BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

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	[illegible]
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

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

Pursuant to the presiding Administrative Law Judge's ("ALJ") direction, Arizona Public Service Company ("APS" or "Company") hereby submits its Initial Post-Hearing Brief ("Brief") on Track B issues to the Arizona Corporation Commission

("Commission"). This Brief identifies both the issues discussed in the Company's direct and rebuttal testimony and certain matters raised just before or during the Track B evidentiary hearings.

SUMMARY OF APS' OVERALL POSITION

APS appreciates the effort and endorses the general goals of the Commission's Utilities Division Staff ("Staff") and its consultant in carrying out the Track B process ordered by this Commission. Like Staff, APS supports an effective power procurement process for consumers. After all, consumers must rely on the utility and its regulator to act in the consumers' best interests. APS believes its past efforts to acquire needed and economical resources for its customers at reasonable prices have been extremely successful—producing rate decreases when virtually every other western electric utility was raising prices, often substantially. It further submits that having the flexibility to determine its own procurement needs, as well as the timing and manner of meeting those needs, were and are critical to both the Company's past and future success in such procurement.

This Track B process necessarily restricts that flexibility. That is less a criticism than a fact. And whether those restrictions are limited and procedural, or extensive and substantive, is now up to the Commission to determine. APS asks the Commission to keep closely in mind its own findings in Track A about the vagaries of the wholesale market. It should take that same measured and conservative approach to mandating significant changes to what has heretofore worked and worked well in Arizona during one of most difficult times in the history of the electric power industry.

APS likewise suggests that this Track B process would warrant and benefit from the Commission taking an active role in reviewing and approving the results of at least this initial foray into a government-mandated, uniform and simultaneous multi-year procurement by the state's two largest electric public service corporations. This would add certainty to the process for all concerned and should lower the ultimate cost to Arizona consumers.

INTRODUCTION

The major unresolved issues in Track B, at least prior to the filing of rebuttal testimony on November 18, 2002, were those set forth at page 34 of the Final Staff Report of October 25, 2002 ("Staff Report"). They include[1]:

- Determination of unmet need
- Role of the Commission, Staff and independent monitor, both during the solicitation and in evaluating the reasonableness of the bids
- Role of the utility in designing and conducting the Track B solicitation
- "Price to beat"[2]
- Standards of conduct for utility-affiliate communications regarding the Track B solicitation
- Least Cost Planning
- Demand-side management ("DSM") and "Environmental Risk Management"

One of the more significant issues arising with the November 18, 2002 filing was Staff's decision to make certain utility-owned and previously rate-based generation "contestable" in Track B despite the absence of any unmet need associated with such generation. (*See* Staff Exhibit S-5.) The issue of the Commission's treatment of reliability must-run or "RMR" generation will be discussed both under the UNMET NEEDS and TRANSMISSION AND RMR ISSUES Sections of this Brief.

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[1] APS has rephrased and consolidated certain of the issues listed at page 34 of the Staff Report to better match how it believes these issues were presented during the evidentiary hearing.

[2] Staff withdrew this recommendation, and APS no longer considers it an issue in the Track B proceeding.

Staff made a similar determination that certain utility purchase power contracts entered into prior to September 1, 2002 would be "contestable." However, Staff later withdrew that recommendation and adopted the Company's position. (Tr. vol. V at p. 960 [C. Kempley].)

In addition, Staff went beyond the language of the Track A order to make economy energy purchases—power purchases made by a utility if and when the cost of power is less than the utility's incremental cost of generation from existing resources—a part of the Company's "contestable load," even though such purchases cannot be considered a part of the Company's "unmet needs." This new and significant change to the Staff Report will also be addressed in the UNMET NEEDS discussion below.

ISSUE NO. 1 – UNMET NEEDS

A. *The Company's calculation of unmet needs is consistent with the language repeatedly used by the Commission in the Track A Order.*

As Mr. Ewen explained in his testimony, APS' unmet needs were calculated by comparing APS' October 2002 estimate of expected energy and peak demand requirements over the next ten years with the availability of APS resources to meet those needs. (P. Ewen Direct Test. at p. 2.) That calculation of APS' unmet needs precisely followed both the Commission's Decision No. 65154 (September 10, 2002) and the Staff Report's direction. (P. Ewen Rebuttal Test. at pp. 2–3.) That calculation also is the best current estimate of what APS requires for reliability purposes over the next several years, as evidenced not only by the lack of any credible alternative calculation being put forth for any of the specific elements of the APS calculation, but also the fact that Tucson Electric Power Company ("TEP") calculated its Track B unmet needs in the same manner. (*Id.* at p. 3.)

In Decision No. 65154, the Commission ordered APS to "acquire, at a minimum, any <u>required</u> power <u>that cannot be produced from its own existing assets</u>, through the competitive procurement process as developed in the Track B proceeding." (Decision No. 65154 at pp. 23, 30 and 33, emphasis added.) As can be seen by the citation, the Commission said this not once, but three separate times in its Decision. The Commission also explained and limited its qualifier "at a minimum" to mean that APS "may decide to retire or replace inefficient, uneconomic, environmentally undesirable plants," an action that would necessarily result in an increase in unmet needs. (Decision No. 65154, fn. 8 at p. 23). The Commission further clarified that it was ordering this approach to "encourage a *phase-in* to competition" because "the wholesale market is not currently workably competitive [and] reliance on that market without recognizing its current uncertainty and limitations will not result in just and reasonable rates for captive customers." (Decision No. 65154 at pp. 29-30, emphasis added.) All of these statements clearly indicate that the Commission wanted to move cautiously and did not intend for APS to subject more of its energy and capacity needs to the procurement process than was reasonable to begin the transition to competition.

