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# EXHIBITS
# FOR
# E-01345A-03-0437

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PPL 1 & 2
RUCO 1-15
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**0000020460:** ACPA 1-4, AECC 1, 2, AECC/PD/FEA/K 1-3, APS 1-4

**0000020461:** APS 5-27, APS 33-39

**0000020462:** APS-R 1-15

**0000020463:** APS-R 16-22, APS-SD 1-4, ASP-SR 1-3, AUIA, AUIA-S, AZCA 1-5 & 7-10 (6 NOT USED) CNE/SEL 1-5, DOME VALLEY, FEA 1 & 2, GLEASON 1, IBEW 1, KROGER 1, MESQUITE 1 & 2, MUNDELL 1

**0000020465:** STAFF 10-32, SWEEP 1-4, WRA 1-4

PPL

EXHIBIT
PPL #1
Admitted

# DIRECT TESTIMONY OF JESSE A. DILLON

**On Behalf of PPL EnergyPlus, LLC and PPL Sundance Energy, LLC**

**Docket No. E-01345A-03-0437**

September 27, 2004

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**DIRECT TESTIMONY OF JESSE A. DILLON**
**ON BEHALF OF PPL PARTIES**
**(Docket No. E-01345A-03-0437)**

I. INTRODUCTION

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

A. My name is Jesse A. Dillon, and my business address is 2 North Ninth Street, Allentown, PA 18101.

Q. **BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by PPL Services Corporation ("PPL Services") as Senior Counsel.

Q. **PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A. I received a Bachelors of Arts in General Arts and Sciences from The Pennsylvania State University in 1983 and a Juris Doctor from The George Washington University in 1986. In 1986, I joined the law firm of Morgan, Lewis & Bockius as an associate. While at Morgan, Lewis & Bockius, I represented a number of gas, water and electric utilities before the Pennsylvania Public Utility Commission. In 1991, I joined Pennsylvania Power & Light Company as Counsel. Subsequently, I was promoted to the position of Senior Counsel. During the corporate realignment of Pennsylvania Power & Light Company in 2000, I became an employee of PPL Services Corporation ("PPL Services") along with the rest of PPL's Office of General Counsel. PPL Services is a direct subsidiary of PPL Corporation.

Q. **PLEASE DESCRIBE YOUR DUTIES AS SENIOR COUNSEL.**

A. In my capacity as Senior Counsel I am responsible for numerous legal and regulatory matters affecting PPL and its subsidiaries including matters before state and federal courts and regulatory agencies. My primary responsibilities include advising and representing PPL and its subsidiaries in matters involving litigation, state and federal energy regulation and antitrust laws.

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

A. My testimony presents PPL Sundance Energy, LLC's and PPL EnergyPlus, LLC's ("PPL Parties") positions regarding the settlement in this proceeding.

## II. SUMMARY

Q. **PLEASE SUMMARIZE YOUR CONCLUSIONS.**

A. The PPL Parties support the settlement in this proceeding as a reasonable compromise reached among the many diverse interests represented by the settling parties.

## III. POSITIONS OF PPL PARTIES' REGARDING SETTLEMENT

Q. **PLEASE DESCRIBE THE PPL PARTIES' POSITION REGARDING THE SETTLEMENT.**

A. The PPL Parties are members of the Arizona Competitive Power Alliance ("ACPA") and also have intervened individually in this case. The ACPA has actively presented the position of merchant generators in this proceeding. In

any broad settlement such as this one, no party is likely to obtain everything it proposed in litigation. However, given the significant risks and costs of obtaining a favorable, fully litigated result, this settlement represents a reasonable compromise. Therefore, the PPL Parties support the settlement that has been reached in this case. The Testimony of Mr. Greg Patterson, on behalf of the ACPA, explains why the ACPA also supports the settlement that has been reached. The PPL Parties support the settlement for the same reasons explained in the Testimony of Mr. Greg Patterson.

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

A. Yes, it does.

SUMMARY OF THE TESTIMONY OF

JESSE A. DILLON

On behalf of PPL EnergyPlus, LLC, and PPL Southwest Generation Holdings, LLC

Docket No. E-01345A-03-0437

November 4, 2004

Admitted
EXHIBIT
PPL - 2
LB 12/2/09

SUMMARY OF THE DIRECT TESTIMONY
OF
JESSE A. DILLON

I am testifying on behalf of PPL EnergyPlus, LLC and PPL Southwest Generation Holdings, LLC (collectively "PPL"). PPL supports the settlement agreement filed in this proceeding (the "Settlement") as a fair and reasonable compromise among many parties representing a broad spectrum of diverse interests, and believes the Settlement is in the best interest of the public.

In response to the request of Commissioner Mayes, I note that upon intervention PPL did not independently take a "litigation position" in this case. PPL does independently support the Settlement. PPL is also a member of the Arizona Competitive Power Alliance ("ACPA") and agrees with the position of ACPA in support of the Settlement. PPL concurs with the response of Greg Patterson explaining how key components of the Settlement achieve substantial objectives of ACPA. PPL believes those objectives are best advanced by the Settlement, in contrast to the alternative of litigating the extremely diverse initial positions of parties in this case and possibly litigating in other cases other important disputed issues that are resolved by the compromises in the Settlement. The Settlement is conducive to an effective and competitive wholesale market. PPL believes that an effective and competitive wholesale market will promote the availability of the lowest cost power to ratepayers and serve the best interest of the public.

RUCO

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ

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ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 3, 2004

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**INTRODUCTION**

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's revenue requirement recommendation for APS based on my own analyses as well as the analyses of other RUCO witnesses.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application as it relates to operating income, rate base, and the Company's overall revenue requirements. I worked closely with RUCO consultants in formulating RUCO's position regarding APS's request to transfer generation assets

from an affiliate to APS, and was responsible, along with RUCO witness William Rigsby for reflecting the impact of those positions on APS's revenue requirements.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-7.

**SUMMARY OF ISSUES**

Q. Please summarize the issues and recommendations you address in your testimony.

A. My testimony addresses the following issues:

* Retail Competition – examination of status of retail competition and recommendation to return APS to regulated monopoly status.
* PWEC Assets – pursuant to RUCO witness Mr. Schlissel's finding to allow the market to determine the economic value of the PWEC energy and capacity, recommend this docket be divided in two phases – Phase I to determine the revenue requirement for all aspects excepting PWEC energy and capacity and Phase II dedicated to APS's generation resource needs.
* PWEC Interest Premium – recommendation to include an on-going annual credit to ratepayers for the 264 basis point premium that APS receives from PWEC.

* 1999 Settlement Agreement – examination of the status of the terms of the agreement and recommendation to nullify the terms of the agreement prospectively.
* Interim Spent Fuel Storage – examination of cost deferrals and on-on-going costs and recommendation for recovery of both deferred and on-going costs, with no return on accrued deferred balance.
* Direct Access Expenses – examination of to-date deferrals and projected on-going costs. Recommendation of recovery of deferred costs, with no on-going costs pursuant to RUCO's recommendation to return to retail rate of return regulation.
* Transmission Assets and Expenses – recommendation that the ACC retain jurisdiction over APS's retail transmission assets and expenses.
* Environmental Portfolio Standard and Demand Side Management Funding – recommendation to redirect revenues collected through the EAASE fund to DSM programs and to allow the EPS surcharge to remain the sole funding source for EPS.
* Future Demand Side Management Programs – recommendation to increase the funding level for DSM programs to achieve a 1% reduction in load growth.

**REVENUE REQUIREMENTS**

Q. Please summarize your recommended revenue requirements for APS.

A. RUCO recommends that APS's revenue requirement be reduced by at least $53.605 million, or 2.84%. RUCO's recommended revenue requirements are summarized on Schedule MDC-1. RUCO's Original Cost, Fair Value, and Reconstruction Cost New Depreciation rate bases of $3,051,479,000, $4,065,086,000 and $5,078,693,000 respectively are shown on Schedule MDC-2. The detail supporting the rate base is presented on Schedule MDC-3. RUCO's recommended adjusted operating income is presented on Schedule MDC-4. The detail supporting this recommendation is presented on Schedule MDC-5.

**RETAIL COMPETITION**

Q. What were RUCO's primary concerns in this case?

A. It has been many years since APS's rates have been fully audited and litigated. The fairness and reasonableness of the current rates is called into question given this long lapse of time between rate reviews, as well as the impact of failed regulatory attempts to create a competitive electric market. RUCO's primary concern in this docket is to establish fair and reasonable rates and to recreate a regulatory model that will protect both ratepayers and the Company from the volatile effects of competitive electric markets.

Q. Has the Commission already taken some steps to protect ratepayers from dysfunctional competitive electric environments?

A. Yes. On September 10, 2002 the Commission issued Decision No. 65154 which among other things stayed the generation divestiture requirement of the APS 1999 settlement agreement. Decision No. 65154 effectively rendered APS a vertically integrated utility once again. The Commission attributed its actions in Decision No. 65154 to the failed development of a functional competitive wholesale electric market and the need to protect the public interest. The Commission stated as follows:

> In actuality, no retail competition exists; market power is held by the incumbent utilities; no RTO is in effect; transmission constraints exist that potentially exacerbate market abuse; the GAO has issued a negative report on the FERC's ability to manage competitive markets; both TEP and APS recognize a problem – one wants to postpone its divestiture while the other is affected by its parent's and affiliates' adverse financial considerations; proposed new generation may be cancelled if it is not able to find a market; more protections are needed against self-dealing and inappropriate affiliate transactions; and investigations are ongoing into market manipulations and improprieties. . . .
>
> We find that due to circumstances outside our control or the control of any party, and in order to protect the public interest, we must take further action to regulate the transition to competition. [Decision No. 65154, page 22]

Q. What other steps has the Commission taken?

A. The Commission recognized in Decision No. 65796 that the affiliate created to hold APS's generation assets (Pinnacle West Energy Corporation or PWEC) was rendered unable to raise capital as a direct result of the stay in divestiture. In that decision the Commission authorized APS to issue debt to cover the financing needs of the generation assets held by PWEC.

Q. Did RUCO support the findings in that decision?

A. Yes, as far as those findings went. At that time RUCO advocated for these additional findings:

1) A provision that APS be required to file for ACC approval of a transfer of the PWEC assets to APS;
2) Full investigation of APS's cost of service in the context of a rate case;
3) A review of the PWEC assets regarding economic value and used and usefulness;
4) A comprehensive review of the electric competition rules and the desirability and applicability in today's environment, and
5) The formulation and development of a regulatory framework that will protect ratepayers and the Company from market dysfunction.

These additional findings were not included in Decision No. 65154. However, RUCO believes these issues are just as applicable today as they were a year ago. In fact, probably more so given APS's pending rate case.

Q. What does RUCO believe needs to be accomplished in this case?

A. As with any rate case, there needs to be a determination of cost of service and fair and reasonable rates. More importantly, a new regulatory framework needs to be developed that will protect ratepayers from

dysfunctional electric markets, yet allow the Company an opportunity to earn a fair rate of return on its utility assets. The competition rules need to be revised to reflect the new regulatory framework, and the status of the 1999 settlement agreement needs to be resolved in some manner (i.e. renegotiated, litigated through this proceeding, or voided to be consistent with a new regulatory framework and the lack of functional retail electric markets).

Q. Why is it important that these issues be resolved in this docket?

A. As I have testified to in many previous APS dockets, a functional retail electric market has failed to develop as envisioned. The Commission has recognized this, and via Decision No. 65154, has modified the intended course of retail competition. RUCO supports the Commission decision to modify the course of retail electric competition. However, RUCO also recognizes that Decision No. 65154 has left a number of unresolved issues or "loose ends". These loose ends include the status of the provisions in the 1999 settlement agreement, the electric competition rules, and the future shape of retail electric regulation. These loose ends are a detriment both to ratepayers and the electric utilities and put both in the unenviable situation of not knowing the rules of the game. For the best interests of all parties, new rules need to be clearly defined as a product of this docket.

