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IN THE MATTER OF THE GENERIC PROCEEDINGS CONCERNING ELECTRIC RESTRUCTURING	DOCKET NO. E-00000A-02-0051
IN THE MATTER OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR VARIANCE OF CERTAIN REQUIREMENTS OF A.A.C. 4-14-2-1606	DOCKET NO. E-01345A-01-0822
IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING THE ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	DOCKET NO. E-00000A-01-0630
IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC POWER COMPETITION RULES COMPLIANCE DATES	DOCKET NO. E-01933A-98-0471
ISSUES IN THE MATTER OF TUCSON ELECTRIC POWER COMPANY'S APPLICATION FOR A VARIANCE OF CERTAIN ELECTRIC COMPETITION RULES COMPLIANCE DATES.	DOCKET NO. E-01933A-02-0069

POST-HEARING BRIEF OF ARIZONA PUBLIC SERVICE COMPANY ON "TRACK A" ISSUES

Pursuant to the Chief Administrative Law Judge's ("ALJ") direction at the close of evidentiary hearings for Track A Issues on June 28, 2002, Arizona Public Service Company ("APS" or "Company") hereby submits its Post-Hearing Brief. This Brief is generally organized around the issues identified as "Track A" in the ALJ's May 2, 2002 Procedural Order. However, it also addresses certain other specific matters raised during the evidentiary hearings. These include, but are not limited to:

(1) the impact of any Arizona Corporation Commission ("Commission") decision to delay or prevent divestiture of APS generating units as presently authorized by Decision No. 61073 (October 6, 1999) and A.A.C. R14-2-1615(A) ["Rule 1615(A)"];

(2) Commission decisions and regulations affected or potentially affected by any Commission actions herein;

(3) the commitment of certain Pinnacle West Energy Corporation ("PWEC") generating units to serving APS customers;

(4) transmission issues raised by Staff witness Jerry Smith; and,

(5) jurisdictional implications to the Commission, if any, of APS joining a for-profit Regional Transmission Organization ("RTO").

THE COMPANY'S REQUEST IN "TRACK A"

As things stand today, APS is adversely affected by the continuing delay in resolving the divestiture and competitive bidding issues. Its own costs increase as the day-by-day process of preparing for divestiture and associated competitive Standard Offer procurements continues. And the financial strain on the Company's generation affiliate, PWEC, and their common parent company, Pinnacle West Capital Corporation ("Pinnacle West"), of maintaining two large generation entities is itself increasingly unmanageable and seriously threatens the financial condition, credit quality and ability to finance of both. (*See* Tr. vol. I, at pp. 92-93.) At this point, APS must press the Commission for action on "Track A" to resolve this crippling issue of "bifurcation." Such action should permit divestiture as promised in the 1999 APS Settlement Agreement ("APS Settlement"), which was ratified and joined by the Commission in Decision No. 61973, without new conditions or restrictions. Alternatively, if the Commission is unwilling to honor the terms of the APS Settlement or needs significant additional time to make a final determination on divestiture, the Commission can still address the "bifurcation" problem in a timely fashion. It would do this by allowing APS to acquire and finance the PWEC generation dedicated and used to serve APS retail customers. The future regulatory treatment of such generation, assuming its continued ownership by APS, would be addressed under traditional cost-of-service and prudence standards in the Company's next general rate proceeding. In either event (divestiture or acquisition), the Company is entitled to the timely recovery of costs incurred to comply with the terms of the APS Settlement, the Electric Competition Rules, and any Commission order modifying or abrogating the APS Settlement.

INTRODUCTION

APS filed its request for a variance to A.A.C. R14-2-1606 (B) ["Rule 1606(B)"] and Rule 1615(A) on October 18, 2001. It has yet to receive an evidentiary hearing on that request. Ironically, such a hearing was scheduled to have been conducted some two months ago and would have thoroughly considered virtually the same issues as did the recently completed "Track A" hearing in the generic docket—with one critical exception. The Commission still has not heard the Company's case for the proposed Purchase Power Agreement ("Proposed PPA") between APS and Pinnacle West Marketing & Trading ("PWM&T"), which would have given some factual context to such abstract concepts as "reliability," "market power," "divestiture," "affiliate transactions," and "dedicated units." As noted in detail in APS witness Jack Davis' Rebuttal Testimony, the Proposed PPA would address virtually all of Staff's stated "Track A" concerns. (J. Davis Rebuttal Test., at pp. 20-21.) This is especially the case when it comes to mitigation of alleged APS market power and the supposed non-"arm's length" nature of affiliate transactions in general. Those aspects of the Proposed PPA specifically identified by Staff witness David Schlissel as still problematic, e.g., the length of the Proposed PPA, the amount of

Competitively-Procured Energy Products and the specific cost-of-service formula employed in the Proposed PPA (Tr. vol. VI, at pp. 1400-01), could have been determined some months ago during the course of the variance proceeding itself, (Tr. vol. I, at pp. 228-29).

EXECUTIVE SUMMARY

The prospect of APS divestiture of its generation assets to an affiliate is hardly a new issue. It had been authorized, indeed required by the Commission on three separate occasions prior to the APS Settlement. The differences between Decision No. 61973 and these other prior orders of the Commission are that the Commission itself became a party to the settlement agreement approved by such Decision and that APS was required to make specific and very significant concessions as a result of such Decision.

The argument that circumstances have changed since 1999, and that these changed circumstances warrant substantial modification of the APS Settlement as it concerns divestiture does not withstand scrutiny. In fact, some circumstances are completely unchanged from 1999—for example, the jurisdiction of this Commission versus that of the Federal Energy Regulatory Commission ("FERC"), the need to eliminate the potential for cross-subsidization of generation, and the desirability of reducing the potential of vertical market power. Others have actually improved since 1999, including the degree of market concentration, the lessening of transmission constraints, and the filing with FERC of actual RTO protocols, thus making divestiture even more feasible. Yet other alleged changes such as the degree of retail competition in Arizona, the alleged need to expand the APS Code of Conduct, or the continued existence of transmission constraints are either unrelated to divestiture itself or need not be viewed as preconditions to divestiture.

One important change that has taken place since 1999 is the creation of PWEC and the investment by PWEC of over a billion dollars in assets built to provide reliable service to APS customers. This has required Pinnacle West to provide interim "bridge" financing that must be rolled into permanent financing in the very near future. The continued ability to finance that investment is threatened by Staff's recommendations herein, which at best will necessitate continued bifurcation of the generation serving APS into two entities for an indefinite period of time. At worst, Staff would make divestiture and thus the ability to obtain permanent financing of PWEC's reliability-based investment all but impossible, either from a regulatory standpoint or from a commercial standpoint, making PWEC's position completely untenable.

Divestiture has taken place in many jurisdictions without the problems seen in California. Similarly, the problems in California and other western states were neither caused by divestiture nor did subsequent retention of generation by their utilities solve those problems, as is best illustrated in Nevada.

Market power is likewise not a new issue. No party has demonstrated that APS or PWEC will have regional market power or, for that matter, market power outside of transmission constrained areas. Even within constrained areas, market power exists for only a few hours per years and for only a small fraction of APS load requirements. During these periods, local market power is effectively mitigated by the very AISA and WestConnect protocols that were envisioned by the APS Settlement and the Electric Competition Rules.

FERC is presently reviewing Code of Conduct issues. Whether there is need for further state action is quite debatable. The present rate moratorium for APS customers as well as existing regulations dealing with the more significant of Staff's affiliate concerns certainly provide consumers sufficient protection for the next two years. Thus, Code of Conduct should not become a precondition to divestiture in 2002 any more than it was in 1999.

The various transmission issues raised in this proceeding are in some respects very controversial while in other respects they are uncontroverted. What is true about all of them is that they exist independent of divestiture and that their solution is likewise unrelated to the issue of divestiture.

What is also true is that "Track B" issues cannot be meaningfully addressed, let alone resolved, until the divestiture issue is resolved. This is the case whether divestiture is permitted subject to a buyback arrangement such as the Proposed PPA or whether the bifurcation of APS generation resources is addressed by the acquisition of PWEC assets by APS. Both will, at a minimum, affect the size and nature of whatever competitive procurement process is arrived at in "Track B" or perhaps even obviate the need for "Track B."

ISSUE NO. 1 – DIVESTITURE

A. *Divestiture has already been finally authorized by Decision No. 61073 and Rule 1615(A) and cannot be delayed or stayed in these proceedings without breaching the APS Settlement.*

The Commission entered into a binding agreement with the Company to permit divestiture without further conditions in Decision No. 61973. This is not just APS' opinion, but that of the Arizona Court of Appeals, and it is binding as between the parties (APS and the Commission). *See also Elec. Dist. No. 2 v. Arizona Corp. Comm'n*, 155 Ariz. 252, 259 & n.2, 745 P.2d 1383 (1987) (Supreme Court holding that the Commission is bound by a final Court of Appeals decision even if there is reason to believe the decision may not have been the same as would have been issued by the Supreme Court, and noting that an unpublished memorandum decision is "just as binding on the parties as a published opinion"). The Direct Testimony of Jack E. Davis sets forth the relevant provisions of both the APS Settlement and the Court's Opinion:

Decision No. 61973 reaffirmed for the <u>fourth</u> 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.

In its adoption of the 1999 APS Settlement, the Commission went on to state:

> [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.

...

In upholding the 1999 APS Settlement Agreement, the Arizona Court of Appeals stated:

> The agreement <u>requires</u> APS to divest its generation assets by December 31, 2002, and <u>requires</u> 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 <u>a party to the agreement</u>, and section 6.2 <u>precludes the Commission from taking or proposing any action inconsistent with the agreement</u> and <u>requires the Commission to actively defend it</u>. [Opinion at ¶ 33.]
>
> ...
>
> The general rule, however, is that a <u>contract</u> 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] <u>contract</u> 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.] [Emphases supplied.] [Opinion at ¶ 38.]