Staff itself provided clarification of its interpretation of Decision No. 65154 in the Staff Report:

> To the extent that a utility has load requirements, capacity or energy, not served by generating capacity owned by the utility or through existing contracts for capacity or energy or from sources which the utility must purchase power as a result of law or regulation, that unmet need will be acquired through a competitive solicitation.

(Staff Report at p. 4.)

> For 2003, the solicitation will be for all load and energy requirements not served by generation owned by the utility and included in the utility's rate base as of September 1, 2002, except to the extent that such generation is providing RMR service during RMR hours or by power supplied pursuant to FERC or Commission approved contracts with affiliated and non-affiliated suppliers entered into prior to September 1, 2002. . . . Any generation capacity owned by a utility that has not been included in the utility's rate base may be bid by the

> utility in the initial solicitation on the same terms and conditions as all other bidders, including affiliated bidders.

(Staff Report at p. 6.)

These statements by Staff support the conclusions reached by the Commission in Decision No. 65154. The Staff proposal, first raised during the hearing, to add the term "economically" in several places in the Staff Report is not justified in light of the specific language to the contrary in Decision No. 65154. It also ignores current market uncertainties and would subject APS to more financial risk instead of less. This is most clearly evidenced by Staff's and the Commission's own conclusion that the wholesale electric market is not workably competitive, even "dysfunctional." (E. Johnson Direct Test. at p. 3; Tr. vol. I at pp. 112, 117-118 [E. Johnson].)

Following the direction provided by the Commission and Staff, as discussed above, APS calculated the number of hours for which it will require additional supply beyond that which APS' own resources and firm contracts can provide. As would be expected for a utility with a system load factor in the low 50% range, the unmet capacity needs far exceed the unmet energy needs. (P. Ewen Direct Test. at p. 2.) It is undisputed that APS only needs capacity or low capacity factor products and generally in the third quarter of the year. Although some of the merchant intervenors argued, at least originally, that the APS' statement of unmet needs might not be appropriate in this or that respect, they offered no credible alternative calculations for any of the specific elements of the APS calculation.

1. APS Load and Energy Forecasts

Although two of the merchant generator witnesses, Thomas Broderick and Dr. Craig Roach, assert generally that the APS load and energy forecasts reflect a "persistent underestimation" of load, it is noteworthy that neither they nor any other parties to this proceeding offered any specific criticisms of the methods or assumptions APS used in preparing its load forecast. (*See*, e.g., Tr. vol. V at pp. 867-868 [C. Roach].) Indeed, as demonstrated in more detail in Mr. Ewen's Rebuttal Testimony, APS' load forecast has been remarkably accurate, particularly in the last few years, when compared to other relevant industry forecasts. (*See* P. Ewen Rebuttal Testimony at pp. 7-8, and also at Schedule PME-1R.) This accuracy is not surprising—APS has every incentive to be as accurate as possible in its forecasting efforts, while the merchant generators clearly have an incentive for advocating the use of a higher than required retail sales forecast. APS' load forecast should be accepted, as it has been by Staff (Staff Exh. S-5), as the starting point for the solicitation process.

2. Specific Adjustments Proposed to the APS Calculation of Unmet Need

During the hearing, several adjustments to the APS forecast and calculation of unmet needs were proposed or discussed. When examined more closely, however, it becomes clear that APS' calculation of unmet needs was appropriate:

- <u>Citizens, TOUA and Wickenburg contracts</u>: As was demonstrated during the hearing, these three contracts should not be added to or considered as APS load. Citizens and TOUA are served entirely by Pinnacle West Marketing and Trading ("M&T") from M&T's non-APS resources and are not APS contracts. (P. Ewen Rebuttal Test. at p. 9.) While the 5 MW Wickenberg agreement is an APS contract, it is a market rate tariff contract for which non-dedicated resources are used (it is an incremental opportunity sale). Thus, it does not warrant the same level of treatment as the cost of service based contracts that the Company <u>has</u> included in APS load. (Tr. vol. III at p. 531 [P. Ewen]; P. Ewen Direct Test. at Schedule PME-1.) Even Mr. Broderick had abandoned this adjustment by the conclusion of his oral testimony. (Tr. vol. V at p. 933 [T. Broderick].)

