Third, the PPA is a portfolio providing load following, reserves and ancillary services. The indicative cost of the peaking and combined cycle units that I gave were based on full load operation (i.e. full load heat rates); using these units to meet APS load would require cycling, with part load operation, start up costs and minimum load costs. The costs I provided for the peaking and cycling units did not include the cost of reserves and ancillary services. As I had indicated on the page prior to the page containing the cost data that Dr. Roach uses, reserve costs alone add at least $5 per MWh to the cost of alternatives to the PPA.

These errors invalidate this section of Dr. Roach's testimony as well as his conclusions about the PPA derived therein.

Q. Dr. Roach's fourth criticism of your analysis is that the non-price terms and conditions are allegedly inferior to those that would be offered in a market PPA. Do you have any comments?

A. Yes. Dr. Roach spends 17 pages talking about non-price terms of the PPA relative to a hypothetical market PPA. Because other APS witnesses will address the alleged shortcomings of the PPA, I will comment on only selected areas of his testimony.

Dr. Roach's primary complaint is that the APS PPA is a cost plus contract, whereas the strawman market PPA is not. For example, the fixed charges of the strawman market PPA are assumed to be fixed or indexed to inflation and similarly fuels cost is fixed or indexed. I agree that the PPA is in essence a cost of service-type contract that mimics in most respects the operation of the dedicated units were they to be subject to conventional regulation. In my opinion, no supplier would take on the various real or fanciful risks that Dr. Roach enumerates in discussing the potential shortcomings of a cost of service contract without a higher expected value price. However, it does not follow that the PPA is "riskier" to APS customers than Dr. Roach's strawman PPA. Any long term contract based on the gas-fired technologies that are the potential competition to the PPA will pass through the price of gas. This makes the price of these contracts much more uncertain than the PPA.

Dr. Roach seeks to make much of the fact that it is actual rather than indexed fuels costs that are passed through in this PPA. He raises the specter that this will result in PWEC contracting for, and APS ratepayers paying, out-of-market fuels costs. However, passing though actual costs is the only way to give consumers the benefit of long term coal contracts. Moreover, in my experience with utilities in other regions, I know that if cost recovery is limited to short term indexed prices, this creates a disincentive to hedge.

Dr. Roach also complains that APS's right to dispatch the dedicated facilities is limited by any "must run" or "minimum take" requirements imposed on the Dedicated Units. While he says he is not concerned with the costs *per se*, he objects that the cost responsibility is open-ended. He does not say, however, how APS could avoid paying "must run' costs. The party that Dr. Roach is supporting wants APS to conduct an auction to procure its supplies. To the extent that meeting APS load necessarily relies on "must run" facilities, it would need to contract for them in the auction. The Panda units (and the other merchant units available from intervenors) would not qualify for any "must-run" requirement of which I am aware. Finally, it is entirely sensible that "must-run" costs are the responsibility of the buyer in any requirements contract. The seller does not control the amount or cost of such requirements since "must-run" requirements are determined by RTOs. Any supplier, including PWEC, will not have discretion to dispatch its unit in a manner inconsistent with an RTO instruction to dispatch "must-run" units.

Dr. Roach expresses considerable concern with the absence of availability guarantees in the contract. However, these concerns are based mainly on his failure to understand the fact that the contract is not for 4720 MW of nameplate capacity, but for the fully reserved deliverability of 4,720 MW of capacity. Indeed, the reserve of 16 percent is very conservative. Provided that PWCC engages in good utility practices, as mandated by the contract, it is quite unlikely that it will fail to deliver 4,720 MW. His concern with the absence a guaranteed minimum deliverability at times other than system peak is still less valid, since the reserve margin generally will be still larger at such times. Moreover, as I have noted earlier, PWCC's ability to receive profits from off system sales gives PWCC a strong incentive to make capacity available under the contract.

The last comment that I would make about the non-price elements of the PPA is simply to note that the parties to the contract are affiliates. In arms-length contracts between unrelated parties, particularly parties engaged in "one-off" transactions, it is entirely sensible to consider all of the things that the counter-party could possibly do to game the contract in order to increase its profits. Here, in both the negotiation of the contract and in its operation, PWCC cannot be indifferent to the costs that it imposed on APS and its customers. PWCC and its affiliates remain corporate citizens of Arizona and APS in particular remains vulnerable to regulatory and political sanction should the contract be abused in any way by the counter-parties.

Q. **Dr. Ruff, at pages 28 to 30 of his testimony for Sempra Energy, discusses PWEC having market power. He asserts that your conclusion that a market to serve 3000 MW of load beginning in January, 2003 would not be workably competitive suggests that APS should not have market rate authority and should be required to divest generation. Please comment.**

A. First of all, I do not agree that PWEC has market power in the wholesale market in which it participates. APS was granted market rate authority by FERC and easily would pass the new

Supply Margin Assessment market power standard adopted by the FERC late last year. More generally, PWEC and its affiliates have relatively little energy and capacity to sell at market rates in the wholesale market. What they do have available to sell principally is off-peak energy, available for sale only during times when markets are quite competitive.

The APS market area is unique in that, unlike most traditional utilities, its area is shared with another comparably sized utility. As the intervenor witnesses point out at length, its area also contains substantial merchant generation, with still more due on line over the next three years. APS also has atypically strong transmission links with its neighbors, particularly with California.

However, as I have testified, there is not a workably competitive market to meet the requirements of Section 1606(B). Most intervenor witnesses implicitly accept this in arguing that the auction should be delayed or should be structured so as to create near-term opportunities for them to win contracts with effective dates subsequent to January, 2003. However, Dr. Ruff is simply wrong that this results in PWEC being able to exercise market power. On the contrary, the effect of the PPA is to continue the *status quo ante* in which PWEC and its affiliates have relatively little available to sell to the market and a consequently small market share.

It is well known that a means of constraining what otherwise might be market power is to require that the firm in question sell output on a long term basis, with the price of the output determined on some basis other than market prices. This is an effective control because it strikes at the heart of the incentive to exercise market power. The standard definition of market power is the ability <u>profitably</u> to increase prices by a "small but significant" amount on a sustained basis. Exercising market power requires that the firm withhold output; absent such withholding the supply and demand balance, and hence price, is not affected. Withholding capacity necessarily reduces profits since it results in lost sales. The strategy is profitable if the firm has sufficient other capacity that receives the now higher market price to more than compensate for the lost margin on the foregone sales.

The PPA dedicates all of PWCC's capacity and substantially all of its energy to serving APS load at prices that do not vary with the market. Indeed, the company is projected to be several hundred megawatts short of sufficient owned and currently contracted capacity to meet its load. None of the capacity dedicated to the contract would benefit from any hypothetical action that PWEC might take to raise prices. Thus, any market power that PWEC might be deemed to have in the abstract argues for the acceptance of the PPA, not the reverse.

Dr. Ruff suggests that there are only two logical outcomes concerning the market power issue: either that PWEC and its affiliates lack market power or that they have it, in which case PWEC should be denied market rate authority and the affiliates "should not be allowed to negotiate a 'market' PPA among themselves." Dr. Ruff mischaracterizes the facts. 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. Moreover, for the reasons I discussed previously, there is no reason to deny PWEC market rate authority in the existing wholesale market either now or after execution of the PPA.

Q. Mr. Engelbrecht, another Sempra Energy witness, answers the question, "Will APS customers likely pay more than necessary under the proposed PPA?" He responds, "Most definitely." Does he have a valid basis for this conclusion?

A. No. It simply is an unsupported assertion. Such "facts" as he uses to support it are themselves untrue. He first asserts that the contract simply is too big for a single counter-party. Why? The counter-party is a part of the same economic unit as APS and is, in large part, the same supply sources that have met its load for many decades. Moreover, unlike the situation where one is signing a contract with a merchant supplier who is not supplying from its own resources and might go bankrupt if the market moves against it, PWCC's dedicated assets would not go away, even if PWCC were to go bankrupt. For example, while Enron's contracts may have been abrogated when it went bankrupt, PG&E's supplies from its own generation have not been interrupted as a result of its bankruptcy.

He next appears to be arguing that PWCC could sell output to the market at high prices while simultaneously buying at those same high prices in order to meet standard offer load. This simply is not correct. APS has first call on the dedicated resources and PWCC will not have power to sell to the market when APS is short. Hence, it will not be the case that PWCC is simultaneously selling into the market while buying for APS.

Next, he accepts that a substantial portion of the Dedicated Units are coal or nuclear, but argues that since coal and nuclear units have higher fixed costs than gas-fired units, they cannot compete with the cost of new gas units. He may be correct that the high fixed costs of <u>new</u> coal and nuclear units make them uneconomic relative to new gas units, but this is not a relevant comparison. Under the PPA, coal and nuclear capacity is priced at its depreciated value, which is far lower than the cost of similar new units. He then goes on to make the odd argument that since the coal and nuclear units will be operated at full output they "would largely be unavailable to provide additional power if the gas supply in the state became constrained." However, at least their output would not be reduced by the constraint, which cannot be said for gas-fired units collectively. In this same context, he argues that coal and nuclear units are ill-suited for peaking use. This is irrelevant. The PPA does not contemplate using coal and nuclear units for peaking, but rather using peaking units. These, not the coal and nuclear units (and not the combined cycle units that Sempra is building), are the appropriate units to use for this purpose. Notably, merchant generators are building only a single peaking facility in Arizona.

His last argument is that since many of APS's units likely would be designated as Reliability Must-Run units, they will exercise market power and have the ability to set the market price at a higher level than new coal units would have set at a different location. As a former employee of San Diego Gas & Electric (whose retained capacity was nearly all "must-run" in the California market), he surely must be aware that Reliability Must-Run units do not set the market price. If his argument is that Reliability Must-Run units could exercise market power based on their location, that is precisely why there are Reliability Must Run agreements. Indeed, I was SDG&E's witness in the FERC proceeding in which its locational market power was acknowledged and, on behalf of the company, I proposed that the units be subject to what came later to be called Reliability Must-Run agreements. In any event, the Reliability Must-Run issue is irrelevant to this proceeding, since he acknowledges that the "must-run" requirement cannot be met by gas-fired units in other locations.

Mr. Engelbrecht concludes with the observation that Mr. Davis' comparison of the cost of the PPA to the LRMC of gas-fired units is biased since the PPA recovers the fixed cost of the dedicated units in a separate fixed charge. He concludes that a proper, full cost, comparison would "differ dramatically" from Mr. Davis's comparison. However, he simply is incorrect that Mr. Davis' analysis does not include the full cost of the PPA. This should have been self-evident from Mr. Davis's Figure 5. For example, the savings in 2003 relatively to an LRMC of $60/MWh is about $300 million. Since the load met by the dedicated units is about 25 million MWh, the LRMC price is about $1.5 billion. If only the PPA fuel cost were included in the calculation, the savings would have been in excess of $1 billion.

Q. Mr. Taylor states that the purpose of his testimony is to describe how competitive bidding has worked elsewhere in the U.S. In that testimony, on page 9, he addresses APS's concern that the market may not be deep enough to support competitive bidding for 50 percent of its load. Is there anything in his answer that you wish to emphasize?

A. Yes. He begins his explanation of why the concern is invalid by saying, "In all of the utility resource solicitations that I have conducted, the overwhelming majority of proposals have been for new generation that was to be sited where none existed at the time of the solicitation. There were no generation facilities, no gas pipeline laterals or other fuel transportation infrastructure, no interconnection facilities, and no transmission lines. There were simply proposed plans for such undertakings." These statements demonstrate clearly that his supposed evidence concerning the validity or invalidity of APS's concern is wholly irrelevant. APS and its witnesses have never said that competitive bidding is permanently impossible. Our point has been that a variance from 1606B is necessary because there is insufficient capacity deliverable to load to create a competitive market for deliveries starting in January 2003. As a separate matter, APS also is saying that the PPA likely will be better for ratepayers than would buying power at market prices to serve half (or all) of its load. Plainly, the types of facilities that Mr. Taylor characterizes as being in the auctions in which he has played a role could not deliver power in January 2003.

Q. Various witnesses take issue with APS's position that reliance on gas exposes its customers to volatile prices, arguing that gas need not be bought in the spot market. Do you agree?

A. Certainly, it is possible to hedge gas for relatively short periods of time and if the hedged cost is what is passed through, prices will be less volatile on a day-to-day or even seasonal basis. However, this is merely a caveat. These witnesses cannot, and do not argue that gas prices are not more volatile than coal and nuclear fuel prices or a mix dominated by coal and nuclear as the PPA represents. Nor do they assert that suppliers will hedge gas prices for free.

Moreover, it is not clear that the more typical types of contracts with gas-fired units would protect customers from even the short run fluctuations in gas costs. Most gas-based power contracts are indexed to the gas market. These contracts pass through the fluctuating price of gas. While one can conceive of long term power contracts that are indexed to hedged prices, such contracts presumably would require that hedging costs are recoverable. While not objectionable in and of itself, this means that such contracts themselves become "cost-plus" contracts, undercutting a major supposed advantage of competitively procured power.

Q. Mr. Kebler argues that in a competitive procurement, APS's customers would not lose the advantage of the coal and nuclear power being offered in the PPA since the APS units likely to lose a competition are older, inefficient gas units operating in the intermediate service range rather than the coal and nuclear units. Please comment.

A. I agree with Mr. Kebler that PWCC's baseload units likely would succeed in a fair competition. Of course, APS would have to pay the competitive price for power from those units, rather than a quasi-cost of service price. It is less clear that APS's older cycling gas units would lose out. Certainly they would lose if Reliant and other bidders drove prices down to the variable cost of the new units, but I very much doubt that this is what they have in mind.

The other observation that I would make is that there is an inconsistency between Mr. Kebler's expectation of the outcome of an auction and his preferred design of it. Mr. Kebler proposes that the auction be for vertical slices of APS's load. In an auction with this design, it is not at all clear how APS's older gas-fired units would somehow "lose" while its baseload and peaking units "win".

Q. Does this complete your pre-filed rebuttal testimony?

A. Yes, it does.

Exhibit WHH-R1

LEVELIZED COST OF THE DEDICATED UNITS

Year	Fuel	Capital	Total	Nominal Cost/MWh	Real Cost/MWH	Inflation	Nuclear	Gas	Coal Index	Fuel/KWh Index Valu real(2003)	Nom Fuel per KWh
2003	444220609	781179000	1225399609	48.0	48.0	1.016	0.6	3.20	1.00	1.740	1.740
2004	425999434	823487000	1249486434	48.9	48.2	1.018	0.6	3.24	0.99	1.690	1.717
2005	390259164	824310487	1214569651	47.6	46.0	1.020	0.6	3.34	0.99	1.604	1.659
2006	419800582	826783418	1246584001	48.8	46.3	1.022	0.6	3.43	1.00	1.647	1.737
2007	422650221	830917336	1253567556	49.1	45.5	1.024	0.6	3.44	0.97	1.634	1.762
2008	427730035	836733757	1264463792	49.5	44.9	1.026	0.6	3.44	0.96	1.625	1.794
2009	440080698	844264361	1284345059	50.3	44.4	1.028	0.6	3.47	0.94	1.627	1.843
2010	453831192	853551269	1307382460	51.2	44.0	1.031	0.6	3.50	0.92	1.630	1.898
2011	474896743	864647435	1339544178	52.5	43.7	1.031	0.6	3.54	0.91	1.642	1.971
2012	498242826	878481794	1376724620	53.9	43.6	1.031	0.6	3.58	0.90	1.656	2.050
2013	519902682	892537503	1412440184	55.3	43.4	1.031	0.6	3.61	0.90	1.666	2.126
2014	539144906	906818103	1445963009	56.6	43.0	1.031	0.6	3.62	0.90	1.671	2.199
2015	556112021	921327193	1477439214	57.9	42.7	1.031	0.6	3.63	0.89	1.671	2.267
		NPV		$318.15	$331.76						
		LevNom./real		$49.57	$45.72						

Notes:

Gas and Cholla Fuels prices are $ MMBtu from EIA 2001 (Mountain Region, delivered to electric utilities).
Minemouth coal is EIA 2001 minemouth for AZ-NM and is in $/Short ton.
Nuclear fuel assumed to escalate at zero percent real.
EIA fuels prices are used solely to derive a real rate of escalation for composite fuel. The 2003-4 bases to which it is applied is per the contract.
2004-5 Prices reflect unwinding of Hedges.
Inflation trends from 1.6 to 3.1 percent to conform to Meehan assumption for comparison purposes.
Capital costs for 2003 and 2004 are per the contract with ancillary services offset added back. Future costs increase at inflation less 1.5 %.
Cost per MWh is based on 25,531,000 MWh
Levelization is based on a 9 percent composite rate. As with Meehan, the calculation is not rate sensitive.