(J. Davis Direct Test., at pp. 5-6.)

The Commission may be assured by Staff counsel and others that Decision No. 61973 is no different than other decisions of the Commission and can therefore be rescinded or amended at the discretion of the Commission under the provisions of A.R.S. Section 40-252. That statute grants the Commission only limited power under circumstances such as these and even at that, these proceedings can hardly be construed as complying with the procedural requirements of A.R.S. Section 40-252.[1] APS notes that these arguments (claiming the ability of the Commission to change the APS Settlement) were previously raised by the Commission and rejected by the Court in the very opinion cited by Mr. Davis. Moreover, attempts to "reinterpret" Decision No. 61973 in a manner inconsistent with the plain meaning of its words will not be any more successful. *See U S West Comm. v. Arizona Corp. Comm'n*, 185 Ariz. 277, 280-82, 915 P.2d 1232 (Ct. App. 1996) (rejecting attempt by Commission to change settlement agreement). Preventing APS from transferring its generation to PWEC or conditioning such transfer in a way so as to make divestiture impractical would constitute a breach of the APS Settlement, pure and simple, and would require an assessment and recognition of the consequences of such breach. APS urges the Commission to honor the APS Settlement, just as APS has honored its commitment to take a $234 million write-off of otherwise recoverable costs, to voluntarily reduce rates by some $500-600 million (to date), to dismiss with prejudice its pending litigation against the Commission, to forego recovery of a third of the costs of

[1] The ALJ permitted the parties to present their evidence in a fair manner considering the constraints imposed by the May 2, 2002 Procedural Order and the Commission's suspension of the APS variance proceeding. However, a Section 40-252 proceeding requires that the Commission give affected parties specific notice of both the Commission orders or portions of orders that are being considered for amendment or rescission and, in the case of the former, the specific amendments that are to be considered in such proceeding. The Commission has given no such bill of particulars. Moreover, neither Staff nor any of the other parties presented this information or explained what the impact of these recommendations would be on the Company, its customers or its affiliates. The very fact that the parties are being requested to identify in their post-hearing briefs the orders that will have to be rescinded or amended is ample proof that the initial notice to the Company in this generic proceeding was inadequate. Also, the evidentiary hearing required under Section 40-252 must be "as upon complaint." Such an adversarial process is inherently inconsistent with a "generic proceeding," where the focus is on general policies rather than the specific facts, if any, warranting a change to or rescission of a prior Commission decision.

divestiture, and to make the other concessions implicit and explicit in the APS Settlement. (*See* Tr. vol. I, at pp. 86-87, 170-71.)

B. Staff's claims of "Changed Circumstances" as justifying an abrogation of the APS Settlement do not withstand scrutiny.

Staff's only claimed "change[s] in circumstances" (N. Talbot Direct Test., at p. 31) appear to be the failure of retail competition to develop as apparently Staff had envisioned back in 1999, the existence of market power during a few hours of the year in transmission constrained areas of the APS service territory, the alleged "loss" of Commission jurisdiction over electric generation, and some non-specific concerns over the efficacy of the wholesale market. Even if one were to assume the truth of each of the above as stand-alone statements of fact, they represent no "change" of circumstances since 1999 or represent changes irrelevant to the issue of divestiture.

The movement toward separating the production function of electric service from the delivery and retail service functions predated the concept of retail competition and, as noted later in this Brief, continues to exist even in those jurisdictions that have rejected retail competition altogether. That is because the twin virtues of structural separation, reduced opportunities for cross-subsidization and the exercise of vertical market power, exist primarily for the benefit of the wholesale market, which is precisely were Staff anticipates most of the tangible benefits to consumers will come from in the immediate future. (*See* M. Rowell Direct Test., at p. 2.)

Load pockets are as old as the electric utility industry and will continue to exist for as far into the future as presently can be contemplated. Both APS and the Commission were certainly aware of this fact in 1999, and Staff can make no credible claim that this represents a "change in circumstances."

The same is true as to the division of regulatory authority as between this Commission and FERC. This has remained unchanged for over 60 years—hardly the basis for setting aside an agreement less than three years old.

The failure of the wholesale competitive market to develop as quickly as was once envisioned and the apparently inherent volatility and unpredictability of the wholesale electric market is a legitimate concern. It was a major motivation for the Company's variance request and the Proposed PPA. Wholesale market immaturity, volatility and unpredictability do not, however, warrant a rescission of the Company's rights under the APS Settlement, although these conditions do argue for a prompt consideration by the Commission of the Proposed PPA.

In at least one important respect, there has been a dramatic change of circumstances since 1999. APS has been required by this Commission to create a new and separate generation affiliate. That affiliate has undertaken an extensive generation construction program without which APS would not have been able to serve its customers' loads in 2001 and would likely not be able to serve them in either 2002 or 2003. The alternative of seeking contractual supplies during the market disaster of late 2000 and early 2001, even if available, would have saddled APS customers with the same high cost supplies as California and Nevada are to this day attempting to litigate/negotiate their way out from underneath and would have exposed Arizona consumers to the same double-digit rate increases as those jurisdictions have endured. PWEC is now unable to permanently finance that construction without the clear and imminent acquisition of APS' existing owned generation. Pinnacle West's own ability to sustain such financing on an interim basis without a credit down rating is questionable at best. (Tr. vol. I, at p.92.) The creation and subsequent activities of PWEC on behalf of APS customers were the logical consequences of the Commission's action in approving and joining the APS Settlement. Rather than warranting rescission or reformation of the APS Settlement, APS' and

PWEC's justifiable reliance on its terms requires such settlement's reaffirmation by the Commission.

C. Divestiture as called for under the APS Settlement and Rule 1615(A) will benefit APS consumers in the long run and will not harm them in the short run.

One of the principal reasons the Commission chose to mandate divestiture to begin with was the desire to prevent the cross-subsidization of potentially competitive services by those that would continue to be provided on a regulated monopoly basis. (J. Davis Direct Test., at pp. 4-5.) The failure of retail competition to develop in Arizona as anticipated by some back in 1999 does not alter the desirability of the above goal, which is a necessary precondition if competition, retail or wholesale, is ever to flourish. Second, many parties to this proceeding have lamented the existence of vertical market power. Such market power can be mitigated through regulation, as FERC has done and is attempting to do through its Orders 888 and 2000, but it cannot be eliminated so long as the transmission-owning entity remains a vertically-integrated electric utility. Structural separation is admittedly not the complete solution to vertical market power, since both FERC and Commission Staff are suggesting comprehensive regulatory safeguards in the form of new Standards/Codes of Conduct. But it is an absolutely necessary part of that complete solution, as has long been recognized by this Commission. (*Id.* at p. 4.)

Finally, there are the more intangible benefits cited by Staff witness Neil Talbot:

> Q. If you were advising APS or TEP, would you recommend that they divest their assets?
>
> A. Yes.
>
> Q. And why?
>
> A. I think it gives them a degree of flexibility moving forward to a competitive market. It creates, I think, a more competitive outlook in the affiliated generator, PWEC, or TEP's affiliate. They will be increasingly market-oriented and will do a better job of running their plants in relation to the competitive market. And I'm loosely referring to PWEC, but also in the

> marketing and trading function. Those are things that need to be done and will be more efficiently done I think in separate organizations. And it's more appropriate, I think, for a transfer—after transfer for an affiliate to bid against competitors in the market, to clear a situation than if the UDC is trying to bid against its own assets.
>
> So broadly, I personally am in favor of transfer, provided it has the appropriate conditions attached and occurs in a manner that reflects prudent acquisition on the part of the utility and is combined with a mitigation strategy for market power or potential market power which overcomes over time the concerns that there might be with respect to market power.
>
> And finally, I think that the protection of customers through some kind of a cost basis or some other means of protecting the customers from erratic swings in the market don't need to last forever. I think that should be defined by the Commission a transition period. And that transition period, as Staff testified, would extend from today, basically, to the time when the Commission is comfortable that the regional market is functional as opposed to dysfunctional. And in that way, take care of the regional market problems. So that's kind of a long-winded way of answering yes.

(Tr. vol. VI, at pp. 1391-93.)

APS acknowledges that the benefits of divestiture may appear more long term in nature, while the risks of the market loom today. In point of fact, APS customers have complete protection against the market through June of 2004 so long as the APS Settlement is in place. Even then, some predict we will be in a generation oversupply situation, hardly an immediate threat to consumers. (Tr. vol. II, at p. 511; Tr. vol. IV, at p. 941.) Intermediate to long-term protection for consumers is available through the Proposed PPA, with both the scope and duration of the protection to be afforded by such an arrangement a matter for consideration in the stayed variance proceeding.

D. Other jurisdictions have authorized divestiture without harm to consumers and in furtherance of industry restructuring.

The divestiture of generation assets with or without the implementation of a purchase power agreement is certainly not uncommon. Indeed, the separation of generation ownership from transmission and distribution ownership continues to be viewed as a necessary precondition to viable electric competition. Even in states that have commenced electric restructuring but have not required or been legally able to require divestiture, voluntary transfers of generation assets have been nonetheless routinely approved. *See, e.g., Request of Central Ill. Light Co.*, 2002 Ill. PUC LEXIS 414 (Apr. 10, 2002). Generation divestiture has even occurred or been endorsed in states that have either delayed retail competition or abandoned it altogether. In Florida, for example, Governor Bush's Energy 2020 Study Commission Final Report recommended that Florida utilities be given the discretion to transfer generation assets to affiliates even though the Report only proposed wholesale competition for the state. *See* FLORIDA...ENERGY WISE: A STRATEGY FOR FLORIDA'S ENERGY FUTURE (Dec. 2001) at 69-72.