- Summer 2003 Contracts: As discussed in Mr. Ewen's rebuttal testimony and acknowledged by Staff during the hearing, Mr. Broderick's proposal that four APS purchase power contracts be treated as M&T contracts, thereby arbitrarily reducing the existing APS resources available to APS to meet demand and energy needs, should be rejected. Each of the contracts at issue is an APS firm contract obtained from non-affiliates prior to September 1, 2002 to meet and serve APS' retail customer load in the summer of 2003. (P. Ewen Rebuttal Test. at p. 10 and at Schedule PME-2R.) Three of the agreements clearly were entered into by APS in 2000. Even the one contract (with Morgan Stanley) signed by M&T on APS' behalf was a replacement contract in 2001 for an Enron agreement with APS that was contemporaneous to the other three contracts. (*Id.*; see also Tr. vol. V at p. 947 [T. Broderick].) Thus, those contracts should not be included in the calculation of contestable energy. (Tr. vol. V at p. 960 [C. Kempley]; *see also* Tr. vol. II at p. 360 [A. Kessler]; and Tr. vol. III at p. 507 [S. Wheeler].)
- Non-APS RMR Needs: The parties agreed during the hearing that the APS estimate of non-APS RMR needs will be used as a placeholder pending the completion of the RMR study. (P. Ewen Direct Test. at p. 21.) That study will clarify a number of aspects relating to the calculation of RMR needs, including deliverability to both the Phoenix and Yuma load pockets. Once that study is completed, APS believes that the non-APS RMR needs should be addressed separately in the overall procurement process due to the unique delivery issues associated with such needs. (*Id.* at p. 20; Tr. vol. III at p. 504 [S. Wheeler].)

- APS RMR Resources: APS opposes any inclusion of the APS-owned RMR resources in the estimate of contestable load. Such inclusion is contrary to the Track A order, contrary to the Staff Report, contrary to Staff's position in Track A, and wholly unsupported by any articulated rationale. Additionally, making those APS resources "contestable" fails to consider the range of system benefits they provide beyond their ability to provide RMR service (Tr. vol. III at pp. 504-505 [S. Wheeler]) and will add unnecessary complexity and cost to the procurement process. APS will address this issue in more detail below due to its fundamental importance.
- Environmental Portfolio Standard: APS' calculation of its Environmental Portfolio Standard ("EPS") requirements was not disputed during the hearing. APS has proposed and Staff has agreed that generators may submit proposals to meet APS' EPS needs as part of the general procurement process. (Tr. vol. III at p. 687 [P. Ewen] and 698 [S. Wheeler].) In addition, APS currently has outstanding a renewables RFP. APS does not believe, however, that it should be required to include its EPS requirement in the calculation of unmet needs (Tr. vol. III at p. 691 [P. Ewen] and at p. 699 [S. Wheeler].) Nor does APS believe that renewable proposals should receive any preference in the general procurement process.

B. The Commission should not require APS to make APS-supplied RMR resources contestable

The record does not support making APS-supplied RMR "contestable" in the competitive solicitation. There is no precedent of which APS is aware for bidding out company-owned RMR capacity, and Staff witnesses could point to no example that supported their proposal to make such capacity contestable. (Tr. vol. III at pp. 504-05 [S. Wheeler]; Tr. vol. II at p. 352 [J. Smith].) Moreover, making APS-supplied RMR capacity contestable is contrary to both the Track A order (which specifically referred to needs that could not be met by the utility) and to Staff's earlier position that the Commission should order APS to retain its generation, and most specifically its RMR generation, which was to be retained under any circumstances. (Tr. vol. II at p. 344 [J. Smith]; Tr. vol. III at pp. 429-30 [D. Hutchins]; and Tr. vol. VII at p. 1584 of the Track A proceeding, of which the ALJ took official notice in Tr. vol. II at p. 337.) Staff acknowledged that the pricing protocols for such an RMR solicitation are not known—could APS bid its own units at cost or market, and what is "market" when dealing with RMR generation? (Tr. vol. II at pp. 350-52 [J. Smith].) The universe of potential bidders is certainly more limited than for the general solicitation. (Tr. vol. II at p. 348 [J. Smith].) It could require amendments to the soliciting utility's Open Access Transmission Tariff. (Tr. vol. III at p. 431 [D. Hutchens].) It also runs the risk of ignoring benefits offered by APS-owned RMR units, such as local spinning reserve and voltage support. (Tr. vol. III at p. 505 [S. Wheeler].) Further, the horizon for the first solicitation is unlikely to provide much in the way of either new local generation or significant transmission projects, either of which would require years to complete and could probably not be fully relied upon until closer to an in-service date. (*See* Tr. vol. II at pp. 377-80 [J. Smith]).

Given the already complex nature of the current solicitation and the lack of precedent around the country for such a proposal, including APS-supplied RMR in the competitive solicitation is an experiment that is best left for another day and another proceeding. Moreover, APS has agreed to competitively bid for <u>non-APS</u> supplied RMR requirements, which will allow for a market test as suggested by Staff and some of the intervenors. (T. Carlson Direct Test. at p. 4.)

C. The financial community has likewise interpreted the Track A order as preserving traditional cost-of-service regulation for the Company's existing utility-owned generation resources.

Although the likelihood of receiving a competitive bid for the handful of RMR hours served by APS-owned generation resources is slight, the continued non-contestability of existing APS generation has important symbolic significance in the financial community. (Tr. vol. III at pp. 507–509 [S. Wheeler]; and also at pp. 434-435 [D. Hutchens].) As noted in the Standard & Poor's report attached to Chairman Mundell's letter of October 18, 2002 in Docket No. E-01345A-02-0707, the most (perhaps only) positive feature of Decision No. 65154 from the perspective of the ratings agencies was the continued rate base cost-of-service regulation of existing APS generation, including that used to provide RMR service to the Company's customers. (*Id.*) Such an interpretation was consistent with Staff's position in Track A, as evidenced by the Supplemental Testimony of Staff witness Matthew Rowell. (Official notice taken in Tr. vol. II at p. 344; see also pp. 341-343 [J. Smith].) Staff has articulated no rationale for its sudden and belated change of position—a fact that would make its adoption all the more troubling for the financial community.

