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June 11, 2002

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

RE: ARIZONA PUBLIC SERVICE COMPANY'S REBUTTAL TESTIMONY ON "TRACK A" ISSUES
UNDER THE GENERIC DOCKET
DOCKET NUMBERS: E-00000A-02-0051, E-01345A-01-0822, ~~E~~-00000A-01-0630, E-01933A-
02-0069, E-01933A-98-0471

Dear Sir or Madam:

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

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

Sincerely,

Jana Van Ness
Manager
State Regulation

Attachment

JVN/srm

Cc: Original (plus 18 copies)
Service List

Arizona Corporation Commission

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REBUTTAL TESTIMONY OF JACK E. DAVIS

On Behalf of Arizona Public Service Company

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

June 11, 2002

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1
2 **REBUTTAL TESTIMONY OF JACK E. DAVIS**
3 **ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
4 **(Docket No. E-00000A-02-0051, et al.)**

5 I. INTRODUCTION

6 Q. **PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.**

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

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

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

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

20 A. My primary purpose is to relate to the Commission the potentially devastating
21 impact of Utility Division Staff's ("Staff") recommendations as set forth in its
22 May 29th testimony – devastating to the Company, to its customers and to the
23 hopes for a competitive retail and wholesale market in Arizona. I also address
24 the efforts of the merchant generator intervenors ("Merchant Intervenors") to
25 both interject "Track B" issues into this "Track A" phase of the proceedings and
26 to at the same time hobble their most formidable competition – the generation

1 comprising the "Dedicated Units" under the proposed purchase power
2 agreement ("Proposed PPA"), which PPA is currently pending Commission
3 consideration in the Variance Docket.¹ Finally, I will respond to specific
4 contentions made by Staff and Intervenor witnesses.

5
6 **Q. WILL APS PRESENT OTHER REBUTTAL WITNESSES IN THIS
7 GENERIC PROCEEDING?**

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

16 **II. SUMMARY**

17 **Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL
18 TESTIMONY.**

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

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

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

3 Substantively, Staff would have this Commission undo virtually every provision
4 and reverse virtually every finding from the 1999 APS Settlement Agreement
5 ("1999 APS Settlement" or "Settlement"), excepting, of course, the rate
6 reductions, the \$234 million write-off and other concessions made by the
7 Company in the course of such Settlement. Indeed, the very existence of the
8 1999 APS Settlement is barely acknowledged. As noted in my Rebuttal
9 Testimony in the Variance Docket, this Settlement involved the Commission
10 itself as a party and has been characterized as a binding contract with the
11 Commission by the Arizona Court of Appeals. And in the place of the very
12 Settlement that has allowed Arizona to move forward towards a restructured and
13 competitive electric industry without the sort of economic disruptions that have
14 erupted almost everywhere else in the Western United States, Staff proposes a
15 bizarre and oppressive form of "regulated competition" that is neither
16 competition nor traditional regulation and which will utterly fail to provide
17 consumers the benefits of either regime. It is premised on a "lower of cost or
18 market" philosophy that this Commission and others have repeatedly rejected
19 and which is inherently unreasonable, inequitable and unsustainable.

20
21 Taken in combination with the suggestions of the Merchant Intervenors, Staff's
22 recommendations are more likely to lead to a repeat of California than to the
23 reliable service at just and reasonable rates that Staff professes to be its
24 objective. This is because Staff's position represents a complete failure to
25 recognize the essentials of a competitive market or to acknowledge the
26 regulatory bargain inherent in traditional cost-of-service regulation.

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

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

10
11 While Staff's testimony was, to put it mildly, greatly disturbing, that of the
12 Merchant Intervenors was, for the most part predictable, self-interested and
13 procedurally inappropriate. The "Track A" issues about which they originally
14 expressed no opinion back in December of 2001 now become a new source of
15 leverage in "Track B." The PWEC that they bravely challenged to open
16 competition in December 2001 now becomes some form of market
17 "superpower" that must be restrained from meaningful competition with the
18 Merchant Intervenors. Rather than support the Company's original request to
19 resolve "Track A" and "Track B" issues in a single proceeding or acquiesce to
20 the Commission's decision to address them separately, the Merchant Intervenors
21 apparently want two turns at bat, once in this proceeding and another in the
22 "Track B" proceeding. What is new is the Merchant Intervenors new-found
23 interest in delay, since many of their proposals are so radically different than
24 anything heretofore proposed in this jurisdiction that they could likely not be in
25 place even by the summer of 2003. This is in stark contrast to a group that as
26

1 recently as April of this year urged the Commission to immediately order APS
2 to begin competitive bidding.

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

18
19 Arizonans for Electric Choice and Competition ("AECC") witness Kevin
20 Higgins generally presents a balanced recommendation that both recognizes
21 AECC's responsibility to uphold the 1999 APS Settlement and urges appropriate
22 vigilance regarding the wholesale electric market. While APS and the AECC
23 will apparently continue to have disagreements over the particulars of the
24 proposed PPA, we do not appear to have major disagreements in this phase of
25 the Generic Docket, and thus I will not further address in any detail the AECC's
26 testimony in the body of my Rebuttal Testimony. (Dr. Hiernoymus will,

1 however, discuss the new market power test proposed in Mr. Higgins'
2 testimony.)

3
4 **III. THE STAFF RECOMMENDATIONS**

5 **1. Lower of Cost or Market**

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

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

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

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

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

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

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

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

3
4 **Q. WOULD STAFF LIMIT THIS APPLICATION OF A “LOWER OF COST**
5 **OR MARKET” TO PURCHASES OF POWER FROM AN AFFILIATE**
6 **SUCH AS PWM&T OR PWEC?**

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

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

20 This passage appears to indicate that whether APS transfers its existing
21 generation to PWEC or not, it will be limited to recovering the lower of those
22 generating assets’ “already established cost of service” (whatever that means)
23 or the cost of procuring an equivalent amount of power in the market. In the
24 divestiture case, this means that APS would not recover all its purchase power
25 costs even if the latter was prudently acquired in conformance with Rule
26 1606(B) and fairly represented the then market price of power. Were APS to

1 retain its existing generation, this means that APS would not recover its cost-
2 of-service unless market prices were continually above such cost-of-service for
3 the entire remaining life of these generation assets.

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

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

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

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

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

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

8
9 **Q. DOES STAFF'S POSITION REPRESENT THE TRADITIONAL COST-
10 OF-SERVICE REGULATION THAT ELECTRIC CONSUMERS AND
11 UTILITIES HAVE OPERATED UNDER FOR THE PAST 90 YEARS?**

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

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

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

1 traditional cost-of-service pricing, another important distinction from Staff's
2 seeming position in this proceeding.

3
4 **Q. ISN'T WHAT STAFF PROPOSES THE SAME AS THE OLD LEAST
COST PLANNING REGULATION OF THE 80'S AND EARLY 90'S?**

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

23
24 **Q. DOES STAFF CITE ANY AUTHORITY OR PRECEDENT FOR THE
25 LIMITATION OF RATE RECOVERY TO THE "LOWER OF COST OR
26 MARKET?"**

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

13
14 **Q. HOW WILL SUCH A PRICING PHILOSOPHY DESTROY THE UDC’S
FINANCIAL VIABILITY?**

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

21 Let me give you a specific hypothetical example. APS enters into a PPA either
22 with an affiliate or with one of the Merchant Intervenors for a five-year period.
23 In four of the five years, PPA costs are anticipated to be below the “benchmark”
24 cost of the Company’s existing generation. (I have put aside for purposes of
25 this hypothetical the difficulty in making such a comparison unless the products
26

1 being acquired through competitive bidding are comparable to the products to be
2 provided from the existing generation portfolio.) The anticipated PPA costs are
3 also lower on average for the entire five-year period. I interpret Mr. Rowell's
4 testimony to mean that APS could only recover the actual cost of the PPA
5 during the four years it was below the cost of the existing generation, but would
6 be penalized during the fifth year. Worse yet, even when the PPA was
7 anticipated to be below the cost of the existing generation for every year of this
8 hypothetical five-year period, if (on an after-the-fact basis) the PPA ever turned
9 out to be above such "benchmark" cost for any period of time, the Company
10 would be likewise penalized. The same penalties would seemingly apply if the
11 Company determined that it would retain its existing generation, and it later
12 turned out that market prices were below the "benchmark" cost-of-service for
13 any period of time during either the "transition period" or the remaining life of
14 the retained generation.²

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

21
22 **Q. DOES STAFF PURPORT TO ADDRESS THE POTENTIAL IMPACT OF**
23 **THIS PROPOSAL ON THE FINANCIAL VIABILITY OF THE UTILITY**
24 **DISTRIBUTION UTILITY ("UDC")?**

25
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² I say "seemingly" because Mr. Rowell's responses to the Company's data requests on this issue were somewhat confusing, ambiguous, and contradictory.

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

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

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

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

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

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

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

In large part the Commission's analysis was similar to the discussion of "economic excess capacity" in Docket No. U-1345-85-367, a seemingly endless rate proceeding filed in 1985 but not finally decided until the Spring of 1988. In that proceeding, Staff proposed to subject Palo Verde to a "market cost" test while at the same time constraining the value of the Company's other generating

1 plants to original cost. Thus, as in Staff's current proposal, APS cost recovery
2 for generation would be the lower of cost or market. But unlike Staff's present
3 recommendation, Staff was at least willing to compare the present value of Palo
4 Verde's life cycle costs to the present value of the market alternative for a
5 comparable period of time rather than a year to year spot analysis. Then, as in
6 this case, Staff contended that its standard for cost recovery would be
7 "reasonably applied," similar to Mr. Rowell's admonition that "the financial
8 health of the UDCs cannot be forgotten." Testimony of Matthew Rowell at page
9 4, lines 15-16. At the time, the Company was honored to present as a rebuttal
10 witness Dr. Alfred E. Kahn, former head of the New York Public Service
11 Commission and former Chairman of the Civil Aeronautics Board, and almost
12 literally the father of modern utility regulation. His response to this "lower of
13 cost or market" scheme was eloquent, if somewhat blunt:

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

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

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

1 erroneous and later withdrawn assessment that they fell short of
2 the standard.