Quantity 25531000

REBUTTAL TESTIMONY OF JOHN H. LANDON
ON BEHALF OF
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-01-0822

PRINCIPAL AND DIRECTOR,
ENERGY AND TELECOMMUNICATIONS PRACTICE,
ANALYSIS GROUP/ECONOMICS

April 22, 2002

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REBUTTAL TESTIMONY OF JOHN H. LANDON

(DOCKET NO. E-01345A-01-0822)

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John H. Landon, and my business address is Two Embarcadero Center, Suite 1750, San Francisco, California, 94111.

Q. Are you the same John H. Landon who testified earlier in this proceeding?

A. I am.

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

A. Purpose of Testimony and Conclusions

Q. What is the purpose of your rebuttal testimony?

A. I have been asked by Arizona Public Service Company (APS) to address the prefiled testimony of the Arizona Corporation Commission Staff (Staff) and some of the other parties to this proceeding regarding APS' Request for a Partial Variance to A.A.C. R14-2-1606B (Rule 1606B) and for approval of a purchase power agreement (PPA) with Pinnacle West Capital Corporation (PWCC). The proposed PPA would supply a portion of the resources necessary to serve the needs of retail customers receiving APS Standard Offer Service under the Arizona Corporation Commission's (Commission) restructuring regulations. A number of the other witnesses in this proceeding have questioned the proposals on various grounds. Issues have been raised concerning the benefits to Standard Offer customers and the effects on developing wholesale markets. Furthermore, some of the witnesses have suggested approaches that treat the APS proposal as a random collection of separable parts, which it is not.

Q. Do you agree with the alternatives suggested by witnesses who argue for substantial modification of the requested variance or PPA?

A. No. Under the current conditions of uncertainty and incomplete market development, I believe that the APS proposal, together with the Company's proposed revisions or clarifications to the PPA detailed in Jack Davis' rebuttal testimony, offers a balanced approach to meeting its responsibilities to supply Standard Offer Service in a manner that provides a safer haven for those customers' requirements than the alternatives available at this time.

B. Conclusions

Q. Having reviewed the testimony of the other witnesses in this proceeding, what are your conclusions regarding the APS proposal?

A. I conclude that:

1. PPA does offer advantages to ratepayers relative to the requirements of Rule 1606B.

2. At this time, the benefits of the PPA outweigh any claimed disadvantages and APS has proposed several revisions or clarifications to the PPA which improve incentives to both parties

3. APS/Pinnacle West is likely to be more sensitive to the concerns of Arizona consumers and this Commission than independent power producers (IPPs).

4. The proposed PPA will not appreciably affect development of vigorous, economically efficient wholesale markets.

5. Requiring that APS retain existing dedicated assets and "bid" them only at cost of service into the market for Standard Offer service is economically inefficient and inequitable.

Q. **Has your review of other witnesses' testimony in this proceeding led you to change any of the opinions that you express in your direct testimony?**

A. No.

III. DISCUSSION

A. Advantages of the PPA relative to the requirements of Rule 1606B.

Q. **A number of witnesses to this proceeding have suggested that strict compliance with the requirements of Rule 1606B would be more beneficial to customers than the proposed PPA. Please discuss the advantages of the PPA relative to the requirements of Rule 1606B to purchase 100 percent of electricity supply for Standard Service customers competitively with at least 50 percent to be acquired through competitive bidding processes by January 1, 2003.**

A. The PPA's main advantages compared to the requirements of Rule 1606B are that it offers Standard Offer customers relative price stability and, in the absence of well-developed wholesale markets, largely shields Standard Offer customers from market development risks.

Q. Please discuss how the PPA offers price stability relative to alternative sources of supply under Rule 1606B.

A. The PPA captures for Arizona's Standard Offer customers a portfolio of resources with a diversity of technologies and fuel supplies. It is this diversity together with the obligation to price at cost that offers price stability relative to alternatives.

Q Alan Taylor testifying for Harquahala, indicates that gas fired facilities could be offered into the market at firm or, more commonly, at indexed prices (Taylor, page 11). Would this affect the price volatility?

A. Certainly contracts with firm price provisions would reduce volatility relative to the spot market. However, fixed price contracts essentially contain insurance provisions against volatile gas prices, and like most seller-provided insurance, it will be very expensive. The longer the period of price protection, the greater the cost will be. APS fuel diversity provides partial insurance against changing gas prices by averaging volatile gas prices with long-term contracts for other fuels. The whole APS portfolio is available on a cost basis.

Individual contracts with partial price protection, while protecting Standard Offer consumers from some portion of the potential price volatility in electricity markets, do not protect them from volatility in fuel prices as effectively as the APS diversified, cost-based portfolio does.

Q. How does the diversity of resources under the PPA hedge against scarcity rents?

A. Scarcity rents are amounts above costs that reflect the increased value of a good or service in tight markets. Because there are a variety of fuel types and contract lengths under the PPA, each priced to retail customers at cost, consumers are to some extent protected against unexpected supply interruptions or unavailability of a specific fuel which could lead to scarcity rents. An example of these kinds of extraordinarily high prices occurred in California natural gas markets following the explosion on and subsequent impaired operation of the El Paso pipeline on August 19, 2000. Moreover, there are other reasons that prices for a specific fuel could spike relative to others, for example, insufficient transportation or production infrastructure and therefore insufficient supplies in the face of growing demand. Commodities such as natural gas often follow such a boom bust cycle, and while prices are at historically low levels just now, it is to be expected that they will rise. Exhibit ____JHL-1R shows a twenty-year record of Arizona gas prices adjusted for changes in the consumer price index. In real, February 2002 dollars, the average price of gas in Arizona has been about $3.91 per MMbtu over the period with prices as high as $8.03 and as low as $2.00. This compares with the current price of $2.79. It is reasonable to expect that prices for natural gas will change and most likely will rise, perhaps significantly.

Firm contract prices would need to take account of this likelihood. At a minimum they would need to be sufficiently short (Dr. Ruff has suggested five years) to keep the risk premium reasonable. After this period, they would rise to market levels. Thus, even though prices under firm contracts would be guaranteed for a period of time, they would be revisited at regular intervals. Over the life of the PPA, it is likely that these price visitations would result in more volatile electricity prices than those contemplated under the PPA due to the fuel diversity of plants covered by the PPA.

Q. Have you prepared an example illustrating this effect?

A. Yes, I have. The results below compare the PPA Purchase option with a Competitive Purchase option consisting of a 50/50 combination of bid prices and arms-length transactions with renewal every three years. The bid prices are based on the fixed and variable costs of a gas-fired combined cycle facility. The arms-length transaction prices are 97 percent of the bid prices in each year (a discount of three percent). I have assumed that the risk premium for locking in gas prices for three years would be ten percent. In both options, gas prices escalate at 7.5 percent per year. Prices under the PPA Purchase option escalate as gas prices increase and the portion of power supplied from gas-fired facilities under the PPA becomes greater over time. Prices under the Competitive Purchase option increase much more rapidly as a result of the gas price escalation over the period.

Although the 2004 prices are slightly higher for the PPA Purchase option, Standard Offer customers would be better off under the PPA Purchase option in all of the later years because of the diversity of technologies and fuel supplies that I discussed earlier.

Purchase Comparison	**2004**	**2007**	**2010**	**2013**
	-------------Year 2004 $/MWh------------			
PPA Purchase	$48.00	$50.34	$54.00	$59.24
Competitive Purchase	$46.57	$52.95	$60.81	$70.54

Q. Are there other advantages to the diversified portfolio of resources that are dedicated to serving Standard Offer requirements under the PPA?

A. Yes. The PPA offers a technologically diverse asset-backed portfolio in the absence of workably competitive wholesale market.

Q. How does this form an advantage to the benefit of Standard Offer customers?

A. Under the PPA, new plants with new technologies have the back stop of older plant with tried and true technologies. Thus, if newer technologies (either dedicated plants or IPP plants supplying power to APS under the proposed provisions for competitive procurement) fail relative to expectations, the PPA enables APS access to well-established generation utilizing proven technologies.

Q. Should failure of these newer technologies be a concern? Mr. Schulyer indicates that he is "...aware of no evidence to support the contention that combined-cycle facilities have performed at anything less that the level of performance expected of state-of the-art technology."

A. Although this somewhat imprecise statement is liable to a variety of interpretations, my assumption is that Mr. Schulyer believes the reliability level of these plants to be quite high. As I testified in my direct testimony, the record appears to indicate otherwise. While I am not an engineer, reports indicate that in addition to the fits and starts one might expect from new plants and new technologies, there appear to be fundamental difficulties with the design of new combined cycle technologies which are leading to shortened intervals between maintenance outages, increased costs of maintenance investments and possibly shortened life expectancies for these plants.[1]

Q. Have these difficulties led to reduced levels of reliability relative to expectations?

A. It appears so, since reports indicate that machines do not "live up to all of the performance and economic demands expected of them." As a result, "...the life-cycle costs of these machines are substantially higher than most owner/operators anticipated in the project financials."[1]

Q. Are there other price-related benefits to having hard assets stand behind APS' supply obligations to Standard Offer customers?

A. Yes. As I indicated in my direct testimony, hard assets provide certainty relative to agreements to purchase and supply which are subject to risks of supply disruptions in developing markets. An example of consumers' vulnerability to these risks occurred last summer when utilities in the Pacific Northwest were thrown on the market due to a drought that substantially compromised hydro generation. Prices for power soared. This is not to say that the Southwest is the same as the Pacific Northwest, just that events external to a system can have unanticipated effects. At present, there is insufficient depth in wholesale markets to supply Standard Offer customers in Arizona enough comfort that the wholesale market will supply ample opportunity for competitive suppliers to cover their obligations at reasonable cost.

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[1] " *Managing Gas Turbine Maintenance Risks*, prepared for EPRI Maintenance Conference August 14-18, 2001, prepared by Jason Makansi and Jeff Fassett.

Q. Please comment on Mr. Schulyer's statement that "Any risk of poor performance in a competitive long-term power supply agreement would be borne by Panda not by the APS customers."

A. I appreciate that Mr. Schulyer's company is willing to shoulder responsibility for its performance under its contractual obligations. In this regard, it is interesting that merchant plants in Arizona have been organized in a manner that limits ultimate liability to their parent companies. In light of recent events concerning Enron, and the difficulties of other, once flourishing companies, I think that the Commission should carefully consider all scenarios for meeting customers' electricity demands under all conditions of supply. In my opinion, the proposed PPA, backed by a diversified portfolio of hard assets which can reach the APS load centers, offers significant security to Arizona consumers.

Q. Please discuss the substitutability of merchant generators' contracts for portions of the APS/Pinnacle West PPA.

A. The PPA is offered as a package deal. As discussed further in Jack Davis' rebuttal testimony, the terms and prices of a partial APS/Pinnacle West supply contract are likely to be quite different than those imputed by others to an attempted disaggregation of the resources behind this contract.

Q. Are there particularly attractive features of the package of generation plants behind the PPA?

A. As mentioned above, the package mixes tried and true nuclear and coal baseload generation along with new, technologically advanced gas units like Redhawk and backs up the baseload plants with other, older units to supply additional reliability. A significant amount of that capacity is now capable of reaching the load pocket in APS' Phoenix service territory.

B. The Benefits of the PPA Outweigh Any Claimed Disadvantages

Q. **Please discuss the benefits of the proposed PPA relative to the claimed disadvantages.**

A. During the period of wholesale market development, the proposed PPA trades off known risks against larger and less predictable risks, especially market development-related risk. For example, while there may be disagreement as to how best to address it, several parties to this proceeding have indicated fuel price risk is a known and possibly manageable risk both with and without the PPA. In contrast, the risks associated with the developing wholesale market are large and difficult to predict or hedge and involve issues over which the Commission has little control in any event. At this stage, these risks properly reside with market participants, i.e., with IPPs, not with Standard Offer customers.

Q. **Please discuss the types of market development risks that concern you in more detail.**

A. Examples of these risks include:

1. How and when will RTOs develop and what will be their effect on market price and market supply in Arizona? Who will own the transmission facilities? Who will operate them? Who will plan and develop them? Over what areas will the RTO operate? What input will states have in the process?

2. Will gas transmission capacity will be adequate? Can the projected units get the gas supply needed to proceed with construction and operation?

3. What is the amount of and rate of transmission expansion? Who will pay for that expansion and how will that affect the development of regional markets? What transmission resources will be ready, when will they be ready? What and where will future constraints be felt? What are the implications for future costs at specific locations relevant to APS Standard Offer loads?

4. What are the effects of additional transmission links and the elimination of "pancaked" rates on Arizona generation availability and price in the state? Will the availability and cost of generation alternatives in Arizona go up or down?

Q. Dr. Ruff testifying on behalf of Sempra Energy Resources indicates that while "[T]here have been teething problems in all competitive markets,...these have usually been less serious than the problems in the monopoly systems they replaced and have been the predictable/predicted results of bad market designs that can be avoided." He goes on to offer as an example the benefits of competition in markets where there was no apparent [preexisting] crisis: in the UK and PJM. Please comment on how these observations might apply to Arizona today.

A. In contrast to the UK and PJM, there is not a long history of an operating power pool to establish market clearing prices in Arizona. Without established institutions and agreements for joint ownership, control, planning and operation, the integration and institutional development process for implementing competition is likely to be long, and the results may be quite different than those experienced elsewhere. This is especially true since it is not obvious that the established models for market infrastructures that are appropriate to densely populated and highly interconnected regions are transferable to the Western United States. Thus, creating competitive markets in the West may entail designing new institutions that are more appropriate.

Q. A number of witnesses have expressed concerns over adverse incentive aspects of the proposed PPA. For example, commencing at page 10 of his testimony Dr. Ruff enumerates several objections, including that the PPA supplies inadequate or perverse incentives to efficiency and that there are inadequate performance guarantees in the PPA. Please discuss APS/Pinnacle West proposed several revisions or clarifications to the contract that address these concerns.