D. APS should not be required to acquire economy energy through the Track B process.

Economy energy is energy that is purchased either in real time or a relatively short period prior to its intended use. Such transactions are entered into when it is cheaper to buy energy in the market, even if it carries with it some capacity costs, than to continue to operate APS generation or to begin operating what was a previously idle APS resource. Because this self-generation option must necessarily exist to support an economy purchase, economy energy cannot, by its very definition, be "required power <u>that cannot be produced from its [APS'] own existing assets</u>." (*See* Decision No. 65154 at pp. 23, 30 and 33; emphasis added.) Neither can it represent APS needs that were heretofore produced by generating units that APS "may decide to retire or replace" as "inefficient, uneconomic, environmentally undesirable plants." (*Id.* at p. 24.) Such plants cannot be an alternative to purchase power, economic or otherwise, if they are "retired or replaced," and APS has already accounted for such retirements and replacements in its calculation of unmet need. (P. Ewen Direct Testimony at p. 18; P. Ewen Rebuttal Test. at p. 3.)

In fact, Staff's decision to recommend the pre-bidding of economy energy through some formal multi-year RFP or auction process is unprecedented anywhere in the country. (Tr. vol. III at pp. 505-506 [S. Wheeler]; and also Tr. vol. II at p. 321 [A. Kessler].) It is inconsistent with Staff's position in Track A. (Tr. vol. II at p. 325 [E. Johnson].) And it is bad for APS customers because it makes it harder for APS to align economy purchases with available resources, while at the same time managing and mitigating risk. (T. Carlson Rebuttal Test. at pp. 6-9.)

In its rebuttal case, APS proposed a compromise that both increases the amount of energy bid as a result of Track B and allows APS some of its current flexibility in the purchase of economy energy. This compromise proposal involved bidding 50% of forecast estimated economy energy needs for the upcoming 12 months through a series of quarterly auctions held on the first business day of the month preceding each quarter. The balance of APS' economy and other short-term energy needs would, with some exceptions required to maintain reliability, be acquired from non-affiliates or through "blind" procurements using electronic trading platforms or independent brokers. (T. Carlson Rebuttal Test. at pp. 10-13.) This experimental procurement program would only be continued after 2004 by express order of the Commission because of the real potential of higher costs to consumers caused by this departure from the Company's normal procurement practices. (*Id.*)

E. The amount of capacity and energy bid affects both the perception and the reality of the potential harm from the Track B bidding process.

TEP witness David Hutchens noted that the amount TEP was required to bid, even though it would be under no obligation to accept any of such bids, was negatively perceived in the financial community as adding to the utility's risk. (Tr. vol. III at p.434.) This was especially true if the utility lacked a rate adjustment mechanism covering the costs of purchased power. (*Id.*) APS witness Steven Wheeler not only agreed with Mr. Hutchens, but went on to add:

> And that would also be the case with respect to the higher numbers in Staff's Exhibit S-5 creating a heightened and perhaps unrealistic expectation that bids will or should be accepted for all of such amounts, even though accepting such bids would not be in the customers' best interest.
>
> I understand Staff has said we have the discretion to reject bids, but I also know that if heightened expectations are frustrated, there is an additional potential for hearings and litigation, also which would not be positive.
>
> Therefore, and with respect to this issue, and particularly given the absence of any showing in this proceeding, at least any showing that I'm aware of, that suggests that this [Track B] procurement process will indeed produce results better than APS' existing procurement program, I would urge the Commission and I would urge the Staff to be cautious, to be conservative, and to be realistic in establishing the parameters for bid amounts.

(Tr. vol. III at p. 509 [S. Wheeler]; *see also* Tr. vol. III at p. 574 [S. Wheeler].) And a recent Fitch publication dated December 17, 2002 likewise cited the uncertainty over Track B procurement issues as a negative factor facing APS. *See* Appendix A attached hereto.

ISSUE NO. 2 – ROLES OF THE COMMISSION, COMMISSION STAFF AND THE INDEPENDENT MONITOR

A. The Commission should explicitly approve both the process and the result of a procurement process it has mandated.

APS and several of the merchant intervenors have testified that express Commission approval of the Track B procurement process (and of the resulting power purchase agreements) will benefit customers. (Tr. vol. III at p. 510 [S. Wheeler]; Tr. vol. IV at p. 789-790 [C. Kebler]; and Tr. vol. V at p. 866 [C. Roach]; see also C. Kebler Rebuttal Test. at p. 2.) It will benefit them by reducing or eliminating any regulatory risk premium that would otherwise attach to the bids offered in Track B. (*Id.*) It will also give them confidence in the process itself. (Tr. vol. V at p. 866 [C. Roach].)

Such Commission approval and its corresponding assurance of cost recovery on the part of the utility are especially appropriate in this proceeding. The Commission is mandating many new aspects of this Track B purchase power acquisition process. It will be a process other than that believed to be the most prudent by Company management. (Tr. vol. III at pp. 511-513 [S. Wheeler]). And it is not the process that APS has used very successfully during the most turbulent time in the history of the electric power industry in this country. (T. Carlson Rebuttal Test. at pp. 4-5.) Indeed, one of Staff witnesses in the Track A proceeding indicated that subsequent Commission disallowance of what were in effect Commission-mandated costs would be, in his words, "disingenuous." (Track A Tr. vol. VII at p. 1577 [M. Rowell].)