3 In short, under Dr. Yokell's [Staff's] regulatory scheme,
4 the utility company would be penalized not just for its own lapses
5 from omniscience but also those of its regulators!

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

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

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

17 2. What 1999 APS Settlement?

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

22 A. Yes, and I know some may think I'm a broken record on this topic. But I am
23 continually puzzled and confounded by the fact that the 1999 APS Settlement
24 apparently means so little to Staff. Whether you accept the Court of Appeal's
25 pronouncement about this Settlement being a binding contract or believe it just
26 part of another order of the Commission, the 1999 APS Settlement deserves
27 more consideration and deference than has been repeatedly evidenced by Staff's

1 recommendations in this proceeding as well as in the Variance Docket. The
2 1999 APS Settlement specifically found that APS could transfer the power
3 marketing function, which of necessity includes power acquisition. *See* 1999
4 APS Settlement at Section 4.2. Yet Staff now is recommending that either this
5 function be retained at APS or worse yet, that APS and PWM&T have
6 redundant power marketing functions. *See* Testimony of Matthew Rowell at
7 page 7, lines 15-18. The 1999 APS Settlement specifically held that the
8 Company's new generation affiliate would not be placed under any different
9 regulatory scheme on account of its affiliation with APS:

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

15 1999 APS Settlement at Section 4.4 (emphasis supplied). Yet Staff proposes
16 both limiting the ability of APS affiliates to compete for sales of power to APS
17 in a manner not applicable to non-affiliates and requires nonsensical affiliate
18 pricing rules for such sales that would likewise not be applicable to non-
19 affiliates. *See* Testimony of Barbara Keene at page 8 lines 13-20.

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

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

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

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

19 **A.** Absolutely. For example, Staff witness Jerry Smith is suggesting an acceleration
20 of transmission projects and a general substitution of transmission for
21 generation. Both these recommendations will be exceedingly expensive to
22 implement. APS has already spent hundreds of millions to comply with the
23 1999 Electric Competition Rules and the 1999 APS Settlement, both of which
24 are now being dismantled or ignored by Staff. Staff is recommending a whole
25 new code of conduct when APS has already formally trained over 2000
26 employees on the existing Code of Conduct that Staff itself helped to draft just

1 two years ago and concerning which there has not been even one alleged
2 violation. Staff is recommending that APS get back into the generation
3 business when it has already devoted millions of dollars to get out of it in
4 compliance with divestiture provisions in the Electric Competition Rules drafted
5 and promoted by Staff and with the divestiture provisions in the 1999 Settlement
6 Agreement that were supported by Staff and which were indistinguishable from
7 the divestiture provisions insisted upon by Staff in the ill-fated 1998 settlement
8 also discussed in my Rebuttal Testimony in the Variance Docket. Aside from
9 the Company's many and profound substantive disagreements with most of
10 Staff's positions, there is the quite legitimate question whether any or all of
11 Staff's recommendations are likely to be completely changed or abandoned
12 altogether within a few short years, if not sooner.

13 **Q. DOES STAFF OFFER ANY EXCUSE FOR ITS TREATMENT OF THE**
14 **1999 APS SETTLEMENT?**

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

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

8
9 **3. The Proposed PPA Would Resolve Most of Staff's Stated Concerns**

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

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

18 ***Market Power*** – The Proposed PPA completely eliminates even
19 the potential exercise of market power by APS affiliates against
20 APS or its customers. And Staff's own analysis demonstrates
21 that neither APS (pre-divestiture) nor PWEC (post-divestiture)
22 can exercise any significant market power on a regional basis.

23 ***Affiliate Transactions*** – The Proposed PPA gives the Commission
24 prior-approval authority for most of APS' purchases from PWM&T.
25 The balance of the Company's needs would come from a transparent
26 and open competitive bidding process under the direct control of
27 APS. Except as regards its responsibilities under the PPA, PWM&T
28 will undertake no other significant affiliate transactions with APS.
29 The same is true as regards PWEC. As it is, those transactions are
30 already subject to Commission review in both rate proceedings and
31 as a result of the Affiliate Rules (A.A.C. R14-2-801, *et seq.*).

Code of Conduct – Approval of the PPA moots most potential code

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

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

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

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

16 Please note that the above analysis does not purport to "solve" the "jurisdictional
17 issue." If by "solve," it is meant a means by which the Commission can wrest
18 jurisdiction over wholesale power transactions from FERC or by which the
Commission can arrest FERC's progressive stranglehold over transmission
19 issues, I can offer no "magic bullet." Only Congressional enactment can serve
20 those purposes. But I can say that the Commission's influence over wholesale
21 market participants such as PWM&T and PWEC, both because of their
22 affiliation to APS and their status as Arizona-centered businesses rather than a
23 collection of Delaware LLCs, is and will remain far greater than the influence it
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25
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1 believes it can exercise through the occasional power plant siting proceeding or
2 even by the Merchant Intervenors' participation in this proceeding.

3
4 **4. Procedural and Timing Issues**

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

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

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

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

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

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

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

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

17
18 **Q. DID STAFF RAISE THESE ISSUES IN 1999?**

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

1 and since 1999, the generation market share of APS generation has dropped
2 significantly.

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

14
15 Aside from the amorphous nature of the preconditions (to divestiture)
16 themselves, which require significant further definition before they could
17 possibly be adopted and implemented, Staff also assumes completion of an as of
18 yet uninitiated rulemaking proceeding to amend Rules 1615, 1616 and 1606.
19 This is easier said than done, and once you begin pulling on the essential threads
20 of restructuring, you don't know how much of the cloth will unravel. Even if
21 such a proceeding were begun immediately and conducted concurrently with the
22 market power and code of conduct proceedings contemplated by Staff's
23 recommendations, something Staff has been most reluctant to do, completion
24 prior to December 31, 2002, or any time remotely close to such date, is
25 impossible.
26

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

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

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

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

17 IV. THE MERCHANT INTERVENORS

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

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

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

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

9
10 Dr. Roach also suggests that APS not be permitted to divest its generation in
11 accordance with the 1999 APS Settlement until APS established a short-term
12 energy market in Arizona. Testimony of Dr. Craig Roach at page 4, lines 6-7.
13 While I appreciate the vote of confidence, neither APS nor any other single
14 market participant can establish such a market. In California, it took a concerted
15 effort by all market participants and the state over many months to establish a
16 liquid short-term market, and even it eventually failed.

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

24 I also disagree with Dr. Roach's assertions at page 15, lines 1-5, and thus
25 further disagree that there is anything this Commission can and should do to
26

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

16 Finally, Dr. Roach suggests using an RFP process followed by private
17 negotiations, with PWEC and PWM&T being excluded from this process, as a
18 "mitigation" measure for non-existent market power. Whatever merit there is in
19 Dr. Roach's recommendation, it has nothing to do with mitigation of market
20 power. In fact, as we saw in California, the use of the RFP process and private
21 bilateral negotiations magnified the market power of the merchant generators to
22 the considerable detriment of consumers. To the extent that "Track B" issues
23 are in any way related to market power, this is just another argument in favor of
24 having as open and transparent a competitive procurement process as is feasible.
25 Also, eliminating or handicapping the merchant generators' major competitors
26

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

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

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

16 **Q. WHAT ABOUT RELIANT'S PROPOSAL?**

17 A. Reliant witness Curtis Kebler presents the unusual scenario wherein APS or
18 PWEC generation is first sold to merchant entities and then resold with some
19 undisclosed markup back to APS. Although I don't know how long it would
20 take to set up what would be in effect a second auction, I would agree that this
21 would allow parties without uncommitted generation in Arizona to participate in
22 providing generation for Standard Offer customers, but I fail to understand why
23 this is particularly desirable. One of the things APS, and I believe the
24 Commission, wish to encourage is the construction of new generation in
25 Arizona, not a proliferation of "asset-less" power marketers. From a reliability
26 point of view, the proposal may have some merit since it allows others to

1 purchase APS' and PWEC's then existing reliable portfolio of generation, but I
2 again struggle to see how essentially adding a "middleman" (and a
3 "middleman's" profit) to the Proposed PPA benefits the Company's customers
4 or enhances Arizona's future energy supplies.

5
6 **Q. BOTH THE MERCHANT INTERVENOR WITNESSES AND STAFF**
7 **WITNESSES HAVE SUGGESTED THAT MANY ADDITIONAL STEPS**
8 **NEED TO TAKE PLACE BEFORE WE CAN HAVE RESTRUCTURING**
9 **AND REALLY EFFECTIVE WHOLESALE COMPETITION. DO YOU**
10 **AGREE?**

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

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

26 A. I don't really know. It was just this past April that Panda/TECO was filing a
Motion asking an "Order to Show Cause" because the Company was not
immediately proceeding to competitive bidding. All the other Merchant
Intervenors supported Panda/TECO in this request. The scheduled hearing on
the Company's request in the Variance Docket was cancelled so that we could

1 get on with the bidding. Now, just as suddenly, the Merchant Intervenors are
2 the co-proponents (with Staff) of delay. Maybe they simply are hoping that
3 market conditions will improve before they have to commit any resources to
4 Arizona. Maybe some of them don't believe their plants will be done in time for
5 2003. Or it may be that getting a competitive edge vis-a-vis APS and its
6 customers by structuring the procurement process in "Track B" to their liking is
7 more important to them than getting the procurement process started on time.

8 V. RUCO AND AECC

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

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

1 VI. CONCLUSION

2 Q. **DO YOU HAVE ANY CONCLUDING REMARKS IN REBUTTAL?**

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

18
19 Aside from the substance of Staff's recommendations, I continue to be dismayed
20 by the lack of deference, or even consideration, afforded the 1999 APS
21 Settlement. Reinventing regulation every two to three years is certainly not in
22 the best interests of customers. I see no reason to give Staff's proposals in this
23 Generic Docket any greater consideration since if I wait a year or two, they too
24 will likely be rescinded or significantly modified.