Q. What is required in this docket?

A. First, to recognize the experiment into retail competition has failed. This is evident from the California experience and how that situation affected local power costs. Second, to recognize that no retail market has developed, and ratepayers have not chosen to seek direct access electric power. Third, to rebuild a retail regulatory framework, and abandon the failed specter of a competitive retail market.

Q. Why isn't this recommendation inconsistent with RUCO's position at the time of the 1999 settlement agreement?

A. Much has occurred in the past four years that has made it evident that a retail competitive electric industry not only has not developed, but also is fraught with risk. In light of what has transpired since the signing of the settlement agreement, the parties, as well as the Commission in Decision No. 65154, have had to rethink their earlier positions. RUCO does not believe blind adherence to a previous position merely for consistency's sake is necessarily prudent. The foremost concern is protection of the public interest as well as the health of Arizona's largest electric utility.

Q. Did a competitive electric market, even as envisioned five years ago, have any real potential benefits for residential customers?

A. No. The envisioned benefits were only of consequence for large commercial and industrial customers. Only through large scale

aggregation was there much potential for residential customer benefit, and even then, the expected individual benefit was minimal. Thus, residential ratepayers should not be subject to the high level of risk that comes from a competitive electric market, given a relatively small potential for benefit.

Q. What actions does the Commission need to take in the instant docket to safeguard the public?

A. The electric competition rules need to be overturned or substantively revised, the 1999 settlement agreement declared expired and voided, and retail customers returned to rate of return regulation. The ACC already has a docket in place that is addressing the competition rules issue, and the remaining two issues (voiding of the settlement agreement and returning to regulation) can be resolved as part of the Commission order in this docket. RUCO's position on the two remaining issues identified here are discussed in greater detail later in my testimony.

**PWEC ASSETS**

Q. Please explain the treatment APS has proposed for the PWEC generation assets in this rate application.

A. APS proposes to include the Arizona PWEC generation assets[1] in its rate base at original cost and to include all revenues and expenses associated with those assets in operating income.

[1] Specifically, Redhawk 1, Redhawk 2, West Phoenix 4, West Phoenix 5, and Saguaro

Q. Did RUCO examine and analyze APS's proposal from a capacity, engineering, and macro-economic standpoint?

A. Yes. RUCO witness David Schlissel has examined the PWEC asset issue from various standpoints which are discussed in his direct testimony along with his recommended treatment in this case.

Q. What aspect of the PWEC asset issue are you responsible for?

A. I am responsible for RUCO's recommended ratemaking and accounting treatment of Mr. Schlissel's findings.

Q. What ratemaking treatment are you recommending for the PWEC assets?

A. At this time, I recommend that PWEC assets not be included in rate base until the least cost resources of APS's energy and capacity needs can be accurately determined. Mr. Schlissel explains in detail in his direct testimony the information that is needed to make this determination.

Q. How long of a delay do you anticipate between the Phase I portion of this case and the Phase II portion?

A. As explained in depth in Mr. Schlissel's testimony, a specific process is necessary to obtain the information to accurately determine the appropriate cost of APS's resource needs. Potentially the recent APS bid process could yield the necessary information, were the Commission to require that APS reveal the details of the bids received through that

process. In that event, Phase II could commence within a relatively short time frame. Absent the detailed information from the recent bid process, commencement of Phase II would have to be delayed until APS completed a new bid process (or an auction and least-cost process as specifically described by Mr. Schlissel).

Q. Once the least cost value of APS's energy and capacity needs are determined how will such costs get reflected in rates?

A. RUCO recommends that this docket be divided into two phases. Phase I would be used to determine APS's revenue requirements for all current ratemaking elements, including costs of its Track B contracts. Phase II of this docket would proceed only after the least cost process explained by Mr. Schlissel is completed, and a determination will be made in Phase II of any necessary revenue requirement[2].

Q. Have you prepared a schedule that shows your recommended adjustments for the PWEC assets in the Phase I portion of this rate case?

A. Yes. Schedule MDC-3, Adjustment #1 shows the necessary rate base adjustment for the Phase I portion of this case, which decreases APS's proposed proforma rate base by $895,109,000. Schedule MDC-5,

[2] RUCO envisions that the Phase II portion of this docket would be patterned after the step rate increase methodology previously authorized in APS Decision No. 48319 (August 1, 1979), as limited by the Arizona Supreme Court in Arizona Community Action Association v. Arizona Corporation Commission, 123 Ariz. 228, 599 P.2d. 184 (1979). The step increase would only be necessary in Phase II if any of the PWEC assets prevail in the least cost process.

Adjustment #1 shows the necessary operating income adjustment for the Phase I portion of this case of $2,504,000. Collectively, these two adjustments remove all rate impacts of the PWEC assets from the Phase I portion of this proceeding. Pursuant to Mr. Schlissel's recommendations the rate impacts of APS's additional energy and capacity needs will be determined in Phase II of this docket.

**PWEC INTEREST PREMIUM**

Q. Is PWEC currently paying APS an interest premium on the debt that APS has secured on behalf of PWEC for financing of PWEC's generation assets?

A. Yes. Pursuant to Decision No. 65796 the Commission required PWEC to pay a 264 basis point interest premium to APS on the debt APS had secured to finance the PWEC assets. Decision No. 65796 also required that APS accrue the interest premiums in a deferral account for later credit to ratepayers.

Q. Has APS been accruing and deferring the interest premium as required by Decision No. 65796?

A. Yes. APS has requested an estimated premium accrual of $14.850 million through June 30, 2004. The Company is proposing to amortize this amount over 5 years in the current case, for an annual net credit (after calculation of a 6% return to customers on the deferral) of $3.416 million.

Thus, the Company's proposed ratemaking treatment would flow the interest premiums received by APS through June 30, 2004 to ratepayers.

Q. Has the Company made an adjustment to credit to ratepayers the on-going annual interest premiums paid by PWEC?

A. No. APS proposes to acquire these assets in the instant case and accordingly, would then carry the debt on its own behalf. Thus, there would no longer be an interest premium payment from PWEC.

Q. Under your recommendation regarding the PWEC assets in the Phase I portion of this case would PWEC continue to make interest premium payments to APS?

A. Yes. The debt arrangement between APS and PWEC would remain unchanged under my Phase I recommendations. Thus, as shown on Schedule MDC-6, Adjustment #2, I have made an adjustment to credit both the amortization of the deferred interest premium as well as the on-going annual premium to ratepayers. This adjustment increases operating income by $1.336 million.

**THE 1999 SETTLEMENT AGREEMENT**

Q. What is the status of the 1999 APS settlement agreement?

A. The current status of the 1999 APS settlement remains a question mark that must be resolved as part of this docket. The parties to recent APS

proceedings have expressed differing opinions on the status of the agreement. These opinions range from the view that the agreement may have become null and void when Decision No. 65154 modified one of the terms of the agreement (divestiture), to the opinion that all terms of the agreement excepting the divestiture provision remain in full effect.

Q. What position does APS appear to have taken with regards the current status of the 1999 settlement agreement?

A. APS appears to have taken the position that those terms of the agreement to which it wants to abide remain in full effect and those terms to which it no longer wants to abide are null and void.

Q. Why does it appear that way?

A. APS has picked and chosen the terms of the 1999 settlement it considers still in effect vs. those it considers void. This is evident from positions APS has taken in previous dockets. For example, in the Adjustment Mechanism docket (E-01345A-02-0403) APS initially proposed a purchased power adjustor mechanism as provided for under the terms of the 1999 settlement agreement. Subsequently, after the issuance of Decision No. 65154, APS modified its proposed adjustor mechanism to include terms not provided for under the 1999 settlement, thus, showing it believed that specific term of the agreement was no longer valid. In the Financing docket (E-01345A-02-0707) APS witness Davis testified as

follows regarding APS's view of the continued applicability of the various terms of the 1999 settlement agreement:

> As part of the consideration for allowing us to move our assets to the Pinnacle West Capital Corporation, we agreed to several things in the document. One was the $234 million write-off, which we took in the fourth quarter of 1999, and we also agreed in the document to only collect two-thirds of the transition costs. And with the, now, provision of the moving of the generation assets to Pinnacle West Energy Corporation being truncated, we think we are entitled to recovery of those costs. [Docket No. E-01345A-02-0707 transcription at page 692]

and

> Q. With reference to the settlement agreement, tell me what other provisions you think remain. You did mention one, the reduction in rates. Are there any further years in which the rates will be reduced?
> A. Yes, there's a rate reduction coming in July of this year.
> Q. And I take it that APS does not intend to rescind that part of the settlement agreement?
> A. That's not our intention. [Docket No. E-01345A-02-0707 transcript at page 692]

and

> Q. You have indicated that you believe that the settlement agreement is still in effect, is that not correct?
> A. Yes, I do.
> Q. And there are other parties to the settlement agreement, are there not?
> A. Yes, there are.
> Q. And I think you testified earlier that you have not conferred with those other parties concerning the rescinding of those other provisions that you've been discussing here just now?
> A. Not to my knowledge. But we certainly have been pretty public about what our intentions are. This is the first time I've heard any concern about it. [Docket No. E-01345A-02-0707 transcript at page 695]

Finally, APS again proposes in the instant docket to rescind the term of the 1999 settlement agreement that provided for a regulatory write-off of $234 million.

Q. Should APS be allowed to pick and choose the individual terms of the 1999 settlement agreement to which it will continue to adhere?

A. No. By definition negotiated agreements involve some give and take from each of the parties. One party gives up something it wants in return for getting something else. Without such give and take on part of the parties to a negotiation, there will be no agreement. The terms of the settlement agreement therefore are intrinsically entwined and modification of even one term can bias and/or void the entire agreement.

Q. Should the Commission render the 1999 settlement agreement null and void in this docket?

A. Yes. The status of the 1999 agreement needs to be defined thereby putting to rest any ambiguity. The assumptions that were the foundation of the 1999 settlement agreement have not come to pass (i.e. retail competition). Thus, the terms of that agreement are inapplicable in the current environment. The 1999 agreement itself foresaw the possibility of this situation and included the following provisions:

> This Agreement establishes the agreed upon transition for APS to a restructured entity and will provide customers with competitive choices for generation and certain other retail services. The parties believe this Agreement will produce benefits for all customers

> through implementing customer choice and providing rate reductions so the APS service territory may benefit from economic growth. [Decision No.61973, Attachment 1, page 1]

and

> The Parties acknowledge that APS' ability to offer retail access is contingent upon numerous conditions and circumstances, a number of which are not within the direct control of the Parties. Accordingly, the Parties agree that it may become necessary to modify the terms of the retail access to account for such factors, and they further agree to address such matters in good faith and to cooperate in an effort to propose joint resolutions of any such matters. [Decision No. 61973, Attachment I, section 1.3]

The retail competition that was the cornerstone of the 1999 agreement has not materialized. Pursuant to the agreement at page 2, paragraph 1.3, RUCO's proposed resolution is to end retail direct access and return to rate of return regulation, which will render the 1999 settlement void.

Q. Will voiding the 1999 settlement agreement at this junction result in the non-performance of any of its terms?

A. No, I do not believe so. With the exception of the divestiture requirement, the principle terms of the agreement have already been fulfilled as following:

* The APS distribution system was opened to retail access per section 1.1 of the agreement;
* The unbundled rates provided for in section 2.1 of the agreement have been implemented;

* The rate reductions provided for in paragraph 2.2 of the agreement became effective on the agreed upon dates;
* The adjustment clauses provided for in section 2.6 of the agreement have been acted upon by the Commission;
* The rate case required under section 2.7 of the agreement has been filed;
* The stranded cost recovery allowed in section 3.3 of the agreement has been realized by APS;
* The write-off required in section 3.3 was recorded on APS's books in 1999;
* The regulatory assets are being amortized as required in section 3.4 of the agreement.; and
* All parties have withdrawn their various court appeals in accordance with section 5.1 of the agreement.

Thus, the parties have fulfilled their obligations under the agreement and on a going forward basis there are no outstanding actions required by any of the parties. The agreement serves no future purpose nor is it applicable to rate of return regulation, to which RUCO recommends APS return at this juncture. Thus, no party will be left unwhole by the expiration of the agreement.