B. Staff's role should first be that of an active partner and participant in the Track B procurement and secondly as advisor to the Commission in the approval process.

Staff has an absolutely vital role in the Track B process. It was Staff that brought about the consensus that emerged from the workshops. (Staff Report at pp. 31-33.) It was Staff that has determined the timeline and sequence of events in Track B. (Staff Report at pp. 27-29.) And Staff has asked the Commission to determine what products APS must include in the Track B solicitation (A. Kessler Rebuttal Test. at p. 9), for what period the solicitation should cover (Staff Report at p. 35), and how much APS should be required to solicit for each of those years (Staff Exh. S-5). Having taken such as activist role to date, it is reasonable for Staff to continue as a full partner in the actual Track B solicitation and to timely advise the Commission as to which contracts should or should not be approved by the Commission for subsequent full cost recovery. (Tr. vol. III at pp. 510-513 [S. Wheeler] and pp. 551-552 [S. Wheeler].)

Indeed, even if there is no formal Commission approval process, the parties to the Track B solicitation, both buyers and sellers, would no doubt take considerable comfort in what would be a form of de facto prudence review of the solicitation and its outcome. (C. Roach Rebuttal Test. at pp. 9-10.) If no such prudence review is undertaken by Staff contemporaneously with the Track B procurement, there is an even more compelling case for direct Commission involvement and approval as was discussed in the previous subsection of the Company's brief.

C. The independent monitor's role should be that of advisor to Staff rather than that of a substantive decision-maker.

The role of the independent monitor described in the Staff Report at pages 9 through 11 strikes APS as appropriate so long as Commission Staff and the independent monitor work closely with the utility to contemporaneously identify and correct potential problems with the Company's Track B solicitation. (S. Wheeler Direct Test. at p. 6.) But APS would suggest that it would not be appropriate for Staff and the monitor to criticize the Company for alleged deficiencies in the procurement process that had not been raised initially with APS while there was still time and opportunity to address them. (Tr. vol. III at p. 513 [S. Wheeler].)

APS is opposed to making the monitor a substitute for either the Commission or Staff. The monitor should not be able to "vote" on which contracts are to be awarded by APS nor should it be the final say on whether or not the Track B solicitation was conducted in an appropriate manner. Although the Commission should afford great weight to the unchallenged conclusions of the monitor in its review of the Track B process, the

Commission must accept responsibility for the ultimate approval of the Track B solicitation and the results thereof.

ISSUE NO. 3 – AFFILIATE RELATIONS

A. APS already has submitted a proposed expanded Code of Conduct in response to the Track A order, and it is presently subject to a FERC Code of Conduct and FERC Standards of Conduct, in addition to this state's comprehensive set of general affiliate regulations.

APS presently has a Code of Conduct covering itself and Competitive Electric Affiliates that was approved by the Commission in Decision No. 62416 (April 3, 2000), as well as Policies & Procedures ("P&P") to effectuate that Code. This existing APS Code of Conduct, which is required by A.A.C. R14-2-1616, addresses each of the following areas:

- 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

Other issues, such as access to proprietary customer information and affiliate financing arrangements, are also subject to specific existing Commission regulations. *See* A.A.C. R14-2-1612 (E) and A.A.C. R14-2-804.

Both the Code itself and the P&P were negotiated between the Company and Staff, and in the over two years since their implementation, APS has not been so much as accused of a violation of either. Even in California, where market abuse is alleged to have become the norm and not the exception, APS refused to compromise business integrity for unjust profit.

As a result of the Track A order, APS submitted a revised Code of Conduct on November 12, 2002. Pursuant to the terms of Decision No. 65154, a separate hearing will be held to consider this revised Code of Conduct. (*See* Decision No. 65154 at p. 25.)

The Commission has also had general rules and regulations concerning affiliate transactions with public service corporations since the early 1990s. *See* A.A.C. R14-2-801, *et seq*. These rules cover a wide array of transactions and have extensive reporting requirements. APS is one of the few Arizona Class A utilities that has not received a waiver of the affiliate rules and has always taken a conservative view in complying with such regulations.

APS is further 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. There is also a FERC code of conduct dealing with specific affiliate transactions, although APS has been granted a very limited waiver of such code during the Company's present retail rate moratorium and in consideration of the Commission's Electric Competition Rules.

APS makes these observations to emphasize to the Commission that the Company is already subject to considerable regulation in the field of affiliate relations. (Tr. vol. III at p. 536 [S. Wheeler].) Moreover, APS is taking proactive steps to more carefully delineate regulated from non-regulated functions within the Pinnacle West companies.

B. APS is presently developing Standards of Conduct for the Track B procurement consistent with the recommendation contained within the Staff Report even though the Commission has not adopted the Stafff Report or any part thereof.