Of the seventeen U.S. jurisdictions that are currently actively pursuing retail competition, at least eleven have already approved divestiture of utility generation assets in one form or another.[2] Several of these jurisdictions have even required divestiture of generation assets. For example, Connecticut, which requires the divestiture of both nuclear and non-nuclear assets to allow stranded cost recovery, has already approved asset transfers from several utilities, including Connecticut Light & Power. *See* Order, Docket No. 98-10-08 (Conn. D.P.U.C. Jan. 8, 1999) (CL&P); Order, Docket No. 98-10-07 (Conn. D.P.U.C. Mar. 5, 1999) (United Illuminating). In the District of Columbia, divestiture is required for all rate-based assets not needed to provide transmission and distribution service, and PEPCO received approval for divestiture of their generation assets. *See* Order No. 11576 (D.C. P.S.C. Dec. 30, 1999). In Maine, another state that requires divestiture of all non-nuclear generation assets, the state's three major utilities sold their assets and contractual power entitlements by 1999. *See, e.g., Re: Maine Public Service Co.,* 1999 Me. PUC LEXIS 340 (Apr. 5, 1999). And in Rhode Island, the first state to implement retail electric competition, utilities have divested all of their generation assets.

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[2] These jurisdictions include Connecticut, the District of Columbia, Ohio, Illinois, Maine, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Rhode Island.

In states that have not required divestiture as part of their restructuring plans, approval of voluntary divestitures has nonetheless been permitted without significant conditions. In Illinois, for example, several utilities have already spun off their non-nuclear generation units to their affiliates. *See Request of CILCO, supra.* In Massachusetts and Maryland, several utilities and affiliates have divested most if not all their generation to other companies. *See, e.g.,* Docket Nos. DTE 98-78/83 and DTE 98-78/83A (Mass. D.T.E. 1999); *Re: Potomac Elec. Power Co.*, Order No. 75850 (Md. P.S.C. Dec. 22, 1999). New York has strongly encouraged divestiture of generation assets while negotiating restructuring settlements with its utilities. Under these settlements, the state's largest utilities, Consolidated Edison of New York, Orange & Rockland Utilities, New York State Electric & Gas, and Central Hudson Gas & Electric have all divested their generation assets. *See* NEW YORK PUBLIC SERVICE COMMISSION, ANNUAL REPORT 1998-1999, at 4. In Pennsylvania, no less than five utilities have likewise divested, including Duquesne Light, Pennsylvania Power & Light, and Allegheny Power.

In states such as California, the decision to suspend divestiture is more reflective of the complex interplay between many factors, including regulatory mismanagement and flawed implementation of restructuring, rather any supposed "dangers" of divestiture. In addition to California, Virginia, Nevada and New Hampshire have limited or restricted divestiture. Each, however, is distinguishable from the situation in Arizona.

The Virginia Commission denied a proposal by Virginia Power to divest its generation to an affiliate in favor of separation into an unregulated division of Virginia Power, but specifically recognized that it might approve divestiture at a later time and had, in fact, approved divestiture for utilities other than Virginia Power. *See Application of Virginia Elec. & Power Co.*, 2001 Va. PUC LEXIS 298 (Dec. 18, 2001). That decision, however, is inapplicable in Arizona because the Virginia Power divestiture proposal had not been previously approved by the Virginia Commission, and mere functional separation was all that was required under Virginia's then-existing laws and rules. *See id.* at 50-51.

In Nevada, the legislature repealed the 1997 restructuring law allowing divestiture and placed a temporary moratorium on asset transfers until July 2003. *See* A.B. 369 (Nev. 2001). However, the Nevada decisions are likewise inapplicable to Arizona because divestiture was never required under Nevada's 1997 restructuring law, A.B. 366 (Nev. 1997). In fact, the temporary moratorium on divestiture was initiated by the state legislature after the Nevada Commission had imposed divestiture as a merger condition for the Sierra Pacific entities and had allowed only a very limited transition PPA (three years) to protect consumers.

Finally, New Hampshire's decision to delay divestiture of Public Service New Hampshire's ("PSNH") fossil generation assets until at least February 2004 is also distinguishable. Unlike Arizona's restructuring plan, New Hampshire eliminated required "standard offer" service for PSNH, and only provided for a short period of "transition" and limited "default" service for retail customers. The delay of divestiture in New Hampshire arose partly out of concern of price volatility and the lack of retail competitors given that all retail customers were required to move to direct access. House Bill 489 (N.H. 2001) allowed PSNH to continue to use its fossil and hydro assets to provide extended transition service to PSNH customers. Further, that law did not affect or delay the divestiture of PSNH's interest in the Seabrook nuclear plant. *See generally New Hampshire P.U.C. Biennial Report, 1999-2001*, at 8-9.

The experience and track record of states that have approved divestiture of generation assets outside of California overwhelmingly suggests that, when implemented as part of a balanced restructuring plan, divestiture has not in practice resulted in any significant loss of state commission jurisdiction over retail ratemaking, nor has it jeopardized reliable service at reasonable rates. Thus, the Commission should not disavow the already-approved transfer of APS' generation based on alleged concerns in a very limited spectrum of states with different factual and procedural backgrounds, and that are not borne out by the broader, national experience with electric restructuring.

E. Staff's preconditions to a so-called "discretionary" divestiture by APS are so ambiguous and onerous as to make timely divestiture impossible from both a regulatory and commercial standpoint.

As is discussed in more detail later in the Company's Brief, Staff has established as preconditions to divestiture "at the discretion of the utility" (M. Rowell Direct Test., at p. 10) the filing of a new "market power analysis" and a new "Code of Conduct" (*id.*). Both would then have to be reviewed and approved by the Commission, with both the timing of and the substantive standards for such a review and approval being left to the Commission's discretion. The former consists of an ill-defined and unprecedented hodgepodge of existing market power studies that would be modified in some unspecified fashion. (*See* J. Davis Rebuttal Test., at pp. 22-24.) The second would address in some unspecified manner a litany of issues unrelated to divestiture or "readdress" issues already covered by existing Commission regulations. *Id.*

Even if these hoops could be cleared, APS would be required to retain at least its "must-run" generating units, thus not completely resolving the "bifurcation" (of generation) issue that is so troublesome to the Company. And Staff further argues that APS should bear all risk associated with a decision to divest its generation assets. Again, however, it was not APS that decided in 1998 and 1999 to require divestiture. But now that the Commission has approved such divestiture and APS has acted in reliance on that decision, Staff's effort to make divestiture commercially unpalatable or to force APS to guarantee that wholesale competition will always benefit retail customers is wholly inappropriate and is tantamount to a prohibition of divestiture. (*See* Tr. vol. I, at pp. 73-74.)

F. No party has presented a compelling argument against divestiture as approved by the Commission in the 1999 APS Settlement.

Other parties attack the divestiture that this Commission approved in the APS Settlement, and that the Electric Competition Rules have required since 1998, on grounds that likewise do not withstand close scrutiny. Staff and some other parties claim that there are now horizontal market power concerns associated with divestiture, but ignore the fact that since the Commission approved divestiture in 1999, the depth of the wholesale generation market has significantly <u>improved</u> and the generation market share of APS has significantly <u>decreased</u>. (*See* J. Davis Rebuttal Test., at pp. 19-20.)[3] These concerns were not raised in 1999, when Staff and the Commission advocated divestiture as a means to address vertical market power concerns and concluded that divestiture was "in the public interest." (*See* Decision No. 61272, App. C., at p. 33; Decision No. 61973, Att. 1, at p. 7.) As discussed below, APS passes or would pass all applicable market power tests at FERC. The so-called market power issue is merely an attempt to indefinitely delay or unnecessarily condition divestiture.

Also, Staff and other parties claim that a Code of Conduct is required before divestiture can occur. Again, at no time in 1999 or prior to this proceeding did Staff or another party suggest that a second or third code of conduct was necessary to address any new affiliate issues. Regardless, divestiture would in no way restrict the Commission's ability to adopt an appropriate code of conduct for APS to address its generation affiliates, and it is certainly not a necessary prerequisite for divestiture. Indeed, because APS is operating under a rate ceiling until July 1, 2004 pursuant to the APS Settlement, APS customers cannot be adversely affected by any transaction between APS and a generation

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[3] Also, compare the 1999 Western Systems Coordinating Council Information Summary, noting 2,239 MW of Arizona/New Mexico/Southern Nevada planned generation additions in 1999-2008, with the 2001 Information Summary, noting 12,180 MW of Arizona/New Mexico/Southern Nevada planned generation additions in 2001-2010. The Information Summaries are public records available at the WECC Website, www.wecc.biz.

affiliate prior to that date. Thus the Commission has ample time to adopt whatever code of conduct requirements it believes are necessary.

Similarly, Reliant's and Panda's claims that competitive bidding needs to be resolved and fully implemented prior to any divestiture is nothing more than a tactic to delay or hamstring divestiture. Regardless of whether it approves the proposed PPA, the Commission retains jurisdiction over APS' power procurement activities and it will address competitive bidding in the Track B process. In fact, Reliant and Panda have the analysis backward—divestiture is a precondition to competitive bidding because if the Commission prohibits divestiture Rule 1606(B) would not apply. Mr. Davis's direct testimony explains how divestiture and competitive bidding have always been linked:

> Q. ARE DIVESTITURE AND COMPETITIVE BIDDING UNDER *RULE 1606(B) 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 Rule 1615] 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.