Q. Is the Company proposing in this docket to undo some of the previously acted upon terms of the agreement?

A. Yes. In this rate case the Company is requesting authority to reinstate the $234 million it agreed to write off in the 1999 agreement.

Q. Is this a fair and reasonable request?

A. No. As just discussed, the terms of the agreement represent a set of trade-offs agreed to by the parties which are intrinsically enmeshed. Given that all terms of the agreement have been fulfilled it would be unreasonable and biased to go back and retroactively undo the effect of select terms of the agreement. As previously discussed, the only aspect of the agreement that was altered by Decision No. 65154 was that of generation divesture. The divestiture provision of the agreement was included because the Commissioners supported it, and was not a part of the parties' negotiation.

Just as it would be unreasonable for RUCO to renege on its agreement to allow recovery of the stranded costs or recovery of the prudently incurred deferred transition costs after the fact, so it is unreasonable for the Company to renege on its agreement to the $234 million write-off.

Q. What adjustment is RUCO recommending regarding APS's request to reinstate the $234 write-off in the 1999 settlement agreement?

A. As shown on Schedule MDC-3, Adjustment #2 I have removed the Company's proforma adjustment to reinstate the $234 million write-off, net of deferred income taxes. I have also removed the Company's proposed $15.6 million annual amortization of the write-off from operating expenses, as shown on MDC-5, Adjustment #7.

**INTERIM SPENT FUEL STORAGE**

Q. Please discuss the Company's Interim Spent Fuel Storage Installation (ISFSI).

A. Due to delays in the US Department of Energy's siting and constructing of a permanent spent nuclear fuel storage facility, the Palo Verde nuclear plants required an interim alternative storage solution. That solution is a dry storage facility for spent nuclear fuel at the Palo Verde Generating Station. The accrued cost of this facility as of the end of the test year was $46,140,000 and APS estimates the accruals will reach $50,461,000 by the time rates from this docket go into effect in June 2004.

Q. What is the basis of the accrued amounts?

A. The accruals are based the annual levels of generation at Palo Verde multiplied by a factor representing the storage cost per unit of generation. Thus, the accruals do not represent actual expenditures made, but rather a pro rata annual allocation of the total estimated cost of the ISFSI. This

has occurred because of a timing difference between when the Company made the accruals vs. when actual expenditures were made.

Q. What ratemaking treatment is the Company requesting for these costs?

A. The Company's requested ratemaking treatment is three fold. APS is requesting rate base treatment of the $50,461,000 in deferred ISFSI accruals, amortization expense for these deferred balances, and recovery of the annual on-going cost of the ISFSI.

Q. Do you agree with the Company's proposed ratemaking treatment?

A. In part. Spent nuclear fuel qualifies as a System's Benefit Charge under the Arizona Administrative Code and certainly is a cost of providing electric service through the Palo Verde plants. Thus, RUCO agrees that amortization of the accrued cost of storage and recovery of the annual go-forward cost of storage are appropriate. However, I do not agree with the Company's proposal to rate base the deferred balance.

Q. Why not?

A. Under rate of return regulation a utility is entitled to earn a return on its capital invested for the public service. In the case of the ISFSI deferrals, APS has virtually no invested capital. The ISFSI deferred balance does not represent actual expenditures made by the Company, but rather mere accounting accruals. The deferred balance requested by APS in rate

base is over $50 million, yet APS's actual expenditures on the ISFSI to date are approximately $5 million. Since APS has not actually made a $50 million investment it is not entitled to a return on $50 million.

Q. What adjustment have you made?

A. As shown on Schedule MDC-3, Adjustment #3 I have decreased rate base by $50,461,000 to remove the ISFSI accruals.

**DIRECT ACCESS EXPENSES**

Q. What ratemaking treatment is APS requesting for its costs to comply with the electric competition rules?

A. The Company is seeking recovery of $34,013,000 in direct access expenses that it had deferred for future recovery pursuant to section 2.6, item (3) of the 1999 settlement agreement. The Company is requesting a five year amortization of these direct access deferrals, or $6,802,5000 in annual amortization expense.

Q. Is the Company requesting rate base treatment of the direct access expenses deferrals?

A. No. The 1999 settlement agreement granted APS the authority to defer these expenses as well as accrue returns on the deferred amounts. Thus, the Company's return on the deferred amounts is already included in the proposed amortization expense.

Q. Do you agree with the Company's proposed ratemaking treatment of the direct access expense deferrals?

A. Yes. The Company's proposed ratemaking treatment of the deferred direct access expenses comports with the terms of the 1999 settlement agreement. While RUCO recommends the voiding of the agreement on a going forward basis, it does not recommend reneging on the terms of the agreement on a retrospective basis.

Q. Is APS requesting any direct access expenses beyond the just described deferrals provided for in the settlement agreement?

A. Yes. APS is requesting an additional $1,477,000 annually to cover its estimated on-going annual cost of compliance with the electric competition rules.

Q. Do you agree that an on-going level of expense needs to be provided?

A. No. As discussed earlier, a retail competitive market has failed to develop in Arizona and even if it were to develop, it is fraught with unacceptable risk to retail customers. Thus, RUCO has recommended a return to retail rate of return regulation. Accordingly, there will be no on-going cost to comply with the electric competition rules.

Q. What adjustment have you made?

A. As shown on Schedule MDC-5, Adjustment #3 , I have reduced test year operating expenses by $1,477,000 to remove the estimated cost of on-going compliance with the electric competition rules.

**TRANSMISSION ASSETS AND EXPENSES**

Q. Have you included an adjustment in your recommended revenue requirements to reflect the position of RUCO Witness Richard Rosen regarding APS's transmission pricing?

A. No. Through data requests RUCO asked the Company to provide a break-out of its transmission costs between wholesale and retail, as defined in Mr. Rosen's testimony. The Company did not provide this information, therefore, I am unable to reflect the impact of Mr. Rosen's recommendation on RUCO's recommended revenue requirements.

Q. Is the necessary adjustment likely to be very material?

A. No. Transmission costs are a small portion of APS's overall expenses and the necessary adjustment would merely be the difference between the FERC OATT and APS's cost to serve transmission. Mr. Rosen's recommendation for retail transmission to remain under ACC jurisdiction is based primarily on the desirability of retaining local control over this aspect of APS's operations as opposed to its revenue requirement effects.

Q. Do you intend to update your testimony at a later date with this information?

A. Hopefully, APS will provide this information, or potentially RUCO could estimate the wholesale/retail allocation once its cost of service study is complete.

**ENVIRONMENTAL PORTFOLIO STANDARD AND DEMAND SIDE MANAGEMENT FUNDING**

Q. What amount is currently included in APS's rates to fund Demand Side Management (DSM) programs and Environmental Portfolio Standard (EPS) projects?

A. Included in APS's current base rates is $6 million in funding originally earmarked for DSM programs. It is my understanding that pursuant to Decision No. 63364 APS has redirected the DSM base rate funding to EPS projects. APS also receives additionally funding for EPS projects through the EPS surcharge. This charge provides approximately $6.5 million in funding per year.

Q. Given your recommendation that retail customers should be returned to rate of return regulation do you believe the current allocation of the EPS and DSM funds is appropriate?

A. No. The current allocation between DSM and EPS funding is 100% for the EPS. While this allocation maybe appropriate in a competitive retail

market, it is not in a regulated rate of return model, as I am recommending. Under the regulated model, DSM can be a very effective tool in controlling load growth, mitigating the need to acquire additional capacity, allowing customers to control their electric bill as well as promoting conservation. I am therefore recommending the $6 million in current base rate funding be redirected from EPS projects to DSM programs, as was originally intended.

Q. How would the EPS continue to be funded?

A. The EPS would continue to be funded through the EPS surcharge. Thus, my recommendation to reassign the $6 million in base rates from EPS to DSM does not mean that EPS would not continue to be funded through the surcharge at what is ultimately determined to be an adequate level.

Q. Is any adjustment necessary to the ratemaking model to reflect the reassignment of $6 million in rate base funding from EPS to DSM?

A. No adjustment is necessary for the reassignment. However, a small adjustment is necessary to correct an error in the Company's calculation. The Company has incorrectly recognized $5.263 million in base rate revenue for the EPS programs and $6 million in EPS expenditures, thereby mathematically creating an additional revenue requirement of $737,000. Base rates provide for $6 million in revenue not $5.263 million.

On Schedule MDC-5, Adjustment #4 I have corrected this calculation, which increases test year revenues by $737,000.

**FUTURE DEMAND SIDE MANAGEMENT PROGRAMS**

Q. Does your recommended reassignment of $6 million from EPS to DSM provide adequate funding for an aggressive level of DSM?

A. No.

Q. Is RUCO advocating an aggressive approach to DSM?

A. Yes. Well planned and funded DSM programs can go a long way to control load growth, forego or at least forestall additional investment in energy and capacity, as well as provide tools for customer bill management. DSM programs when properly designed and administered can be very cost effective. In fact, statistics show that APS's DSM programs historically have generated more benefit per dollar expended vs. industry averages. An aggressive DSM approach in a regulated monopoly model, as RUCO is recommending here, can generate significant savings and benefits for ratepayers as well as stockholders.

Q. How much additional funding are you recommending for DSM programs?

A. RUCO is recommending an additional $29 million in funding for DSM programs, for a total DSM funding of $35 million per year. The recommended funding level is equivalent to an overall amount

accumulated from a 1.5 mil charge on all kWh usage. RUCO's adjustment to include this additional DSM funding in rates is shown on Schedule MDC-5, Adjustment #5.

Q. Are you recommending that the Commission maintain continuing oversight on the use of the $35 million in DSM funding?

A. Yes. The mere provision of $35 million in funding for DSM does not ensure that reductions in load or load growth will be achieved. Although APS has historically made effective use of its DSM funding, I am recommending the following annual oversight and monitoring:

1) All programs will be subject to a preapproval process, where APS will be required to submit the details of all proposed programs to Staff for approval. The details submitted must include a cost benefit analysis that specifically provides estimated load reductions.

2) All approved programs will be subject to an annual review by Staff to determine the effectiveness of the programs. The review process will determine if a program is continued, modified, or replaced. Staff will also review the level of program expenditures and to the extent anything less or more than $35 million is utilized in any given year the difference will be preserved in a deferred balancing account. If the cumulative balance in this account is a credit (APS net expenditures were less than funded) at the time of the next rate case the under expenditures will be returned to

ratepayers. Any net debit balance in the balancing account will not be eligible for future recovery.

**CONCLUSION**

Q. Why should the positions' of the RUCO witnesses be adopted?

A. All the RUCO witnesses, utilizing their individual areas of utility expertise, worked as a team to put together recommendations that would address the loose ends and various risks that currently exist as a direct result of a vision of a functional retail electric market that never developed. RUCO's recommendations are designed to return ratepayers and shareholders alike to a regulatory foundation that is designed to protect the public interest. This will be accomplished through the return to rate of return regulation, finally laying to rest the provisions of the now inapt 1999 settlement agreement, and resolving out-dated competitive rules. RUCO's recommendation also ensures that APS acquires any additional energy and capacity resources at least cost, through the Phase II part of this case, provides a fair rate of return to stockholders, and takes an aggressive approach to DSM and conservation.

Q. Does RUCO's recommendation come with a large price tag?

A. No. RUCO's recommendation in the Phase I portion of this docket will result in a rate *decrease* of approximately 3%. This result clearly shows the rate decreases called for by the 1999 settlement agreement were fully

warranted. RUCO's recommendation also provides a methodology, through Phase II of this docket, for ensuring that APS acquires its additional energy and capacity needs in the most prudent least-cost manner. RUCO urges the Commission to embrace its recommendations and support the return of APS to protected regulated status.