A. As I will discuss at greater length later in my testimony, APS and its parent have strong and long-term interests in Arizona which provide significant incentives to treat customers and regulators well. Thus, in his testimony, Jack Davis proposes several revisions or clarifications to the PPA language that improve the incentive aspects of the proposal. These include language clarifying that APS has first call on all available kilowatt-hours generated by the Dedicated Units as well as language to make it clear that *force majuere* conditions for Pinnacle West Capital Corporation, the counterparty to the PPA, do not include deliberate withholding of generation by Pinnacle West Energy Corporation. Both of these changes improve incentives under the PPA.

Q. You have indicated that the proposed PPA comprises a package, please discuss how this package benefits Standard Offer customers.

A. Absent the PPA, each of the APS resources, including the low-cost generation APS/Pinnacle West coal and nuclear plants, would be transferred to Pinnacle West and be available to bid into competitive markets at whatever price the market would bear.

Q. William Engelbrecht testifying on behalf of Sempra Company indicates that the "...value alleged by APS/PWCC in having fuel diversity as a hedge against gas curtailment or price spikes during the summer peak is a myth..." since baseload generation will be operating at high capacity factors year around and "...would be largely unavailable to provide additional power if the gas supply in the state became constrained." Please comment.

A. Mr. Englebrecht misses the point. The PPA preserves for Standard Offer customers the price advantages of stable long-term fuel prices for these baseload resources, which under the PPA are averaged with more volatile prices for natural gas to the benefit of Standard Offer customers. Absent the PPA, power produced by these plants would be marked to market levels.

Q. How would market-based prices for these resources be determined?

A. At present, it appears that the marginal resources in the market most likely will be gas-fired for some time. While it is possible that additional coal generation could be built and even that existing nuclear facilities expanded, it is highly unlikely that new, non-gas capacity will be up and running in the immediate future and certainly not in time to comply with the requirements of Rule 1606B. Thus, absent the PPA, the market price for all generation would be driven by the likely higher costs of the gas-fired generation alternative.

Q. Please discuss other beneficial aspects of the PPA that are not acknowledged by Staff and intervener witnesses.

A. As I mentioned above, there a number of risks and uncertainties with regard to the development of future wholesale markets in the region that includes Arizona. Because these matters are regulated at the federal level, state authorities have little control over them. Concurrently with these developments, however, this Commission retains responsibility for ensuring that electricity consumers in the state have service to supply their needs. The proposed PPA provides the Commission some certainty (i.e., plants and transmission lines already exist) in this evolving environment. In contrast, the proposals advocated by merchant generators rely on assumptions that sufficient wholesale infrastructure and markets will be developed within the necessary timeframe so that they can meet APS' Standard Offer obligations at reasonable cost. Mr. Taylor, for example, testifies that for resource solicitations that he has conducted, "…the overwhelming majority of proposals have been for new generation where none existed at the time of the solicitation. There were no generation facilities, no gas pipeline laterals or other fuel transportation infrastructure, no interconnection facilities, and no transmission lines." However, he fails to mention how many of these proposals ultimately resulted in viable, operating power projects.

C. APS/Pinnacle West are likely to be more sensitive to the concerns of Standard Offer customers in Arizona and the Commission than IPPs during the period of market development

Q. Witness for the ACC Staff, Mr. Schlissel, disputes your claim that the final years of the PPA are probably the most valuable to ratepayers as being "overly optimistic, to say the least. First, it is not clear that ratepayers ever will see the claimed benefits in the final years of the PPA because either APS or PWCC could terminate the contract in 2015, 2020, or 2025 merely by providing notice to the other party..." Dr. Ruff also expresses concern that the term and the renewal provisions of the PPA may not be in the best interests of Standard Offer customers. Please comment.

A. Mr. Schlissel's comment focuses on the entire, potential length of the contract, but ignores the initial contract term which was the focus of my remark. Even for the initial period of the contract, I expect that, as time goes on, the prices under the proposed PPA will be increasingly attractive relative to the competitive market for the reasons I gave in my direct testimony. Moreover, APS/Pinnacle West has clarified changes to the contract terms and conditions which speak to some of Mr. Schlissel's concerns. This clarification specifically recognizes that the Commission could advise APS, if the Commission thought it appropriate, to exercise its termination rights under Section 11.2 of the proposed PPA.

I note that the exact nature of Mr. Schlissel's concern is unclear. While he complains that perhaps consumers may never see the benefits of lower prices in the out years if the contract is terminated too soon, he also criticizes the overall length of the contract as being too long: "The proposed 28-year term of the PPA is unreasonably long." (Schlissel, page 5)

Q. **Should the Arizona Commission place any significance on the fact that APS and Pinnacle West are both domiciled in Arizona in evaluating the proposed PPA?**

A. Yes, I believe that it is significant that APS and Pinnacle West have a substantial interest in the health of the State of Arizona and in the welfare of its citizens. APS/Pinnacle West has a greater stake in the economic health of the state of Arizona and the welfare of its residents than that of the IPPs. For example, 80 percent of APS and 100 percent of Pinnacle West Energy dedicated megawatts of capacity are in the State of Arizona. This compares with, for example, 18 percent (Panda), 6 percent (PG&E), 6 percent (PPL), and 20 percent (Sempra) based upon information from the companies' websites. The Commission needs to acknowledge in its deliberations the relative incentive effects on the companies of their investments in Arizona.

Q. **Will this continue to be an important factor as competitive markets develop?**

A. Yes. APS will continue to have regulated operations in the state as competitive wholesale and retail markets develop. The company therefore has an ongoing incentive to be responsive to the concerns of customers and regulators.

Q. **Mr DeRosa testifying on behalf of Harquahala Generating Company states that "The opportunity to compete to serve APS' load spurred an unprecedented level of investment in new generating capacity in Arizona. Since the APS Settlement was completed in October, 1999 over 9,500 MWs of**

new generation has been committed to Arizona." Do you agree that the original terms of Rule 1606B are necessary to ensure that new plants will be built in Arizona?

A. No. On the contrary I believe that it is disingenuous for IPPs to suggest that Rule 1606B was or is necessary to ensure that new plants will be built in Arizona. As stated in my direct testimony, the proposed PPA does not alter the supply/demand balance in the market. Decisions to build plant and the ability to arrange financing are driven primarily by expected price levels and the perceived need for new capacity. If prices are depressed, IPPs may scale back expansion plans or cancel projects to build new resources and purchase power in the market place to meet contractual commitments. This scenario is currently being played out in California. According to press reports, while energy developers filed applications for 22 new power plants during 2000 and 2001, more recently, no new applications have been filed, applications have been withdrawn, and construction on several plants has been halted or delayed. State officials are concerned whether there will be sufficient capacity for expected demands by 2004.[2]

[2] *California Officials Hope to Keep Averting Power Crisis,* Knight Ridder/Tribune Business News, April 15, 2002, Darla Martin Tucker.

D. Effects (non-effects) of the Proposed PPA On Vigorous, Economically Efficient Wholesale Markets

Q. Several parties to this proceeding have indicated that vigorous, economically efficient wholesale markets are desirable and necessary to support retail competition. Do you agree?

A. Yes, I do. However in order for fully efficient wholesale markets to function, there are a host of institutional and infrastructure developments that need to be put in place such as market clearing mechanisms, centralized regional dispatch and transmission planning. While these institutions are under development, they are not yet well-defined in the region that encompasses Arizona. Furthermore, while APS together with other utilities in the region are supporting development of wholesale markets, most notably with the filing of the WestConnect proposal with FERC, FERC has not yet responded to the application. There is, therefore, considerable uncertainty about the future shape of market institutions in the area.

Q. Given these circumstances, what is your opinion on the current viability of wholesale markets for power produced in Arizona?

A. While there is not a centrally dispatched and balanced wholesale market in Arizona, there are opportunities for new bilateral transactions between Arizona resources and loads outside of the state. Alternatively, there are opportunities to sell into spot markets and ancillary services markets run by the California Independent System Operator.

1. Transmission to reach broader regional markets from Arizona

Q. Is the infrastructure necessary to these transactions in place?

A. Yes. There is presently transmission for new generating units to reach the broader regional markets from Arizona as well as planned additions to transmission that will facilitate greater access of Arizona generators to those broader regional markets. Exhibit___JHL-2R gives examples of available transmission capacity from and to other hubs in the West. Exhibit___JHL-3R gives planned significant transmission capacity expansion in the WSCC over the period 2001-2010. Over 57 percent of planned additions in the WSCC are in the Arizona New Mexico and Southern Nevada region.

2. Transmission within Arizona to reach APS Standard Offer customers

Q. How does this compare with transmission within the State of Arizona to meet APS' likely Standard Offer loads?

A. Mr. Smith, testifying for Staff indicates that "...significant transmission constraints around Arizona's major load centers are...contributing to the thinness of the wholesale market in Arizona." He goes on to detail several planned transmission improvements that will relieve at least some of these constraints, one of these is scheduled for completion in mid-year 2003 with the remainder due to come on line thereafter.

Q. Please discuss economic criteria for evaluating the appropriate amount of transmission capacity and need for expansion.

A. Let me begin by explaining that the amount of transmission resources necessary to support fully competitive wholesale markets will necessarily be significantly greater than those needed for a regulated utility service from a vertically integrated system. Thus, it is hardly surprising that transmission in Arizona is not sufficiently robust to allow an immediate shift to fully competitive wholesale markets. Furthermore, even in competitive markets, it would be highly unrealistic to project no constraint on any point in the system at any time. Transmission investments are expensive and constraints may be of such limited duration that system expansion cannot be economically justified. Furthermore, transmission investments should be traded off against investments in generation. This was true under regulation, and will continue to be true under competition. The presence of transmission constraints (and the effects of locational price differences) encourage generation to be built where it is most needed. The correct tradeoffs between investments in transmission and in generation are most likely to occur where generators pay the costs of transmission expansion necessary for their access to distant markets.

3. Effect of PPA on development of regional markets

Q. Does the proposed PPA affect development institutions that will be implemented on a regional basis to support wholesale markets, such as RTOs?

A. No. It does not. As discussed above, APS together with other utilities in the region is participating in the development of such institutions.

Q. Please discuss the likely effects of RTOs on regional wholesale markets.

A. If a regional RTO is formed that removes "pancaked" rates as proposed, one more barrier to a widespread regional wholesale market will be removed. For example, as discussed in my direct testimony, prices for power in California and elsewhere are typically above those in Arizona. It is therefore likely that as the underlying institutions evolve, Arizona IPPs will seek market opportunities over a wider and wider geographic area. Conversely, resources located outside of the state will gain greater access to Arizona markets. However, it is too soon to predict with specificity what the market for transmission will look like. For example, we do not yet know what the rules will be or how transmission will be priced. At this point in time it is risky to rely on a market that has not yet been defined to support competitive procurement.

Q. **Is the proposed PPA likely to affect negatively the emerging wholesale market as claimed by witnesses for the IPPs?**

A. No. As I explained in my direct testimony, even without the wholesale market institutions that are under development, Arizona loads are a small portion of existing regional market. As this market develops and grows more robust, the importance of Arizona's loads to establishing regional wholesale prices is likely to diminish further.

4. New opportunities for long-term sales, potentially sufficient to support financial institution criteria for power plants are forthcoming in the region.

Q. **Please give an example of emerging opportunities for wholesale sales in the regional market by IPPs.**

A. A fairly recent example, is that of opportunities arising from the California ISO's redesign of wholesale markets in the state in anticipation of the expiration of FERC's "soft" price cap on September 30, 2002. Central to the market redesign are capacity markets entailing an available capacity obligation (ACAP) on the part of Load Serving Entities (LSEs). While the full scope of the ACAP requirement is still under discussion, there seems little doubt that capacity markets will emerge in California.

Q. How does the emergence of capacity markets in California represent an opportunity for IPPs in Arizona?

A. As I have been stating throughout my testimony, competitive wholesale markets are regional and are not confined to a single state. In this case, California presently is import-dependent to satisfy its ACAP requirements, thus LSEs will have to rely upon out-of-state resources such as the IPPs in Arizona to meet these new obligations. Furthermore, as discussed above, recent delays and cancellations of new generation projects have increased the likelihood that the state will remain import dependent. In addition, ACAP obligations likely will entail arranging for ongoing resources to cover capacity obligations. These long-term commitments, in turn, supply the kind of guaranteed revenue stream required by investors for financing generation investments.

Q. Is this obligation likely to be established soon?

A. The schedule for meeting ACAP requirements has not yet been established; however the ISO plans to file an ACAP design with FERC on May 1, 2002. Penalties on LSEs for failure to meet ACAP may commence after April 1, 2003. It is interesting to note that the start-up schedule for these new ACAP requirements runs roughly concurrent with the requirements for 100 percent competitive procurement under Rule1606B.

Q. How might the concurrency of these two procurement processes affect prices for Standard Offer service in Arizona?

A. Clearly, if California LSEs and APS each are attempting to obtain competitively, resources to cover mandatory commitments from a limited pool of capacity resources, prices for those resources will rise.

E. Effects of Requiring APS to Retain Generation and to Bid It Only at Embedded Cost of Service

Q. Please comment on Staff's suggestion that APS retain its generation and bid it into its competitive resource procurement plan, perhaps capped at embedded cost of service.

A. If this is truly staff's proposal, I am appalled. The Staff's consultant, Neil Talbot of Synapse has surveyed generation resource procurement practices in fourteen states. None of the states surveyed have adopted this model.

Q. Why have state commissions elsewhere avoided this approach to resource procurement?

A. There are good reasons for other states' reluctance based on the record, to embrace the model suggested by Staff. Whereas transferring dedicated assets to a competitive entity and executing a long-term PPA does not affect the market, since both load and assets are in some sense still in play, requiring that APS retain generation assets impedes development of competitive markets.

Q. Please discuss why transferring generation assets to a competitive entity, with market-determined profits and losses, instead of regulatory oversight is desirable.

A. Virtually by definition, such actions are necessary to the development of competitive markets. While regulatory oversight of prices to Standard Offer retail consumers may be required at least in the near term, markets by definition rely upon competitive forces to supply the optimum level of economic benefits. The spin-off of generation assets will produce enhanced broad incentives to increase financial performance and therefore market contribution. Consumers will benefit from increased efficiencies, the effects of which will be passed on through the PPA as will as through the effects of these efficiencies on the competitive electric market in the region.

Q. Please discuss in more detail how these incentives occur in competitive markets.

A. Moving assets from a regulatory framework to the competitive environment transfers significant incentives to plant owners. This is the case under the proposed PPA. Extra output that is not needed to supply APS Standard Offer load can be sold in the market. This increases the incentive to increase availability and capacity factor and to improve heat rates. Together with the competitive forces of the marketplace, these incentives motivate plant owners to do the best possible job of managing their assets. The financial consequences of failure to do so are much more immediate than in the regulated environment.

Q. Will there also be incentives to use better plant sites and other generating assets?

A. Yes. In addition, plant operators in a competitive environment will face broad incentives to optimize use of all plant-related assets. These will lead them to consider the advantages of repowering options (or other efficiency enhancing investments in existing units), adding unit(s), and optimizing the use of air, water or other rights. They may also consider enhancing efficiency or use of grid interconnections which will strengthen the competitive market overall.

Q. How is development of competitive markets impeded by Staff's proposal?

A. Under Staff's proposal, assets and load both are effectively removed from market and from establishing market-clearing prices, and the reach of the Commission in regulating electricity markets is extended. These actions send the wrong signal to potential investors in competitive Arizona power plants.