(J. Davis Direct Test., at pp. 9-10.)

RUCO similarly argues against divestiture, at least without the Proposed PPA, which is in direct contradiction to the Settlement Agreement that it signed. It advocates a return to vertically-integrated cost-based service. (*See, e.g.,* R. Rosen Direct Test. at p. 49.) However, many of RUCO's and Staff's arguments do not so much criticize divestiture, as they criticize competition. In fact, most of the arguments of both Staff and RUCO are arguments strongly supporting a long-term, cost-based PPA that includes the divested assets. [*See, e.g., id.* at p. 2 (recommending that divestiture should only proceed with long-term cost-based PPA); M. Rowell Direct Test., at pp. 4-5 (asserting an overriding goal of just and reasonable rates and use of existing cost-based rates as competitive benchmark); J. Davis Rebuttal Test., at pp. 20-21.]

ISSUE NO. 2 – MARKET POWER

A. The evidence presented during the Track A hearing demonstrates that PWEC will not have unmitigated market power post-divestiture.

APS witness Dr. William Hieronymus has probably conducted more market power analyses than anyone in the United States—not just for traditional utilities such as APS, but for many of the merchant power entities as well. (W. Hieronymus Rebuttal Test., at p. 23 and WHH-1.) In contrast, Panda/TECO witness Dr. Roach has conducted only 2 studies for FERC, while the experience of Staff witness Schlissel and Residential Utility Consumer Office ("RUCO") witness Dr. Richard Rosen seem to be limited to conducting academic studies of the subject or analyses in the context of state merger reviews.[4] (*See* Tr. vol. III, at pp. 734-738; C. Roach Direct Test., at CRR-1; D. Schlissel Direct Test., at DAS-1; and R. Rosen Direct Test., at Appendix 1.) Yet surprisingly, all the witnesses that even attempted to conduct a Supply Margin Assessment ("SMA") analysis as used by FERC came to the conclusion that APS passes the most recent and stringent market power test proposed by FERC in determining whether or not a wholesale electric market is

[4] Other witnesses have thrown the term "market power" around, including Staff witnesses Jerry Smith, Matthew Rowell, and Paul Peterson, as well as Reliant witness Curtis Keebler. However, none of them actually conducted any market power analysis of their own. They either assume the existence of market power without proof or rely on the analysis done by another witness.

functionally competitive. It was only when they improperly altered the fundamental assumptions of such a study, or changed the scope of their analysis to study something not at issue (i.e., the existence of ephemeral market power in transmission constrained areas of the APS service territory) that their results differed in any material way from those of Dr. Hieronymus. (*See* Tr. vol. IV at pp. 909-10; W. Hieronymus Rebuttal Test., at p. 1.)

For example, Dr. Roach excluded all competitors of APS from his revised market power analysis. As noted by Dr. Hieronymus, such an approach is logically flawed and inconsistent with FERC precedent on the subject. (Tr. vol. IV, at pp. 909-11.) Dr. Roach then joins Staff witness Schlissel in "proving" that APS generation is, in the words of the SMA, "pivotal" within the Phoenix load pocket. Even at that, each failed to consider non-APS generation and non-APS transmission within and into such constrained areas. (*Id. See also* Tr. vol. VI, at pp. 1417-18.) They further ignore the fact that such constraints exist for only a tiny fraction of the year for a tiny portion of the Company's load. (*See* C. Deise Rebuttal Test., at pp. 10-11, 13.)

The market power of owners of generation within transmission constrained areas is neither caused by divestiture nor will it be ameliorated by APS retention of its load pocket generation, which consists of a few hundred megawatts of decades-old capacity at West Phoenix, Ocotillo, Yucca, and Douglas. It was, is, and will be mitigated by the "must-run" provisions of the AISA and WestConnect protocols. (*See* J. Smith Rebuttal Test., at p. 6; K. Higgins Direct Test., at p. 8.). It can be further reduced by new reliability-driven transmission projects. (D. Schlissel Direct Test., at p. 7.) In addition, A.A.C. R14-2-1609(I) requires that contracts for "must-run" must be in place prior to divestiture. The Proposed PPA is an example of just such an agreement. However, even in its absence, post-divestiture interconnection agreements between APS and the now divested APS "must-run" generation will also be required by FERC, and will add yet another layer of market power protection.

B. Staff's proposed new market power study is unnecessary and assumes the existence of a problem requiring a solution.

Staff witness Rowell proposes a mega-market power study encompassing unspecified features of the HHI, the "Hub and Spoke," and the SMA market power analyses,[5] all of which APS has passed. (*See* W. Hieronymus Direct Test., at pp. 31-36.) Although Mr. Rowell was unable to describe precisely what manner of market power studies Staff would consider sufficient or how such an amalgam of studies is to be conducted, it appears that what little is new about Staff's recommendation is the addition of some ill-defined manner of "strategic behavior analysis." (*See* Direct Test. of M. Rowell, at p. 11.)

Although the time necessary to run such an analysis is itself significant—some six weeks (Tr. vol. IV, at pp. 921-23)—the time necessary to gather the data for the analysis (even assuming the merchant generators would provide it, which based on their failure to respond to APS discovery is doubtful), and then establish the necessary assumptions for running the simulation is much more considerable, probably at least a year. And since all strategic behavior market power studies familiar to Dr. Hieronymus and Staff witness Schlissel start with the assumption of illegal collusive behavior on the part of market participants, it comes as little surprise that they always conclude that effective competition is impossible. (*See* Tr. vol. IV, at pp. 921-23; *see also* W. Hieronymus Rebuttal Test, at p. 22.) This is all the more significant since market power arising from such posited illegal collusion can never be mitigated in any conventional meaning of that term, only deterred through vigorous enforcement of existing antitrust laws.

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[5] The "Hub and Spoke" test defines the relevant market as the applicant's control area plus every directly interconnected (or first-tier) control area, and looks at whether the applicant's market share in this market is less than 20 percent considering both total installed capacity and uncommitted capacity. The Herfindahl-Hirschman Index (HHI) is a calculation of market concentration using the sum of the squares of the market shares of suppliers in a market, and is a number between 0 and 10,000. The SMA involves calculating the supply margin in a market, which is the difference between installed capacity and peak demand. If an applicant has more generation than the supply margin, it is deemed pivotal.

ISSUE NO. 3 – CODE OF CONDUCT/AFFILIATE TRANSACTIONS

A. APS already has both a Commission-approved Code of Conduct and FERC Standards of Conduct, in addition to this state's comprehensive set of affiliate regulations, none of which appear "broken" and in need of "fixing."

APS presently has a Code of Conduct approved by the Commission in Decision No. 62416 (April 3, 2000), as well as Policies & Procedures ("P&Ps") to effectuate that Code. The latter were submitted and approved on June 2, 2000. Both were negotiated between the Company and Commission Staff, and in the over two years since their implementation, APS has not been so much as accused of a violation. The Commission has also had general rules and regulations concerning affiliate transactions since the early 1990s. (*See* A.A.C. R14-2-801, *et seq.*; J. Davis Direct Test., at p. 10.) And there have been individual Commission orders specific to APS and its affiliates. (*Id.* at p. 11.) As with the Code of Conduct, APS' compliance with both these general affiliate regulations and the APS-specific Commission orders has been exemplary. Even in California, where market abuse is alleged to have become the norm and not the exception, APS refused to compromise business integrity for profit. (J. Davis Rebuttal Test., at p. 31; Tr. vol. I, at pp. 78-79.)

APS is also subject to FERC-imposed Standards of Conduct that prevent the subsidization of generation by transmission and prevent APS from granting preferential access to either its physical transmission system or to information concerning such system. (J. Davis Direct Test., at p. 12; Tr. vol. VI, at pp. 1449-50.) At present, FERC is considering significant changes to its Standards of Conduct in FERC Docket No. RM01-10-000. These changes may serve to moot some of Staff witness Barbara Keene's concerns over the relationship of PWM&T, APS and PWEC.

The sole development since 1999 alleged to necessitate this renewed "hand wringing" over affiliate transactions is the Proposed PPA, an agreement which APS voluntarily brought to the Commission for its review and approval in the most open and public forum possible, and APS' use of PWM&T as its agent for purposes of power acquisition. Only the unwarranted elevation of process over substance would ask the Commission to reject an otherwise advantageous deal for APS customers simply because it failed some definition of "arm's length" or was negotiated using an agent rather than directly by the principals. Thus, APS respectfully suggests that there is nothing "broken" as regards its relationship with either PWM&T or PWEC that warrants Commission "fixing" at the present time.

B. Staff Witness Keene has not proposed any specific changes to the existing affiliate regulations or the APS Code of Conduct.

Ms. Keene was very specific in indicating that she was not proposing any amendments to A.A.C. R14-2-801, *et seq*. (*See* Tr. vol. VI, at p. 1443.) Neither did APS nor any other party, and thus the Company assumes this is a dead issue for the present. (J. Davis Direct Test., at p. 12.)