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

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

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

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

A. Yes, it does.

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REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

On Behalf of Arizona Public Service Company

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

June 11, 2002

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REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

INTRODUCTION

Q. Please state your name and business address.

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

Q. Have you testified previously in this proceeding?

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

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

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

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

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

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

15
16 **REBUTTAL TO PANDA WITNESS ROACH**

17
18 **Q. At page 5, Dr. Roach is asked whether his “concern about market power**
19 **[would] persist even if the transfer entailed a contract to sell back at cost-plus**
20 **rates.” He responds, “Yes, absolutely.” Do you agree?**

21 **A.** No, absolutely not. His response makes no sense whatsoever. The purported basis
22 for this conclusion is his assertion in the variance proceeding that Standard Offer
23 customers would pay higher prices, face higher risks and have lower reliability than

1 if served by competing suppliers. In my rebuttal in that proceeding I explained the
2 total invalidity of his conclusions, to the extent that they had any basis beyond bald
3 assertion. However, that is not the point I wish to make here. The point that is
4 relevant to my testimony in this proceeding is that the PPA of which he complains
5 is not, and could not be, the result of "market power".

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1 mean that its capacity in the APS control area does not and would not discipline
2 APS/PWEC's hypothetical market power.

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

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

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

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

20 **Q. What mitigation does Dr. Roach propose?**

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

1 Q. Do you agree with his first mitigation?

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

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

1

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

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

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

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

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

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

1 not accept a contract that it believes is over-priced as a result of PWEC exercising
2 market power.

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

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

1 that this is an arms-length transaction, so that the issue of whether PWEC might or
2 might not be in a position to exercise market power over sales to APS is frankly
3 irrelevant.” This statement was and is true.

4 **Q. What do you conclude concerning Dr. Roach’s testimony?**

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

18

19 **REBUTTAL TO ACC STAFF**

20

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

22 A. Because Staff’s testimony is inter-related and cross-referenced, rebuttal is
23 somewhat hard to organize. Since Mr. Rowell summarizes Staff’s positions, I will

1 begin with him and deal with other Staff witnesses relevant to the issues I am
2 addressing in turn, to the extent that relevant testimony has not been covered in my
3 rebuttal to Mr. Rowell.

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

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

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

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

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

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

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

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

16 However, Staff does not appear to be thinking only in terms of an *ex ante*
17 determination that APS is pursuing a strategy that will result in just and reasonable
18 rates. What Staff appears to have in mind is absolutely inappropriate. While the
19 language used by Staff is a bit imprecise, I am especially concerned by the question
20 and answer on Page 14 of Mr. Rowell's testimony. The question asked is, "After a
21 utility transfers its generating assets to an affiliate, how should the UDCs recover
22 the cost of power purchased from that affiliate?" He asserts that the prudence of
23 purchases from any of "its affiliates or for any other wholesale provider should be

1 evaluated based on (1) the costs of other competitive alternatives and (2) the costs
2 the UDC would have borne had the transfer of assets not happened” [emphasis
3 supplied]. This smacks of the worst sort of after-the-fact, lesser of cost or market
4 regulation. Purchases from an affiliate made on a cost of service basis would be
5 judged based on costs of competitive alternatives. When lower, they are
6 recoverable. When higher, they are not. Similarly, the cost of purchases from the
7 competitive market is recoverable only if they are less than the cost of service
8 alternative. Indeed, the comparison of competitive purchases to cost of service
9 does not exhaust risk. The Nevada Commission recently disallowed nearly half a
10 billion dollars of the power purchase costs of Nevada Power Company, enough to
11 put the company on the verge of bankruptcy, on the theory that it should have
12 entered into a different market contract at an earlier time.

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

20 If this indeed is Staff’s proposal, it is repeating the worst of the policy errors
21 committed by the state of California. When the power shortage developed and
22 prices went sky-high, there was no impact on Edison’s and PG&E’s retail prices.
23 They remained at levels based on historic cost of service, a ceiling that Staff

1 proposes here. With no pass through of cost and hence no demand response, the
2 California shortage persisted. Once a material increase in retail prices was allowed
3 to occur, demand fell substantially. This substantially eased the supply-demand
4 imbalance eliminating the shortage wherein any major supplier was "pivotal".
5 And, of course, this ill-conceived policy bankrupted a utility with far deeper
6 pockets than the Arizona UDCs and nearly bankrupted another. An end result was
7 that a state agency ended up having to contract for power to meet Standard Offer
8 loads and, having paid what is believed (with hindsight) to be too much, retail
9 access had to be suspended so that these above market contract costs could be
10 imposed on all consumers, including Direct Access.

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

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

1 benchmark tests, the distinction should not matter, but Staff's language suggests
2 otherwise.

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

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

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

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

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

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

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

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

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

18 Second, any local market power that PWEC might have hypothetically will
19 be constrained by contract provisions, market oversight and, in the future, RTO
20 monitoring. Moreover, as I have discussed at length, PWEC will not be in a
21 position to exercise market power with respect to APS's customers to the extent
22 that their needs are covered by contracts or with respect to anyone to the extent that

1 its power is sold into the larger regional market or that its sales are under contracts
2 that pre-exist the period of alleged concern.

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

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

12 Let me begin by noting that much of this already has been done. Both Dr.
13 Roach and I have provided SMA analyses in this proceeding, and APS passes. In
14 1999, I provided the Commission with an analysis based on the Merger Guidelines;
15 APS also passed. Market changes since then have been clearly pro-competitive.
16 The vertical issue is not new and is not exacerbated by the transfer of assets. Indeed,
17 the greater remoteness from transmission that is a consequence of the transfer
18 should reduce market power concerns. APS already has a regulation-imposed code
19 of conduct governing affiliate dealings, and FERC has imposed restrictions
20 intended to eliminate the potential use of vertical market power. I am unaware of
21 any allegations that APS has exercised such power. An analysis of entry barriers
22 seems an empty exercise in view of the very substantial entry that has occurred in
23 Arizona.

1 I would not recommend the “strategic behavior analysis” that Mr. Rowell
2 asserts should be done. I have reviewed a number of such analyses, all of which
3 assume forms of tacit collusion among market participants. I have yet to see one in
4 any electric market that did not conclude that the market structure would not
5 support competition. Indeed, some of Mr. Talbot’s colleagues performed a study of
6 the PJM market that concluded that 30 firms, each of whom owned identical plants,
7 were required before the market would be acceptably competitive. Thus, a market
8 with concentration index of 300 (30 times 3.33 squared) is necessary to achieve
9 workable competition, according to their analysis. In contrast, the DOJ/FTC
10 Merger Guidelines that Mr. Rowell also proposes regard a concentration index of
11 1,000 (ten identical firms) as so competitive that the effects of a merger do not
12 matter, and an index of 1,800 as only moderately concentrated and presumptively
13 still workably competitive.

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

16 **A.** No. This is unfortunate, because the tools themselves, having been written for
17 general application, ignore facts that are knowable in the Arizona context. The two
18 FERC tests – merger guidelines and SMA, have been used often and have well-
19 known limitations. I have performed, or had performed under my direction, more
20 such tests than anyone else in the country. I am very familiar with them and how
21 they operate. A major problem with both tests is that they are presumptive of what
22 the relevant geographic market is and of what share of the capacity that the utility
23 owns is available to sell at market prices in the relevant market. The core

1 presumption of both SMA and the Merger Guidelines-related delivered price test is
2 that all of the load in a control area is uncontracted and must buy in the competitive
3 market and that none of the local utility's capacity is sold under regulated tariffs.
4 Both assumptions are patently false for APS today, for APS if the PPA is signed, or
5 under any other plausible outcome of these proceedings.

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

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

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

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

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

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

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

19 A. My only substantive comment is that APS can properly resent his discussion of
20 various APS "admissions" concerning market power. This terminology suggests an
21 inadvertent disclosure of something that APS is seeking to hide. APS always has
22 voluntarily acknowledged the need to regulate the pricing of units that are must run
23 as a result of these constraints. FERC policy similarly insists that such prices be

1 mitigated. There is no dispute that when these areas are constrained for a few hours
2 each year, market power mitigation is warranted.

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

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

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

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

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

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

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

22 He then discusses jurisdictional issues, noting that the ACC would lose
23 authority over wholesale pricing. He accepts that a buyback agreement or PPA

1 could overcome this problem. He notes that APS has proposed such a PPA but also
2 notes that Staff opposes it. He provides no information, useful or otherwise,
3 concerning the basis for that opposition.

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

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

17 A. In his summary, he urges caution in view of the recent problems in the industry and
18 the in-progress status of various regulatory initiatives concerning the wholesale
19 market. He concludes by supporting Staff's recommendation that "if APS is
20 confident that the transfer of its assts is in best course of action at this time, then it
21 is appropriate to assign to APS the financial risks associated with such a decision."
22 This statement of Staff's position is an egregious distortion. Staff is not merely
23 asking that APS take on the risks of the asset transfer. Indeed, the proposed PPA

1 fundamentally eliminates those risks by putting all jurisdictional assets under a
2 long-term contract. Staff's "lower of cost or market" proposal demands that APS
3 take on a wholly new risk that it did not have pre-transfer; the risk that cost of
4 service will be, from time to time, above market.

5 Indeed, the more of Staff's testimony one reads, the more one is convinced
6 that Staff doesn't know what it wants. Mr. Rowell appears to be saying that the
7 1606(B) auctions must go forward and that utilities should be free to transfer assets.
8 Mr. Peterson comes quite close to saying that the time is not right for asset transfer
9 and the utilities should bear the consequences of any costs incurred on other than a
10 cost of service basis – including any purchases from the competitive market.

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

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

20 Mr. Peterson also describes the level of congestion that has occurred in New
21 England and surmises about the causes. While not particularly relevant to this
22 proceeding, I disagree with his diagnosis. The main reason why congestion
23 increased in New England after the ISO was formed was that the formerly-

1 integrated utilities had dispatched around congestion. The Arizona analog to the
2 congestion that did not exist previously but that has occurred in Connecticut and
3 greater Boston after ISO formation would concern the Arizona load pockets. I am
4 confident that, historically, the Tucson and Valley transmission is rarely congested
5 (i.e. loaded to their limits). What is unsaid is that it is not congested because RMR
6 units are run, despite costs that exceed those of external units, before the inbound
7 transmission is exhausted fully. APS does not pretend, as did some NEPOOL
8 utilities, that these areas are not load pockets within which generation must be run
9 even when their costs exceed external units' costs.