Q. Does this proposal affect economic efficiency?

A. Yes. As I just explained, spinning off assets supplies incentives to enhanced economic efficiency. Conversely, retaining generation units within a regulated entity and requiring that their output be offered based upon embedded cost of service removes incentives to invest in order to reduce costs or increase output. The regulated owner would be limited to prices that, at best, would cover costs. If 100 percent of its assets were covered by winning bids, it would recover cost of service.

Q. How can APS avoid conflicts of interest and self-dealing if it is required to bid its generation assets to itself?

A. Requiring that APS bid generation assets to itself will necessarily mean that a third party will be needed to evaluate both the need for resources and the bids themselves to avoid conflicts of interest. Such a system may also require a third party to dispatch the alternatives to avoid shifting revenue or cost responsibility between regulated and competitive participants.

Q. What might be the outcome if APS were constrained to recovering embedded costs-of–service for some of its resources while others were competing in the market place?

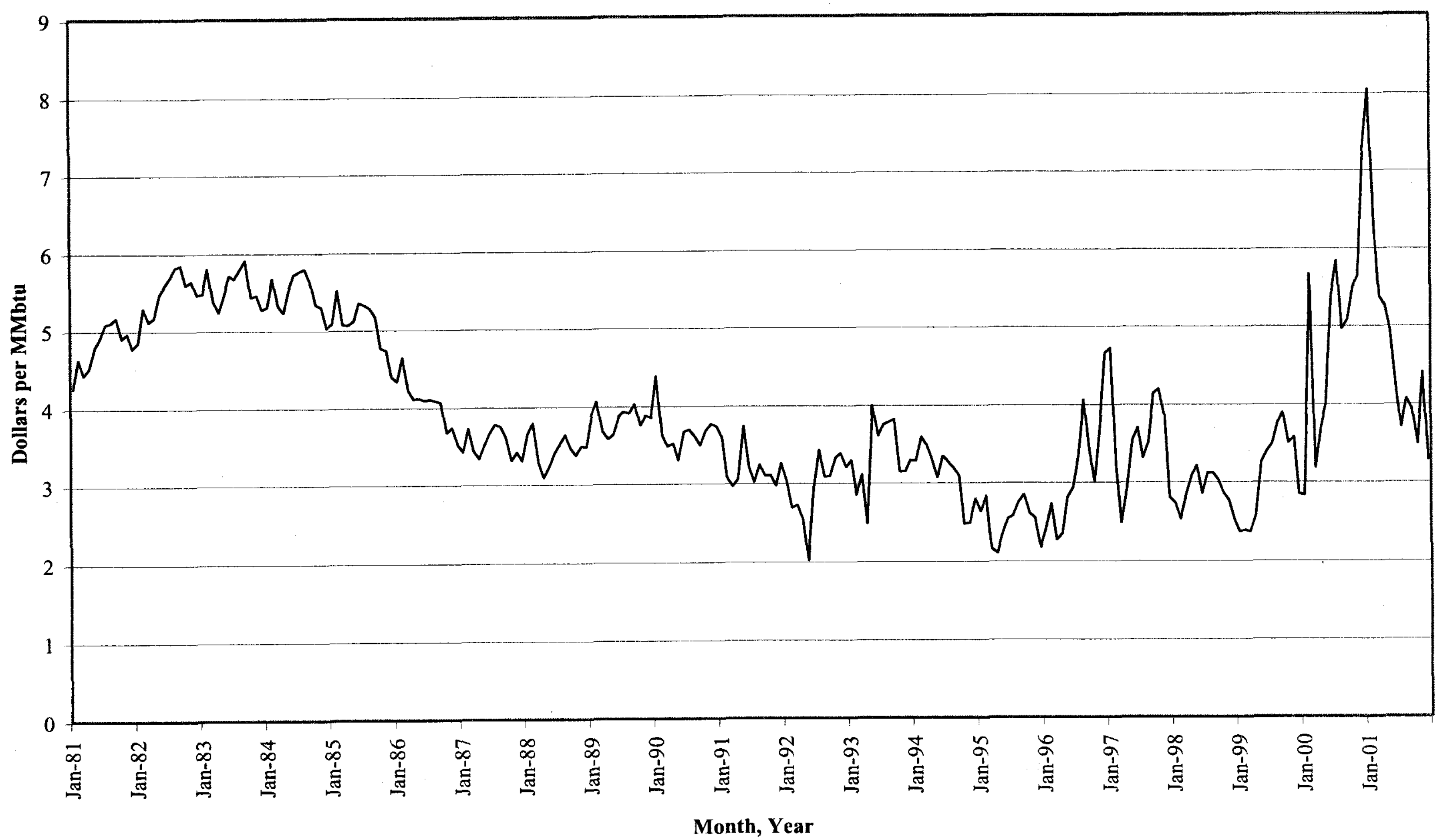
A. If APS' low-cost resources such as coal and nuclear generation were required to recover only their embedded costs at a regulated rate-of-return, while newer gas units were required to compete in the market, the effective outcome would be to set prices at "the lower of cost or market." This is clearly unfair and likely would lead to financial distress sooner or later. I am concerned that retaining generation assets within the regulated entity (whether or not they are within a separate division), may tempt the Commission to value the assets at market when competitive prices are low, while reverting to cost of service when market prices are high, thereby institutionalizing the "lower of cost or market" scenario.

Q. Does this conclude your testimony?

A. Yes. It does.

Exhibit__JHL-1R

Average Citygate Price for Arizona: 1981 - 2001
2002 Dollars



Source: EIA and BLS

Analysis Group/Economics

Summary of Transmission Into and Out of Arizona

	(MW)
Exports to:	
West	236
North - via Four Corners	762
North - via Navajo	449
Imports from:	
West	236

Source: Revised Biennial Transmission Assessment: 2000 - 2009, Arizona Corporation Commission

Summary of Significant Transmission Additions (Net) 2001 - 2010
(Circuit Miles)

Voltage	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WSCC Total	% of Total
115 -161 kV	29	381	341	44	795	21.4%
230 kV	375	107	564	117	1163	31.3%
287 -340 kV	0	0	0	0	0	0.0%
345 - 450 kV	173	0	752	0	925	24.9%
500 kV	370	0	459	0	829	22.3%
260 - 280 kV DC	0	0	0	0	0	0.0%
±500 kV DC	0	0	0	0	0	0.0%
Total	947	488	2116	161	3712	100.0%
Percent of WSCC Total	25.5%	13.1%	57.0%	4.3%	100.0%	

Source: WSCC 10 Year Coordinated Plan Summary 2001 - 2010, page 54.

REBUTTAL TESTIMONY OF CARY DEISE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-01-0822, et al.

April 22, 2002

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ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-01-0822

Rebuttal Testimony of Cary Deise

Director, Transmission Operations and Planning
Arizona Public Service Company

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. **WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. I will discuss APS' current and planned transmission system and how that system affects the various proposals for competitive bidding in intervenor testimony, as well as compliance with Rule 1606(B) as written. I will respond to the interim proposal for competitive bidding contained in the testimony of Staff witness Jerry Smith and Staff witness Matthew Rowell, and discuss why that proposal is ill-advised and based on inaccurate assumptions. I will also respond to errors in the testimony of several other intervenor witnesses relating to APS' transmission system and its capabilities.

II. WITNESS QUALIFICATIONS

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 have worked for APS in numerous different positions relating to transmission system planning and operations continuously for the last 30 years. I am Chair of the WestConnect Interim Committee, and 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 all of the 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, merchant generator interconnections, and the preparation of the Company's 10-Year Transmission Plans.

III. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Many of the intervenor witnesses suggest, either explicitly or implicitly, that there are few or no system-related impediments to competitively bidding 50 percent of APS' Standard Offer Service load, as currently required by Rule 1606(B). They fail to appreciate that APS' complex transmission system was designed over the last 75 years to deliver power from APS' generating plants to APS' diverse loads in a cost-effective and reliable manner. The system simply was not designed, nor should it have been designed, with large amounts of surplus capacity to accommodate unplanned generation additions (competitive or otherwise) within a relatively concentrated area, let alone allow unconstrained access to all of APS' loads or to loads in other regions or states. The nature of APS' existing transmission system, as well as the uncertainty of future regulatory and technical developments relating to that system, does not support an immediate transition to 50 percent competitive bidding as apparently envisioned by some intervenors, and certainly not without significant reliability risk to APS' customers.

In fact, Staff witness Jerry Smith agrees that the current transmission system would not support the immediate transition to competitively bidding 50 percent of APS' Standard Offer Service load, and that there are "risks and uncertainties" associated with any transition to competitive bidding. He proposes an "interim" competitive bidding system for APS as a "starting point for discussion." That interim proposal, however, is based on several incorrect assumptions and does not present an acceptable alternative to the phased-in competitive bidding process that is provided in the proposed Purchase Power Agreement ("PPA"). I also disagree with Mr. Smith's suggestion that transmission owners like APS could control transmission constraints and must-run generation to affect market prices, and with his analysis of how a competitive supply margin of generation is emerging given the configuration of APS' transmission system.

Additionally, I will address errors in the testimony of those witnesses who assert that there is adequate transmission infrastructure to support the rapid transition to competitive bidding contemplated by Rule 1606(B). For the most part, these witnesses simply fail to understand the critical limiting factors that necessarily exist on APS' transmission system. APS is committed to working closely and cooperatively with merchant plants to assist in interconnections to APS' system, and our track record shows that commitment. But simply interconnecting to the grid does not resolve the complex operational and reliability issues that will accompany a radical "redesign" of how the system is expected to operate. Nothing in the intervenor testimony supports jeopardizing continued reliable service to APS' Standard Offer Service customers while Regional Transmission Organizations ("RTOs") such as WestConnect, other market institutions, and the physical infrastructure evolve and a competitive bidding program is prudently phased in under the proposed PPA.

IV. APS' TRANSMISSION SYSTEM

Q. PLEASE DESCRIBE HOW APS' TRANSMISSION SYSTEM WAS DESIGNED.

A. Essentially, APS' transmission system has been designed and constructed over the last 75 years or so with two principal concepts in mind: (1) integrated resource planning to serve load; and (2) the interconnection of the APS system with the area transmission grid for reliability purposes.

Integrated resource planning has caused the system to evolve incrementally by selecting over time cost-effective solutions to meet APS' load serving requirements. In some cases, that involved the construction of generation; in others it meant building transmission capacity. The interconnections of the APS system to the regional grid were made primarily for reliability purposes and reserve sharing. By interconnecting to the Western transmission grid, APS' system is made more reliable because it can take advantage of other resources on the integrated system should elements of the APS system fail. Also, the interconnection of transmission systems has allowed utilities to share reserves (through organizations such as the Southwest Reserve Sharing Group) in a more cost effective manner than if each separate utility had to provide all of their own reserves.

Because the system was designed with a focus on integrated resource planning and with interconnections mostly to support reliability and reserve sharing, the system was never meant to support <u>all</u> resources being able to serve <u>all</u> loads at <u>all</u> given times. Thus, those intervenors who suggest or imply that system constraints and related issues can be ignored in favor of a massive shift to competitively bidding an uncoordinated assemblage of new resources that were not designed with the present system in mind are vastly underestimating the risk to system operation and APS' customers.

Q. FOR BACKGROUND TO YOUR TESTIMONY, COULD YOU DESCRIBE APS' TRANSMISSION SYSTEM.

A. APS' transmission system ties together several relatively remote areas of load, including Yuma, Northern Arizona, and Southern Arizona, with the portion of the Metropolitan Phoenix ("Valley") area that is served by APS. Essentially, there are four injection points where APS' transmission system ties to the Extra-High Voltage ("EHV") grid and from which APS imports bulk power to its system and exports to other systems. These are: (1) Mead, near the Arizona border in Nevada, (2) Navajo/Moenkopi, which is several hundred miles north of Phoenix, (3) Four Corners, which is in northwestern New Mexico, and (4) the Palo Verde/Hassayampa switchyard complex west of Phoenix. A simplified diagram of this system is attached as Schedule CD-1R. Of these injection points, Mead, Four Corners and Palo Verde could be considered market hubs, in that there is trading occurring among suppliers at these hubs. Although Navajo/Moenkopi is an injection point to APS' system, there is not currently significant trading activity at either Navajo or Moenkopi.

By far the largest part of APS' system from a load standpoint is the Valley, where the expected summer peak for 2003 will be 4112 MW. The Valley is itself a complex transmission system that is partly shared with Salt River Project ("SRP"). APS' Valley 230 kV system is served from four bulk switchyards that electrically form a square around the Valley—Westwing to the northwest, Pinnacle Peak to the northeast, Southwest Valley (now called the Rudd Switchyard) to the southwest, and Kyrene to the southeast. A simplified diagram of the Valley system is attached as Schedule CD-2R. While there are several interconnections to other systems, such as to the Western Area Power Administration ("WAPA"), geographically located near or in the Valley, these interconnections are electrically outside of what is known as the Valley "cut plane" which determines APS scheduling capability on the Valley system.

In addition to Phoenix, APS serves the Yuma area; Northern Arizona including communities such as Flagstaff, Prescott and Payson; Southern Arizona including communities such as Gila Bend, Casa Grande, and Douglas; the Eastern Mining

Area including Globe and Miami; and several smaller remote loads. All together, the APS retail system peak for 2003 is estimated to be 5911 MW.

V. TRANSMISSION CONSTRAINTS AND MARKET POWER

Q. STAFF WITNESS SMITH ASSERTS THAT THERE ARE TRANSMISSION CONSTRAINTS ON APS' SYSTEM. DO YOU AGREE?

A. Of course. Transmission constraints—which emerge as load growth occurs and retreat as additional resources are brought into service to meet that load growth—are inherent aspects of any complex transmission system like APS' during certain peak hours of the year. Unless there is massive and uneconomic overbuilding of both transmission lines and local generation, I expect that transmission constraints will continue to be a factor that must be considered when looking at the capabilities of APS' transmission system. I also believe that constraint issues will likely be appropriately addressed by an RTO in the future. The Federal Energy Regulatory Commission ("FERC") itself recognizes that it is neither practical nor desireable to eliminate all transmission constraints, and through its Standard Market Design initiative intends to manage constraints using physical and financial protocols. Currently, both Yuma and the Valley are transmission constrained areas on APS' system at peak hours during the summer.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW TRANSMISSION CONSTRAINTS ARE INHERENT ASPECTS OF APS' SYSTEM?

A. The history of Yuma offers a good illustration of both how transmission constraints ebb and flow and how the current APS transmission system developed under integrated resource planning. In the 1960s, loads in Yuma could generally be served by the steam turbine at the Yucca power plant and local transmission. In the early 1970s, loads in Yuma were increasing to the point that additional load serving capability was needed. At the same time, APS needed additional generating capacity for its system. Given these needs, the logical and economical choice was to install new generating capacity at Yucca to meet both needs, rather than construct both a power plant in Phoenix and a transmission line to Yuma. When the Yucca combustion turbines were added, the local generating capacity increased, eliminating the need for new transmission at that time. That outcome was the most cost effective solution to the situation.