Q. Does this conclude your direct testimony?

A. Yes.

## APPENDIX I

Qualifications of Marylee Diaz Cortez

**EDUCATION:** University of Michigan, Dearborn
B.S.A., Accounting 1989

**CERTIFICATION:** Certified Public Accountant - Michigan
Certified Public Accountant - Arizona

**EXPERIENCE:** Audit Manager
Residential Utility Consumer Office
Phoenix, Arizona 85007
July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted

of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION

| Utility Company | Docket No. | Client |
|---|---|---|
| Potomac Electric Power Co. | Formal Case No. 889 | Peoples Counsel of District of Columbia |
| Puget Sound Power & Light Co. | Cause No. U-89-2688-T | U.S. Department of Defense - Navy |
| Northwestern Bell-Minnesota | P-421/EI-89-860 | Minnesota Department of Public Service |
| Florida Power & Light Co. | 890319-EI | Florida Office of Public Counsel |
| Gulf Power Company | 890324-EI | Florida Office of Public Counsel |
| Consumers Power Company | Case No. U-9372 | Michigan Coalition Against Unfair Utility Practices |
| Equitable Gas Company | R-911966 | Pennsylvania Public Utilities Commission |
| Gulf Power Company | 891345-EI | Florida Office of Public Counsel |

| | | |
|---|---|---|
| Jersey Central Power & Light | ER881109RJ | New Jersey Department of Public Advocate Division of Rate Counsel |
| Green Mountain Power Corp. | 5428 | Vermont Department of Public Service |
| Systems Energy Resources | ER89-678-000 & EL90-16-000 | Mississippi Public Service Commission |
| El Paso Electric Company | 9165 | City of El Paso |
| Long Island Lighting Co. | 90-E-1185 | New York Consumer Protection Board |
| Pennsylvania Gas & Water Co. | R-911966 | Pennsylvania Office of Consumer Advocate |
| Southern States Utilities | 900329-WS | Florida Office of Public Counsel |
| Central Vermont Public Service Co. | 5491 | Vermont Department of Public Service |
| Detroit Edison Company | Case No. U-9499 | City of Novi |
| Systems Energy Resources | FA-89-28-000 | Mississippi Public Service Commission |
| Green Mountain Power Corp. | 5532 | Vermont Department of Public Service |
| United Cities Gas Company | 176-717-U | Kansas Corporation Commission |

| | | |
|---|---|---|
| General Development Utilities | 911030-WS & 911067-WS | Florida Office of Public Counsel |
| Hawaiian Electric Company | 6998 | U.S. Department of Defense - Navy |
| Indiana Gas Company | Cause No. 39353 | Indiana Office of Consumer Counselor |
| Pennsylvania American Water Co. | R-00922428 | Pennsylvania Office of Consumer Advocate |
| Wheeling Power Co. | Case No. 90-243-E-42T | West Virginia Public Service Commission Consumer Advocate Division |
| Jersey Central Power & Light Co. | EM89110888 | New Jersey Department of Public Advocate Division of Rate Counsel |
| Golden Shores Water Co. | U-1815-92-200 | Residential Utility Consumer Office |
| Consolidated Water Utilities | E-1009-92-135 | Residential Utility Consumer Office |
| Sulphur Springs Valley Electric Cooperative | U-1575-92-220 | Residential Utility Consumer Office |
| North Mohave Valley Corporation | U-2259-92-318 | Residential Utility Consumer Office |
| Graham County Electric Cooperative | U-1749-92-298 | Residential Utility Consumer Office |

| | | |
|---|---|---|
| Graham County Utilities | U-2527-92-303 | Residential Utility Consumer Office |
| Consolidated Water Utilities | E-1009-93-110 | Residential Utility Consumer Office |
| Litchfield Park Service Co. | U-1427-93-156 & U-1428-93-156 | Residential Utility Consumer Office |
| Pima Utility Company | U-2199-93-221 & U-2199-93-222 | Residential Utility Consumer Office |
| Arizona Public Service Co. | U-1345-94-306 | Residential Utility Consumer Office |
| Paradise Valley Water | U-1303-94-182 | Residential Utility Consumer Office |
| Paradise Valley Water | U-1303-94-310 & U-1303-94-401 | Residential Utility Consumer Office |
| Pima Utility Company | U-2199-94-439 | Residential Utility Consumer Office |
| SaddleBrooke Development Co. | U-2492-94-448 | Residential Utility Consumer Office |
| Boulders Carefree Sewer Corp. | U-2361-95-007 | Residential Utility Consumer Office |
| Rio Rico Utilities | U-2676-95-262 | Residential Utility Consumer Office |
| Rancho Vistoso Water | U-2342-95-334 | Residential Utility Consumer Office |
| Arizona Public Service Co. | U-1345-95-491 | Residential Utility Consumer Office |
| Citizens Utilities Co. | E-1032-95-473 | Residential Utility Consumer Office |
| Citizens Utilities Co. | E-1032-95-417 et al. | Residential Utility Consumer Office |

| | | |
|---|---|---|
| Paradise Valley Water | U-1303-96-283 &<br>U-1303-95-493 | Residential Utility<br>Consumer Office |
| Far West Water | U-2073-96-531 | Residential Utility<br>Consumer Office |
| Southwest Gas Corporation | U-1551-96-596 | Residential Utility<br>Consumer Office |
| Arizona Telephone Company | T-2063A-97-329 | Residential Utility<br>Consumer Office |
| Far West Water Rehearing | W-0273A-96-0531 | Residential Utility<br>Consumer Office |
| SaddleBrooke Utility Company | W-02849A-97-0383 | Residential Utility<br>Consumer Office |
| Vail Water Company | W-01651A-97-0539 &<br>W-01651B-97-0676 | Residential Utility<br>Consumer Office |
| Black Mountain Gas Company<br>Northern States Power Company | G-01970A-98-0017<br>G-03493A-98-0017 | Residential Utility<br>Consumer Office |
| Paradise Valley Water Company<br>Mummy Mountain Water Company | W-01303A-98-0678<br>W-01342A-98-0678 | Residential Utility<br>Consumer Office |
| Bermuda Water Company | W-01812A-98-0390 | Residential Utility<br>Consumer Office |
| Bella Vista Water Company<br>Nicksville Water Company | W-02465A-98-0458<br>W-01602A-98-0458 | Residential Utility<br>Consumer Office |
| Paradise Valley Water Company | W-01303A-98-0507 | Residential Utility<br>Consumer Office |
| Pima Utility Company | SW-02199A-98-0578 | Residential Utility<br>Consumer Office |
| Far West Water & Sewer Company | WS-03478A-99-0144<br>Interim Rates | Residential Utility<br>Consumer Office |
| Vail Water Company | W-01651B-99-0355<br>Interim Rates | Residential Utility<br>Consumer Office |

| | | |
|---|---|---|
| Far West Water & Sewer Company | WS-03478A-99-0144 | Residential Utility Consumer Office |
| Sun City Water and Sun City West | W-01656A-98-0577 & SW-02334A-98-0577 | Residential Utility Consumer Office |
| Southwest Gas Corporation<br>ONEOK, Inc. | G-01551A-99-0112<br>G-03713A-99-0112 | Residential Utility Consumer Office |
| Table Top Telephone | T-02724A-99-0595 | Residential Utility Consumer Office |
| U S West Communications<br>Citizens Utilities Company | T-01051B-99-0737<br>T-01954B-99-0737 | Residential Utility Consumer Office |
| Citizens Utilities Company | E-01032C-98-0474 | Residential Utility Consumer Office |
| Southwest Gas Corporation | G-01551A-00-0309 & G-01551A-00-0127 | Residential Utility Consumer Office |
| Southwestern Telephone Company | T-01072B-00-0379 | Residential Utility Consumer Office |
| Arizona Water Company | W-01445A-00-0962 | Residential Utility Consumer Office |
| Litchfield Park Service Company | W-01427A-01-0487 & SW-01428A-01-0487 | Residential Utility Consumer Office |
| Bella Vista Water Co., Inc. | W-02465A-01-0776 | Residential Utility Consumer Office |
| Generic Proceedings Concerning Electric Restructuring Issues | E-00000A-02-0051 | Residential Utility Consumer Office |
| Arizona Public Service Company | E-01345A-02-0707 | Residential Utility Consumer Office |
| Qwest Corporation | RT-00000F-02-0271 | Residential Utility Consumer Office |
| Arizona Public Service Company | E-01345A-02-0403 | Residential Utility |

| | | |
|---|---|---|
| | | Consumer Office |
| Citizens/UniSource | G-01032A-02-0598<br>E-01032C-00-0751<br>E-01933A-02-0914<br>E-01302C-02-0914<br>G-01302C-02-0914 | Residential Utility<br>Consumer Office |
| Arizona-American Water Company | WS-01303A-02-0867 | Residential Utility<br>Consumer Office |

**ARIZONA PUBLIC SERVICE COMPANY**
**DOCKET NO. E-01345A-03-0437**
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| MDC - 2 | ORIGINAL COST RATE BASE (000'S) |
| MDC - 3 | SUMMARY OF RATE BASE ADJUSTMENTS (000'S) |
| MDC - 4 | OPERATING INCOME - TEST YEAR AND RUCO PROPOSED (000'S) |
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| MDC - 6 | OPERATING INCOME ADJUSTMENT #2 - AMORTIZATION OF OF PWEC INTEREST PREMIUM |
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**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**ACC JURISDICTIONAL REVENUE REQUIREMENTS (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-1**


| LINE NO. | DESCRIPTION | (A) COMPANY ORIGINAL COST | (B) COMPANY RCND | (C) COMPANY FAIR VALUE | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 4,207,476 | $ 6,744,328 | $ 5,475,902 | $ 3,051,479 | $ 5,078,693 | $ 4,065,086 |
| 2 | ADJUSTED OPERATING INCOME | 263,870 | 263,870 | 263,870 | 258,992 | 258,992 | 258,992 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 6.27% | 3.91% | 4.82% | 8.49% | 5.10% | 6.37% |
| 4 | REQUIRED RATE OF RETURN | 8.67% | 5.41% | 6.66% | 7.43% | 4.46% | 5.57% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 364,788 | 364,788 | 364,788 | 226,578 | 226,578 | 226,578 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 100,918 | 100,918 | 100,918 | (32,414) | (32,414) | (32,414) |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65290 | 1.65290 | 1.65290 | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 166,807 | $ 166,807 | $ 166,807 | $ (53,605) | $ (53,605) | $ (53,605) |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,940,146 | $ 1,940,146 | $ 1,940,146 | $ 1,885,120 | $ 1,885,120 | $ 1,885,120 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 2,106,953 | $ 2,106,953 | $ 2,106,953 | $ 1,831,515 | $ 1,831,515 | $ 1,831,515 |
| 11 | PERCENTAGE AVERAGE INCREASE | 8.60% | 8.60% | 8.60% | -2.84% | -2.84% | -2.84% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**ACC JURISDICTIONAL RCND RATE BASE (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-1**


| LINE NO. | DESCRIPTION | (A) TOTAL COMPANY AS FILED | (B) RUCO ADJUSTMENTS TOTAL COMPANY | (C) RUCO ADJUSTED TOTAL COMPANY | (D) RUCO ADJUSTED ACC JURISDICTIONAL |
|---|---|---|---|---|---|
| 1 | GROSS UTILITY PLANT IN SERVICE | $ 12,602,163 | $ (1,562,070) | $ 11,040,093 | $ 11,005,365 |
| 2 | LESS: ACCUMULATED DEPRECIATION & AMORT. | (4,950,671) | 116,610 | (4,834,061) | (4,806,037) |
| 3 | NET UTILITY PLANT IN SERVICE | $ 7,651,492 | $ (1,445,461) | $ 6,206,031 | $ 6,199,327 |
| 4 | DEDUCTIONS: | | | | |
| 5 | LESS: TOTAL DEDUCTIONS | $ (1,605,285) | $ 147,519 | $ (1,457,766) | $ (1,455,314) |
| 6 | TOTAL ADDITIONS | 698,121 | (359,900) | 338,221 | 334,680 |
| 7 | TOTAL RATE BASE | $ 6,744,328 | $ (1,657,842) | $ 5,086,486 | $ 5,078,693 |