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

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

1 that Mr. Peterson cites, purport to demonstrate that market prices are above short
2 run marginal costs. In itself, this does not demonstrate that prices are not
3 competitive.

4

5 **REBUTTAL TO RELIANT RESOURCES' WITNESS KEBLER**

6

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

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

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

16 A. No. Pinnacle West companies own the same amount of assets pre- and post-
17 transfer. The asset concentration and purported problems that it creates for
18 allowing multiple bidders to access the market are not at all related to the transfer.
19 Indeed, absent the transfer, the auction of 50 percent of load requirements under
20 1060(B) clearly would not occur.

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

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

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

12 **Q. What risks does this proposal imply for PWEC?**

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

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

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

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

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

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

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

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

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

1

2 **REBUTTAL TO AECC WITNESS HIGGINS**

3

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

5 A. Mr. Higgins discusses market power. Primarily, his testimony does two things.

6 First, it cites approvingly the various market power mitigation measures that have

7 been included in existing AISA and WestConnect protocols and in more general

8 FERC policies. These include, in particular, measures to mitigate market power in

9 load pockets. He urges the Commission to take notice of what has been

10 accomplished so as not to “reinvent the wheel”. He also offers his opinion that

11 FERC is strongly focused on vertical market power and that, in a post-California

12 environment, horizontal market power is also on the “front burner” at FERC.

13 Second he proposes using the California ISO’s Residual Supply Index (RSI) in lieu

14 of the FERC SMA test as a measure of market power. It is on this latter issue that I

15 would like to focus.

16 **Q. What is the RSI?**

17 A. The RSI is a measure developed by the California ISO to look at whether there are

18 pivotal suppliers in the real time market. The test looks at the amount of capacity

19 offered into the market in a particular hour. In looking at whether a large supplier

20 is pivotal, it then compares 110 percent⁵ of load offered into the real time market to

21 the capacity offered into the market by participants other than the supplier being

22 studied. If the competing supply exceeds 110 percent of load, the supplier being

23 analyzed is not pivotal and “passes” for that hour.

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

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

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

11 **Q. What does the California ISO propose?**

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

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

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

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

1 hour-by-hour on a prospective basis will not uncover “pivotal suppliers” that are
2 not also found with the SMA.⁶

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

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

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

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

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

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

3 **Q. Does this complete your prepared rebuttal testimony?**

4 **A. Yes, it does.**

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REBUTTAL TESTIMONY OF CARY DEISE

On Behalf of Arizona Public Service Company

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

June 11, 2002

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Rebuttal Testimony of Cary Deise
DOCKET NO. E-00000A-02-0051, et al.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

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

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

A. Yes.

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

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

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

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

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

1 II. SUMMARY OF TESTIMONY

2
3 **Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

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

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

25 Staff’s proposal wrongly urges the Commission to require jurisdictional
26 utilities—but not SRP, the Western Area Power Administration (“WAPA”), or

1 merchant generators—to embark on overbuilding transmission in an uneconomic,
2 fractured, and likely futile effort to relieve all existing or potential transmission
3 constraints in Arizona under all conceivable generation marketing patterns. This would
4 be poor policy anywhere, but in the Desert Southwest, where load centers are both
5 relatively concentrated and widely separated from each other, it makes absolutely no
6 sense. In fact, I know of no jurisdiction that has taken the position or even suggested
7 that all transmission constraints should be remedied by constructing more transmission.
8 Staff also vastly underestimates the costs, including economic, environmental, social
9 and opportunity costs, associated with a policy focused on so overbuilding
10 transmission. Further, the suggested “reliability” standards associated with this
11 policy—standards which were unilaterally developed by Staff without a rulemaking
12 process—are substantively deficient and far too vague to ever realistically implement.

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

22 Lastly, Staff and some intervenors have alleged that because APS or its
23 affiliates would own both transmission and generation, there is the potential for the
24 exercise of vertical market power. For a FERC-jurisdictional transmission owner such
25 as APS, that is incorrect. In Orders 888 and 889, FERC required non-discriminatory
26 access to transmission and imposed restrictions on the inappropriate sharing of

1 information between those involved in transmission and generation. Pinnacle West and
2 its affiliates' FERC-mandated Standards of Conduct also would prohibit the exercise of
3 such market power. Panda witness Roach asserts that the designation of generation as
4 a network resource has "market power" implications for APS and its affiliates. This is
5 simply incorrect—transmission, network transmission service and network resource
6 designation are all related to load and are driven by load. They are unaffected by
7 transmission ownership. If a generator (whether or not affiliated with APS) is serving
8 APS' loads, it will be given the appropriate network designation and have the
9 appropriate network transmission rights. However, simply calling a power plant a
10 "network resource" will not change physical transmission limits. So, for example, all
11 of the new capacity being constructed at Palo Verde could still not simultaneously
12 serve all of APS' load requirements regardless of whether all were designated as
13 "network resources"

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REBUTTAL TESTIMONY OF CARY DEISE

On Behalf of Arizona Public Service Company

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

June 11, 2002

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Rebuttal Testimony of Cary Deise
DOCKET NO. E-00000A-02-0051, et al.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

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

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

A. Yes.

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

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

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2 am responsible for 10-year and general transmission system planning for APS, as well
3 as the overall operation of APS' transmission system. Among other activities, I oversee
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7 Transmission Plans.

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10 "inadequate." I will also respond to the assertion in Staff witness Jerry Smith's
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12 Valley. In conjunction with that discussion, I will explain how Staff's proposal to
13 significantly overbuild transmission, while largely ignoring local generation, load-
14 related opportunities, and accepted utility planning practices, is both unprecedented in
15 nature and unwise from a policy standpoint. Specifically, Staff's proposal ignores the
16 significant costs (economic, environmental, social and opportunity) associated with
17 overbuilding transmission and dismisses the institutions that are emerging to
18 effectively deal with transmission planning in a competitive marketplace. Finally, I will
19 respond to the claims of Staff and some intervenors, such as Panda witness Roach and
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II. SUMMARY OF TESTIMONY

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

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

Staff’s proposal wrongly urges the Commission to require jurisdictional utilities—but not SRP, the Western Area Power Administration (“WAPA”), or

1 merchant generators—to embark on overbuilding transmission in an uneconomic,
2 fractured, and likely futile effort to relieve all existing or potential transmission
3 constraints in Arizona under all conceivable generation marketing patterns. This would
4 be poor policy anywhere, but in the Desert Southwest, where load centers are both
5 relatively concentrated and widely separated from each other, it makes absolutely no
6 sense. In fact, I know of no jurisdiction that has taken the position or even suggested
7 that all transmission constraints should be remedied by constructing more transmission.
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24 exercise of vertical market power. For a FERC-jurisdictional transmission owner such
25 as APS, that is incorrect. In Orders 888 and 889, FERC required non-discriminatory
26 access to transmission and imposed restrictions on the inappropriate sharing of

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8 APS' loads, it will be given the appropriate network designation and have the
9 appropriate network transmission rights. However, simply calling a power plant a
10 "network resource" will not change physical transmission limits. So, for example, all
11 of the new capacity being constructed at Palo Verde could still not simultaneously
12 serve all of APS' load requirements regardless of whether all were designated as
13 "network resources" or have network transmission service.

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

17 **A.** Yes. I am not suggesting that APS won't need additional transmission and access to
18 load-serving resources. As our 2002-2011 Ten-Year Plan indicates, APS will be siting
19 and constructing over \$750 million of new transmission upgrades and additions, and
20 we intend to continue to work closely with Staff on these projects. So I agree with Mr.
21 Smith when he states that "there has certainly been a good faith demonstration by
22 Arizona utilities of their commitment to respond favorably on a forward looking basis."
23 (J. Smith Test. at p. 22.) I also agree that transmission planning needs to be a broadly
24 collaborative process, and that the Central Arizona Transmission Study ("CATS") was
25 a good example of such collaboration.(J. Smith Test. at p. 24.) And, I further agree that
26 system planning is more challenging in a competitive environment, and that RTOs will
be important institutions in that process. Mr. Smith also has acknowledged that there

1 are trade-offs between using local generation and constructing additional transmission
2 especially considering that must-run generation is only required for limited times
3 during the summer. (J. Smith Test. at p. 13.) But my agreement with Staff on these
4 issues does not change my conclusion that Staff's analysis and recommendations are
5 neither correct nor appropriate.

6
7 **III. LOAD SERVING ADEQUACY AND RELIABILITY**

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

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

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

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

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

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

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

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

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

21 Mr. Smith also asserted that on July 4, 2001, "APS was within one-half hour of
22 activating rolling blackout procedures due to unavailability of several generating
23 units..." (J. Smith Test. at p. 18.) This too is incorrect. On July 2, 2001, there was a
24 multiple contingency on the system, but APS was within one-half hour of initiating a
25 public request to voluntarily curtail electricity use, not to commence "rolling
26 blackouts." This voluntary curtailment effort was to maintain adequate operating

1 reserves under a multiple contingency situation. It was ultimately avoided by a
2 wholesale purchase, and is not evidence of any system-wide adequacy or reliability
3 problem.

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

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

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

26 A. No. The use of local generation (whether "reliability must run" or otherwise) is not a
reliability defect or evidence of an "inadequate" system. No accepted reliability
standard (i.e., those of the NERC or the WECC) holds that the use of local generation

1 is either "inadequate" from a system planning or operational standpoint or is evidence
2 of "inadequacy." Local generation actually contributes to the reliability of a system. In
3 fact, when it adopted the Electric Competition Rules, the Commission specifically
4 recognized that a UDC's obligation to provide reliable electric service "depends upon
5 the adequacy of its distribution, local generation and interconnections with the bulk
6 transmission system..." (emphasis added). Decision No. 61969 (Sept. 29, 1999).