Even as to the present APS Code of Conduct, Ms. Keene indicated that it was adequate for its intended purpose. (*See* Tr. vol. VI, at pp. 1447-48.) Instead, she suggested that APS should submit a new Code of Conduct that would supplement rather than replace the existing one. (*See* Tr. vol. VI, at pp. 1444-45.) This new Code of Conduct would cover the following areas:

- arms-length transactions
- access to confidential information
- cross-subsidization
- preferential treatment of affiliates
- joint employment
- employee transfer
- sharing of office space, equipment, and services

- proprietary customer information
- financing arrangements with affiliates
- conflicts of interest

(B. Keene Direct Test., at p. 8.) Most of these same areas are in the existing APS Code of Conduct, which as required by A.A.C. R14-2-1616, addresses:

- cross-subsidization
- access to confidential information
- joint employment
- preferential treatment of affiliates
- inference of preferential service to affiliates
- inter-affiliate transactions
- joint advertising, sales, and marketing
- use of the APS name and logo
- complaint procedures

Others on Ms. Keene's list, such as access to proprietary customer information and affiliate financing arrangements, are already subject to specific existing Commission regulations. *See* A.A.C. R14-2-1612(E) and A.A.C. R14-2-804. The only potentially new concerns raised by Ms. Keene are "employee transfer issues," sharing of office space, equipment and services, and "conflict of interest."

The subjects of employee transfers and the sharing of space, equipment and services are only "potentially" new because it is not clear whether Staff wishes to prohibit employees of APS from transferring to another affiliate or to prohibit the sharing of space, equipment and services or merely to have provisions regulating them in some fashion. If it is the latter, the presently effective Code of Conduct Policy No. 1 of the P&Ps (which unlike the balance of the P&Ps, is generally applicable to affiliate transactions and not just to APS and its Competitive Electric Affiliate) addresses pricing and cost-allocation of shared or transferred employees, equipment and services. Pursuant to Section VIII of the APS Code of Conduct, this Policy is up for review each year, and yet Staff has never proposed any change to either Policy No. 1 or to any of the other P&Ps. (*See* Tr. vol. VI, at p. 1447.)

The issue of "conflict of interest" is more nebulous. It appears tied to the requirement that inter-affiliate transactions be "arm's-length." Unlike the present Code of Conduct, as well as the Standards of Conduct, such concepts again elevate process over substance. According to Ms. Keene, "arm's-length" means that the same individual cannot participate on both sides to a transaction and both sides must vigorously pursue their separate interests. (*See* Tr. vol. VI, p. 1444; *see also* B. Keene Direct Test., at p. 8.) Although it would perhaps be literally possible to comply with these restrictions, APS does not wish to mislead the Commission as to the essential nature of a utility holding company. No transaction between affiliates can be free of "conflict of interest" or be "arm's length" to the same degree as transactions between unrelated parties. That is why there are regulatory substitutes for arm's-length negotiation such as affiliate pricing guidelines, requirements for prior regulatory approval, stricter "after-the-fact" prudence scrutiny, etc. Indeed, that is one of the reasons why APS submitted the Proposed PPA for Commission approval in the first place. To insist that affiliates act in all respects as if they are not affiliates is to expect the impossible. It would in effect prohibit affiliate transactions of any sort—a step both unprecedented anywhere in this country and clearly contrary to the interests of APS consumers.

A corollary issue to that of Code of Conduct/Affiliate Transactions is Staff's newly-articulated opposition to the use of an affiliate, PWM&T, as the Company's agent in certain APS procurement functions. (*See* Tr. vol. VII, at p. 1574-75.) This retention by APS of specialized expertise from its affiliates to supplement its own resources is hardly news, and certainly there has been no objection from Staff to the many benefits APS has derived from such expertise. (*See* Tr. vol. I, at pp. 186-87.) Like many other parent companies, Pinnacle West has provided legal, environmental, regulatory, human resource, and tax services to all of its subsidiaries for some time now. Never has there been the suggestion by either Staff or the Commission that this is in any way improper, that it somehow divested the Commission of its ability to scrutinize the prudence of the Company's legal, environmental, employment, or tax practices, or that APS would be held any less accountable by the Commission for the actions of its agents. Moreover, it should be remembered that both under the Proposed PPA and under the Company's July 1, 2002 "Track B" filing, an independent third party would be utilized by APS for power procurement in those instances in which PWM&T was a potential seller to APS of competitively-procured power.

In fact, the APS Settlement specifically permits the transfer of the power marketing function to an affiliate. (Tr. vol. VII, at p. 1575.)[6] As recognized by Staff witness Talbot, these are precisely the skills most useful for power acquisition. (*See* Tr. vol. VI, at p. 1379.) PWM&T's activities on behalf of APS have contributed greatly to the Company's ability to actually reduce rates when other states have seen significant increases. (*See* Tr. vol. I, at pp. 186-187.) As APS indicated in response to a Staff Data Request:

> The benefits [of using PWM&T] are many fold, including both the fact that APS was required to divest this function and the fact that there are significant costs and expenses associated with performing the "power procurement" functions. It would be extremely costly for APS to develop the infrastructure necessary to provide these functions for itself. Second, an "APS-only" power procurement function would lack the economies of scale and scope of PWM&T. Finally, PWM&T personnel have gained considerable experience in power procurement and sale (even if APS has no generation, it will still need to remarket energy from purchases from time to time) during a most difficult period of time.

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[6] No assets were involved in this transfer, and thus no 30-day notice was required under terms of the APS Settlement.

The economies of scale and scope referenced in that response are achievable because PWM&T conducts many transactions that neither involve nor directly affect APS. APS and its customers take none of the risk involved in this trading. But APS and its customers nevertheless benefit both from the aforementioned operational economies and the experience PWM&T traders derive from these non-APS transactions. To insist that these economies be lost by maintaining in effect two marketing operations or that APS customers now be placed at risk for trading losses unrelated to their service needs is unreasonable at best and downright foolish at worse.

C. If divestiture is permitted in accordance with the APS Settlement, APS would be willing to submit a revised Code of Conduct consistent with the provisions of Section XIV of its existing Code of Conduct to address Staff's concerns.

Despite the questionable need for chasing new solutions to non-existent problems, APS has repeatedly taken steps to assure this Commission that divestiture will not adversely affect either APS customers or the competitors of post-divestiture PWEC, and it is prepared to do so again in this instance. Should divestiture of APS generation be permitted to proceed as promised in the APS Settlement, APS would, if such is desired by the Commission, submit a revised Code of Conduct covering PWEC, PWM&T and APS Energy Services. It will address the issues set out in Ms. Keene's testimony, while at the same time attempting to preserve the proven advantages of shared services and common corporate governance. This revision would be filed for Commission review and approval within 30 days of a final FERC order in Docket No. RM01-10-000 or by December 31, 2002, whichever is sooner. APS has tied the filing of this new Code of Conduct to FERC's ongoing Standards of Conduct proceeding because there is no point establishing a state Code of Conduct based on one set of assumptions about the structure of APS and its electric affiliates if it turns out that FERC will require an entirely different structure.

APS would also suggest a new Code of Conduct rather than a second Code of Conduct for several reasons. First, APS has already formally trained more than 2000 management and mid-management employees concerning the present Code of Conduct. Retraining of anything is always more difficult than the original training, and it will be made all the more difficult if there are two, arguably conflicting Commission-approved Codes of Conduct. Second, having two state Codes of Conduct, in addition to the FERC Standards of Conduct, will make an already confusing situation for employees and regulators that much worse. Finally, there just is not any reason, good or otherwise, for having separate Codes of Conduct at the retail and wholesale level.

Divestiture should not be held up pending Commission consideration and approval of any amended Code of Conduct. APS customers are protected from inappropriate affiliate dealings through at least the summer of 2004 so long as the APS Settlement remains in effect. The Commission's general affiliate rules, and specifically Rule 804, remain in full force and effect as to APS. Even absent that Settlement and the Commission's affiliate regulations, the Commission has considerable experience dealing with affiliate charges in individual rate and non-rate orders. *See, e.g.,* Decision Nos. 56548 (July 12, 1989) and 55196 (September 18, 1986). Other important aspects of Staff's recommendations are already covered under Code of Conduct Policy No. 1, discussed above, and other existing regulations such as Rule 1612(E).

ISSUE NO. 4 – JURISDICTION OF THE COMMISSION

A. The Commission will not lose any meaningful jurisdiction over the setting of retail rates as a result of generation divestiture.

This is another issue where form or process has tended to take precedence over substance. State regulators have never had jurisdiction over most wholesale transactions. *See Public Utility Comm'n v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927). Federal jurisdiction over most such transactions has been exclusive since the 1930s.[7] APS purchases at wholesale, whether they be pursuant to the Proposed PPA or from the competitive market, have been and will be (for the most part) under terms, conditions and prices that are regulated by FERC. That is not to say, however, that the Commission will surrender its jurisdiction to set just and reasonable rates for consumers.

As a vertically integrated electric utility, the Commission can review and pass on the prudence of the Company's resource acquisitions, whether that is a new power plant or a power purchase—for example, the PacifiCorp contract approved by the Commission in Decision No. 57459 (July 11, 1991). The Commission can also determine the prudence of the utility's operation of its plants or the administration of its power contracts. Finally, the Commission can determine the timing of a resource's introduction into retail rates, i.e., when the resource is "used and useful." However, the Commission does not have the power to deny rate recovery to a prudently acquired and operated resource that is used and useful in providing service to the Company's customers.

With APS becoming a Utility Distribution Company ("UDC"), the Commission's role will be essentially the same. It will assess the process by which resources are acquired. It will review the administration and deployment of those resources. It will determine when and if a new resource is "used and useful." Similarly, the Commission cannot deny rate recovery of a prudently acquired and administered purchase power expense that is used and useful in providing service to the Company's customers.

Thus, the Commission's "loss" of jurisdiction is more apparent than real. In the case of the Proposed PPA, it would be even less so. (*See* J. Davis Direct Test., at pp. 13-14; Tr. vol. IV, at pp. 921-23.) APS has already offered up the Proposed PPA for the Commission's prior review and approval. It has agreed to a rate formula that is similar to

[7] FERC has limited jurisdiction over public power entities and has deferred to the United States Department of Agriculture, Rural Utility Service, as to many issues concerning electric cooperatives.

cost-of-service excepting only that the return component is fixed at historically low levels. Various provisions of the Proposed PPA require APS approval for this or that action, each time providing the Commission the opportunity to review such a discretionary decision by the Company. And, in its rebuttal testimony in the variance proceeding, the Company modified the Proposed PPA to require prior Commission approval of any extension of the agreement.