By the mid-1980s, load in Yuma was again reaching the point where additional load serving capability was required. Now, however, a California utility was proposing to construct the North Gila 500 kV transmission line from Phoenix (i.e., Palo Verde) into Southern California to allow it access to the Arizona and New Mexico systems and markets. Given those circumstances, the logical choice was for APS to partner with that utility for a share of the capacity on the North Gila line, which allowed more transmission import capability and thus provided more load serving capability in Yuma. And, after the North Gila line was constructed, the Yuma local generation requirement was significantly reduced.

Today, however, load growth in Yuma has again reached a point where additional load serving capability will soon be necessary. Thus, APS has included a new transmission line in its 10-Year Plan from Gila Bend to Yuma, which will provide more transmission import capability and, accordingly, more load serving capability. For a time, that new line will relieve transmission constraints into Yuma.

The point of this example is that the displacement of transmission by local generation is neither "bad," nor indicative of "poor planning" by the incumbent utility. Instead, it is simply the byproduct of least cost planning to meet load serving requirements. In some cases, the least cost solution is to build local generation. In fact, some local generation is always needed to provide voltage support and reactive power to a system regardless of how much transmission is built. Sometimes, the least cost solution is to construct new transmission lines. And again, in most cases transmission constraints only exist for a small portion of the year and for a relatively small amount of an area's overall load requirements.

However, it is never least cost to redundantly construct both transmission and local generation, or to overbuild the transmission system so that APS customers have to pay for significant unused transmission capacity. Thus, I disagree in concept with Staff witness Smith when he states that merchant generators outside a constrained area "<u>may</u> be more cost-effective than generation available locally." (emphasis added) In fact, they are likely <u>not</u> more cost-effective given the need to build additional transmission to allow them to reach load during the relatively few hours per year when an area is constrained. Mr. Smith has certainly not presented any evidence supporting the accuracy of this statement when the cost of siting and constructing additional transmission lines through an urban area is compared to the incremental generation costs for a limited period of time during the year. This is one critical area where Mr. Smith does not account for how APS' system was planned and constructed.

Q. DO YOU AGREE WITH STAFF WITNESS SMITH WHEN HE STATES ON PAGE 7 OF HIS TESTIMONY THAT OWNERS OF CONSTRAINED TRANSMISSION CAN USE THE CONSTRAINTS TO EXERCISE MARKET POWER?

A. Absolutely not. Like Mr. Smith, I am an engineer and not an economist, but it is clear that Mr. Smith makes several inappropriate inferences and conclusions in his evaluation of market power and transmission constraints. First, I disagree that a utility can exercise "market power" simply because they own or operate must run generation. In the Valley, for example, APS is not preventing any merchant generator from siting competing local generation. Any competitive supplier (including an ESP) is perfectly free to construct its own local generation or fund transmission upgrades to supply capacity within transmission constrained areas. Further, the prices that must run generation can charge during constrained periods are capped using a cost-based rate. Because the price is regulated during constrained periods, the utility operating must run generation cannot manipulate the market price. So Mr. Smith is simply incorrect when he claims that utilities with local generation "control" the market.

Mr. Smith also does not discuss various regulatory requirements currently in place that would preclude FERC-regulated transmission providers like APS from exercising market power due to transmission constraints. The Open Access requirements set forth in FERC Orders 888 and 889 were developed in large part to mitigate the potential for market power. APS' OATT includes specific FERC-approved protocols regarding cost-based pricing for must run generation and the allocation of APS' network transmission service to suppliers of Direct Access loads. FERC Orders 888 and 889, coupled with APS' OATT, require transmission providers such as APS to make available transmission capacity accessible to other users on a non-discriminatory basis, which also prevents market power abuse such as Mr. Smith suggests can exist.

Finally, Mr. Smith's discussion of how must run generation could adversely impact Direct Access customers of Electric Service Providers is also faulty. Although APS' retail rates are capped today as a result of the 1999 Settlement Agreement, once the purchase power adjustment mechanism provided for in that agreement is incorporated into APS' rates 2004, regulated cost-based prices resulting from the operation of must run generation would presumably be passed through equally to both Direct Access and Standard Offer customers. In this case, because there would be no relative difference in costs between Standard Offer and Direct Access customers, there would be no impact on the "shopping credit."

Q. **DO YOU BELIEVE THAT APS SHOULD CONSTRUCT ENOUGH TRANSMISSION SO THAT IT NEVER HAS TO RELY ON LOCAL GENERATION?**

A. No. In its recent Biennial Transmission Assessment, Staff essentially took the position that there should be enough transmission constructed into "constrained" areas so that local generation was never required. If adopted, such a policy would dictate considerable and unwise overbuilding of transmission capacity and would ignore the unquestionable value to the system of local generation resources. For example, constructing new transmission lines through urban areas is expensive, both in terms of money and impacts to property and the environment. If local generation is needed due to transmission constraints for the 300 to 400 hours per year projected for the Valley, or less than 5 percent of the 8760 hours in a year, the hundreds of millions of dollars and environmental impacts it would take to fashion a 8760 hour solution to relieve a 400 hour "problem" would be a real waste of resources. This is particularly true when during constrained periods, the price that a local must run generator can charge is regulated. Further, local generation offers a significant reliability advantage compared to 100 percent dependence on transmission imports.

Local generation requirements must be considered hand-in-hand with the load service obligations of a company like APS. When it is necessary to construct load serving capability to meet APS' load serving requirement, as I discussed in my Yuma example above, it may be appropriate to construct new transmission lines. It is not appropriate to just ignore local generation resources and overbuild transmission lines.

Q. **IS STAFF WITNESS SMITH CORRECT IN ASSERTING THAT TRANSMISSION CONSTRAINTS AT THE PALO VERDE HUB ALSO GIVE RISE TO MARKET POWER CONCERNS?**

A. No. APS did not tell Duke, Sempra or PG&E National Energy Group to construct plants at the Palo Verde hub. If too much capacity has been constructed at that location so that some capacity is "stranded" due to inadequate transmission away from the hub, that is in no way attributable to any action, let alone "market power", of the transmission owners in that area. Further, I don't see how Mr. Smith can claim that the over-construction of capacity at Palo Verde by merchant generators somehow "protects" higher pricing at other non-merchant generating sources. And, even if it had such an effect, why would that be the fault of a transmission owner, who was not responsible for the merchant generator's selection of its plant site?

No merchant generator interconnecting at Palo Verde asked for firm transmission capacity to serve APS' load (and only PWEC's Redhawk Project asked to be designated as a network resource). Thus, it would have been foolish and imprudent for APS to construct additional transmission capacity from Palo Verde for, say, Sempra's Mesquite power plant, at APS ratepayer expense only to later find out that Sempra contracted to serve California or some other non-APS loads unless the merchant plant owner were willing to purchase sufficient firm transmission rights over such additional capacity. Indeed, APS generally does not know where a given merchant plant intends to sell its output over the life of a project.

Finally, Mr. Smith is incorrect in suggesting that there is at present, or will be in the future, some ability to "bid" for transmission rights in a way that would affect delivered energy prices so as to give an incumbent transmission provider and its generation affiliates a competitive advantage. I cannot tell you today what will ultimately be adopted, but it certainly will not be driven by transmission owners attempting to manipulate constraints, given that each one of the merchant generators at Palo Verde freely selected that location and made whatever transmission service requests that it felt were appropriate. If such congestion management arrangements are implemented, I expect them be administered by a FERC-authorized and independent RTO and not controlled by individual transmission owners. I can also tell you that, even absent an RTO, the FERC Code of Conduct between transmission owners and generation affiliates would prohibit the improper leveraging of generation by using affiliated transmission.

Q. **IS APS FRUSTRATING THE EFFORTS OF MERCHANT POWER PLANTS TO INTERCONNECT TO THE TRANSMISSION GRID?**

A. Of course not. I am proud of APS' track record, which includes the development of a pro forma interconnection tariff and process while FERC is still in the pre-rulemaking stage on a similar effort; the siting and permitting of Panda/TECO's interconnection on a significantly faster pace than has historically been possible for 500 kV transmission line projects requiring National Environmental Policies Act ("NEPA") review; and the proactive resolution of transmission constraints at Reliant's Desert Basin plant when it was discovered that WAPA had facility limitations on its 115 kV system.

Q. **IS APS TAKING APPROPRIATE STEPS TO ADDRESS TRANSMISSION CONSTRAINTS ON ITS SYSTEM?**

A. Yes. As Mr. Smith recognized in his testimony, APS and other Arizona transmission owners have made plans to construct additional transmission capacity in Arizona. He also mentioned several planned transmission enhancements by APS that have been identified in our 10-Year Plan. I appreciate and agree with his comments that "...Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions..." and that this represents a "...good faith demonstration of Arizona utilities commitment to respond favorably on a forward looking basis." Also, PPL witness Saline confirmed in response to a discovery question that he was not alleging that APS had been deficient in planning or constructing transmission to serve APS' load. These statements further contradict any notion that APS is taking advantage of transmission constraints, particularly when merchant generators are simply not siting their plants inside any constrained areas nor offering to construct transmission into such constrained areas.

Generally, the additional transmission that APS is planning is being driven by load requirements or when reliability issues require additional transmission capacity. There currently are no established and proven mechanisms to provide for cost recovery to construct transmission capacity that is not needed for load serving capability or system reliability, but which might still be appropriate for economic reasons in the long term. That issue is one that I expect will be addressed after WestConnect becomes operational in the Desert Southwest and more flexibility towards system planning is introduced, including transmission lines that on a "stand-alone" basis might not be economic for a single transmission provider or load serving entity to construct, but which may be economical on a regional basis.

I would also note, again, that the resolution of transmission import constraints and local generation requirements through the construction of new resources is rarely a permanent fix. To use my earlier discussion of the Yuma area, the construction in 2006 of a 230 kV transmission line from Gila Bend to Yuma will reduce the amount of local generation that is necessary to run in Yuma to meet load serving requirements. So initially, it can be said to reduce transmission constraints at Yuma. But as load growth occurs in Yuma, we will likely reach "constrained" status again at some point in the future until yet another resource, whether a transmission line or generator, is added to serve load.

Q. ARE THERE OTHER WAYS THAT WESTCONNECT MAY HELP ADDRESS TRANSMISSION ISSUES IN THE FUTURE?

A. Yes, I think WestConnect will go farther than Mr. Smith suggests in addressing even perception problems arising from transmission limitations of the various systems in the Desert Southwest. Under the WestConnect model, which was submitted to FERC for approval on October 16, 2001, WestConnect would be responsible for transmission planning and expansion across its region. WestConnect proposes a planning process that is active, hands-on, and open to all stakeholders. WestConnect proposes to coordinate those efforts with all appropriate state and federal regulatory authorities and, additionally, in coordination with the WECC, ensure that expansion efforts do not interfere with the expansion of other facilities within the Western Interconnection. The stakeholder transmission planning group would also be responsible for developing regional transmission expansion plans. However, all of these measures are still some time in the future, which leads me to concur with Mr. Smith's assessment that the time is not yet ripe for the immediate transition to competitively bidding 50 percent of APS' Standard Offer Service requirements, as if all of these market and infrastructure issues were already resolved.

VI. STAFF'S "INTERIM" COMPETITIVE BIDDING PROPOSAL

Q. IS STAFF'S "INTERIM" COMPETITIVE BIDDING PROPOSAL ACCEPTABLE?

A. No, certainly not in its entirety.

Q. WHAT AREAS OF THE INTERIM COMPETITIVE BIDDING PROPOSAL DO YOU AGREE WITH?

A. First of all, I appreciate Staff's acknowledgement that their proposal is intended as a starting point or "straw man" for further discussion. So although I have significant substantive disagreements with much of Staff's proposal, I understand that it was developed in the spirit of searching for creative solutions to the inherent problems associated with a 50 percent competitive bid requirement on APS' system. However, I don't believe that the significant risks of implementing creative solutions—risks that Mr. Smith admits—are appropriate when balanced against the phased-in approach to competitive bidding set forth in the proposed PPA.

I specifically agree with Staff's suggestion that load growth can be served through competitive bidding. In fact, this is what the increasing competitive bid component of the proposed PPA was itself intended to capture. I also understand that competitively bidding new load serving requirements or load growth is being done in several other states, so I do not believe that it is a totally untested proposal. I also agree with Staff that there should be exceptions to any mandatory competitive bidding requirements for emergency or short-term purchases.

Q. IS STAFF'S PROPOSAL FOR COMPETITIVELY-BIDDING UNCONSTRAINED LOAD APPROPRIATE?

A. As a <u>theoretical concept</u>, Staff's notion that unconstrained load on APS' system <u>could</u> be competitively bid is correct. I do, however, have corrections to Mr. Smith's analysis of this component of Staff's interim proposal and I have concerns over whether competitively bidding this remote load is either practical or economical.

Specifically, Mr. Smith concludes that there is roughly 1600 MW of unconstrained load that could be competitively bid under the interim proposal. To reach that figure, he subtracted APS' Valley load and Yuma load (the two transmission constrained areas noted in his testimony) from APS' overall load requirement reported in the 2001 Biennial Transmission Assessment. This calculation method, however, improperly includes APS' wholesale loads and transmission losses in the 1600 MW and does not reflect the most current estimates for APS' system. The correct and more accurate way to determine APS' unconstrained loads is to look at the system from the bottom up, rather than the top down. At system peak, such an analysis would yield the following loads for APS' unconstrained system:

Northern Arizona (Flagstaff, Prescott, Payson, etc.)	250 MW
Southern Arizona (Douglas, Casa Grande, etc.)	350 MW
Eastern Mining Area and other remote loads	100 MW
Total	700 MW

While I think it is theoretically possible to competitively bid this 700 MW of unconstrained loads, I have serious reservations on the feasibility of such an approach. First, serving this load would require delivery and interconnection to the local 230 kV system at one or more remote points on the APS system, which may potentially exclude some suppliers and further limit the size of the bidding pool. Second, the figures provided above are at system peak and would usually be significantly lower during the remainder of the year. Thus, for example, a generator serving the Southern Arizona load would often be supplying much less than 350 MW and would have to be capable of supplying baseload, intermediate and peaking capacity for this load.

Further, if a merchant generator were to be the "sole supplier" of the power requirements to one of these communities, as the Staff proposal appears to contemplate, the merchant generator would have to essentially devote a unit (or possibly two, when reserves are considered) to serving a relatively small load. Even assuming the metering technology to integrate the generator into APS' overall control area to serve the remote loads were available, Staff's proposal may also require the merchant generator to install Automatic Generation Control ("AGC") for load-following, and require related system control and telemetry equipment. Therefore, I do not believe that it would be appropriate or practical to require competitive bidding for all, or even a significant portion, of this unconstrained load as suggested by Staff.

Q. DO YOU AGREE WITH STAFF'S PROPOSAL ON MAKING "NEW ATC" AVAILABLE FOR COMPETITIVE BIDDING?

A. No. The proposal for competitively bidding new Available Transmission Capacity ("ATC") has a number of serious flaws and includes several inaccurate assumptions, so I do not believe that this component of Staff's interim proposal can work at all in practice. Even as a theoretical construct, I do not believe it could work to the extent suggested by Mr. Smith.

Mr. Smith begins by assuming that there is 1840 MW of new generation being constructed inside the Valley constrained area, including Reliant's 520 MW Desert Basin plant, SRP's 250 MW Kyrene expansion, PPL Sundance's 450

MW peaking plants, and Pinnacle West Energy Corporation's ("PWEC") 620 MW West Phoenix expansion. Of these plants, however, both Desert Basin and Sundance are interconnected to the transmission grid outside of the "cut plane" which determines APS' Valley scheduling capability, so neither Desert Basin nor Sundance could increase APS' Valley scheduling capability by <u>any</u> amount under <u>any</u> circumstances.