Under the Staff Report's recommendation, APS must submit Standards of Conduct by the end of January 2003. (Staff Report at p. 38.) APS is attempting to accelerate that process even though it is unlikely that there will be a final Commission decision adopting or rejecting that portion of the Staff Report until approximately that same time. However, given the already stringent regulation of the Company's affiliate relations and the anticipated participation in the Track B solicitation of the monitor and Commission Staff, both of which will serve to alleviate merchant concerns, APS would not hold up an already tardy (for 2003) solicitation until there is complete agreement over these Standards. Such agreement is not likely given the position of the merchant intervenors in this proceeding.

ISSUE NO. 4 – PROCUREMENT ISSUES

A. APS should have the discretion to determine the specific energy products required to satisfy its unmet needs and the specific manner of their Track B procurement.

Page 16 of the Staff Report states that "[E]ach utility shall determine the specific products it will contract for in order to maintain an appropriately structured power supply portfolio." APS strongly agrees with that statement and would hope that Staff's apparent retreat from this position (A. Kessler Rebuttal Test. at p. 9.) is just that—more apparent than actual. To that point, APS witness Thomas J. Carlson has identified three basic electric product groups for which it would solicit bids: (1) capacity only; (2) capacity with firm energy; and (3) physical call options. (T. Carlson Direct Test. at pp. 7-8.) Mr. Carlson also explained how combinations of these products would give him dispatchable energy, albeit perhaps at a premium. (T. Carlson Rebuttal Test. at p. 14.). And it would not preclude unit contingent bids of the type advocated by Dr. Roach. (*Id.* at p. 17.)

B. APS should have the discretion to use an RFP, an auction, or any combination of these procurement vehicles in conducting the Track B solicitation, and most importantly, it must retain the power to say "no" to any or all the bids received as a result of Track B.

The Staff Report again would grant such flexibility. (Staff Report at pp. 22 and 24.) Staff witnesses repeated that position during cross-examination. (Tr. vol. I at pp. 105 [E.

Johnson], 130 and 156 [A. Kessler].) Only merchant intervenor witness Curtis Kebler appeared to take issue with this position as to the procurement method. (C. Kebler Direct Test. at pp. 3-8; C. Kebler Rebuttal Test. at p. 6.) However, APS fully explained its reasons for adopting both an RFP process for at least the initial Track B solicitation while retaining an auction format for potential quarterly solicitations of economy energy or subsequent solicitations of unmet needs. (T. Carlson Direct Test. at pp. 5-7; and T. Carlson Rebuttal Test. at pp. 10-13.) And no witness directly disputed the Company's power to reject bids, which power to say "no" is essential to a prudent procurement process. (T. Carlson Direct Test. at pp. 15-16.)

C. APS should have discretion in determining the timing of secondary solicitations if the Track B solicitation does not result in contracts for all of the Company's unmet needs.

The Staff Report is silent about secondary solicitations, and Staff was somewhat unclear on this point during cross-examination. (Tr. vol. II at pp. 364-366 [A. Kessler].) About the closest Staff came to addressing this issue is its discussion at page 4 of the Staff Report: "Short-term power and daily, weekly or monthly power acquired to meet unplanned needs, would continue to be purchased in the normal course of business <u>as it is today</u>." (Emphasis added.) APS endorses this concept and asks that it be explicitly adopted for all secondary solicitations outside the formal Track B process.

Indeed, given the delay in Track B from its originally scheduled completion date in October 2002, APS has already expressed its concerns about obtaining its third quarter of 2003 reliability needs. (T. Carlson Direct Test. at pp. 14-15.) And it has already begun the process of implementing appropriate hedge strategies. (*Id.*)

D. APS should have the discretion to establish the term for which it will solicit unmet needs through the Track B process and the length of contracts used for such purpose.

The former of these two related aspects of power procurement is granted by the Staff Report on the high side (i.e., there is no maximum term), but the Staff Report would require the Track B solicitation to encompass at least four years. (Staff Report at p. 35.) Although this does match the Company's own selected solicitation period (T. Carlson Direct Test. at p. 3), APS opposes mandatory solicitation terms whether on the high side (see T. Carlson Rebuttal Test. at p. 20) or the low side.

On the issue of contract length, APS witness Carlson explained the present difficulties with long-term agreements. (T. Carlson Direct Test. at p. 9.) This does not mean that APS will not consider longer-term proposals, but such proposals should be prepared to address and satisfy these legitimate concerns of the Company. (T. Carlson Rebuttal Test. at pp. 18-20.)

ISSUE NO. 5 – TRANSMISSION AND RMR ISSUES

A. APS' RMR requirements for the Valley and Yuma.

As is common with most metropolitan areas in the Western United States (T. Glock Rebuttal Test. at p. 5; Tr. vol. IV at p. 811-12 [W. Kendall]), APS has some RMR generation requirements when transmission import into its service area becomes constrained. For APS, there are RMR requirements in both its Phoenix and Yuma service areas, but the need for RMR is primarily limited to the summer during peak hours. Most of APS' RMR requirements can be accommodated by APS-owned generation (Ocotillo, APS West Phoenix, and Yucca), but there will be some limited requirements for non-APS RMR capacity and energy. (*See* P. Ewen Direct Test. at p. 20 and Schedule PME-1; P. Ewen Rebuttal Test. at p. 11.) And, APS' specific RMR requirements in Phoenix and Yuma will change (perhaps significantly) over time based both on transmission system improvements and additions and energy and demand growth inside the constraint. (T. Glock Rebuttal Test. at p. 4.)