B. The Commission's jurisdiction is not affected by the Company's formation of or participation in a "for profit" RTO.

Similarly, neither the formation of WestConnect nor APS' participation in that RTO will wrest jurisdiction from the Commission in favor of FERC.[8] The Commission's jurisdiction over retail transmission rates is not adversely affected by the corporate structure of WestConnect—the choice of a for-profit WestConnect RTO over a not-for-profit RTO is jurisdictionally irrelevant. Instead, the only jurisdictionally significant factor is whether legal ownership of transmission assets is transferred to the RTO (whether for-profit or not-for-profit), which is a decision that ultimately requires approval by the Commission under A.R.S. Section 40-285.

Neither the Florida and Louisiana commissions' recent decisions regarding RTOs suggest the contrary. The Florida Public Service Commission delayed several Florida utilities' proposal to <u>divest</u> <u>ownership</u> of their transmission assets to a transco, which in Florida was being proposed under a for-profit model. *See* Order No. PSC-01-2489-FOF-EI (Fla. P.S.C. Dec. 20, 2001). The Florida Commission believed that such an action might constitute an unbundling, which could allow FERC to exercise jurisdictional control over Florida's retail transmission rates even though Florida had not adopted retail electric competition. The Commission wrote, "In essence, our approval of the transco model could

[8] The Commission has long supported the formation of RTOs, which is evident from current Rule 1609(C) stating the "Commission supports the development of [FERC] approved Regional Transmission Organization[s]…."

be viewed as voluntary unbundling, because ownership of the transmission assets would be transferred away from the retail-serving utility." *Id.* at 11. However, the Florida Commission specifically noted that it made "no judgment…as to whether [the proposed RTO] should be structured as a for-profit or not-for-profit RTO." *Id.*

The Louisiana Commission reached a similar conclusion for similar reasons. *See* Order No. U-25965 (La. P.S.C. Feb. 27, 2002). That commission also was primarily concerned with the transfer of ownership of the transmission assets, which could result in a potential for unintended unbundling of retail rates and general state jurisdictional impacts resulting from such a transfer. *Id.* at 16. However, the Louisiana Commission also concluded that "[a]t this time, we will not rule out the possibility of a for-profit RTO [without transmission asset divestiture]," but noted that it would carefully review such a proposal to determine whether the benefits outweighed any potential rate impacts resulting from the for-profit nature of the RTO. (*Id.* at 26.) Staff witness Jerry Smith also agreed with this analysis in his preliminary remarks, where he noted that "in both cases the issue was one of the state being concerned by losing jurisdictional control by unbundling of service." (Tr. vol. VII, p. 1472.)

In contrast to both Louisiana and Florida, Arizona has previously authorized retail competition, and FERC has already decided that the Electric Competition Rules have unbundled transmission. *See Re: Arizona Independent Sched. Admin. Assoc.*, 93 FERC ¶ 61,231 (Nov. 30, 2000) (review pending). Further, the WestConnect RTO as proposed does not require transmission owners like APS to transfer their transmission assets to the RTO. In fact, APS does not at present intend to seek authority to transfer its transmission assets to the WestConnect RTO. And, as noted above, this Commission ultimately would have the final say, pursuant to A.R.S. Section 40-285, on whether APS or other jurisdictional utilities transfer transmission assets to the WestConnect RTO regardless of what action is taken in this case.

ISSUE NO. 5 – TRANSMISSION

A. The Commission should continue to monitor transmission issues and complete the next Biennial Transmission Assessment.

Although there are disagreements on transmission issues discussed in Staff witness Jerry Smith's testimony and APS witness Cary Deise's testimony, there is certainly significant consensus on broad matters relating to transmission planning. APS acknowledged that transmission planning in a competitive environment will be more difficult. In fact, one of the problems that both APS and Staff recognized is that many merchant generators have not chosen to site their power plants in locations that allow efficient utilization of the existing transmission system or that bolster overall system reliability. (*See* Tr. vol. VII, at p. 1502.) Nor, for the most part, have merchant generators been willing to significantly commit to resolving transmission congestion or expanding the transmission grid in Arizona. (*See id.* at p. 1522-23; C. Deise Rebuttal Test., at pp. 19-20.) For example, the proposed Southeast Valley 500 kV transmission project, which when constructed will provide additional Valley transmission import capacity, initially involved significant participation by merchant generators in the "CATS" planning process. However, when it came time to commit real dollars to that specific project, only APS, SRP, TEP, and some public power entities actually stepped up to the plate.[9] (*See* C. Deise Rebuttal Test., at p. 20.)

Thus, APS and Staff agree that successful transmission planning will require collaboration with all affected parties, including those that are not subject to the Commission's general regulatory jurisdiction. Such a process will be advanced by the formation of the WestConnect RTO, which will be able to encompass more than just

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[9] Any notion that regulatory restrictions on merchant generators, such as "exempt wholesale generator" status, prevented such participation are, as Staff witness Jerry Smith recognized, nothing more than "shallow" arguments. (Tr. vol. VII, at p. 1547.) Any merchant generator could simply form a separate corporate affiliate if it really wanted to participate in the project, or it could directly commit funds through one of the participants and receive transmission service credits in return.

Commission-jurisdictional utilities and can tackle issues such as cost-recovery for non-reliability related transmission and transmission projects that bring regional benefits. (*See id.* at p. 23.) However, because authority over all stakeholders is required for effective transmission planning in a competitive environment, it is inappropriate to order only Commission-jurisdictional utilities to develop accelerated transmission solutions. Indeed, forcing Commission-jurisdictional utilities to go-it-alone could actually <u>diminish</u> the likelihood of effective collaboration, because non-jurisdictional entities would believe that regardless of whether they act or not, the Commission would order APS or TEP to solve any transmission problem at the expense of those utilities' customers. However, APS does believe that Staff's proposal for continued voluntary collaboration among participants (*see* J. Smith Direct Test., at p. 25) coupled with additional system-wide study work (*see id.*; Tr. vol. VII, at p. 1493) is appropriate.

Staff also acknowledged that it was not proposing the elimination of <u>all</u> transmission constraints on the system and that transmission and local generation were alternative methods to serve a utility's load. (Tr. vol. VII, at p. 1490, 1499.) APS is taking appropriate steps to address transmission issues in a prudent, cost-effective manner. (C. Deise Rebuttal Test., at p. 7.) Indeed, Staff specifically acknowledged that:

> Arizona transmission owners have over the past year made significant progress in planning and announcing new transmission additions to resolve local import constraints and mitigate perceived transmission market power within Arizona.

(J. Smith Direct Test., at p.22.) Staff also agreed that a cost-benefit analysis may show that the continued use of "reliability must run" or local generation is in the best interest of APS' customers. (*See* Tr. vol. VII, at p. 1478.) In fact, the cost-benefit analysis provided by Cary Deise shows that, at present, significant new, <u>unplanned</u> transmission expansion to relieve the Valley constraint is not warranted.[10] This cost-benefit analysis and its

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[10] APS does, of course, have several transmission projects already planned or under construction. (*See* Tr. vol. VII, at pp. 1536-41.)

assumptions were not rebutted by Staff or any other party either on cross-examination or later through Staff witness Jerry Smith.

Further, no party has actually proposed that any specific transmission project is either required for a competitive market to work in Arizona or would specifically benefit APS customers. Staff acknowledged that it was not suggesting that APS has violated any existing Western Electricity Coordinating Council reliability or planning rule. (*See* Tr. vol. VII, at p. 1510.) APS certainly has not violated or ignored any Commission rule by not attempting to preemptively rebuild and reconfigure its transmission system in the three-year period since the current version Rule 1606(B) was adopted, something that Staff's cross-examination of Mr. Deise seemed to imply. Of course, this would have required making hypothetical assumptions on generating plant locations during that period and knowing who would win a competitive bid at the end of that period. Rather, Staff simply believes—without pointing to any specific technical study or cost-benefit analysis—that more infrastructure <u>may be</u> needed to help the competitive market develop.[11] Accordingly, Staff proposes reliability standards that, if the Commission agrees are necessary, should be adopted in a rulemaking proceeding. All of these broad transmission planning and infrastructure issues may well be appropriate for the next Biennial Transmission Assessment, but they are not directly related to Track A issues and need not (and probably cannot)[12] be resolved in this proceeding.

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[11] This is a point that APS itself raised in its Partial Variance Request, when it noted that competitively-bidding fifty percent of APS' Standard Offer is not practicable at present and that the cost-based Proposed PPA is more appropriate.

[12] As Mr. Deise noted in his testimony, a transmission project will generally require at least three years to study, site, acquire right of way and construct. (C. Deise Rebuttal Test., at p. 19.) And, Staff witness Smith acknowledged that its transmission concerns ultimately depend on future study work. (Tr. vol. VII, p. 1499.) Thus, Staff's proposal for accelerated development of transmission solutions will not have an immediate impact on any of the issues presented in these consolidated dockets.