7
8 **IV. LOCAL GENERATION AND "MUST RUN" REQUIREMENTS**

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

10 A. Yes.

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

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

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

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

23 In addition to economic trade-offs between new transmission line investments
24 and local generation investments, there are significant system operation and reliability
25 reasons that justify local generation. For example, local generation offers critical
26 voltage support, particularly to large load centers like the Valley, and is absolutely

1 necessary to provide a dynamic reactive reserve margin, as reactive power cannot be
2 transmitted over long distances. Local generation is also important as contingency
3 support for the Valley. By that, I mean that such generation is available to meet local
4 load requirements when, for example, there is a disturbance on or loss of a
5 transmission line outside of the local area that trips remote generation. I would never
6 recommend relying solely on importing remote power over transmission lines to
7 support the entire Valley system at peak load. Finally, local generation (and generation
8 located near load centers) minimizes transmission line losses.

9 Mr. Smith also appears to ignore the environmental and non-economic costs
10 associated with transmission line construction. For example, in his testimony he refers
11 to the "environmental merits" of transmission capacity in providing access to "more
12 environmentally friendly generation external to the constraint." (J. Smith Test. at p. 8.)
13 This assertion misses several key issues. First, is a remote coal-fired generator "more
14 environmentally friendly" than a local gas-fired plant? And, how does one quantify the
15 difference? Second, local generation is not necessarily less efficient than remote
16 generation and is often subject to more stringent air permitting requirements and
17 emission offset requirements than remote generation, which may actually make it
18 "more environmentally friendly." Third, while local generation may only run several
19 hundred hours per year, transmission lines are permanent and have their own
20 environmental impacts. Fourth, transmission lines may directly impact more people
21 and their property than local generation due to the right-of-way requirements for such
22 lines. Fifth, the premature or unwarranted construction of transmission has significant
23 opportunity costs, both in terms of the finite resources that APS can devote to such
24 construction and in foregoing possible future developments in advanced transmission
25 technologies. This list is not exhaustive; there are undoubtedly other non-economic
26

1 costs that should be considered when balancing the need for transmission or local
2 generation.

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

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

8 **Q. DO YOU AGREE WITH THAT ANALYSIS?**

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

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

24
25 ² At page 10 of his testimony, Mr. Smith has misapplied the concept of "reliability must run" to
26 the concept of the Local Generation Requirement that I included in Schedule CD-3R in my Rebuttal
Testimony in the APS Variance Docket. In that testimony, I noted that Local Generation Requirements
for the Valley were around 400 hours per year, or roughly 5 percent of all hours in a year.

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

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

10 A. Let me start with Mr. Smith's formula for determining avoided costs associated with
11 transmission line investment. In general, the assumed transmission line capital cost of
12 \$1 million per mile is significantly understated, particularly if part or all of a project
13 will be constructed in urban or suburban areas. For monopole construction, the cost of
14 facilities, excluding right-of-way, is approximately \$1.6 million per mile of 345
15 kV/500 kV transmission line. Lattice towers cost approximately \$1.2 million per mile.
16 Right-of-way costs will add at least \$1 million to \$2 million per mile for construction.
17 A conservative analysis would use a blended cost assuming 15 miles of monopole with
18 the remainder using lattice tower construction, and \$1 million per mile for right-of-way
19 costs. Also, Mr. Smith's assumed transmission termination costs for a new
20 transmission line of \$4.5 million is significantly lower than APS' experience. Recently
21 planned source and sink terminations on APS' system average approximately \$18
22 million. However, adding new bulk power feeds into the Valley system also will likely
23 require additional upgrades on the APS and SRP local system, the costs of which are
24 not even captured in that \$18 million figure.
25
26

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

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

12 A. Yes. That calculation also has faulty inputs. Perhaps most significant is Mr. Smith's
13 assumption that the marginal market price for "alternative" generation will be
14 \$35/MWh. Because local generation is only required on peak in the June through
15 September period, it is inappropriate in the context of the Mr. Smith's analysis to
16 assume an annualized market price for "alternative" generation of \$35/MWh. A more
17 appropriate but still conservative benchmark for such power during June-September
18 peak hours is approximately \$56/MWh at the Palo Verde hub. This is conservative
19 because truly "alternative" generation from Palo Verde needed to meet load would be a
20 non-standard product which would add to the \$56/MWh figure.

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

25 A. Yes. Schedule CD-GD-1R is an analysis using two scenarios—427 MW of local
26 generation in 2003 for 400 hours at a 65 percent load factor, and 1034 MW in 2007 for
400 hours at a 65 percent load factor. The cost-benefit was then tested using a
\$56/MWh price for generation at the Palo Verde hub and a \$75/MWh cost for local

1 generation. I did not use hypothetical local generation costs above \$75/MWh because it
2 is unreasonable to assume that local generation costs will significantly increase, due to
3 higher natural gas prices for example, without a corresponding increase in the price of
4 "alternative" generation from Palo Verde. In other words, what is important is not the
5 absolute cost of local generation but the difference between local generation and
6 "alternative" generation. The result is then compared to the same three transmission
7 line length alternatives (50, 100 and 150 miles) used by Mr. Smith in his analysis.
8 Attached as Schedule CD-GD-2R is a graphical summary of this analysis in the same
9 format used by Mr. Smith.

10 **Q. WHAT DID YOUR COST-BENEFIT ANALYSIS SHOW?**

11 A. APS' analysis shows that the economic costs associated with local generation do not
12 warrant building significant new, unplanned transmission lines. Additionally, Mr.
13 Smith incorrectly concluded that APS' hourly operating costs for RMR generation are
14 "in excess of \$75/MWh." In fact, the cost for RMR generation in 2001 was slightly
15 less than \$75/MWh (\$73.11/MWh). Further, new combined cycle units, such as West
16 Phoenix 4 and 5, are expected to have lower per-MWh costs than existing local
17 generation. So I expect the cost of local generation, let alone RMR generation, after
18 2002 to decrease and it will be significantly less than \$75/MWh. Thus, a cost-benefit
19 analysis does not support the construction by APS of additional, unplanned
20 transmission into the Valley—even without considering the other significant
21 environmental, social and opportunity costs that I discussed earlier.

1 transmission constraints. For example, although Mr. Smith noted the illustrative
2 discussion from my rebuttal testimony in the APS Variance Request on resource
3 selection and least-cost planning for the Yuma area, the remainder of his testimony still
4 appears to take the position that UDCs should be responsible for alleviating all
5 transmission constraints (regardless of cause, cost, duration or impact), and that such
6 constraints are something that generally need to be remedied by building more
7 transmission. This is an inappropriate and overly-simplistic conclusion. In the recently
8 issued National Transmission Grid Study, the Department of Energy noted that:

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

17 (National Transmission Grid Study at p. 20.)

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

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

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

30 A. No.

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

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

12 Such a system, even if designed as a "best guess" of future loads and resources,
13 and their timing and location, would certainly not be practicable because merchant
14 generators will likely serve multiple customers at different locations over the life of
15 any given power plant. For example, it would be inappropriate for APS to construct
16 several new transmission lines from Palo Verde into the Valley, and also upgrade all
17 necessary Valley facilities to accommodate the new lines, just to allow more generation
18 the opportunity to sell from Palo Verde, when five years from now these same
19 generators may be serving loads in California over a new Arizona-to-California
20 transmission line. In fact, much of the new transmission required by Staff would likely
21 do little more than facilitate merchant generators selling their capacity out-of-state at
22 the expense of Arizona consumers. After all, based on Mr. Smith's testimony, over
23 19,000 MW of merchant generation is being constructed in or proposed for Arizona.
24 Much of that capacity is obviously intended for out-of-state loads.

25 To overbuild the transmission system to accommodate all of this capacity
26 would also eliminate any incentive or price signals to merchant generators on where to

1 appropriately site local generation. This is contrary to existing Commission policy.
2 When the Electric Competition Rules were adopted in 1999, the Commission
3 specifically recognized that “ideally market forces, and not UDC decisions, should
4 drive plant-siting decisions by new market entrants or merchant generators.” (Decision
5 No. 61969, Concise Explanatory Statement, at p. 41.)

6 **Q. ARE THE COSTS THAT WOULD BE ASSOCIATED WITH STAFF’S**
7 **“ACCELERATED DEVELOPMENT” PROPOSAL JUSTIFIABLE?**

8 A. No. As I discussed earlier, Staff’s focus on overbuilding transmission, including its
9 proposal to eliminate the need for any local generation, ignores many of the costs that
10 need to be considered when making resource decisions between transmission lines,
11 power plants, and even load-based alternatives such as load reduction or demand
12 response. The analysis that I provided earlier shows that a cost-benefit analysis does
13 not warrant the construction of significant new, unplanned transmission capacity for
14 non-reliability related purposes. Further, the addition of transmission has ripple effects
15 on the system, which means that there will most likely be costs on the local 230 kV and
16 69 kV systems if additional bulk power terminations are added in the Valley. Not all of
17 these costs will occur on APS’ system, and there may be impacts to the interconnected
18 systems of WAPA and SRP or even others.

19 Apart from the increasing costs of permitting, obtaining right-of-way,
20 constructing, and operating transmission lines, there are also costs in building new
21 transmission lines that are difficult to quantify. For example, transmission lines sited in
22 urban and suburban areas may require the condemnation of residential or commercial
23 properties. While such action is often necessary for the good of our society, I expect
24 that people evicted by unneeded or prematurely-constructed transmission lines would
25 object to Staff’s proposal. Also, there is significant progress being made in new
26 advanced transmission technologies, including high-voltage direct current (“HVDC”),

1 energy storage, superconductor technologies, and new higher-capacity conductor
2 materials. Prematurely constructing transmission using current technology may limit
3 the ability of utilities to take advantage of these new advanced transmission
4 technologies when they become available, or at best the deployment of these
5 technologies will strand transmission investments that become no longer necessary.