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1
COLUMN (B): SCHEDULE MDC-3 x RCND FACTOR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) x JURISDICTIONAL FACTOR

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**GROSS REVENUE CONVERSION FACTOR (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-1**


| LINE NO. | DESCRIPTION | TOTAL AMOUNT | REFERENCE |
|---|---|---|---|
| 1 | REVENUE | 1.0000 | |
| 2 | UNCOLLECTIBLES | - | COMPANY SCH. C-3 |
| 3 | SUB-TOTAL | 1.0000 | LINE 1 - LINE 2 |
| 4 | LESS: TAX RATE | 39.53% | NOTE (a) |
| 5 | TOTAL | 0.6047 | LINE 3 - LINE 4 |
| 6 | REVENUE CONVERSION FACTOR | 1.65375 | LINE 1/LINE 5 |

NOTE (a):
CALCULATION OF EFFECTIVE TAX RATE

| | |
|---|---|
| OPERATING INCOME BEFORE TAXES | 100.00% |
| ARIZONA STATE TAX | 6.97% |
| TAXABLE INCOME FEDERAL | 93.03% |
| FEDERAL INCOME TAX RATE | 35.00% |
| SUBTOTAL | 32.56% |
| ADD STATE TAX RATE | 39.53% |
| LINE 3 ABOVE | 100.00% |
| EFFECTIVE TAX RATE | 39.53% |

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**ORIGINAL COST RATE BASE (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-2**

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED TOTAL COMPANY | (B) RUCO ADJUSTMENTS TOTAL COMPANY | (C) RUCO TEST YEAR AS ADJUSTED TOTAL COMPANY | (D) RUCO TEST YEAR AS ADJUSTED ACC JURISDICTION |
|---|---|---|---|---|---|
| 1 | GROSS UTILITY PLANT IN SERVICE | $ 8,244,170 | $ (1,021,886) | $ 7,222,284 | $ 7,198,657 |
| 2 | LESS: ACCUMULATED DEPRECIATION & AMORT. | (3,115,987) | 73,395 | (3,042,592) | (3,024,981) |
| 3 | NET UTILITY PLANT IN SERVICE | **$ 5,128,183** | **$ (948,491)** | **$ 4,179,692** | **$ 4,173,676** |
| | DEDUCTIONS: | | | | |
| 4 | DEFERRED TAXES | $ (1,282,822) | $ 147,519 | $ (1,135,303) | $ (1,133,906) |
| 5 | INVESTMENT TAX CREDITS | (4,040) | - | (4,040) | (4,033) |
| 6 | CUSTOMER ADVANCES FOR CONSTRUCTION | (45,513) | - | (45,513) | (45,513) |
| 7 | CUSTOMER DEPOSITS | (39,865) | - | (39,865) | (39,865) |
| 8 | PENSION LIABILITY | (49,511) | - | (49,511) | (48,751) |
| 9 | OTHER DEFERRED CREDITS | (124,050) | - | (124,050) | (123,798) |
| 10 | UNAMORTIZED GAIN - SALE OF UTILITY PLANT | (59,484) | - | (59,484) | (59,381) |
| 11 | TOTAL DEDUCTIONS | **$ (1,605,285)** | **$ 147,519** | **$ (1,457,766)** | **$ (1,455,247)** |
| | ADDITIONS: | | | | |
| 12 | REGULATORY ASSETS/LIABILITIES NET | $ 300,589 | $ (284,461) | $ 16,128 | $ 16,087 |
| 13 | MISCELLANEOUS DEFERRED DEBITS | 27,379 | - | 27,379 | 26,959 |
| 14 | DEPRECIATION FUND - DECOMMISSIONING | 194,440 | - | 194,440 | 191,608 |
| 15 | ALLOWANCE FOR WORKING CAPITAL | 175,713 | (75,439) | 100,274 | 98,396 |
| 16 | TOTAL ADDITIONS | **$ 698,121** | **$ (359,900)** | **$ 338,221** | **$ 333,050** |
| 17 | TOTAL RATE BASE | **$ 4,221,019** | **$ (1,160,872)** | **$ 3,060,147** | **$ 3,051,479** |

REFERENCES:
COLUMN (A): COMPANY SCHEDULE B-1
COLUMN (B): SCHEDULE MDC-3
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) x APPROPRIATE JURISDICTIONAL FACTOR

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**SUMMARY OF RATE BASE ADJUSTMENTS (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-3**

| LINE NO. | DESCRIPTION | (A) TOTAL COMPANY | (B) ADJ. #1 | (C) ADJ. #2 | (D) ADJ. #3 | (E) ADJ. #4 | (F) ADJ. #5 | (G) RUCO ADJUSTED TOTAL COMPANY |
|---|---|---|---|---|---|---|---|---|
| 1 | GROSS UTILITY PLANT IN SERVICE | $ 8,244,170 | $ (1,021,886) | | $ - | $ - | $ - | $ 7,222,284 |
| 2 | LESS: ACCUMULATED DEPRECIATION & AMORT. | (3,115,987) | 73,395 | | | | | (3,042,592) |
| 3 | NET UTILITY PLANT IN SERVICE | $ 5,128,183 | $ (948,491) | $ - | $ - | $ - | $ - | $ 4,179,692 |
| | DEDUCTIONS: | | | | | | | |
| 4 | DEFERRED TAXES | $ (1,282,822) | 53,382 | $ 92,430 | $ 1,707 | $ - | $ - | $ (1,135,303) |
| 5 | INVESTMENT TAX CREDITS | (4,040) | | | | | | (4,040) |
| 6 | CUSTOMER ADVANCES FOR CONSTRUCTION | (45,513) | | | | | | (45,513) |
| 7 | CUSTOMER DEPOSITS | (39,865) | | | | | | (39,865) |
| 8 | PENSION LIABILITY | (49,511) | | | | | | (49,511) |
| 9 | OTHER DEFERRED CREDITS | (124,050) | | | | | | (124,050) |
| 10 | UNAMORTIZED GAIN - SALE OF UTILITY PLANT | (59,484) | | | | | | (59,484) |
| 11 | TOTAL DEDUCTIONS | $ (1,605,285) | $ 53,382 | $ 92,430 | $ 1,707 | $ - | $ - | $ (1,457,766) |
| | ADDITIONS: | | | | | | | |
| 12 | REGULATORY ASSETS/LIABILITIES NET | $ 300,589 | $ - | $ (234,000) | $ (50,461) | $ - | $ - | $ 16,128 |
| 13 | MISCELLANEOUS DEFERRED DEBITS | 27,379 | | | | | | 27,379 |
| 14 | DEPRECIATION FUND - DECOMMISSIONING | 194,440 | | | | | | 194,440 |
| 15 | ALLOWANCE FOR WORKING CAPITAL | 175,713 | | | | | (75,439) | 100,274 |
| 16 | TOTAL ADDITIONS | $ 698,121 | $ - | $ (234,000) | $ (50,461) | $ - | $ (75,439) | $ 338,221 |
| 17 | TOTAL RATE BASE | $ 4,221,019 | $ (895,109) | $ (141,570) | $ (48,754) | $ - | $ (75,439) | $ 3,060,147 |

| ADJUSTMENT #: | REFERENCE: |
|---|---|
| 1. REMOVE PWEC ASSETS | DIRECT TESTIMONY MDC |
| 2. REINSTATE SETTLEMENT WRITE-OFF | DIRECT TESTIMONY MDC |
| 3. ISFSI ACCRUALS | DIRECT TESTIMONY MDC |
| 4. RESERVED FOR TRANSMISSION ASSETS | DIRECT TESTIMONY ROSEN |
| 5. WORKING CAPITAL | SCHEDULE WAR-1 |

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**OPERATING INCOME - TEST YEAR AND RUCO PROPOSED (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-4**

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED TOTAL COMPANY | (B) RUCO ADJUSTMENTS TOTAL COMPANY | (C) RUCO TEST YEAR AS ADJUSTED TOTAL COMPANY | (D) RUCO TEST YEAR AS ADJUSTED ACC JURISDICTION | (E) RUCO PROPOSED CHANGES ACC JURISDICTION | (F) RUCO RECOMMENDED ACC JURISDICTION |
|---|---|---|---|---|---|---|---|
| 1 | ELECTRIC OPERATING REVENUES | $ 1,978,176 | $ (56,105) | $ 1,922,071 | $ 1,885,120 | $ (53,605) | $ 1,831,515 |
| 2 | LESS: FUEL & PURCHASED POWER COSTS | 568,870 | 34,946 | 603,816 | 594,272 | | 594,272 |
| 3 | TOTAL OPERATING REVENUES | **$ 1,409,306** | **$ (91,050)** | **$ 1,318,256** | **$ 1,290,848** | **$ (53,605)** | **$ 1,237,242** |
| 4 | OTHER OPERATING EXPENSES: | | | | | | |
| 5 | OPERATIONS AND MAINTENANCE | $ 616,060 | $ (34,685) | $ 581,375 | $ 556,852 | $ - | $ 556,852 |
| 6 | DEPRECIATION AND AMORTIZATION | 331,492 | (57,141) | 274,351 | 273,102 | | 273,102 |
| 7 | INCOME TAXES | 86,606 | 20,679 | 107,285 | 106,728 | (21,191) | 85,537 |
| 8 | OTHER TAXES | 110,144 | (15,016) | 95,128 | 95,174 | | 95,174 |
| 9 | TOTAL OPERATING EXPENSES OTHER THAN FUEL & POWER | **$ 1,144,302** | **$ (86,162)** | **$ 1,058,140** | **$ 1,031,856** | **$ (21,191)** | **$ 1,010,664** |
| 10 | OPERATING INCOME | **$ 265,004** | **$ (4,888)** | **$ 260,116** | **258,992** | **$ (32,414)** | **$ 226,578** |

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C-1
COLUMN (B): SCHEDULE MDC-5
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (E) x APPROPRIATE JURISDICTIONAL FACTOR
COLUMN (E): SCHEDULE MDC-1
COLUMN (F): COLUMN (D) + COLUMN (E)

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**SUMMARY OF OPERATING ADJUSTMENTS (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-5**