B. The record shows that there are no "must run" or transmission market power issues that should affect divestiture.

The only direct Track A issue in Mr. Smith's testimony on transmission is "must-run" or local generation requirements and transmission market power. Staff and other parties agreed that the existing "must run" protocols and the proposed WestConnect protocols were "effective operational tools assuring nondiscriminatory access to constrained load pockets at nondiscriminatory prices." (*See* J. Smith Rebuttal Test., at p. 6; K. Higgins Direct Test., at p. 8.) Those witnesses with expertise in market power analysis recognized that the existing and proposed "must run" protocols mitigated horizontal market power issues inside the Valley or other transmission constrained areas.[13] (*See, e.g.,* K. Higgins Direct Test., at p. 8; W. Hieronymus Direct Test., at p. 28-29.) Moreover, the Phoenix area is served by two electric utility companies (APS and SRP), unlike virtually every other "load pocket" in the United States, has multiple transmission-owning entities, and APS has not prevented any merchant generator from constructing capacity inside the transmission constraint. (Tr. vol. IV, at p. 1095.) These facts further mitigate any alleged horizontal market power relating to the Phoenix area. Also, existing FERC regulations and APS' FERC Standards of Conduct prohibit inappropriate sharing of information between the transmission and merchant functions of APS and its affiliates and requires nondiscriminatory access to transmission service, which mitigates any potential vertical market power issues. (*See* C. Deise Rebuttal Test., at pp. 24-25.) Thus, there are no "must run" or transmission market power issues that warrant delaying or further conditioning the divestiture of APS' generation pursuant to the APS Settlement.

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[13] Mr. Smith specifically acknowledged that he was an engineer and not an economist. (*See* J. Smith Rebuttal Test., at p. 4.) Also, several witnesses, including Mr. Higgins from AECC who was a participant in drafting the AISA protocols, pointed out that Mr. Smith's assertion that the "must run" protocols were not designed to mitigate market power was flatly incorrect. (*See* Tr. vol. V, at p. 1181.)

ISSUE NO. 6 – WEST PHOENIX AND REDHAWK

At the close of the hearing, the ALJ asked questions of Staff as to whether PWEC's West Phoenix and Redhawk projects were "merchant plants." (Tr. vol. VII, at p. 1542.) However, no definition of that term was provided by either the ALJ or Staff, and it would be erroneous to assume that a "merchant plant" could not be constructed primarily to serve APS customers. The West Phoenix Power Plant Expansion and Redhawk Power Plant Units 1 and 2 are being constructed by PWEC[14] and thus are nominally "merchant plants" only in the most literal sense that they are not being constructed by a vertically-integrated utility company.[15]

However, such a denomination does not detract from the fact that PWEC's West Phoenix Plant Expansion and Redhawk Units 1 & 2 were built to meet the reliability needs of APS' Standard Offer customers. Specifically, APS could not itself construct either the West Phoenix Expansion or Redhawk. The Commission's Electric Competition Rules do not allow Affected Utilities to own generation because generation is considered a "Competitive Service." [*See* A.A.C. R14-2-1601(7) and R14-2-1615(A).] Further, even though the APS Settlement delayed the divestiture requirements of Rule 1615 until January 1, 2003, Section X.B of APS' Commission-approved Code of Conduct specifically prohibited APS from providing "interim" Competitive Services, which APS

[14] There was testimony at the hearing that PWEC was an Exempt Wholesale Generator ("EWG"). These witnesses were mistaken. In fact, PWEC is not an EWG nor, like most of the merchant generators in this proceeding, a Delaware limited liability corporation. PWEC is an Arizona corporation and a "public utility" under the Federal Power Act, 16 U.S.C. § 824.

[15] This is a recognized definition even when the power plant is being used to serve standard offer loads of affiliated utility companies. For example, the Hardee Power Station, owned by Panda Gila River's affiliate TECO Power Services, is considered to be a "merchant plant" by the Florida Public Service Commission even though its output is dedicated to serving customers of TECO's utility-affiliate, Tampa Electric Company. *See Tampa Elec. Co. v. Garcia*, 767 So.2d 428, 429 n.3 (Fla. 2000) ("The PSC defines 'merchant plant' as a power plant with no rate base and no captive retail customers."). *See also* the Florida Public Service Commission website which identifies the Hardee Power Station expansion as a merchant plant at *http://www.psc.state.fl.us/general/publications/restruc.cfm#8* and TECO's website on the plant expansion at *http://www.tecopowerservices.com/PSHardee.html*.

believed would have included the construction of any new generation, even if such generation were to be later divested to PWEC.

What were the alternatives? APS could have violated its "provider of last resort" obligations under Rule 1606(A) and compromise reliability. APS could have signed purchase power agreements during the same dysfunctional market as did Nevada and California, thus incurring hundreds of millions of dollars of increased costs—increased costs that could have threatened the rate moratorium provisions of the APS Settlement. Neither course of action would have been in the interests of APS customers, and neither course of action was undertaken. Rather West Phoenix and Redhawk were planned and constructed, and the $140 million of temporary generation at Saguaro and West Phoenix, for which APS and PWEC received no additional compensation, was installed to bridge the gap until these units were completed and in service.

Mr. Davis testified at the hearing without contradiction that the West Phoenix Expansion was build to serve APS customers. (Tr. vol. I, at p. 130.) The West Phoenix Expansion was denominated as a "merchant plant" during hearings for a Certificate of Environmental Compatibility to show that APS customers would not bear the siting and construction risks associated with the plants' not coming into service. And, just like APS' existing generation assets (or TEP's, for that matter), excess output can be sold off-system. Nonetheless, the West Phoenix Expansion, which is being constructed inside the Valley transmission constraint, was clearly intended to serve APS' growing Phoenix load.

Similarly, the Redhawk project was called a "merchant plant" during the siting process, again because the generation was not being concurrently rate-based.[16] However, as Mr. Davis testified, the Redhawk project will be one of the few merchant plants that

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[16] APS has not asserted that Redhawk Units 3 & 4, which are scheduled for construction in the future, were or will be dedicated to APS customers. APS has always assumed that this portion of the project would, when constructed, compete generally in the wholesale market.

will be in-service to meet APS' summer 2002 load-serving requirements—timing that is intentional rather than coincidental. Indeed, APS included Redhawk Units 1 and 2 in Commission presentations on load-serving adequacy in February 2001.[17] Redhawk was also included, under its previous name Hedgehog, as was West Phoenix, in load and resource planning as far back as the 1999 Load and Resource Plan, provided to Commission Staff, and thus constituted a necessary part of the Company's reliability reserve requirements. Both Redhawk 1 and 2 and the West Phoenix expansion were also designated as network resources in 2001, which means they are resources that must serve APS customer requirements. (*See* Tr. vol. IV, at p. 1149.)

Also and particularly telling as to the intent of parties, Mr. Davis testified at the hearing that Pinnacle West and PWEC had opportunities to sell the Redhawk capacity into the California market or to the Pacific Northwest, at what would have been a very substantial profit, but did not (and could not) take advantage of such opportunities because these Redhawk units were committed to reliably meeting APS' resource requirements. (Tr. vol. I, at p. 153.) And as noted above, the cost of then securing replacement (for Redhawk) power from the competitive market to serve today's needs would have been unacceptable. Actions speak louder than words, and the actions of Pinnacle West and PWEC demonstrates the commitment of West Phoenix and Redhawk Units 1 and 2 to APS customers—a commitment that should be recognized by the Commission.

ISSUE NO. 7 – IMPACT OF RECOMMENDATIONS IN "TRACK A"

Since APS is not suggesting any change in the APS Settlement nor to the Electric Competition Rules, and as noted earlier, the Commission has not indicated what action or actions it is considering, as is required by A.R.S. Section 40-252, the Company is at a

[17] APS' February 16, 2001 Energy Workshop presentation, which is on file with the Commission, shows West Phoenix CC4 as meeting APS' resource needs beginning in the Summer of 2001 and Redhawk CC 1 & 2 meeting APS' resource needs beginning in 2002. (*See* excerpts attached as Exhibit A.)

considerable disadvantage in attempting to identify with great specificity what regulations or orders may potentially be impacted by these proceedings. The various recommendations of the parties to this proceeding, excepting APS, could affect all or portions of the Commission's Electric Competition Rules and several prior orders of the Commission.[18] As a practical matter, they also impact APS and its affiliates in a universally adverse fashion. If the Commission adopts such recommendations, either in whole or in part, it should be prepared to deal with these impacts—not in some future order or in the next rate case, but when the damage is done. In this portion of the Company's Brief, it will discuss each of these issues and suggest actions by the Commission to both "fix" its regulations and orders and to allow recovery by APS and its affiliates for the costs inflicted thereby.

A. Commission Regulations

It is obvious that both Rule 1606(B) and 1615(A) will be affected by any final decision that restricts the ability of either APS or TEP to divest their generation, and in the case of APS, power marketing functions.[19] Moreover, Rule 1615(B) would have to reflect whatever changes are made to Subsection A of that Rule. To the extent "must-run" generation is involved, changes to Rule 1609(I) may be appropriate, and any change in the Commission's traditional support of RTOs would necessitate significant changes to several other subsections of Rule 1609. TEP's and RUCO's recommendations to alter or suspend the scope of direct access clearly implicate Rule 1604, and changes to Rule 1606(A) and 1606(H) may be required to reflect the possibly restricted scope of a UDC's obligation to provide unbundled services. Finally, APS would suggest a comprehensive

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[18] Although APS has attempted to be as comprehensive in its analysis as was possible under the circumstances, it does not waive the ability to raise additional issues as it becomes aware of such.