I also disagree with Mr. Smith's assertion that the location of new generation inside the Valley "has the net effect of addressing the transmission import constraint irrespective of who owns, operates or purchases the output." This error is based on a misunderstanding of APS' scheduling capability versus load serving capability. APS' Valley scheduling capability is 3685 MW—a figure that represents the amount of power that can be imported to the Valley on transmission lines expected to be in service by system peak in 2003, and specifically including the Southwest Valley Project. With no local generation running, 3685 MW can be imported to serve load requirements in the Valley. If APS' load increases to 4185 MW, there is not enough transmission scheduling capability on the system to bring in more generation, so local generation must be used to meet APS load serving requirement. In this case, 500 MW[1] of local generation from, for example, West Phoenix would be required. However, the presence of generation in the Valley only increases APS' load serving capability but does not increase scheduling capability. Thus, the operation of the local generation in this example meets APS' 4165 MW load serving requirement, but does not change the transmission scheduling limit of 3685 MW into the Valley.

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[1] 4185 MW load – 3685 import = 500 MW

Moreover, the fact that SRP might be running the Kyrene plant to meet its load serving requirements would neither entitle APS to any more transmission scheduling capability on its (or SRP's) system nor meet APS' load serving requirements unless the Kyrene plant's output was being sold to APS. That project is already included in the calculated Valley import capability. Further, because both companies serve the Valley, APS and SRP have apportioned the total scheduling capacity into the Valley on the basis of 41% to APS and 59% to SRP. Any additional transmission import capacity from system improvements is added on a pro rata basis to this baseline. In the case of the Southwest Valley Project, where each party is paying for 50% of the Project, that means that each party receives 50% of the additional transmission import capability resulting from the Project, which is then added to the base amounts from the initial allocation. In the case of Kyrene, any additional scheduling capability from that project would be allocated only to SRP, since APS did not participate in it.

It is not the case, as suggested by Mr. Smith in his testimony, that APS and SRP simply divide the total import scheduling capability for the Valley in half for any system improvements. APS' transmission import scheduling capability for the Valley after the Southwest Valley Project is in service will be 3685 MW, irrespective of other plants in the area or SRP's local generation or improvements that SRP makes to the system.

The only theoretical concept that could allow for some "new ATC" from local generation consistent with Mr. Smith's proposal appears to me to be wholly impractical. The Arizona Independent Scheduling Administrator's ("AISA") protocols do allow increased transmission import schedules, but only when the amount of local Valley generation exceeds the Local Generation Requirement ("LGR") for the Valley. Using the example above, if West Phoenix were generating 620 MW, with 500 MW going to the LGR and 120 MW being sold outside of the Valley, it is possible to schedule an additional 120 MW into the Valley. This is a concept known as "counter-scheduling," and means that 120 MW of new scheduling into the Valley is essentially "netted out" by the 120 MW being sold from West Phoenix to outside the Valley.

While under these limited circumstances, it may be theoretically possible to schedule into the Valley the amount of local generation that is being sold outside the Valley, I certainly do not believe that this concept could practically be subjected to competitive bidding. To do so would require that a bidder be solely dependent on those times where PWEC was choosing for its own economic reasons to sell local generation off system, and then only for the amounts of those off-system sales, and then only to the extent that the amount sold off-system exceeds the LGR. I cannot see how this concept would result in any firm ability of a bidder to reach the APS system, or allow APS to rely on such a bidder being able to schedule into the Valley whenever APS needs the power.

Also, the amount of capacity that could be subject to this theoretical concept of counter-scheduling would be far less than the 1840 MW that Mr. Smith estimated would be available by simply adding the capacity of four new power plants, and would also decline each year, until additional scheduling capability into the Valley is constructed, as APS' load serving requirement and the LGR increased. A table illustrating the relationship between LGR, transmission import scheduling capability and the theoretical limits to "counter-scheduling" for APS' Valley system is attached as Schedule CD-3.

Q. **CAN MR. SMITH OR ANYONE ELSE TELL THE COMMISSION HOW MUCH POWER CAN BE COMPETITIVELY BID GIVEN TRANSMISSION CONTRAINTS AND APS' TRANSMISSION SYSTEM?**

A. Not without making a number of critical explicit or implicit assumptions. For example, how are the Dedicated Units being used, how specifically will the bid be structured, where will the required delivery points be located, and for what capacities at each delivery point? The bid amount also cannot be determined without knowing the exact location and operational characteristics of all the generation resources that would operate on APS' system following the competitive bid.

I can tell you that resources to serve APS' load would have to be delivered at all of APS' four EHV injection points—Four Corners, Navajo/Moenkopi, Mead and Palo Verde—and that there are potential reliability or contractual impacts based on which units are running or what is being delivered at each location. For example, if Cholla Unit 4 is off line, Pacificorp has transmission rights to 200 MW from Four Corners to Westwing or Palo Verde, which would in turn curtail the amount of transfer capability available to APS on the transmission path from Four Corners. Also, if certain existing generating units are not running on APS' system, the transfer capabilities on each of these paths may change due to voltage limitations or other operational constraints. For example, if energy is delivered to APS at Four Corners from Craig/Hayden in Colorado, the transfer capabilities along the Four Corners path may well be different than if energy is being delivered from Four Corners itself. Of course, it also depends on what one considers to be a "competitive" bid.

Q. DO YOU AGREE WITH STAFF WITNESS SMITH'S CONCLUSION THAT A "COMPETITIVE SUPPLY MARGIN" IS EMERGING IN ARIZONA?

A. Again, like Mr. Smith I am not an economist, so I look at these issues more from an engineering and transmission operating perspective. I certainly agree that significant amount of new generating capacity is being constructed in Arizona and is currently planned for future construction in Arizona. I would also agree that this new capacity should allow Arizona to contribute to the supply needs of the Western Interconnection.

However, much of this new capacity is relatively concentrated around the Palo Verde hub—something that is certainly not surprising given the amount of trading there and the fact that direct interconnections by generators to the "common bus" at Palo Verde reduce transmission costs to the generators. Because APS' system cannot physically take delivery of all its power requirements from one location like Palo Verde, I do not believe that the analysis of whether there is an adequate "competitive supply margin" for delivery to APS' transmission system can be performed by simply adding up all the new and planned capacity in the state and comparing it with load requirements. For APS, power would have to be delivered at all the injection points that I discussed in Part IV of my testimony, which requires a more involved analysis than the additive process that Mr. Smith appears to have performed in his testimony on this issue. Thus, while I agree that there is a significant amount of new generating capacity being added in Arizona and to the

Western Interconnection generally, I don't believe that new capacity can simply be summed to determine whether there is an adequate "competitive supply margin" for APS' system, as Mr. Smith appears to suggest.

VII. TRANSMISSION ISSUES AFFECTING 50 PERCENT COMPETITIVE BIDDING REQUIREMENT

Q. OTHER INTERVENOR WITNESSES HAVE STATED THAT APS SHOULD SIMPLY PROCEED WITH COMPETITIVELY BIDDING 50 PERCENT OF ITS STANDARD OFFER SERVICE REQUIREMENT. DO YOU AGREE?

A. As I discussed earlier in my testimony, from a transmission operator's perspective, competitively bidding 50 percent of APS' Standard Offer Service in January 2003 is not as practical or efficient as such witnesses appear to believe. Put simply, I believe that there are too many emerging regulatory and market issues to reduce the risk of such a change to an acceptable level for APS customers. I also believe that APS' transmission system and transmission constraints on serving Valley loads make implementing such a large competitive bid requirement in such a short period of time much more complicated and risky than is being suggested by these intervenor witnesses, and certainly more risky than the phased-in approach offered by the proposed PPA.

Q. PPL WITNESS SALINE ARGUES IN HIS TESTIMONY THAT COMPETITIVE BIDDING WOULD PRODUCE RESULTS EVERY BIT AS RELIABLE AS THE PROPOSED PPA. DO YOU AGREE?

A. No. Mr. Saline too easily dismisses many critical issues relating to the impacts of competitive bidding on the practical operation of APS' system. In general, he attempts to argue that reliability is limited to literal compliance with NERC and WECC reliability criteria. The reliability issue that APS has discussed in its

Request for a Partial Variance is not whether an individual merchant power plant is "reliably" interconnected at an individual point in APS' or any other party's transmission system. The fact that minimum criteria are met for interconnection does not mean that those plants can serve APS' loads with the same overall reliability as the plants that were designed and built as the system evolved.

For example, Mr. Saline states at page 7 of his testimony that "APS would not allow electrical interconnection of a generator [at Palo Verde] unless APS' system could safely accommodate that generation into the transmission network if that generator were dispatched to serve load." That statement misstates the reliability analysis that APS is required to perform for an interconnection under FERC rules. Under these rules, a generator may request interconnection to APS' system without asking for any transmission service. Thus, many generators interconnected to the Palo Verde hub without requesting any transmission service to reach APS or any other load serving entity. To approve such an interconnection, APS (and SRP in the case of Palo Verde) would look at the interconnection component, but would not at all "guarantee" that every generator can be simultaneously accommodated on the transmission system, as Mr. Saline's testimony seems to infer. Rather, it would be the responsibility of the interconnected generator to secure transmission rights, which might require system upgrades, or use a load serving entity's existing network transmission if it actually sought to serve a specific load.

Similarly, Mr. Saline goes to great lengths to argue that receiving network transmission service from APS guarantees the same ability to serve load as under APS' current system. However, network transmission service has never meant that any generator is entitled to reach any APS load at any time. Thus, his assertions on page 10 of his testimony regarding the "conclusions" one must reach with respect to network resource transmission service are simply not supported.

Q. ARE THERE OTHER ASPECTS OF PPL WITNESS SALINE'S TESTIMONY THAT ARE INCORRECT?

A. Yes. He also suggests that his firm has studied the ability of Sundance to deliver its output to serve the Valley without being limited by current import constraints. While I agree that Sundance's interconnection into the WAPA 230 kV system at Coolidge allows it a different delivery path than the generators interconnecting at the 500 kV system at Palo Verde, the interconnection still does not change APS' scheduling constraints to serve Valley load. Thus, Sundance perhaps could deliver power over the 230 kV system to APS at the Westwing substation, but that does not at all change the 3685 MW transmission import capability that APS has to serve the Valley. And Mr. Saline's suggestion that there may be 500 MW of firm transmission rights to substations accessing Valley loads (page 19) also ignores APS' Valley import limitation, which is independent of whether PPL or another party can deliver to one of these substations.

Q. PANDA WITNESS SCHUYLER SUGGESTS THAT PANDA'S INTERCONNECTION AT THE JOJOBA SWITCHYARD AND RIGHTS TO DELIVERY AT PALO VERDE GIVE IT BETTER ACCESS TO APS' SYSTEM. DO YOU AGREE?

A. Not really. Because the Jojoba switchyard is outside the Valley cut plane, Panda's interconnection (whether at Palo Verde or Jojoba) does nothing to increase APS' Valley scheduling limits of 3685 MW that I discussed above. While using additional capacity on SRP's Kyrene line coupled with the 333 MW of firm transmission rights Panda has from APS may allow Panda flexibility to deliver power to Palo Verde and from Palo Verde to California, it doesn't increase the amount of power that APS can schedule into the Valley.

Q. **PG&E NEG WITNESS DE ROSA STATES THAT NEG AND OTHER INDEPENDENT POWER PRODUCERS ARE TRADING SIGNIFICANT VOLUMES OF POWER AT PALO VERDE, AND THUS APS HAS OVERSTATED THE PRACTICAL BARRIERS TO COMPETITIVE BIDDING. DO YOU AGREE?**

A. No. Like most of the merchant generators, NEG has also focused on trading at Palo Verde, and not the necessary delivery points on APS' transmission system other than Palo Verde. There could be another 20,000 MW at Palo Verde, but that wouldn't alter the limitations of APS' system that preclude all of APS' Valley load from being served from a single injection point like Palo Verde. Simply getting power to Arizona does not necessarily make it possible to serve APS' system.

Q. **NEG WITNESS TAYLOR IS SUGGESTING THAT THE COMPETITIVE BIDDING COULD BE DONE BY SPECIFYING RESOURCES TO BE CONSTRUCTED IN THE FUTURE. WOULD YOU AGREE?**

A. I agree that there appears to be some uncertainty about what Rule 1606(B) actually means. I would also agree that competitively bidding 50 percent of APS' Standard Offer Service load could theoretically include the construction of additional local generation and transmission resources. However, given the relatively long lead times to construct new transmission resources in Arizona, I believe that there would be significant development risk associated with any additional transmission required under the model that Mr. Taylor appears to recommend. Also, his comments that simply getting power to Palo Verde resolves the problem demonstrates the same misunderstanding and oversimplification of APS' transmission system that I addressed earlier.

Q. RELIANT WITNESS KEEBLER STATES THAT APS HAS IGNORED PLANNED TRANSMISSION PROJECTS IN ARIZONA OVER THE NEXT SEVERAL YEARS THAT WOULD PROVIDE RELIABLE TRANSMISSION PATHS FOR NEW GENERATION. DO YOU AGREE?

A. No. My discussion earlier assumes that the Southwest Valley Project is in service by the summer of 2003, which does provide more scheduling capability to APS Valley loads. Even with that project in service, the ability to deliver to APS' loads in the Valley is limited because of the underlying 230 kV system.

VIII. CONCLUSION

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

A. In general, I believe that the intervenors and Staff vastly oversimplify the complexities of APS' transmission system and the difficulties associated with immediately "redesigning" that system to accommodate a competitive bidding model that does not recognize how the system evolved under regulated least cost planning principles. It is not possible to simply drop off half of APS' power supply needs at Palo Verde, where most of the merchant generators have constructed their plants, and let APS and its customers worry about how to deliver that power. There are limitations on deliverability that result from the transmission system that APS has developed over the last 75 years that must be considered.