6 **Q. ARE THERE OTHER SIGNIFICANT FLAWS IN THE PROPOSAL?**

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

20 **Q. DOES STAFF’S PROPOSAL ADDRESS COST RECOVERY FOR THE
21 “ACCELERATED DEVELOPMENT” PROPOSAL?**

22 A. No, and that is another significant flaw. Because so much of Staff’s proposal affects
23 non-jurisdictional entities such as merchant generators, public power, and federal
24 entities, all that Staff can propose is “collaboration” and building on existing industry-
25 driven efforts like the CATS program. Cost-recovery issues have been recognized by
26 virtually all commentators as a significant barrier discouraging the coordinated

1 development of transmission in a competitive market. However, without a specific
2 mechanism or specific authority to address cost recovery, it is unrealistic to think that
3 through collaboration merchant generators or other parties will volunteer to make
4 significant transmission investment—particularly if they believe that a UDC will
5 ultimately be forced to “ante up” if they don’t contribute. The Southeast Valley Project
6 is a good example, in that several merchant generators expressed interest in the early
7 project scoping, but when it came time to make a financial commitment only APS,
8 SRP, Tucson Electric Power Company and a group of public power districts actually
9 committed dollars to the project.

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

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VI. TRANSMISSION PLANNING IN A COMPETITIVE
MARKETPLACE

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

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

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

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

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

A. Yes, but both the Department of Energy's May 2002 National Transmission Grid Study and the August 2001 Report to the WGA were primarily focused on regional transmission interconnections, not an uneconomic effort to relieve every local transmission constraint on utility systems. For example, the principles outlined in the August 2001 WGA Report recognize that transmission expansion can and should have

1 regional as well as local benefits, and should be coordinated on as broadly-based a
2 level as possible. Similarly, the National Transmission Grid Study emphasizes the
3 importance of coordinated regional efforts to address inter-regional transmission
4 constraints.

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

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

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

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

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

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

25 **A.** Absolutely. As I noted earlier, I agree with Mr. Smith that planning in a competitive
26 environment may be more difficult than in a vertically-integrated environment. But I
don't agree that we are "playing chicken" with reliability for Arizona consumers. (J.
Smith Test. at p. 24.) One of the most significant concerns in the current debate over
transmission planning in a competitive environment is the problem of coordinating

1 among varying jurisdictions, regions and interests. However, Staff's proposal to require
2 UDCs on an intrastate basis to commence a "crash course" in new transmission
3 investment within a single control area within a single state threatens simply to add to
4 the fractured nature of system planning when there are so many different constituents.

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

18 We need to let the institutions that have the necessary jurisdiction and authority
19 to coordinate transmission planning in a competitive environment do their jobs and
20 evolve as institutions. Such an outcome is established Commission policy, which has
21 recognized that "eventually, the obligation to ensure adequate transmission import
22 capabilities should rest with the ISO." (Decision No. 61969 at p. 41 and Rule R14-2-
23 1609(B).) Certainly, the Commission will have an important role in this process. But
24 the Commission should reject Staff's recommendation to develop a separate "go it
25 alone" transmission plan for Arizona, which will be limited to Commission-
26 jurisdictional UDCs (apart from any informal collaboration by non-jurisdictional

1 entities). At best, Staff's recommendation would be a massive misallocation of
2 resources. At worst, it could actually interfere with efforts to coordinate regional and
3 inter-regional transmission planning.

4
5 **VII. TRANSMISSION "MARKET POWER"**

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

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

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

12
13 A. No, for several reasons. Under FERC Order 888 and Order 889, and the FERC-
14 approved Standards of Conduct, APS is required to provide non-discriminatory open
15 access to its transmission system. Those orders and the Standards of Conduct prevent
16 APS from favoring PWEC or any other merchant generator in providing transmission
17 service. Also, network transmission rights to serve APS' native load will follow that
18 load. Thus, if Duke or Panda provide service to APS' native load, they would have
19 network transmission rights. If PWEC provides such service, it would have network
20 transmission rights.

21 Of course, the physical configuration of APS' system necessarily impacts
22 transmission. For example, all of the generators at Palo Verde could not simultaneously
23 dispatch to serve APS' native load (even assuming APS' load was high enough to
24 require that) because the capacity from the Palo Verde/Hassayampa switchyard into the
25 Valley is limited. But if network transmission service had to be allocated, FERC rules
26

1 would require that it be allocated on a non-discriminatory basis and would prevent APS
2 from favoring PWEC or any other merchant generator.

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

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

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

1 could always construct their own generation within the constraint or build transmission
2 to relieve the constraint.

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

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

21
22 **VIII. CONCLUSION**

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

25 **A.** Staff's conclusion that APS' transmission system is inadequate to reliably serve APS'
26 customers is simply not true. Staff's analysis regarding the economics of local
generation versus transmission line construction is also incorrect, and by a very large

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margin. A more reasonable analysis currently does not support the “accelerated development” of additional transmission lines, as Staff recommends. Moreover, such a plan ignores the developing regional and inter-regional planning institutions, such as RTOs, that should effectively address any new planning required in the transition to a competitive marketplace. Thus, the Commission should decline to adopt any of Staff’s recommendations regarding transmission and local generation. Finally, the assertions in Staff’s testimony and that of some intervenors that APS can exercise market power in transmission ignores applicable FERC rules and APS’ FERC Standards of Conduct. The intervenor recommendations that are premised on this assertion should also be rejected.

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

A. Yes.

1194932.1

ANNUAL COST OF NEW TRANSMISSION FACILITIES*Estimated Cost of New Transmission Facilities:*

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

Annual Carrying Cost of New Transmission Facilities:

$$AC = OC * FCF$$

Where:

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

<u>Length of Line</u>	<u>Annual Cost</u>
50 Miles	\$19.05 M
100 Miles	\$34.70 M
150 Miles	\$50.34 M

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

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

IGC = Annual incremental cost of generation.

AC = Assumed cost of RMR generation.

MKT = Market price for generation.

T = The number of hours such purchases are needed annually (400 hours).

MW = The number of peak MW needed in lieu of RMR generation.

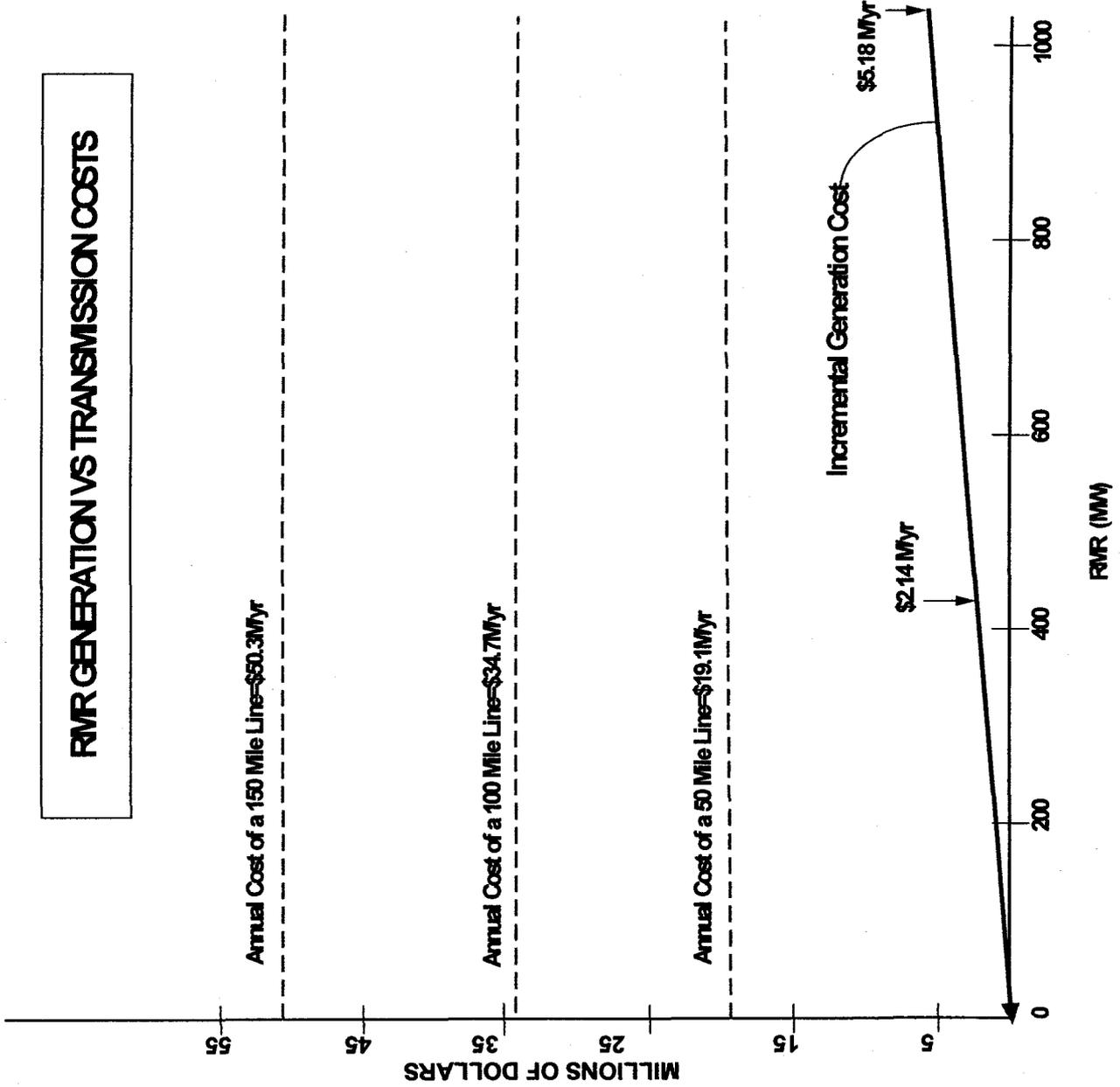
427MW for 2003, 1034MW for 2007

LF = The load factor during constraint period (.65).

$$427\text{MW} = \$2.14\text{M/yr}$$

$$1034\text{MW} = \$5.18\text{M/yr}$$

RMR GENERATION VS TRANSMISSION COSTS



**BEFORE THE
ARIZONA CORPORATION COMMISSION**

**Rebuttal Testimony of
Charles J. Cicchetti, Ph.D.**

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

**On Behalf of
Arizona Public Service Company**

June 11, 2002

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1 **SECTION I. INTRODUCTION AND EXPERIENCE**

2 **Q. PLEASE STATE YOUR NAME, BUSINESS AND ADDRESS.**

3 A. My name is Charles J. Cicchetti. My address is Pacific Economics Group,
4 L.L.C. (PEG) 201 South Lake Avenue, Suite 400, Pasadena, California
5 91101.