| LINE NO. | DESCRIPTION | (A) COMPANY PROPOSED TOTAL COMPANY | (B) ADJ. #1 | (C) ADJ. #2 | (D) ADJ. #3 | (E) ADJ. #4 | (F) ADJ. #5 | (G) ADJ. #6 | (H) ADJ. #7 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | ELECTRIC OPERATING REVENUES | **$ 1,978,176** | **$ (56,779)** | **$ -** | **$ -** | **$ 737** | **$ -** | **$ -** | **$ -** |
| 2 | LESS: | | | | | | | | |
| 3 | FUEL FOR ELECTRIC GENERATION: | | | | | | | | |
| 4 | COAL | $ 138,717 | $ 8,691 | $ - | $ - | $ - | $ - | $ - | $ - |
| 5 | NATURAL GAS | 49,320 | $ 3,090 | | | | | | |
| 6 | FUEL OIL | 1,220 | $ 76 | | | | | | |
| 7 | NUCLEAR: | | | | | | | | |
| 8 | AMORTIZATION | 26,740 | $ 1,675 | | | | | | |
| 9 | SPENT FUEL | 11,178 | $ 700 | | | | | | |
| 10 | TOTAL FUEL FOR ELECTRIC GENERATION | $ 227,175 | $ 14,234 | $ - | $ - | $ - | $ - | $ - | $ - |
| 11 | LESS: | | | | | | | | |
| 12 | PURCHASED POWER & TRANSMISSION: | | | | | | | | |
| 13 | PURCHASED POWER | $ 330,952 | $ 20,736 | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | TRANSMISSION BY OTHERS | 10,743 | | | | | | | |
| 15 | TOTAL PURCHASED POWER & TRANSMISSION BY OTHERS | $ 341,695 | $ 20,736 | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | TOTAL FUEL & PURCHASED POWER COSTS | **$ 568,870** | **$ 34,970** | **$ -** | **-** | **$ -** | **$ -** | **$ -** | **$ -** |
| 17 | TOTAL OPERATING REVENUES | **$ 1,409,306** | **$ (91,749)** | **$ -** | **$ -** | **$ 737** | **$ -** | **$ -** | **$ -** |
| 18 | OTHER OPERATIONS & MAINTENANCE: | | | | | | | | |
| 19 | PAYROLL | $ 218,822 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | SEVERANCE | 5,068 | | | | | | | |
| 21 | PENSION AND OPEB | 45,964 | | | | | | | |
| 22 | EMPLOYEE BENEFITS | 17,723 | | | | | | | |
| 23 | PAYROLL TAXES | 13,677 | | | | | | | |
| 24 | MATERIALS & SUPPLIES | 52,358 | | | | | | | |
| 25 | FRANCHISE PAYMENTS | - | | | | | | | |
| 26 | VEHICLE LEASE PAYMENTS | 7,228 | | | | | | | |
| 27 | RENTS | 5,649 | | | | | | | |
| 28 | PALO VERDE LEASE | 45,202 | | | | | | | |
| 29 | PALO VERDE SALE/LOSS GAIN AMORT. | (4,576) | | | | | | | |
| 30 | INSURANCE | 2,431 | | | | | | | |
| 31 | UNCOLLECTIBLE ACCOUNTS | 2,680 | | | | | | | |
| 32 | OTHER | 203,834 | (41,456) | (1,336) | (1,477) | | 29,000 | | |
| 33 | TOTAL OTHER OPERATIONS AND MAINTENANCE | $ 616,060 | $ (41,456) | $ (1,336) | $ (1,477) | $ - | $ 29,000 | $ - | $ - |
| 34 | DEPRECIATION & AMORTIZATION: | | | | | | | | |
| 35 | DEPRECIATION & AMORTIZATION | $ 331,492 | $ (41,541) | $ - | $ - | $ - | $ - | $ - | $ (15,600) |
| 36 | AMORT. OF ELECTRIC PLANT ACQ. ADJ. | - | | | | | | | |
| 37 | AMORT. OF PROP. LOSSES & REG. STUDY COSTS | - | | | | | | | |
| 38 | TOTAL DEPRECIATION & AMORTIZATION | $ 331,492 | $ (41,541) | $ - | $ - | $ - | $ - | $ - | $ (15,600) |
| 39 | INCOME TAXES: | | | | | | | | |
| 40 | CURRENT: | | | | | | | | |
| 41 | FEDERAL & STATE | $ 86,606 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 42 | DEFERRED | - | | | | | | | |
| 43 | TOTAL INCOME TAXES | $ 86,606 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 44 | OTHER TAXES: | | | | | | | | |
| 45 | PROPERTY TAXES | $ 106,189 | $ (11,256) | $ - | $ - | $ - | $ - | $ - | $ - |
| 46 | SALES TAXES | 3,955 | | | | | | | |
| 47 | TOTAL OTHER TAXES | $ 110,144 | $ (11,256) | $ - | $ - | $ - | $ - | $ - | $ - |
| 48 | | | | | | | | | |
| 49 | TOTAL OPERATING EXPENSES OTHER THAN FUEL & POWER | **$ 1,144,302** | **$ (94,253)** | **$ (1,336)** | **$ (1,477)** | **$ -** | **$ 29,000** | **$ -** | **$ (15,600)** |
| 50 | OPERATING INCOME | **$ 265,004** | **$ 2,504** | **$ 1,336** | **$ 1,477** | **$ 737** | **$ (29,000)** | **$ -** | **$ 15,600** |

| ADJUSTMENT #: | REFERENCE: |
|---|---|
| 1. REMOVE PWEC EXPENSES | DIRECT TESTIMONY MDC |
| 2. AMORTIZATION OF PWEC INTEREST PREMIUM | SCHEDULE MDC-6 |
| 3. REMOVE DIRECT ACCESS EXPENSE | DIRECT TESTIMONY MDC |
| 4. CORRECT EPS REVENUES | DIRECT TESTIMONY MDC |
| 5. RUCO PROPOSED DSM LEVEL | DIRECT TESTIMONY MDC |
| 6. RESERVED FOR TRANSMISSION EXPENSES | DIRECT TESTIMONY ROSEN |
| 7. REINSTATE SETTLEMENT WRITE-OFF | DIRECT TESTIMONY MDC |

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**SUMMARY OF OPERATING ADJUSTMENTS (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-5**
**PAGE 2 OF 2**

| LINE NO. | DESCRIPTION | (I) ADJ. #8 | (J) ADJ. #9 | (K) ADJ. #10 | (L) ADJ. #11 | (M) ADJ. #12 | (N) ADJ. #13 | (O) ADJ. #14 | (P) ADJ. #15 | (Q) RUCO ADJUSTED TOTAL COMPANY |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | ELECTRIC OPERATING REVENUES | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ (63)** | **$ 1,922,071** |
| 2 | LESS: | | | | | | | | | |
| 3 | FUEL FOR ELECTRIC GENERATION: | | | | | | | | | |
| 4 | COAL | $ (8) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 147,400 |
| 5 | NATURAL GAS | (8) | | | | | | | | 52,402 |
| 6 | FUEL OIL | (8) | | | | | | | | 1,288 |
| 7 | NUCLEAR: | | | | | | | | | - |
| 8 | AMORTIZATION | | | | | | | | | 28,415 |
| 9 | SPENT FUEL | | | | | | | | | 11,878 |
| 10 | TOTAL FUEL FOR ELECTRIC GENERATION | $ (24) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 241,385 |
| 11 | LESS: | | | | | | | | | |
| 12 | PURCHASED POWER & TRANSMISSION: | | | | | | | | | |
| 13 | PURCHASED POWER | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 351,688 |
| 14 | TRANSMISSION BY OTHERS | | | | | | | | | 10,743 |
| 15 | TOTAL PURCHASED POWER & TRANSMISSION BY OTHERS | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 362,431 |
| 16 | TOTAL FUEL & PURCHASED POWER COSTS | **$ (24)** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ 603,816** |
| 17 | TOTAL OPERATING REVENUES | **$ 24** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ (63)** | **$ 1,318,256** |
| 18 | OTHER OPERATIONS & MAINTENANCE: | | | | | | | | | |
| 19 | PAYROLL | $ (68) | $ - | $(11,056) | $ - | $ - | $ - | $ - | $ - | $ 207,698 |
| 20 | SEVERANCE | | (6,972) | | | | | | | (1,904) |
| 21 | PENSION AND OPEB | | | | | | | | | 45,964 |
| 22 | EMPLOYEE BENEFITS | | | | | | | | | 17,723 |
| 23 | PAYROLL TAXES | | | | | | | | | 13,677 |
| 24 | MATERIALS & SUPPLIES | | | | | | | | | 52,358 |
| 25 | FRANCHISE PAYMENTS | | | | | | | | | - |
| 26 | VEHICLE LEASE PAYMENTS | | | | | | | | | 7,228 |
| 27 | RENTS | | | | | | | | | 5,649 |
| 28 | PALO VERDE LEASE | | | | | | | | | 45,202 |
| 29 | PALO VERDE SALE/LOSS GAIN AMORT. | | | | | | | | | (4,576) |
| 30 | INSURANCE | | | | | | | | | 2,431 |
| 31 | UNCOLLECTIBLE ACCOUNTS | | | | | | | | | 2,680 |
| 32 | OTHER | | | | (965) | (354) | | | | 187,246 |
| 33 | TOTAL OTHER OPERATIONS AND MAINTENANCE | $ (68) | $ (6,972) | $(11,056) | $ (965) | $ (354) | $ - | $ - | $ - | $ 581,375 |
| 34 | DEPRECIATION & AMORTIZATION: | | | | | | | | | |
| 35 | DEPRECIATION & AMORTIZATION | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 274,351 |
| 36 | AMORT. OF ELECTRIC PLANT ACQ. ADJ. | | | | | | | | | - |
| 37 | AMORT. OF PROP. LOSSES & REG. STUDY COSTS | | | | | | | | | - |
| 38 | TOTAL DEPRECIATION & AMORTIZATION | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 274,351 |
| 39 | INCOME TAXES: | | | | | | | | | |
| 40 | CURRENT: | | | | | | | | | |
| 41 | FEDERAL & STATE | $ - | $ - | $ - | $ - | $ - | $ - | $ 20,679 | $ - | $ 107,285 |
| 42 | DEFERRED | | | | | | | | | - |
| 43 | TOTAL INCOME TAXES | $ - | $ - | $ - | $ - | $ - | $ - | $ 20,679 | $ - | $ 107,285 |
| 44 | OTHER TAXES: | | | | | | | | | |
| 45 | PROPERTY TAXES | $ - | $ - | $ - | $ - | $ - | $ (3,760) | $ - | $ - | $ 91,173 |
| 46 | SALES TAXES | | | | | | | | | 3,955 |
| 47 | TOTAL OTHER TAXES | $ - | $ - | $ - | $ - | $ - | $ (3,760) | $ - | $ - | $ 95,128 |
| 48 | | | | | | | | | | |
| 49 | TOTAL OPERATING EXPENSES OTHER THAN FUEL & POWER | **$ (68)** | **$ (6,972)** | **$(11,056)** | **$ (965)** | **$ (354)** | **$ (3,760)** | **$ 20,679** | **$ -** | **$ 1,058,140** |
| 50 | OPERATING INCOME | **$ 93** | **$ 6,972** | **$ 11,056** | **$ 965** | **$ 354** | **$ 3,760** | **$ (20,679)** | **$ (63)** | **$ 260,116** |

| ADJUSTMENT #: | REFERENCE: |
|---|---|
| 8. NORMALIZE PAYROLL | SCHEDULE WAR-2 |
| 9. EMPLOYEE SEVERANCE | SCHEDULE WAR-3 |
| 10. REMOVE INCENTIVE PAY | DIRECT TESTIMONY WAR |
| 11. REMOVE AVNET SOFTWARE LEASE EXPENSE | DIRECT TESTIMONY WAR |
| 12. INTEREST ON CUSTOMER DEPOSITS | SCHEDULE WAR-4 |
| 13. PROPERTY TAXES | SCHEDULE WAR-5 |
| 14. INCOME TAXES | SCHEDULE WAR-6 |
| 15. SCHEDULE 1 CHANGES | SCHEDULE WAR-7 |

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**OPERATING INCOME ADJUSTMENT #2 - AMORTIZATION OF OF PWEC INTEREST PREMIUM**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-6**

| LINE NO. | DATE | (A) OUTSTANDING BALANCE | (B) TOTAL PAYMENT | (C) PRINCIPLE PAYMENT | (D) INTEREST PAYMENT | (E) ENDING BALANCE |
|---|---|---|---|---|---|---|
| 1 | 15-May-03 | $ 500,000,000 | | | $ - | $ 500,000,000 |
| 2 | 1-Jan-04 | 500,000,000 | 56,600,000 | 50,000,000 | 6,600,000 | 450,000,000 |
| 3 | 1-Jul-04 | 450,000,000 | 55,940,000 | 50,000,000 | 5,940,000 | 400,000,000 |
| 4 | 1-Jan-01 | 400,000,000 | 55,280,000 | 50,000,000 | 5,280,000 | 350,000,000 |
| 5 | 1-Jul-05 | 350,000,000 | 54,620,000 | 50,000,000 | 4,620,000 | 300,000,000 |
| 6 | 1-Jan-06 | 300,000,000 | 53,960,000 | 50,000,000 | 3,960,000 | 250,000,000 |
| 7 | 1-Jul-06 | 250,000,000 | 53,300,000 | 50,000,000 | 3,300,000 | 200,000,000 |
| 8 | 1-Jan-07 | 200,000,000 | 52,640,000 | 50,000,000 | 2,640,000 | 150,000,000 |
| 9 | 1-Jul-07 | 150,000,000 | 51,980,000 | 50,000,000 | 1,980,000 | 100,000,000 |
| 10 | 1-Jan-08 | 100,000,000 | 51,320,000 | 50,000,000 | 1,320,000 | 50,000,000 |
| 11 | 1-Jul-08 | 50,000,000 | 50,660,000 | 50,000,000 | 660,000 | - |
| 12 | INTEREST EARNED 1 JULY 04 THROUGH 1 JULY 08 | | | | $ 23,760,000 | |
| 13 | 5 YEAR AMORTIZATION | | | | $ 4,752,000 | |
| 14 | PER COMPANY | | | | $ 3,416,000 | |
| 15 | ADJUSTMENT | | | | $ 1,336,000 | |