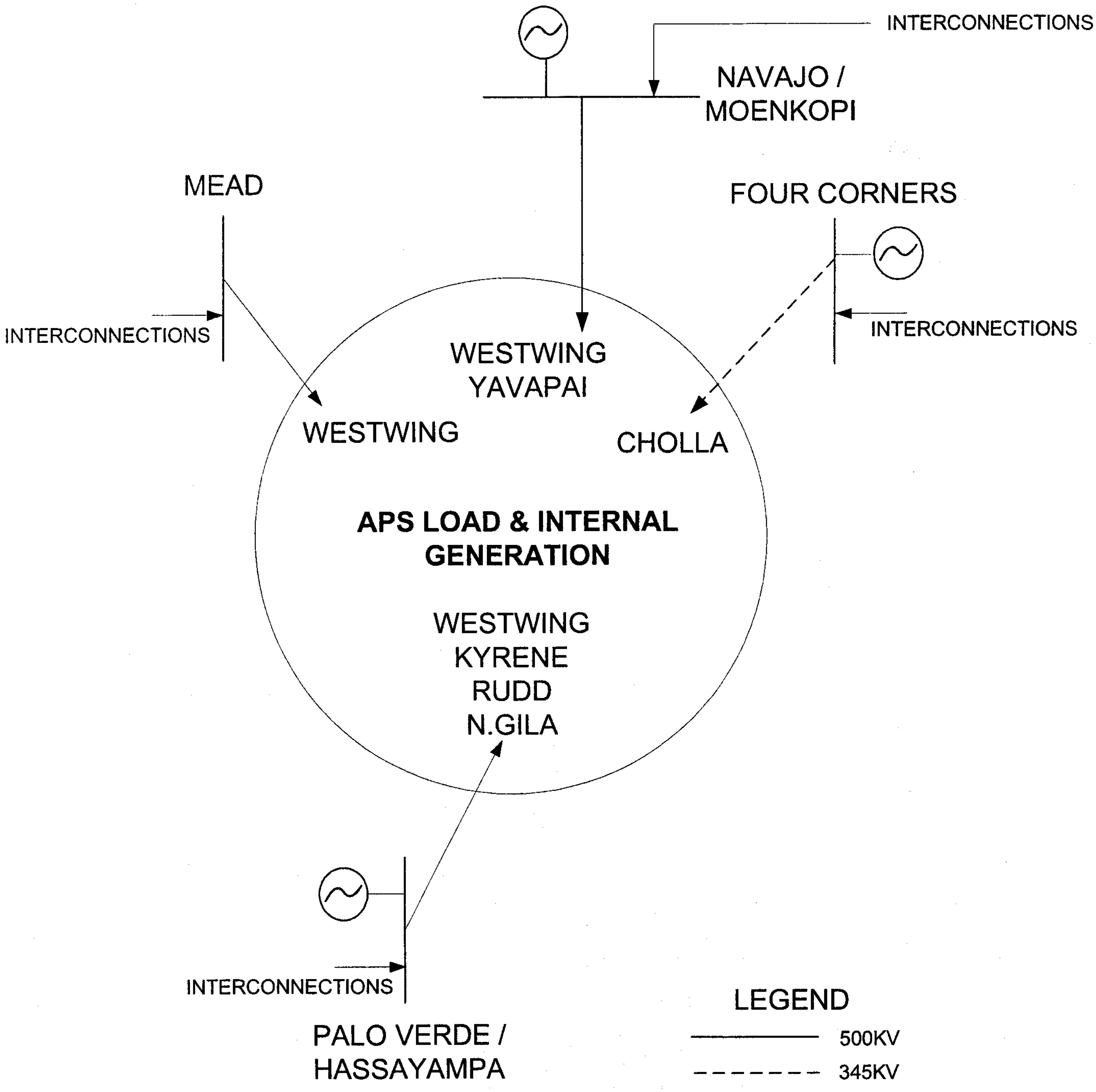
Additionally, Mr. Smith and Mr. Rowell agree that there are "risks and uncertainties" associated with competitive bidding and that APS' system cannot currently support the 50 percent requirement embodied in Rule 1606(B). While I agree with those points, the interim competitive bidding proposal developed by Staff is mostly impractical and based on incorrect assumptions. The Staff interim competitive bidding proposal does not present a superior alternative to the phased in competitive bidding in the proposed PPA. From a transmission system perspective, I believe that the proposed PPA is the most reasonable way to provide continued stable and reliable service to APS' Standard Offer Service customers, while allowing the transmission system and related market institutions like the WestConnect RTO to evolve and while phasing in competitive bidding on a reasonable schedule.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

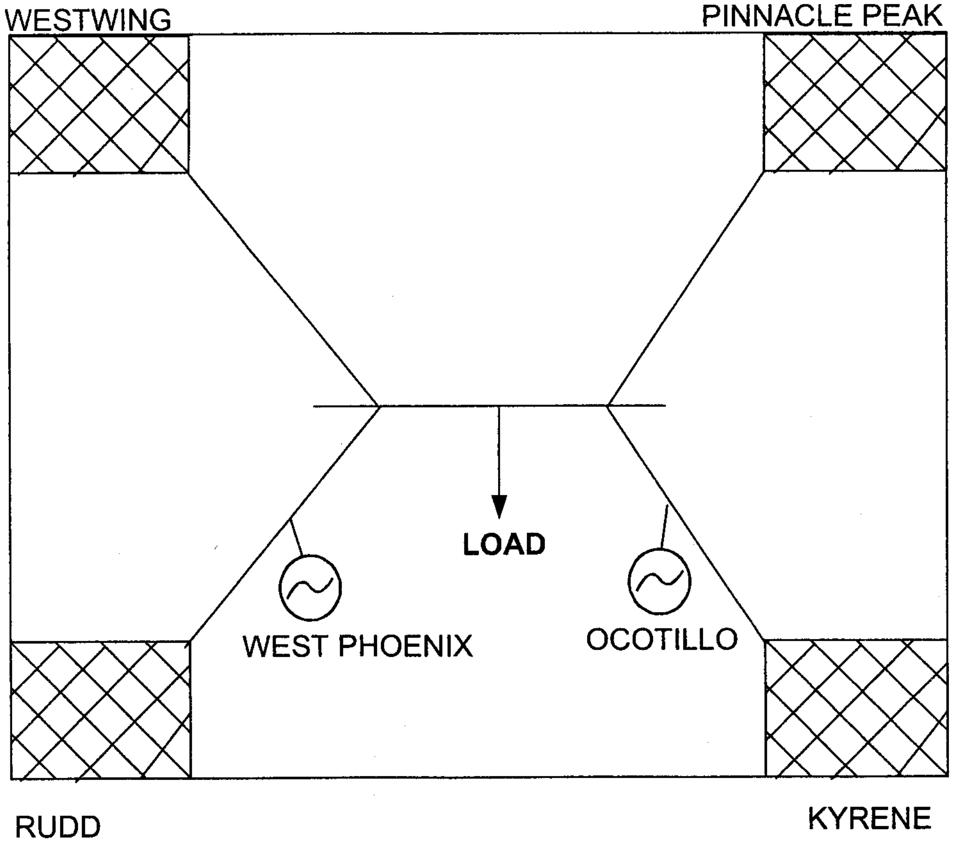
A. Yes.

1165368.1

SCHEDULE CD – 1R
SIMPLIFIED APS EHV DIAGRAM



SCHEDULE CD-2R
SIMPLIFIED APS VALLEY 230KV DIAGRAM



Schedule CD-3R

APS Valley Import Analysis

Year	APS Valley Load	APS Transmission	APS Valley Local Gen Reqmnt	APS Valley Gen-Reqd Margin(2)	Theoretical Limit of Counterschedul-ing(3)
2003	4112	3685	427	1080	653
2004	4256		571		509
2005	4405		720		360
2006	4559		874		206
2007	4719		1034		46
2008	4884	4685 (1)	199		881
2009	5055		370		710
2010	5232		547		533

(1) Palo Verde – Table Mesa 500kV,1000MW

(2) Gen includes WP CC 4 & 5, but not WP St 4 & 6
Required margin = 250MW

(3) Assumes all Valley units can be sold off system

(All values in MW)

BEFORE THE
ARIZONA CORPORATION COMMISSION

Rebuttal Testimony of

Charles J. Cicchetti, Ph.D.

Docket No. E-01345A-01-0822

On Behalf of

Arizona Public Service Company

April 22, 2002

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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 ADMINSTRATIVE 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 Ontario Energy Board on several occasions, and testified before the National Energy Board.

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 testimony in the hearings regarding APS' request for a variance to certain aspects of A.C.C. R14-2-1606B (Rule 1606B), and approval of its purchase power agreement (PPA) with Pinnacle West Capital Corporation (PWCC).

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

A. The Arizona Corporation Commission (ACC), APS, and various parties are well along in the transition to a restructured competitive electricity market in Arizona, which is based upon the ACC's Electric Competition Rules and the APS Settlement Agreement of 1999. Particularly relevant to the requested variance is Rule 1606B, which states that:

> After January 1. 2001, power purchased by an investor owned utility distribution company (e.g., APS) for Standard Offer Service shall be acquired from the competitive market through prudent arms' length transactions, and with at least 50% through a competitive bid process.

As I understand the facts in this proceeding, the ACC granted a two-year extension to this provision until January 1, 2003. In this specific proceeding, APS seeks a variance to some of these related requirements and regulatory approval of its PPA with PWCC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Staff's proposals would essentially negate the 1999 APS settlement by blocking divestiture while simultaneously seeking to competitively bid an unknown amount of APS Standard Offer requirements. Staff also rejects the proposed PPA and ignores or downplays its significance to reliability. Other witnesses in this matter have taken two conflicting and extreme views. APS seeks a variance based upon a middle ground policy. My role here is to address Staff's position and to rebut these two extremes: (1) Dr. Rosen's calls for extended and micromanaged market and contract regulation; and, (2) what I conclude are Dr. Ruff's premature calls for forcing the competitive market to simply rip and be forced upon electric consumers in Arizona, whether or not they freely choose to switch their retail electricity supplier. Dr. Rosen seems not to trust competitive markets to ever be able to replace comprehensive command and control utility regulation in Arizona. Conversely, Dr. Ruff seems wedded to some conceptual adherence to an academic model that ignores some significant basic facts in Arizona and the western United States. I will explain why each of these contradictory positions is not the correct solution for Arizona at this time.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Because I address and rebut only certain elements of the testimonies filed, respectively by Commission Staff, and by Drs. Roach, Ruff and Rosen, I begin with a more conceptual approach. Thus, in Section III, I explain why it is important for the ACC to honor its past commitments, including allowing the APS asset divestiture to proceed. I also explain why APS' proposed generation divestiture is an appropriate and sensible approach for Arizona to take in moving towards a competitive market.

In Section IV, I discuss "reliability" for service under the PPA and service under a broad portfolio of merchant generators and wholesale prices. In this context, I explain why a long-term contract with an affiliate, such as the proposed PPA, is a reasonable method to further this move towards competitive markets.

In Section V, I discuss my specific disagreements with certain arguments and suggestions put forward by Drs. Roach, Ruff and Rosen.

In Section VI, I summarize my conclusions.

III. THE ACC SHOULD HONOR ITS PAST COMMITMENTS

Q. STAFF WITNESSES HAVE SUGGESTED THAT THE ACC IGNORE CERTAIN ELEMENTS OF THE 1999 SETTLEMENT WITH APS. DO YOU AGREE?

A. No.

Q. WHAT ROLE DOES REGULATORY STABILITY AND CERTAINTY PLAY HERE?

A. It is important for state utility regulation to keep its commitments to both consumers and to the entities it regulates. On May 14, 1999, APS entered into a complex settlement, which was adopted in Decision No. 61973 (October 6, 1999). That settlement, as is typical of all compromises, involved gives and gets. Among the rights APS received in the settlement was the right to divest its generation assets to a newly created subsidiary, Pinnacle West Energy Corporation (PWEC). APS also gave up several rights to acquire this "get." In particular, APS:

(1) Agreed to a $234 million write-off of prudently-incurred costs even though it was assured full stranded cost recovery under Decision No. 60977;

(2) Agreed to a series of five rate reductions for standard offer and Direct Access customers;

(3) Agreed to forego any rate increases, absent emergency situations, prior to mid 2004;

(4) Agreed to forego recovering any increased purchase power costs until after mid-2004;

(5) Agreed to give up one-third of the costs associated with the asset divestiture, even though Decision No. 60977 provided for full cost recovery; and

(6) Agreed to a code of conduct more restrictive than required under the current Electric Competition Rules.

The settlement represented a compromise where all sides gave up something and received something. As with all such negotiated settlements, all parties to the settlement perceived that they had received something of value for what they gave up.

Q. WHY IS IT IMPORTANT FOR THE ACC TO KEEP THE COMMITMENTS IT MADE IN THE SETTLEMENT ADOPTED IN DECISION NO. 61973?

A. A regulatory commission should maintain a delicate balance in protecting the myriad interests of the various stakeholders, including primarily consumers and regulated industries, in the state of Arizona. The welfare of these two primary stakeholder groups are inextricably intertwined, so that actions that harm the regulated company will ultimately also harm consumers and actions that are beneficial to the regulated entity will ultimately benefit consumers. When I was the Chair of the Wisconsin Public Service Commission, I was careful not to take actions that would unduly punish a regulated utility because I realized that such punitive actions would ultimately harm consumers by increasing the riskiness of the utility, causing its overall cost of capital to increase, thereby potentially resulting in increased prices to consumers. As I stated, treating utilities fairly and honoring regulatory commitments, settlements and agreements is a cornerstone to this balance.

Q. HOW WOULD REVERSING THE SETTLEMENT AGREEMENT APPROVED IN DECISION NO. 61973 HARM APS OR CONSUMERS?

A. If the ACC reverses its prior commitment to allow APS to divest its generation assets, a pall of uncertainty would be cast over the regulatory environment in Arizona. This is especially true considering the magnitude and visibility of the settlement and order allowing APS to divest its generation assets. Credit rating agencies carefully and diligently track regulatory decisions and actions. They recognize that APS shareholders made concessions in exchange for this outcome. Canceling one aspect of this agreement in mid-game would affect the credit rating agencies' opinions with respect to the regulatory environment in which regulated utilities, such as APS, operate. If important settlements that have been negotiated and agreed upon by the principal stakeholders are unilaterally abrogated by the ACC, a great deal of regulatory uncertainty will be created. This uncertainty will be reflected in the manner in which the various rating agencies view APS.

Q. HOW WOULD THIS REGULATORY UNCERTAINTY AFFECT APS AND CONSUMERS IN ARIZONA?

A. If credit agencies perceive the Arizona regulatory environment to be uncertain or even hostile, and that regulatory compromises and settlements cannot be relied upon, these credit rating agencies could downgrade APS' bond ratings. This would increase APS' cost of debt, which could also cause retail prices to consumers to rise.

Similarly, the market abhors uncertainty. If investors become concerned that regulatory deals that are made and approved by the ACC will not necessarily be honored by the ACC, APS (or its parent) will be considered to be a riskier investment than it would otherwise be if it was operating in a more stable regulatory environment. This will increase the cost of APS' cost of equity, which could also cause rates to consumers to rise.

Thus, if the ACC does not keep its end of the bargain, both APS and its customers could be hurt as investors and credit agencies perceive increased regulatory risk, justifying higher required rates of return on equity and higher interest rates on debt to finance needed utility investments. Both would result in increased capital costs for APS and higher prices for consumers in Arizona.

Q. ARE THERE LIKELY TO BE OTHER CONSEQUENCES IF THE ACC CHANGES THE TERMS OF THE SETTLEMENT?

A. Yes, if the ACC fails to honor its commitments under the settlement agreement, there would likely be an adverse effect on future settlements. This would result in longer, more contentions hearings as parties lose confidence in the finality of the settlement process. As a corollary to this chilling effect, regulated utilities and ACC Staff will be disinclined to reach creative solutions to complex problems if the parties think that these settlement resolutions lack permanence.

Also, if parties think that the ACC is likely to change its mind with respect to settlements it has approved, the ACC will likely be constantly barraged with requests to modify settlements. Quite simply, there would be no finality and parties would eschew attempting to reach settlements in various significant regulatory proceedings. Such results would not be in any one's best interest and would take up too much of the ACC's valuable time and limited resources.

Q. GIVEN THE SETTLEMENT AGREEMENT YOU DISCUSSED ABOVE, WHAT DO YOU CONCLUDE?

A. The planned divestiture of APS generation to PWCC can and should proceed. I also conclude that divesting formerly regulated generation assets with purchase power buy backs tied to cost-of-service standards is increasingly common place around the United States. The proposed PPA would do this and should be approved.