6 **Q. WHAT IS YOUR POSITION WITH PACIFIC ECONOMICS GROUP?**

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

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

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

12 **Q. DO YOU HOLD ANY OTHER POSITIONS?**

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

15 **Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?**

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

21 **Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.**

22 A. I served as chief economist for the Environmental Defense Fund from
23 1972 to 1975, and was a faculty member at the University of Wisconsin

1 from 1972 to 1985, ultimately earning the title of Professor of Economics
2 and Environmental Studies. From 1975 through 1976, I served as the
3 Director of the Wisconsin Energy Office and as Special Energy Counselor
4 for the Governor. In 1977, I was appointed by the Governor as Chairman
5 of the Public Service Commission of Wisconsin and held that position until
6 1979, and served as a Commissioner until 1980. In 1980, I co-founded
7 the Madison Consulting Group, which was sold to Marsh & McLennan
8 Companies in 1984. In 1984, I was named Senior Vice President of
9 National Economic Research Associates and held that position until 1987.
10 From 1987 until 1990, I served as Deputy Director of the Energy and
11 Environmental Policy Center at the John F. Kennedy School of
12 Government at Harvard University, and from 1988 to 1992, I was a
13 Managing Director and ultimately Co-Chairman of the economic and
14 management consulting firm, Putnam, Hayes & Bartlett, Inc. In 1992, I
15 formed Arthur Andersen Economic Consulting, a division of Arthur
16 Andersen, LLP. In late 1996, I left Arthur Andersen to co-found Pacific
17 Economics Group.

18 **Q. HAVE YOU PUBLISHED ANY PAPERS OR ARTICLES?**

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

22 **Q. HAVE YOU EVER GIVEN EXPERT TESTIMONY IN A COURT OR**
23 **ADMINISTRATIVE PROCEEDING?**
24

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

9 **SECTION II. PURPOSE OF TESTIMONY**

10 **Q. WHO RETAINED YOU FOR THIS TESTIMONY?**

11 A. I have been retained by Arizona Public Service Company (APS) to provide
12 rebuttal to testimony in response to the Procedural Order dated May 2,
13 2002 (Procedural Order) entered by the Arizona Corporation Commission
14 (ACC).

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

17
18 A. This is a generic proceeding that, as I understand matters, will involve
19 issues related to the transfer of assets and associated market power
20 issues, code of conduct issues, and Affiliate Interest rules. These issues
21 arise from the ACC's Retail Electric Competition Rules that were intended
22 to develop competitive markets for electricity in Arizona.

23
24 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS**
25 **GENERIC PROCEEDING?**
26

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

8 **Q. CAN YOU BE MORE SPECIFIC?**

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

19 **Q. HOW IS YOUR TESTIMONY ORGANIZED?**

20 A. In Section II, I discuss the testimonies filed by three Staff witnesses. First,
21 I discuss Matthew Rowell's testimony, which I find most troubling. In
22 particular, I focus on Mr. Rowell's testimony with respect to: (1) standard

1 offer service pricing and (2) enhanced prudence reviews of supply
2 acquisition decisions.

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

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

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

1

2 **SECTION III. STAFF WITNESSES**

3 **Mr. Rowell's Testimony**

4

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

7

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

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

23 Mr. Rowell believes that new Standard Offer Service (SOS) should
24 represent the "best" combination of "lowest" price and "lowest" consumer
25 risk, significant terms that he leaves largely undefined. Such a standard
26 would effectively cause Standard Offer customers to "have their regulatory

1 cake and eat a free competitive price dessert.” This is unnecessary and,
2 as far as I know, it is a proposal that is totally without regulatory
3 precedent. Worse, it would mean that no rational retail consumer would
4 ever forgo such a “standard offer” because it would guarantee that retail
5 consumers pay the “lesser of” cost of service prices (i.e., the regulatory
6 default price) or a competitive market price – whichever turns out “best.” I
7 hope this asymmetric result is not what Staff is pushing here. I may be
8 confused, but wish to err on the side of extreme caution because no
9 regulator should seek to impose a “heads I win, tails you lose” retail
10 pricing system.

11 **Q. PLEASE REVIEW IN MORE DETAIL YOUR CRITICISM OF STAFF’S**
12 **PROPOSAL TO CHARGE RETAIL CUSTOMERS THE “LESSER OF**
13 **COST OF SERVICE OR MARKET PRICES?”**

14 A. An example will help to explain what I believe Mr. Rowell is unreasonably
15 seeking to do and why I think that this is a heterodox approach. Suppose
16 a utility has a cost of service generation price of 7 cents per KWh, while
17 market prices generally swing between 5 cents and 10 cents per KWh. As
18 I understand Mr. Rowell’s proposal, he would charge retail customers the
19 “lesser of” the cost of service price (7 cents per KWh) or the lower market
20 price (5 cents per KWh). Thus, when the market price was less than the
21 cost of service price, consumers would pay the market price of 5 cents per
22 KWh, even though the actual cost to serve those customers from
23 dedicated generation was 7 cents per KWh. However, when market

1 prices rose to 10 cents per KWh and were, therefore, above the cost of
2 service price, customers would pay the cost of service price of 7 cents per
3 KWh. Retail consumers would never pay 10 cents per KWh, even though
4 wholesale prices in the Commission-desired competitive market would rise
5 to this level. Thus, the regulated utility would systematically fail to recover
6 its actual costs when market prices are low and would lose the opportunity
7 to profit from the competitive market when market prices are high.

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

18 None of this means that energy service providers (ESPs), should
19 be prevented from offering competitively priced retail contracts that permit
20 customers to switch back and forth between a base charge and
21 competitive market swings in prices. Most important, when retail suppliers
22 offer such contracts, they recognize two facts. First, the base prices are
23 established with respect to competitive market expectations, not on cost of

1 service prices. Second, the greater risk of such retail option offerings
2 increases the costs of suppliers and these costs would need to be
3 recovered through an insurance-like surcharge that would be added to the
4 expected value of the competitive market price.

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

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

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

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

1 4. The financial effects on the incumbent utilities that would be forced
2 to sell retail electricity at the "lesser or" cost of service or market
3 price would be devastating. At best, stranded costs (i.e., the
4 cumulative difference between cost of service and market prices
5 when market prices are lower) could rise to significant levels. At
6 worst, there would be an unfair (and to my way of thinking, clearly
7 illegal) taking of utility assets that, to be blunt, would amount to
8 systematic confiscation on a scale that has no place under either
9 the doctrines of a capitalistic market driven economy or long-
10 standing American regulatory principles and practices.

11 5. Bankruptcy of incumbent utilities would inevitably result. One need
12 only look at the PG&E bankruptcy in California to realize that a
13 utility cannot long afford to sell electricity at prices below those at
14 which it must purchase the power. Buying high and selling low is
15 not a practice that can be sustained for long. State regulators who
16 impose such unreasonable constraints would nearly certainly find
17 that they would cede significant jurisdiction to federal bankruptcy
18 courts.

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

21 **A.** No. A primary purpose of retail, as opposed to wholesale, electricity
22 competition is consumer choice. Differences in price/risk preferences are
23 what will drive the various retail consumer product choices under retail

1 competition. Mr. Rowell seeks to establish a world in which retail
2 consumers would falsely appear to be perfectly insulated from wholesale
3 price risk, yet pay nothing for this "insurance." Compounding this difficulty,
4 Mr. Rowell would guarantee that the load serving entity would not recover
5 its conventional cost of service because the incumbent utility would also
6 be required to sell electricity at lower competitively based retail prices
7 when market prices beat cost of service based prices. Mr. Rowell's
8 proposal is patently inequitable and does not conform to either reasonable
9 competitive market or traditional regulatory practices. This outcome is
10 unfair, unsustainable, and inefficient.

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

14
15 A. Yes. APS has actually reduced its Standard Offer prices each year since
16 the Electric Competition Rules were first implemented in this jurisdiction in
17 1996, and has further decreases scheduled for 2002 and 2003. However,
18 Mr. Rowell's proposed Standard Offer Service (SOS) is far from typical

19 As I understand Staff's proposal, Staff seeks to guarantee the
20 "best" result to retail consumers that take the "Standard Offer," not one
21 based on a fixed competitively set contract reference price, but one based
22 on a fixed cost of service price. Retail consumers would expect to pay
23 more for a fixed competitive price than the expected value of the
24 competitive price because they could avoid price volatility and, in effect,
25 hedge their retail purchase position. Here, Staff seems to propose that

1 the base Standard Offer price would be a cost of service price and if, and
2 only if, competitive prices are less than this cost of service price, retail
3 customer would pay less, but never more.

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

6
7 A. There are two problems that arise. First, if Staff wants to encourage a
8 fixed competitive tariff offering for some retail customers that provides for
9 an anchor or base price with options to purchase at lower competitive
10 prices, the base price needs to be set by competitive energy service
11 providers and *not* an historic cost of service approach. Second, power
12 markets have volatility, as do all commodity markets. Some customers
13 may seek to insulate themselves from price volatility in both directions or
14 on the upside. Regardless, avoiding market price risks is a form of
15 insurance, and premiums must be paid.

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

22 Worse, Staff's proposal increases APS' costs and risks without any
23 compensation for being forced to assume those costs and risks. Much
24 worse, this approach is precisely one of the principal structural flaws that
25 helped to bring on and worsen California's electricity crisis because

1 regulators incorrectly believed that retail customers could, in effect, pay
2 cost of service rates after wholesale markets jumped to more than twenty
3 times their preexisting cost of service levels.