For APS, the Phoenix and Yuma service areas are somewhat different in terms of specific RMR requirements and the analysis of such requirements. In Phoenix, there are three primary transmission owners—APS, Salt River Project ("SRP") and the Western Area Power Administration ("WAPA"). APS and SRP, which each serve load in the Valley, jointly administer the need for RMR generation in this area. There are also only three current suppliers of generation within the Valley transmission constraint—APS, SRP and PWEC. (Tr. vol. II at p. 348 [J. Smith].) However, like APS, SRP's local generation may be committed to meeting SRP load when RMR generation is needed. (*Id.*) In Yuma, APS is the only owner of transmission within the Yuma area, but WAPA interconnects there. Also, there are two non-affiliated electric generators (the Yuma Cogeneration Associates unit and an Imperial Irrigation District unit) located within the Yuma constraint that are selling to California, which frees up additional transmission scheduling capability into the Yuma area without any additional cost to APS or its customers. (Tr. vol. III at p. 716 [T. Glock]).

B. The Commission should reject both calls to ignore RMR or to overstate the RMR situation. Rather the Commission should defer to the Commission-ordered RMR study currently underway.

Some of the merchant generators have asked the Commission to ignore RMR issues in a manner that could force APS and its customers to buy generation that cannot be delivered to APS load. (*See, e.g.,* T. Broderick Direct Test. at p. 16-17.) It is, however, inappropriate to ignore deliverability and the Staff proposal specifically requires a deliverability analysis as part of the evaluation of competitive bids. (*See* T. Glock Rebuttal Test. at pp. 2-3; Tr. vol. II at pp. 355-56 [J. Smith].) Similarly, those merchant generators that criticize the limited need for RMR to justify an "RMR premium" for their power plants overstate the practical concerns on this issue. In Yuma, for example, there is currently significant operational flexibility to reliably meet load and there are numerous future options for increasing that load serving capability such that an "RMR premium" is simply not warranted. (T. Glock Rebuttal Test. at pp. 5-6.) For example, the out-of-area sales from local generators today allows APS to schedule additional generation into Yuma without requiring APS customers to pay for more transmission lines or any sort of premium for RMR generation. (Tr. vol. III at pp. 716-17 [T. Glock].) Similarly, APS believes that the timing and nature of future transmission projects that may alleviate RMR should not be assumed until closer to the actual in-service dates for those projects. (T. Glock Rebuttal Test. at pp. 4-5.)

The issues surrounding RMR for Yuma and Phoenix, including APS' assessment of potential solutions, will be documented in the RMR Studies that are underway pursuant to the Commission's Biennial Transmission Assessment. (*Id.* at p. 4; Tr. vol. II at pp. 354-56 [J. Smith].) Those studies, which will be completed by January 31, 2003, should quantify RMR issues and will be used by APS in developing its solicitation and evaluating its needs. The Commission should therefore defer to those studies to address specific RMR needs and requirements.

<u>ISSUE NO. 6 – LEAST COST PLANNING, DSM, EPS AND ENVIRONMENTAL RISK MANAGEMENT</u>

APS has long supported cost-effective DSM. However, there is presently no funding allocated for DSM. Nor is there any regulatory process in place for evaluating the effectiveness of DSM programs. (S. Wheeler Rebuttal Test. at p. 9.)

Least cost planning has been dormant for a number of years in Arizona. It would take significant time to reactivate and modernize that process even if Arizona is determined to return to traditional regulation. (*Id.* at pp. 8-9.)

The Environmental Portfolio Standard ("EPS") was listed by the Staff Report as a consensus issue. APS is satisfied with that consensus position. (Staff Report at p. 32.)

Environmental risk management" is an issue reminiscent of the "environmental externalities" debated by the Commission in the early 1990s. As with the prior issues discussed in this Section of APS' Brief, the present record is insufficient to warrant adoption of the recommendations of Land and Water Fund witness Dr. David Berry, Wellton-Mohawk witness Robert Kendall or Residential Utility Consumer Office witness Dr. Richard Rosen on these specific issues. (*Id.* at p. 11.) If the Commission wishes to consider the issues raised by these witnesses, the Company would not oppose further workshops to address them.

CONCLUSION

APS has calculated its unmet needs in strict conformance with Decision No. 65154. Deviation from the requirements of that Decision is not only legally inappropriate, given the lack of compliance with A.R.S. § 40-252, it would have an unsettling impact on the financial community, which already is closely watching APS and this Commission. It is also likely to lead to higher costs for consumers and unintended, but nevertheless adverse environmental impacts, especially in metro-Phoenix, should it lead to the construction of redundant generating capacity within these areas or the over-construction of new transmission facilities.

The proper roles of the Commission, Staff and the monitor in the Track B process are a direct result of the origins of this Track B proceeding, which is nothing less than a regulatory mandate. The Commission should, with the aid and advice of Staff and the monitor, make an expedited prudence review of the results of the Track B solicitation and assure both buyers and sellers of full and timely cost recovery.

APS has attempted and is attempting to address the concerns of Staff as to affiliate communications and affiliate relations materially affecting Track B. It has pledged to do what it reasonably can to alleviate those concerns, but APS will not promise the impossible and will not compromise the interests of consumers in a counterproductive effort to address every hypothetical concern.