IV. THE "RELIABILITY ISSUE"

Q. DO MERCHANT GENERATORS HAVE THE SAME SUPPLY AND LEAST COST (OR PRICE) RESPONSIBILITY THAT PWCC AND APS PROPOSE TO JOINTLY ASSUME?

A. No. Merchant generators sell a 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 guarantee 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, there are presently no retail customers that have been 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 severe price spikes in the

West. Through default and its traditional franchise responsibilities, APS is the sole electricity entity that has any responsibility for achieving the joint retail consumer objectives of supply reliability and least price in Arizona.

Merchant generators produce a commodity that is traded like all commodities. Their objective is *best* price, not *least* price. Their sense of reliability is related to unit capacity factors, not a commitment to a specific geographic or a 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.

California's market is large. Its economy and political influence are even greater. Arizona and other western states recognize this fact and need to develop specific ongoing regulations and competitive restructuring policies that reflect these stark political and market realities. 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 such as the one offered by Dr. Ruff, as long as California and the FERC combine to prevent such a market from evolving in the West.

The PWCC's long-term bilateral contract with APS would dedicate generation to Arizona. This represents considerable reliability. The contract's pricing terms and regulatory formula would lock in a significant portion of APS' load to cost-of-service pricing levels. New merchant generators would compete for load growth, not base needs. This approach represents a pragmatic Arizona response to current realities in the West. Retail choice, if it appears and expands, will accelerate wholesale competition and mean that other new retail competitive entities would assume a greater degree of reliability and least price responsibility. These will not be merchant generators, except for any bilateral forward contracting. Arizona is not in a position to design its more competitive electricity markets in isolation.

To be sure, this APS proposal may not be "the" 100 percent or fully competitive market by 2003 as contemplated in Rule 1606B. Under current market and political conditions, the proposed PPA is a pragmatic choice.

Q. ARE THERE ANY OTHER RELIABILITY CONCERNS RAISED BY INTERVENORS' TESTIMONY?

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 at least cost. 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.

Q. DO YOU AGREE WITH DR. RUFF THAT APS SHOULD JUMP INTO A PROGRAM TO PURCHASE ALL OF ITS ELECTRICITY NEEDS FROM COMPETITIVE GENERATORS AND A WHOLESALE BIDDING MARKET WITHIN A FIVE-YEAR PERIOD?

A. No. Arizona is, quite frankly, not ready to jump cold turkey into wholesale electricity market without first establishing some new entity that will assume these roles and functions. Here the PWCC and APS are proposing to fill this vertical integration void for the next thirteen years. Under the factors that I have described, there is no contender for these various transmission, scheduling, and aggregator roles other than the incumbent entities in Arizona that already exist in the Pinnacle West Corporate family.

The PPA will serve as the vertical integrator unless and until an RTO is formed; at that time, I would expect PWCC and APS to participate in the RTO through the PPA. California's fiasco demonstrates that it would be foolhardy to rely on the FERC to timely develop an RTO solution that would fill this vertical integrator role. Accordingly, the ACC needs to grant this variance to Rule 1606B and take steps to assure that the PPA approach will be in place while new regional organizations are being established, organized, and their FERC tariffs and terms are being secured.

None of the APS proposed variances inhibits the ACC from pushing for more competition as APS proposes to do here. The ACC should not assume, however, that the FERC would get things done "in time" and "right." A variance to Rule 1606B is simply the best option under these circumstances.

APS and PWCC plan to separate, while continuing their benefits through the PPA, these various vertical functions over at least thirteen years and still encourage new retail competition and new merchant generation in Arizona. They also recognize the void that must be filled, not in an academic form of competition, but in the real world of Arizona and the western states' electricity market. FERC must do more before the ACC can complete the details of its full competition game plan.

Q. ARE THERE ANY OTHER RELIABILITY ISSUES THAT AFFECT THE SPEED OF ANY PUSH FOR COMPETITION?

A. Yes. 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 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, long-term contracting, 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.

Retail serving entities have these retail consumer reliability concerns squarely in mind. APS is presently the *only* credible retail server entity in its Arizona service area. Under current circumstances, the PPA approach is a just, reasonable and prudent means to achieve these system-wide, retail based reliability objectives while still encouraging more retail competitive entry and increased non-affiliated merchant generation entry in Arizona.

V. SPECIFIC DISAGREEMENTS WITH DRS. ROSEN, ROACH AND RUFF

Q. HAVE YOU FOUND OTHER WITNESSES RAISING CONTRARY ISSUES WITH RESPECT TO THE BASIC REGULATORY POLICY AND COMPETITION ISSUES THAT YOU HAVE OUTLINED?

A. Yes. There are three specific witnesses that I find have addressed many of these same matters and who have reached different conclusions than I have, as well as with each other. The three witnesses are Drs. Rosen, Roach, and Ruff.

Q. WHAT IS YOUR FUNDAMENTAL QUARREL WITH DRS. ROSEN AND ROACH?

A. Dr. Rosen would, in my opinion, go too far in the direction of continued cost-of-service regulation than APS proposes and that I conclude is necessary. The ACC needs to balance regulation with competition and eschew attempting to expand ACC regulation by attempting to micromanage and regulate the PPA as advocated by Dr. Rosen.

Indeed, I was quite surprised by Dr. Rosen's suggestion that the proposed Return on Equity (ROE) and cost of capital components could be increased to a level overly generous to PWCC. Under traditional cost-of-service regulation, IOUs have come to accept embedded original cost rate base in conjunction with RORs that can and do increase with inflation and any underlying related costs of capital. The PPA actually fixes ROR at current levels, thereby reflecting relatively low ROEs and current interest costs.

Here, APS has secured a fixed, non-reopenable ROR. This is a major regulatory concession from PWCC because current RORs are generally (as they are in the PPA) very low compared to past and likely future levels. In competitive markets, locking in contract prices and basic financial terms without re-openers for inflation, interest, and market conditions would typically require the buyer (APS) to pay a higher fixed price to the seller (PWCC). As I understand the PPA, there are neither such re-openers nor any option or hedging payments specifically available to PWCC. Instead, APS has secured a great pro-consumer contract with cost-of-service capacity payments. In addition, there are potential downside price adjustments if and when PWCC earns future margins on any off-system sales because PWCC would split 25% of such earnings with APS' retail consumers.

Dr. Roach's approach to the PPA suggests a form of ongoing prudence review and proof of consumer net benefits. This suggests that consumers simply cannot be expected to or do not know the future prices they will pay under the PPA (presumably due to fuel and purchase power pass throughs on energy). Further, Dr. Roach doesn't seem to like APS selling or "bundling" generation under the SOS. Assuming these concerns are well placed, they are irrelevant because APS has no ability to force retail consumers to stay under the SOS tariff. Further, APS can easily reflect the unbundled cost of the PPA on customer bills, if that is the ACC's desire. New energy service firms and bilateral direct merchant generators can compete for these customers. If the PPA proves to be too costly, new competition would benefit. My guess is that Dr. Roach objects because the SOS and PPA are too pro-consumer, rather than too enriching for shareholders.

Neither Dr. Roach nor Dr. Rosen seem to realize that the PPA addresses these uncertainties to a far greater degree today than traditional periodic rate cases would do under typical cost-of-service regulation. These specific PPA terms, as far as I can tell, all inure to the benefit of APS' retail consumers.

Q. WHAT SPECIFICALLY DOES DR. ROSEN RECOMMEND WITH WHICH YOU DISAGREE?

A. While I neither agree nor disagree with various aspects of Dr. Rosen's evidence, I will not address those aspects here. I am specifically concerned with his following recommendations:

- Dr. Rosen would re-set ROR for PWCC's dedicated units in the next APS rate case. This is problematic because PWCC, not APS, owns these dedicated units. Thus, these units are not part of APS' rate base. Most important, APS has secured a contract under which it would pay PWCC a capacity charge tied to a low regulated cost-of-service ROR.

- Dr. Rosen also proposes to require PWCC and APS to agree to constrain future FERC filings based upon ACC policy and regulatory determinations. This is not necessary under the PPA, nor is it possible for state regulators to preempt the FERC's regulatory authority or judgment.
- Dr. Rosen suggests the ACC alone should be able to determine whether future PPA contract extensions are prudent. In reality, the ACC will continue to have significant influence over APS as it does today. Furthermore, a one-sided option to cancel or continue is valuable, and if the PPA is modified to grant such a one-sided or asymmetric option, I would expect current retail consumers to pay more for PWCC's proposed supply of dedicated units.

Q. PLEASE EXPLAIN THE MOST POINTED DISAGREEMENTS THAT YOU HAVE WITH DR. ROACH.

A. Again, the following list does not reflect all of my agreements or disagreements with Dr. Roach's evidence.

- Dr. Roach falsely claims that APS' retail customers would: 1) bear all risks; (2) pay uncertain future prices; and, (3) not have guaranteed reliability. Dr. Roach also outlines what he calls a market PPA. This is all misleading. Nothing here would keep merchant generators from offering their own long-term forward contracts directly and bilaterally to retail consumers and/or new retail energy service companies and even to PWCC through the six annual 270 MWs of new mandatory competitively bid capacity, or for any supplemental requirements. If Dr. Roach's clients can beat the PPA prices, re-opener, adjustment clauses, and reliability terms in the APS/PWCC long-term contract, then it is to the market, not to the ACC, that his clients should make such offers.

- Dr. Roach also complains that APS offers bundled retail services through its SOS and that new generation owning competitors can "beat" the PWCC/APS PPA. Again, this is a market, not a regulatory matter.
- Dr. Roach seeks to have the ACC assume a more detailed oversight role and extend greater scrutiny to the PPA. I disagree with his recommendation. Regulators should focus on the end result, not the details of a contract between a regulated entity, APS, and a competitive business, PWCC. The fact that these companies are affiliated matters in terms of the end result and the fundamental cost-of-service standards embodied in the PPA. Dr. Roach proposes that the ACC needs to do much more in terms of micromanagement and contract review. I doubt his own clients would stand for such scrutiny and regulatory involvement in their business affairs. Affiliated interest contracts that reflect cost-of-service principles, as the PPA does, should be assigned a rebuttable presumption of regulatory approval. This is especially

true when retail consumers are free to choose an alternative electricity supplier.

Q. DOES THE PPA GO TOO FAR, OR NOT FAR ENOUGH AS SOME APS CRITICS SUGGEST, IN ATTEMPTING TO CONTROL THE FERC'S REGULATION OF DIVESTED GENERATION?

A. I conclude that the PPA does not dilute ACC regulation, nor does it bind the FERC, as some suggest. The PPA gives the ACC time to respond and a reasonable opportunity to react to still unresolved FERC regulation. This is superior to acting first and hoping that the FERC gets it right.

Accordingly, I totally reject Drs. Rosen and Roach's suggestion that more ACC regulation and review, now or ongoing, of the PPA contract and other PWCC micromanagement review and regulation is necessary. The FERC will regulate new institutions, interstate transmission, wholesale power exchanges and more. APS is not bypassing the ACC. Indeed, APS seeks to enter a FERC world with a long-term cost-of-service contract that is approved in advance by the ACC. APS is not shopping jurisdictions for a better deal. APS seeks what is a pro-consumer variance to 1606B under current conditions in the West.

Q. DO YOU AGREE WITH DR. RUFF THAT ARIZONA IS READY TODAY FOR EVEN MORE, IF NOT FULL, COMPETITION?

A. Dr. Ruff's testimony represents the polar opposite conceptual argument that Dr. Rosen makes. Dr. Ruff seeks full wholesale competition. Dr. Ruff's ideas are conceptually and academically quite pure. This is their strength and also why I reluctantly, but necessarily, conclude that they are neither relevant nor ready for the real world in which Arizona finds itself.

I agree with Dr. Ruff that Arizona need not and should not accept California's myriad of mistakes. Indeed, hindsight shows us that California had it wrong. Where I sharply depart from Dr. Ruff is in my conclusion that California's effects on the current market and FERC regulation of the West, and its attendant uncertainty, are still with us. For these and other reasons that I described above, the ACC should extend its transition timetable and proceed more cautiously, as the PPA would do. I disagree with Dr. Ruff's sentiments that Arizona could have and perhaps should have jumped fully and completely into competition yesterday (i.e., in 1999 or 2000).

Saying it this way shows how fortunate Arizona's economy and retail consumers are that the ACC granted its earlier transition extension. The facts have made it more important now than in 1999 to further stretch out the restructuring timetable. The ACC needs to participate in ongoing FERC regulation and the new regional institution creation processes. Until these matters are resolved, the ACC needs to grant a variance to Rule 1606B and adopt the PPA to preserve the necessary reliability and vertical services achieved by this contract with PWCC.

Q. WHAT ARE THE SPECIFIC STEPS THAT DR. RUFF PROPOSES THAT YOU THINK WOULD MAKE THE TRANSITION TO COMPETITION IN ARIZONA TOO RAPID?

A. Dr. Ruff proposes that beginning in 2003 and every year thereafter, APS should purchase twenty percent of its SOS requirements from either a long-term competitively-negotiated or a short-term competitive-bid process.

As I have described, the market is not currently suitable for such proposals because regional supply is weak relative to likely demand. Natural gas prices are rising in the spring of 2002, much like they were in 2000, well before the winter peak demand period.

Necessarily, FERC regulations concerning RTOs and spot power exchanges are mushy, at best. Most important, retail consumers in Arizona continue to show a preference for a blended SOS that reflects embedded cost-of-service for APS plants in rate base, diversified fuel sources, and new dedicated units that, under the PPA, cannot and will not follow any high spot regional or California price spikes for electricity that could develop over the next fifteen years.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND POLICY CONCLUSIONS?

A. First, I think that it is crucial that the ACC honor its past regulatory commitment to allow APS to divest its generation assets to an affiliate. This commitment was made as part of a comprehensive settlement where each side gave up significant rights in order to get certain other rights. Here, in order to secure the right to divest its generation assets, APS gave up the right to guaranteed stranded cost recovery, gave rate reductions, agreed to forego rate increases or increased purchased power cost recovery, and agreed to forego collecting a third of the costs associated with the asset divestiture. In order to maintain regulatory certainty and the sanctity of a negotiated settlement, the ACC should honor its commitment to allow APS to divest its generation assets to an affiliate.

Second, the ACC should approve APS' requested variance to Rule 1606B and approve the PPA. These actions would protect retail consumers from current supply and price uncertainty and volatility. Approving APS' requested variances would permit the ACC to continue moving towards competition at a slower pace, while still retaining retail choice in Arizona. This will allow the ACC to adjust its schedules and the details of its regulatory plans to take into account market facts, regional realities, and FERC decisions that have yet to be made.

Third, the extremes offered by the opposing witnesses do not advance the ACC's goal for an orderly transition to competition. One choice would thrust Arizona headfirst into the deep end of competitive markets before it has learned to swim. The California experience demonstrates that such an approach is ill advised. Consumers have seen how energy markets with no duty to serve can abandon one market to chase higher margins in another market. Consumers have spoken loudly that they do not want to assume these price spike and reliability risks, and prefer APS' SOS service.

The contrary approach, an attempt to micromanage, is equally ill advised and fated to derail completely Arizona's move towards competition. Indeed, I conclude that only a measured approach such as the one APS seeks through the requested variances will likely achieve a competitive environment that reaps consumer benefits while simultaneously protecting consumers.

Q. DOES THIS COMPLETE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes.

ATTACHMENT 1

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