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

6
7 A. Mr. Rowell applies the *coup de grace* when, at page 14 of Direct
8 Testimony. Most important, Mr. Rowell seems to ignore the fact that APS'
9 proposed PPA would be reviewed and approved by the ACC. This is a
10 reasonable regulatory prudence review. That said, Mr. Rowell would
11 seem to invite ongoing, *ex post prudence* review through his advocacy of
12 a "lesser of" tariff standard.

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

20 I am advised that under traditional Arizona regulation, prudently
21 incurred costs should be recovered. Arizona Administrative Code, Title
22 14, Chapter 2 defines "prudently invested" as those:

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

1 the light of all relevant conditions known or which in the exercise of
2 reasonable judgment should have been known, at the time such
3 investments were made.”
4

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

7
8 **Q. HOW DOES MR. ROWELL FAIL TO GRASP THE "LESSONS" OF THE**
9 **RECENT CALIFORNIA ELECTRICITY CRISIS?**

10
11 A. I am the co-author of the California Bureau of State Audits' Report on the
12 causes of the California electricity crisis.¹ A brief review of California, as
13 Arizona moves towards competition, is important in the context of
14 California's recent disastrous experiences. This will help to demonstrate
15 how Staff is falling into some of the same traps that California did when it
16 restructured its markets.

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

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

1 their former cost-of-service levels (2.5¢ to 3¢/KWH versus more than
2 5¢/KWH). I fondly recall a major forum in April of 1999 at the University of
3 Southern California at which all stakeholder groups sang a chorus praising
4 California's great restructuring and electricity deregulation successes.

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

10 **Q. WHAT WENT WRONG IN CALIFORNIA?**

11 A. Unusual climate conditions occurred in the western United States. In the
12 Northwest, the winter was cold and dry, and in the Southwest, the spring
13 and summer were hot. Normally, dry winters mean cool springs. This did
14 not occur in 2000. The unusual weather increased demand, and reduced
15 supply. The last time this happened, the WHOOPS² fiasco was foisted
16 upon the Pacific Northwest. Natural gas and crude oil prices also surged
17 in 2000. Indeed, the average U.S. natural gas price in late 2000 was more
18 than five times its 1999 level; and, in California in late 2000, spot natural
19 gas prices jumped thirty times over the previous year, from about \$2 per
20 MCF to \$60 per MCF.

21 **Q. DID CALIFORNIA'S MARKET HAVE ANY DESIGN FLAWS THAT**
22 **EXACERBATED THE SUPPLY SHORTAGE?**
23

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

1 A. Yes. California's new market design also suffered from structural flaws
2 that combined with supply/demand and fuel related market forces to cause
3 California's wholesale prices in 2000 to average more than three times the
4 levels established under cost-of-service regulation (about \$150 per MWH
5 versus \$50 per MWH), and more than five times 1999 price levels (about
6 \$30 per MWH). Furthermore, in December of 2000, wholesale electric
7 prices jumped in the western region to more than \$1,000 per MWH. Soon
8 thereafter, California's state government through the California
9 Department of Water Resources (CDWR) signed long-term contracts
10 (seven to ten years) at prices typically equal to about \$ 70 to \$80 per
11 MWH. The FERC, after several false starts and much political dancing,
12 began to regulate wholesale prices through western states' market
13 mitigation (soft caps), which remains in effect.

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

1 activities in these much too complex interdependent markets and
2 products.

3 **Q. HOW DOES CALIFORNIA'S EXPERIENCE AFFECT ARIZONA?**

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

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

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

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

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

14 **Q. DO MERCHANT GENERATORS HAVE THE SAME SUPPLY AND**
15 **LEAST COST (OR PRICE) RESPONSIBILITY THAT APS WOULD**
16 **CONTINUE TO HAVE? HOW DOES THIS AFFECT THE**
17 **UNREASONABLE CONSTRAINTS THAT STAFF WOULD IMPOSE?**
18

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

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

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

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

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

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

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

21 Merchant generators neither owe nor have any geographic or
22 jurisdictional allegiance to Arizona. More significantly, the FERC can
23 exercise considerable sway over merchant generators to react to real and

1 politically manufactured emergencies in California. The ACC cannot
2 accept an academic version of a free, unfettered wholesale electricity
3 market as long as California and the FERC combine to prevent such a
4 market from evolving in the west. I conclude that APS needs to be
5 encouraged to sign prudent long-term purchase power contracts without
6 the risk of future *ex post* prudence reviews or some "best" price, "lesser of"
7 pricing scheme in which APS must pay a higher contract price, while
8 charging retail consumers a lower competitive spot market price.

9 **Q. ARE THERE ANY OTHER RELIABILITY CONCERNS THAT STAFF'S**
10 **PROPOSAL DRAW INTO THIS PROCEEDING?**

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

16 Accordingly, a network operating entity must manage the power
17 grid, coordinate transmission line construction and new generation
18 location, serve various load pockets, and sustain system growth.

19 Available transmission capacity may vary periodically and over time. It is
20 also necessary to coordinate or account for generation outages, imports
21 and exports, and more. These are all matters of system reliability that are
22 traditionally the regulated, vertically integrated utility's responsibility.

23 These roles and responsibilities do not disappear under wholesale

1 competition. Indeed, the FERC-led, some might say forced-fed, effort to
2 form large RTOs is based on forming new organizations that will assume
3 these transmission functions plus various scheduling coordinator or
4 dispatch roles.

5 In addition, fuel diversity has been and still is important. Merchant
6 generators mostly build or propose to build new natural gas fired units.
7 There have even been suggestions to convert existing coal generation in
8 the region to natural gas. California's fiasco in the late fall and winter of
9 2000 shows that a single fuel choice is problematic in the western United
10 States.

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

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

1 Ms. Andreasen's Testimony

2
3 **Q. WHY DO YOU CONCLUDE THAT MS. ANDREASEN'S ADVISORY**
4 **GROUP PROPOSAL IS "INEFFECTIVE AND UNNECESSARY"?**

5
6 A. Ms. Andreasen's proposals are unnecessary and most certainly will be
7 ineffective because the advisory group she proposes has no responsibility
8 or authority. It would become a representative stakeholder debating
9 society. As was demonstrated in California, such stakeholder boards are
10 unwieldy in size and provide a false notion that real market performance
11 will be monitored. There is now widespread recognition that such
12 stakeholder advisory boards provide no information about and no security
13 against real market abuse. In virtually all situations, they are simply more
14 trouble than they are worth.

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

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

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

7 **Ms. Keene's Testimony**

8
9 **Q. WHY DO YOU FIND FAULT WITH MS. KEENE'S AFFILIATE AND**
10 **CODE OF CONDUCT PROPOSALS?**

11
12 A. Ms. Keene engages in a "ready, fire and aim" approach to regulation. She
13 fails to identify (i.e., "aim" at) any real target or problem. She simply
14 asserts that "self-dealing" and "preferential treatment" are inevitable, and
15 that "cross subsidies" surely will follow.

16 Ignoring the significant ACC regulation, FERC regulation, and
17 SEC/PUHCA regulation, Ms. Keene creates problems after she "fires" her
18 charges at Arizona's energy companies. This is not reasonable. Worse,
19 she fails to assess current regulatory rules and ratemaking practices. Ms.
20 Keene cites a litany of bad things that could ensue (e.g., predatory
21 pricing), and unreasonably assumes that even though the "lights are on,
22 no one is home." I have much more faith in existing ACC regulation,
23 FERC regulation, competitive market disciplinary forces, and the track
24 record of Arizona's incumbent electric utilities in controlling and regulating
25 affiliate transactions than does Ms. Keene. The ACC and others do not
26 condone and will prevent self-dealing and predatory practices, eschew

1 cross subsidies, and reject unfair competition. Ms. Keene fails to address
2 current responsibilities and facts. Instead, she speculates about potential
3 problems and offers no remedies for these non-existing speculative
4 problems, other than the implication that competitive markets need to be
5 regulated. There is no need for her to conjure up problems and to
6 speculate as she does.

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

9
10 A. Ms. Keene does not explain why the current rules and existing codes of
11 conduct are inadequate. Ms. Keene uses her speculative allegations of
12 self-dealing, cross subsidies, and predatory pricing as a ruse to suggest
13 that utility misconduct is inevitable. In so doing, she misses the target
14 widely. In my experience, utility companies and their affiliates seldom
15 come even close to these excesses. Here, Ms. Keene's speculation does
16 not justify her call for oppressive regulation.

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

19
20 A. Ms. Keene's survey appears to consist of only three states. This review is
21 cursory at best, and not particularly representative.

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

24
25 A. Yes. Like the Massachusetts statute referenced by Ms. Keene, Sections
26 IV(A)&(B) of APS' Code of Conduct prohibit APS from using or providing
27 confidential customer information to any competitive electric affiliate or
28 other third party. As is apparently required by the Maryland statute, cross

1 subsidization is also prohibited by Sections VIII(A)&(B) of APS' Code of
2 Conduct; affiliates are treated the same as non-affiliates (Section III);
3 customer information and privacy is protected (Sections IV(A)&(B)); and
4 services must be provided in a non-discriminatory manner (Section
5 VII(D)). Similar to requirements in Kentucky, APS' Code of Conduct
6 covers affiliate pricing rules (Sections VIII(A)&(B)) and separate
7 accounting treatment is required (Section X(C)).

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

10
11 A. No. Ms. Keene fails to address federal regulatory authority with respect to
12 wholesale electricity transactions. Her "arms' length" transaction reviews
13 are ill-formed and wrongly based on gathering proprietary information
14 without proposing necessary detail, specifics, and relief. Regulators have
15 sufficient experience, expertise, and authority here. Ms. Keene uses the
16 "code of conduct" and "affiliate interest" issues inappropriately and
17 unnecessarily to force unregulated competitive firms and/or affiliates to
18 disclose proprietary information.

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

21 **Q. DOES MS. KEENE DISCUSS AFFILIATE PRICING ISSUES?**

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

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

3 **SECTION IV. CONCLUSIONS AND RECOMMENDATIONS**

4 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE ACC.**

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

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

20 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

21 A. Yes.