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**COST OF CAPITAL**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE MDC-7**

| LINE NO. | TYPE OF CAPITAL | (A) PERCENT | (B) COST RATE | (C) WEIGHTED AVG. COST RATE |
|---|---|---|---|---|
| 1 | COMMON EQUITY | 45.14% | 9.50% | 4.29% |
| 2 | LONG-TERM DEBT | 53.83% | 5.77% | 3.11% |
| 3 | SHORT-TERM DEBT | 1.03% | 3.00% | 0.03% |
| 4 | TOTAL CAPITAL | 100.00% | | 7.43% |

PRE-TAX INTEREST COVERAGE = 3.28X (a)

REFERENCES:
COLUMN (A): TESTIMONY, STEPHEN G. HILL
COLUMN (B): TESTIMONY, STEPHEN G. HILL
COLUMN (C): COLUMN (A) x COLUMN (B)

NOTE:
(a) ASSUMING THE COMPANY EXPERIENCES, PROSPECTIVELY, AN INCOME TAX RATE OF 40.00%, THE PRE-TAX OVERALL RETURN WOULD BE 10.28% [ 7.43% - ( 3.11% + 0.03% ) = 4.29% / ( 1 - 40.00% ) = 7.15% + (3.11% + 0.03% ) ]. THAT PRE-TAX OVERALL RETURN, 10.28%, DIVIDED BY THE WEIGHTED COST OF DEBT ( 3.11% + 0.03% ), INDICATES A PRE-TAX INTEREST COVERAGE OF 3.28 TIMES.

# ARIZONA PUBLIC SERVICE COMPANY

# DOCKET NO. E-01345A-03-0437

## DIRECT TESTIMONY

## OF

## WILLIAM A. RIGSBY

## ON BEHALF OF

## THE

## RESIDENTIAL UTILITY CONSUMER OFFICE

## FEBRUARY 3, 2004

EXHIBIT

RUCO-2

Stamitted

1 **INTRODUCTION** ..... 1

2 **SUMMARY OF TESTIMONY AND RECOMMENDATIONS** ..... 4

3 **RATE BASE** ..... 6

4 **Rate Base Adjustment #5 – Working Capital** ..... 6

5 **OPERATING INCOME** ..... 9

6 **Operating Adjustment #8 - Normalize Payroll Expense** ..... 9

7 **Operating Adjustment #9 - Employee Severance** ..... 10

8 **Operating Adjustment #10 – Remove Incentive Pay** ..... 11

9 **Operating Adjustment #11 – Remove Avnet Software Lease Expense** ..... 13

10 **Operating Adjustment #12 - Interest on Customer Deposits** ..... 13

11 **Operating Adjustment #13 – Property Taxes** ..... 15

12 **Operating Adjustment #14 – Income Taxes** ..... 15

13 **Operating Adjustment #15 – Schedule 1 Changes** ..... 16

14

**INTRODUCTION**

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and your qualifications in the field of utilities regulation.

A. Appendix I, which is attached to this testimony, describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Arizona Public Service Company's ("APS" or "Company") application for a permanent rate increase ("Application"). APS filed the Application with the Arizona Corporation Commission ("ACC" or "Commission") on June 27, 2003. The Company chose the period ended December 31, 2002 as the test year ("Test Year") in this proceeding.

Q. What aspects of the APS Application will you provide direct testimony on?

A. My direct testimony will concentrate on the lead/lag study that was used to develop the Company's recommended level of working capital (included in rate base) and on various operating expense adjustments.

Q. Which other RUCO witnesses will be providing direct testimony in this proceeding?

A. Ms. Marylee Diaz Cortez, C.P.A., the chief of RUCO's Accounting & Rates section, will provide direct testimony on the majority of the rate base issues addressed in the Company's Application and on the operating adjustments proposed by APS that are not addressed in my testimony.

In addition to the direct testimony of Ms. Diaz Cortez, RUCO will also present the testimony of four outside consultants: Dr. Richard Rosen and Dr. John Stutz, both of Tellus Institute, who will address the transmission issues associated with the case, the Company's base cost of fuel, rate design and cost of service; Mr. David A. Schlissel, a senior consultant with Synapse Energy Economics, who will present testimony on the Pinnacle West Energy Corporation ("PWEC") assets; and Mr. Stephen G. Hill, who will address the cost of capital issues associated with the case and will present his recommended rate of return on invested capital which will include his recommended weighted costs of both common equity and debt.

Q. Please describe how you conducted your analysis of the APS Application.

A. I reviewed the APS Application and analyzed various work papers that were provided to RUCO by the Company as part of its initial filing. Other pertinent information and source documents were collected through a series of written data requests, which were faxed and mailed to the Company. After compiling the aforementioned information and materials, I performed an analysis that provided additional insight into the Company's working capital and operating expense proposals. RUCO's recommendations on working capital and the eight operating income adjustments covered in this testimony are based on the results of my analysis.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-7. These schedules exhibit detailed information on RUCO's Rate Base Adjustment #5 and RUCO's Operating Adjustments #8, #9 and #12 through #15 (Operating Adjustments #10 and #11 are explained in my direct testimony). The effects of these specific adjustments on RUCO's recommended levels of rate base and operating income can be viewed in Schedules MDC-2 through MDC-5, which are presented in the direct testimony of RUCO witness Marylee Diaz Cortez.

Q. Does your silence on any of the issues or matters addressed in the Company's Application constitute either your, or RUCO's, acceptance of the Company's position on such issues or matters?

A. No, it does not.

**SUMMARY OF TESTIMONY AND RECOMMENDATIONS**

Q. Please summarize the recommendations and adjustments that you address in your testimony that pertain to rate base, operating revenue, and operating expense.

A. My testimony will present the following recommended adjustments:

**Rate Base Adjustments:**

Working Capital – This adjustment reduces cash working capital by $75,439,000. The adjustment reflects the results of RUCO's recalculation of cash working capital using RUCO's adjusted Test Year levels of expense and the exclusion of non-cash items.

**Operating Adjustments:**

Normalize Payroll – This normalization adjustment reduces the Company-proposed level of payroll expense by $93,000. In making the adjustment, RUCO analyzed payroll data over the 2000 through 2002 operating periods.

Employee Severance – This adjustment decreases the Company's requested level of expense by $6,972,384 as a result of RUCO's use of a

ten-year amortization period in the calculation of the expense as opposed to a three-year period used by APS.

Remove Incentive Pay – This adjustment removes $11,056,000 in incentive pay that was awarded to employees under questionable circumstances.

Remove Avnet Software Lease Expense – This adjustment decreases operating expense by $965,000. The adjustment removes a non-recurring expense associated with software that was leased by the Company during the Test Year.

Interest on Customer Deposits – This adjustment decreases the level of interest paid on customer deposits by $354,000. The adjustment reflects RUCO's use of an updated one-year constant maturities rate that APS uses to calculate levels of interest expense on the Company's year-end balance of customer deposits.

Property Taxes – This pro forma adjustment annualizes property tax expense by using the Arizona Department of Revenue ("DOR") approved formula for computing property tax liability. The Adjustment reduces the Company-proposed level of property tax expense by $3,760,000.

Income Taxes – This adjustment calculates the appropriate level of income tax expense given RUCO's recommended operating income.

Schedule 1 Changes – This adjustment reflects the service charge recommendations of RUCO witness Dr. John Stutz. The adjustment reduces electric operating revenues by $62,629.

## RATE BASE

### Rate Base Adjustment #5 – Working Capital

Q. Is APS requesting that an allowance for cash working capital be included in rate base?

A. Yes.

Q. What methodology has the Company used to calculate the level of cash working capital that it seeks to include in rate base?

A. The Company has used the lead/lag study method as opposed to the formula method (which is generally used for smaller utilities and always produces a positive working capital figure).

Q. Has RUCO analyzed the Company's lead/lag study that was used to compute the level of cash working capital that APS is seeking?

A. Yes.

Q. Does RUCO agree with the Company's computation of cash working capital?

A. No. There are two main areas of disagreement that RUCO has in regard to the way in which the Company has computed its requested level of cash working capital. The first area of disagreement is the Company's decision to include non-cash items in its lead/lag study. This has the effect of increasing the allowance for working capital by $54,097,922. The

second area of disagreement is the Company's use of unadjusted Test Year levels of operating expense as opposed to adjusted Test Year levels of expense.

Q. What non-cash items has APS included in the Company's calculation of cash working capital?

A. APS has included such non-cash items as depreciation & amortization expense, the amortization of a plant acquisition adjustment, deferred income taxes and several other non-cash amortized operating expense items.

Q. What has the Commission's position been in regard to the inclusion of non-cash items in the allowance for cash working capital?

A. The ACC has consistently rejected the inclusion of non-cash items in the calculation of cash working capital. The best example of this can be found in Decision No. 56659 dated October 24, 1989, in which the Commission rejected Tucson Electric Power's ("TEP") inclusion of non-cash items in its calculation of cash working capital. In the decision, the Commission states the following:

> "As we have stated in previous decisions, the calculation is for "cash working capital" and not "cash and non-cash working capital" [emphasis included]. Further, we believe the inclusion of equity costs in working capital provides an additional return over and above the cost of equity. As a result, we clearly reject TEP's request to include "non-cash" items in its cash working capital calculation."

The Commission latter affirmed this same position in Decision No. 61110 dated August 28, 1998, in which Vail Water Company also attempted to include non-cash items in its calculation of cash working capital. Given these facts RUCO believes that it is appropriate to exclude the non-cash items noted earlier.

Q. Why does RUCO disagree with the Company's use of unadjusted Test Year levels of operating expense in its calculation of cash working capital?

A. RUCO believes that the level of cash working capital in rate base should include the adjusted Test Year expenses in order to reflect what the Company's cash working capital requirements are on a going-forward basis.

Q. Has RUCO recalculated the Company's cash working capital requirement using adjusted Test Year expense levels and excluding non-cash items?

A. Yes. My recalculation of the Company's cash working capital requirement can be viewed on Page 2 of Schedule WAR-1. Other than the aforementioned changes, the method that I used to calculate RUCO's recommended level of cash working capital is identical to the method used by the Company. RUCO's total working capital adjustment, exhibited on Page 1 of Schedule WAR-1 is a $75,439,000 decrease to the level of cash working capital requested by APS.

**OPERATING INCOME**

**Operating Adjustment #8 – Normalize Payroll**

Q. Has RUCO studied the Company's adjustment to the Test Year level of payroll expense?

A. Yes.

Q. Does RUCO agree with the Company's method for annualizing Test Year payroll expense?

A. No. RUCO believes that the Company's method for annualizing payroll is too dependent on payroll levels that were incurred only during the Test Year period.

Q. What method has RUCO used in arriving at its recommended level of payroll expense?

A. RUCO believes that a better approach to normalizing payroll expense is to analyze payroll data over multiple operating periods and then calculate a normalized expense figure that is based on that data.

Q. Has RUCO used this approach in calculating its adjustment to payroll expense?

A. Yes. My adjustment was based on payroll data from the Company's 2000, 2001 and 2002 operating periods. RUCO's recommended reduction of $93,000 to the Company's proposed level of payroll expense is the result of my analysis of the amounts of base, overtime and premium pay, attributable to fuel handling and operations and maintenance expense, that was paid out over the aforementioned three-year period. The adjustment is exhibited in Schedule WAR-2.