APS has successfully managed market risk and market volatility for the benefit of its customers. To continue to do so, it must have the maximum degree of flexibility in the procurement of power, including the right to say "no," both in Track B and in secondary procurements outside Track B.

APS and Staff are likewise working together to study RMR issues in Phoenix and Yuma. This analysis will determine the scope of the RMR issue, its possible remedies, and the additional costs of such potential remedies. APS also will utilize this study to determine the Company's unmet RMR needs from non-APS resources, which it will solicit as a separate but concurrent part of Track B.

Finally, the important issues of DSM, EPS and "environmental risk management" should be studied carefully before the Commission considers any substantive action. In some instances, such studies are already under way, while others could be made the subject of upcoming Commission-sponsored workshops.

RESPECTFULLY SUBMITTED this 18th day of December 2002.

SNELL & WILMER L.L.P.

Jeffrey B. Guldner /s/ TLM

Jeffrey B. Guldner

PINNACLE WEST CAPITAL CORP.
Law Department

Thomas L. Mumaw

Thomas L. Mumaw
Karilee Ramaley

Attorneys for Arizona Public Service Company

Original and 21 copies of the foregoing
filed this 18th day of December 2002, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Copies of the foregoing mailed, faxed or transmitted electronically this 18th day of December 2002, to:

All parties of record

Vicki L. DiCola

Vicki DiCola

APPENDIX A

FitchRatings

Fitch : Info Center : Press Release

Fitch Comments On Staff Testimony In APS Financing Request Ratings

17 Dec 2002 2:05 PM

Fitch Ratings-New York-December 17, 2002: Recent testimony filed by the staff of the Arizona Corporation Commission (ACC) supporting Arizona Public Service Company's (APS) requested financing order is positive for the credit quality of Pinnacle West Capital Corp. (PNW), according to Fitch Ratings. The financing order seeks authority to issue $500 million of unsecured debt. Proceeds would be used to refinance maturing parent company debt incurred to fund power plant development at its non-regulated subsidiary Pinnacle West Energy Corp. (PWEC). If ultimately approved by the ACC, the financing would provide sufficient liquidity for PNW to meet debt maturities in 2003. In combination with the 'Principles of Resolution' agreed to by the Staff and APS (and discussed below), the staff testimony also lends some clarity to the regulatory process in Arizona and signals a reasonable working environment with the ACC Staff. Fitch recently placed the 'BBB' senior unsecured debt ratings of PNW on Rating Watch Negative citing concern over the company's ability to refinance $790 million of maturing over the next 14 months, increasing exposure to merchant energy markets, and the uncertain regulatory treatment of 1,800 mw of new generation. The Rating Watch Negative at PNW could be resolved favorably if the financing order were approved by the ACC in combination with a demonstration by the company of access to capital markets at reasonable rates. The transfer of PWEC capacity to APS and its inclusion in rates would also be favorable.

The impact of the staff recommendation on APS' ratings (listed below) will depend on the ultimate treatment of the 1,800 mw of capacity currently owned by PWEC. The current Negative Rating Watch for APS reflects the potential increase in leverage related to PNW's plan to issue debt at APS and regulatory uncertainty over the company's upcoming rate case and the process for securing future power supply. In revising the Rating Watch for APS to Negative from Stable on Dec. 4, 2002, Fitch noted that increased utility debt would be less of a concern if it is part of the cost of acquiring and ultimately rate basing the 1,800 mWs of PWEC generating capacity.

On Friday, Dec. 13, 2002, the ACC Staff filed testimony supporting APS's request for authorization to issue $500 million of unsecured debt, with the intent to use the proceeds to repay maturing PNW debt. Separately, the Staff and APS have agreed to principles for resolving certain issues raised by APS in its appeal of the Commission's Track A order. Under the resolution, APS would limit any prospective Track A appeal to the following issues, which would be appropriate for consideration by the commission in the company's 2003 base rate case: 1) the inclusion of 1,800 mWs of generation constructed by PWEC to meet APS demand growth; 2) the appropriate treatment of $234 million of pre-tax asset write-off agreed to by APS as part of the 1999 settlement agreement; and 3) the appropriate treatment for costs incurred by APS in preparation for the transfer of generation assets to PWEC.

PNW's original plan to issue debt at PWEC is no longer possible due to the ACC's decision to block the transfer of APS' generating capacity to PWEC. Also affecting PNW's refinancing plan are depressed wholesale power markets, a restrictive capital market environment, and PWEC's relatively small generation portfolio (1,300 mWs in operation). The planned asset transfer was in accordance with the ACC-approved electric industry restructuring settlement. The ACC's decision in Track A of its generic review of electric competition blocked the transfer of the generation assets from APS to PWEC, and was silent on the status of 1,800 mWs of unregulated generation capacity built by PWEC to meet APS demand growth.

Pinnacle West Capital's ratings are as follows:

--Senior unsecured 'BBB'; and,

--Commercial paper 'F2'.

Arizona Public Service Company's ratings are as follows:

--Senior secured 'A-';

--Senior unsecured 'BBB+'; and,

--Commercial paper 'F2'.

All of APS and PNW's debt securities are on Rating Watch Negative, with the exception of APS commercial paper, which has a Stable Outlook.

Contact: Philip Smyth 1-212-908-0531 or Robert Hornick 1-212-908-0523, New York.

Media Relations: James Jockle 1-212-908-0547, New York.