[19] Even if divestiture is permitted to proceed as presently authorized, it is still very possible, even probable, that changes to Rule 1606(B) will be necessary as a result of "Track B", and thus it is reasonable to suspend Rule 1606(B) pending resolution of such "Track B" issues. (*See* Tr. vol. VII, pp. 1608, 1611.)

review of all the Electric Competition Rules to determine whether there are other less obvious candidates for repeal or amendment that were nonetheless premised on the eventual divestiture by the Affected Utilities of their competitive lines of business and associated assets. An example of this may be Rule 1606(C)(6), which limits the ability of Standard Offer tariffs to offer special contract rates. This section has always been tied to generation divestiture since it was believed that only physical generation displayed the economic characteristic of increasing economies of scale normally used to justify special contracts for customers with large or unusual loads.

As important as what the Commission does, is what it should not do at this time. A blanket suspension of the Electric Competition Rules, *en masse*, would lead to confusion as to whether such provisions as the Environmental Portfolio Standard, and its accompanying surcharge, or the System Benefits Charge were still in effect. What about the billing and reporting requirements of the Rules or those provisions providing consumer protection, safety, etc. (e.g., Rule 1612)? Any decision to grant a party's requested relief must be carefully targeted and limited to the specific regulations or parts of regulations implicated in that request.

B. Commission Orders

This presents an even more daunting challenge. Not only must the Commission identify all the potentially affected orders and decisions, but it must again act with a scalpel and not an axe in seeking to change these decisions. Such orders may well have provisions that nobody seeks to disturb or which themselves would trigger the need for an ever expanding set of changes to yet other Commission decisions not readily identifiable without more extensive research than present circumstances permit.

Beginning with the obvious, both the APS Settlement (Decision No. 61973) and the TEP Settlement (Decision No. 62103) would require changes to those provisions providing for divestiture. These include Sections 2.6(3), 4.1, 4.2 and 7.8 of the APS

Settlement. Although APS has sought only a variance to Rule 1606(B), which does not require a change in Decision No. 61073,[20] other parties' recommendations, whether in "Track A" or "Track B," are more substantive and would require some modification of the Settlements themselves. Whatever the Commission does, it should be careful not to disturb those portions of the Settlement Agreements unrelated to divestiture except as may be necessary to compensate APS and its affiliates for the impact of Staff's and certain other parties' recommendations.

Less obvious is the impact of Staff's recommendations on Decision No. 62416. As noted above, that Decision approved an APS Code of Conduct that, among other things, prohibited APS from providing competitive generation even during the period prior to December 31, 2002. If APS is to be required to keep its current generation and acquire new generation if cost-effective, it must be freed of these restrictions.

C. The Commission must address the "bifurcation issue" and should also allow APS and its affiliates to recover all costs incurred in reliance on the provisions of the APS Settlement.

APS has incurred millions of dollars in preparing for the transfer of its generation assets by December 31, 2002 as authorized by the APS Settlement and as required by Rule 1615(A). (J. Davis Direct Test., at pp. 7-9.) Its affiliates faced increased financing costs and perhaps the inability to either obtain or maintain an investment-grade debt rating so long as the generation assets devoted to serving APS are split into two entities. (Tr. vol. I, at pp. 92-93.) Staff witnesses have agreed that such increased costs are legitimate claims by APS should its recommended delay, let alone an outright denial, of divestiture eventuate. (*See* Tr. vol. VI, at pp. 1347-49; Tr. vol. VII, at p. 1606.)

Unlike the Merchant Intervenors' claims, APS' detrimental reliance on the APS Settlement and Rule 1615(A) is established by record evidence. It is not based on

[20] The Amended Settlement required by the Decision referenced only the requirements of the Electric Competition Rules, a term defined by the APS Settlement as being inclusive of amendments or variances. (*See* Reply of Arizona Public Service Company to Response of Commission Staff, at p. 6.)

conjecture by counsel or refuted by the Merchant Intervenors' own data responses, which are quoted word-for-word in APS witness Davis' Rebuttal Testimony in the variance proceeding.[21] It is also uncontested in this proceeding. The only remaining questions are what does the Commission do about this situation and when.

The "when" is easy. The Commission should decide both the divestiture issue and acknowledge the consequences of that decision in its "Track A" Opinion and Order. To do less is to compound the very uncertainty that has plagued these proceedings since the initiation of the generic docket back at the beginning of this year. It also is likely to make the eventual resolution of these issues more costly and litigious than necessary.

The "what" is similarly easy if the Commission agrees to simply honor its commitments under the APS Settlement. That commitment is to permit divestiture on or before December 31, 2002 (not at some later date or after jumping through some additional hoops) without conditions not imposed by the APS Settlement (let alone the onerous and likely impossible conditions recommended by Staff) and lift the stay so that the Company can present its arguments for the Proposed PPA. The issue is complicated if the Commission is determined to adopt a different position, which different position can run the gamut from a simple and finite delay in divestiture to an open ended "not now, but someday" to a definitive "no way." First, the Commission should indicate that APS is entitled to recover all reasonably incurred and increased costs occasioned by the Commission's change in position. These would include costs incurred by either APS or its affiliates. Second, the "bifurcation" problem must be addressed by allowing APS to acquire and finance the Dedicated Units presently owned by PWEC. Third, other aspects

[21] These data responses uniformly show that the Merchant Intervenors either had no documentation to support their earlier claims of reliance upon Rule 1606(B) or were unwilling to even respond to the question. And of the Merchant Intervenors, only Reliant presented an actual witness in these generic proceedings that was knowledgeable about its Arizona generation projects, and Reliant by its own admission constructed its project for SRP and not APS load. The Panda/TECO and PG&E witnesses did not testify about the intended market for their projects.

of the APS Settlement should be subject to further reconsideration during the Company's next rate proceeding or, at the discretion of the Commission, in a separate proceeding held prior to the next rate case. This would specifically determine how the $234 million write-off was to be restored to the Company as well as the one-third of divestiture-related costs the Company was forced to absorb under Decision No. 61973.

CONCLUSION

Much time has been lost due to the decision to stay proceedings on the Company's requested variance. Both the Proposed PPA and the Commission's consideration thereof would have shed considerable light. Now, with each day's passing, the continued uncertainty surrounding these proceedings becomes an ever-darker cloud on the Company's image in the nation's financial markets. The situation for PWEC is compounded because it lacks the very asset base that was the foundation for its existence. Pinnacle West, on the other hand, is caught in the middle, attempting to keep both the APS and PWEC balls in the air.

The allegations made in this proceeding of "market power" and "affiliate abuse" range from self-serving to merely mistaken. All are unsupported by the evidence, and thus the continued cries for more studies and more regulations are "red herrings" on the issue of divestiture. Even if APS or PWEC would have market power in load constrained areas, such market power has been and will continued to be restrained by both state and federal regulation. Even if an expanded Code of Conduct is still believed necessary in light of FERC's proposed revisions to its Standards of Conduct, such could be considered and implemented by the Commission post-divestiture. Even if additional transmission is found to be appropriate either for reliability or economic purposes, such would be the case independent of divestiture, and Staff did not propose that it be made a precondition to divestiture. (*See* Tr. vol. VII, at pp. 1585-86.)

Rather than seize upon the passage of time since 1999, as has been opportunistically urged by some parties, the Commission should evaluate the issues based not on fear, conjecture or a desire to retain turf in the centuries old battle between state and federal jurisdiction, but on the facts. Every means possible should be employed to reconcile prior commitments with present circumstances. And where that is impossible, there must be redress for any harm thus occasioned.

RESPECTFULLY SUBMITTED this 10th day of July 2002.

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All parties of record

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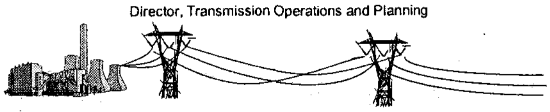
1208897.1

EXHIBIT A

Special
Open Meeting of the
Arizona Corporation Commission
Energy Workshop

February 16, 2001
Arizona Public Service Company
Cary B. Deise
Director, Transmission Operations and Planning



Overview

- Reliability
- Service Territory
- Load Forecast
- Resources
- Fuel Supply Plan
- Transmission
- Conclusion

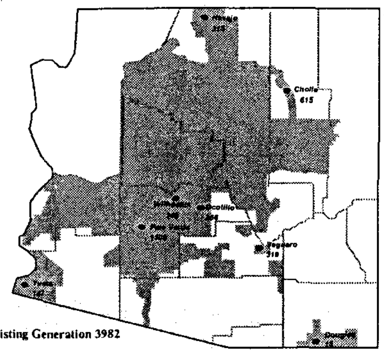
2

Reliability

- To meet customers electric energy requirements on time.
- Factors impacting reliability
  - Customer Requirements
  - Transmission, Generation and Distribution availability
  - Weather
  - Neighboring systems

3

APS Existing Generation
(Nominal ratings in MW)



Existing Generation 3982

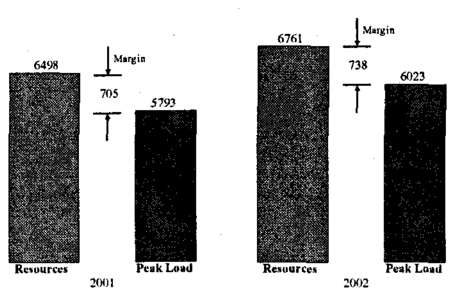
7

Resources

	2001	2002
• **Existing Generation**	3982	4497
Renewable	9	13
• **Additions**		
Upgrade of existing CC&CT	107	-
Reactivate WPhx Steam 4&6	96	-
WPhx CC 4	114	-
Temporary WPhx CT's - 5 units	99	(99)
Temporary Saguaro CT's - 5 units	99	(99)
Redhawk CC 1&2	-	988
Subtotal	515	790
• **Long-term Contracts**		
Pacificorp Exchange	480	480
SRP	336	343
Subtotal	816	823
• ***Short-term Contracts***	1176	638
• **Total Resources**	6498	6761

8

APS Load and Resources



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