**Operating Adjustment #9 – Employee Severance**

Q. Does RUCO agree with APS' calculation of the Company-proposed pro forma adjustment to employee severance expense?

A. RUCO is satisfied with the overall method that the Company used to calculate its adjustment to Test Year employee severance expense. However, RUCO disagrees with the Company's decision to use a three-year amortization period.

Q. What amortization period is RUCO recommending?

A. RUCO is recommending a ten-year amortization period. This is based on RUCO's belief that current APS ratepayers will not see any benefit from the realized savings of the Company's severance program should the Commission adopt the Company-proposed three-year amortization period.

This is because the annual payroll savings attributable to the severance program would equal the three-year amortization expense.

Q. Does RUCO's adjustment reflect the effects of a ten-year amortization period?

A. Yes. As can be seen in Schedule WAR-3, the only difference between RUCO's calculation and the Company's calculation is RUCO's use of a ten-year amortization period. RUCO's adjustment results in a $6,972,384 reduction in Test Year operating expense. This adjustment will allow today's customers as well as future customers to benefit from the savings attributable to the severance program.

**Operating Adjustment #10 – Remove Incentive Pay**

Q. Why has RUCO removed $11,056,000 in incentive pay from operating expense?

A. RUCO believes that the removal of the incentive pay is warranted when the circumstances under which the incentive payment was made are taken into consideration.

Q. What were the circumstances surrounding the issuance of the incentive payments?

A. Based on confidential information provided by the Company, APS had instituted a performance incentive pay program that was based on the

maximization of earnings levels. Once a specific level of earnings (predetermined by APS as part of the incentive plan's goals) were achieved by APS employees, set amounts of incentive awards, as a percentage of earnings, would be paid out by the Company.

Q. Did the Company's employees reach the goals set forth in the APS incentive plan?

A. No, they did not. The Company stated that even though the employee efforts fell far short of the earnings threshold levels established in the plan, the Company's board of directors elected to pay out a bonus anyway[1]. Given these circumstances, RUCO believes that the payment of bonuses should not be recovered from ratepayers.

Q. Why does RUCO believe that the payment of bonus money, paid out without meeting performance goals, should not be recovered from ratepayers?

A. The original terms of the incentive plan were not achieved by the Company's employees and the ratepayers will not receive any benefit from the level of expense reductions that were originally set by APS. In effect, we have a situation where the Company set goals for its employees that they failed to meet but the Company's board members said hey, that's okay, we'll still give you something anyway. RUCO believes that if the

[1] Company response to Utilitech data request UTI-12-299.

Company wants to make such an incentive payment it should treat the bonus as a below the line expense item. In this case, since employee performance did not reach its goals, there is no incremental benefit that would warrant ratepayers funding of the bonuses.

**Operating Adjustment #11 – Remove Avnet Software Lease Expense**

Q. Please explain your adjustment, for Avnet software lease expense.

A. The adjustment removes $965,000 in non-recurring software leasing expense. The adjustment was based on information provided by the Company in its response to data requests issued by Utilitech[2].

**Operating Adjustment #12 - Interest on Customer Deposits**

Q. How does APS calculate interest on customer deposits held by the Company?

A. APS calculates interest on customer deposits by multiplying the year-end customer deposit balance by a one-year treasury constant maturities rate. The one-year constant maturities rate used by the Company is the daily rate that is published in the Federal Reserve's website on the first business day of the New Year. In this proceeding, APS used the customer deposit balance booked on the last day of the Test Year and the one-year constant maturities rate published on January 2, 2003. The

[2] Utilitech data requests UTI 4-158 and UTI 10-266.

Company stated in its Application that this is the same method that has been used by the Commission in prior rate case proceedings.

Q. Has RUCO made an adjustment for interest on customer deposits?

A. Yes. RUCO is recommending that the level of interest on customer deposits be reduced by $354,000. The adjustment reflects a known and measurable change and can be seen in Schedule WAR-4.

Q. How did you determine your recommended level of interest on customer deposits?

A. I multiplied the customer deposit balance, that was booked on December 31 of the Test Year, times an updated one-year constant maturities rate that appeared in the Federal Reserve's website on January 26, 2004. The daily rate, listed for January 2, 2004, is 1.31 percent, or 89 basis points[3] lower than the 2.20 percent January 2, 2003 rate used in the Company's application. The 1.31 percent rate that I used was the published rate for the first business day of 2004. This is the same rate used by APS to calculate interest on customer deposits.

[3] 100 basis points are equal to 1.00 percent.

**Operating Adjustment #13 – Property Taxes**

Q. Please describe your adjustment to property tax expense.

A. The adjustment to property taxes was calculated by using the methodology used by DOR for determining the amount of property taxes owed. In performing the calculation, the level of Test Year plant in service was reduced by the Test Year amounts of land and transportation assets that were booked in the Company's plant in service account. The reduced amount of plant, less accumulated depreciation, was then increased by the level of materials and supplies on hand at the end of the Test Year and by 50 percent of the construction work in progress that was booked on December 31, 2002. This amount represents the Company's full cash value. Per DOR guidelines, 25 percent of this full cash value (i.e. the assessed value) was subject to the Company's property tax rate of 9.60 percent. This results in a property tax liability of $103,381,000, which is $3,760,000 less than the $107,141,000 level of property tax expense proposed by APS. The property tax calculation, which I have just described, is exhibited in Schedule WAR-5.

**Operating Adjustment #14 – Income Taxes**

Q. Have you calculated an appropriate level of income tax expense based on RUCO's recommended adjusted operating income for APS?

A. Yes I have. My adjustment for income tax expense is exhibited in Schedule WAR-6.

Q. Does your calculation of income tax expense use the synchronized interest methodology to determine the amount of interest expense to be deducted from income tax?

A. Yes it does. The interest synchronization portion of my income tax liability calculation appears in Note (a) on Schedule WAR-6. The calculation multiplies RUCO witness Marylee Diaz Cortez's recommended level of rate base times RUCO witness Stephen Hill's recommended weighted cost of debt.

**Operating Adjustment #15 – Schedule 1 Changes**

Q. Please explain your adjustment, which reduces APS' electric operating revenues by $62,629.

A. My $62,629 downward adjustment to APS' electric operating revenues is based on the service charge recommendations of RUCO witness Dr. John Stutz. The RUCO adjusted service charges, which are exhibited in Column (F) of Schedule WAR-7, reflect Dr, Stutz's recommended elimination of the Company's proposed Trip Charge and the maximum amount of increase to all of the remaining charges (with the exception of the TONP @ Poll charge) under his 15.0 percent cap recommendation[4].

Q. Does this conclude your testimony on APS?

A. Yes, it does.

[4] Found in Section 8 of the direct testimony of Dr. John Stutz.

**Appendix 1**

# Qualifications of William A. Rigsby

**EDUCATION:**

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

**EXPERIENCE:**

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Revenue Auditor II
Arizona Department of Revenue
Corporate Income Tax Audit Unit
Phoenix, Arizona
November 1993 – October 1994

Tax Examiner Technician I
Arizona Department of Revenue
Transaction Privilege Tax Audit Unit
Phoenix, Arizona
July 1991 – November 1993

**Appendix 1**

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| ICR Water Users Association | U-2824-94-389 | Original CC&N |
| Rincon Water Company | U-1723-95-122 | Rate Increase |
| Ash Fork Development Association, Inc. | E-1004-95-124 | Rate Increase |
| Parker Lakeview Estates Homeowners Association, Inc. | U-1853-95-328 | Rate Increase |
| Mirabell Water Company, Inc. | U-2368-95-449 | Rate Increase |
| Bonita Creek Land and Homeowner's Association | U-2195-95-494 | Rate Increase |
| Pineview Land & Water Company | U-1676-96-161 | Rate Increase |
| Pineview Land & Water Company | U-1676-96-352 | Financing |
| Montezuma Estates Property Owners Association | U-2064-96-465 | Rate Increase |
| Houghland Water Company | U-2338-96-603 et al | Rate Increase |
| Sunrise Vistas Utilities Company – Water Division | U-2625-97-074 | Rate Increase |
| Sunrise Vistas Utilities Company – Sewer Division | U-2625-97-075 | Rate Increase |
| Holiday Enterprises, Inc. dba Holiday Water Company | U-1896-97-302 | Rate Increase |
| Gardener Water Company | U-2373-97-499 | Rate Increase |
| Cienega Water Company | W-2034-97-473 | Rate Increase |
| Rincon Water Company | W-1723-97-414 | Financing/Auth. To Issue Stock |
| Vail Water Company | W-01651A-97-0539 et al | Rate Increase |
| Bermuda Water Company, Inc. | W-01812A-98-0390 | Rate Increase |
| Bella Vista Water Company | W-02465A-98-0458 | Rate Increase |
| Pima Utility Company | SW-02199A-98-0578 | Rate Increase |

**Appendix 1**

**RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)**

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| Pineview Water Company | W-01676A-99-0261 | WIFA Financing |
| I.M. Water Company, Inc. | W-02191A-99-0415 | Financing |
| Marana Water Service, Inc. | W-01493A-99-0398 | WIFA Financing |
| Tonto Hills Utility Company | W-02483A-99-0558 | WIFA Financing |
| New Life Trust, Inc. dba Dateland Utilities | W-03537A-99-0530 | Financing |
| GTE California, Inc. | T-01954B-99-0511 | Sale of Assets |
| Citizens Utilities Rural Company, Inc. | T-01846B-99-0511 | Sale of Assets |
| MCO Properties, Inc. | W-02113A-00-0233 | Reorganization |
| American States Water Company | W-02113A-00-0233 | Reorganization |
| Arizona American Water Company | W-01303A-00-0327 | Financing |
| Arizona Electric Power Cooperative | E-01773A-00-0227 | Financing |
| 360networks (USA) Inc. | T-03777A-00-0575 | Financing |
| Beardsley Water Company, Inc. | W-02074A-00-0482 | WIFA Financing |
| Mirabell Water Company | W-02368A-00-0461 | WIFA Financing |
| Rio Verde Utilities, Inc. | WS-02156A-00-0321 et al | Rate Increase/ Financing |
| Arizona Water Company | W-01445A-00-0749 | Financing |
| Loma Linda Estates, Inc. | W-02211A-00-0975 | Rate Increase |
| Arizona Water Company | W-01445A-00-0962 | Rate Increase |
| Mountain Pass Utility Company | SW-03841A-01-0166 | Financing |
| Picacho Sewer Company | SW-03709A-01-0165 | Financing |
| Picacho Water Company | W-03528A-01-0169 | Financing |
| Ridgeview Utility Company | W-03861A-01-0167 | Financing |
| Green Valley Water Company | W-02025A-01-0559 | Rate Increase |
| Bella Vista Water Company | W-02465A-01-0776 | Rate Increase |
| Arizona Water Company | W-01445A-02-0619 | Rate Increase |

**Appendix 1**

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| Arizona-American Water Company | W-01303A-02-0867 et al. | Rate Increase |
| Rio Rico Utilities, Inc. | WS-02676A-03-0434 | Rate Increase |

**ARIZONA PUBLIC SERVICE COMPANY**
**DOCKET NO. E-01345A-03-0437**
**TABLE OF CONTENTS TO SCHEDULES WAR**


| SCHEDULE # | |
|---|---|
| WAR - 1 | RATE BASE ADJUSTMENT #5 - WORKING CAPITAL (000'S) |
| WAR - 2 | OPERATING INCOME ADJUSTMENT #8 - ANNUALIZE PAYROLL (000'S) |
| WAR - 3 | OPERATING INCOME ADJUSTMENT #9 - EMPLOYEE SEVERANCE |
| WAR - 4 | OPERATING INCOME ADJUSTMENT #12 - INTEREST ON CUSTOMER DEPOSITS (000'S) |
| WAR - 5 | OPERATING INCOME ADJUSTMENT #13 - PROPERTY TAXES (000's) |
| WAR - 6 | OPERATING INCOME ADJUSTMENT #14 - INCOME TAXES (000'S) |
| WAR - 7 | OPERATING INCOME ADJUSTMENT #15 - SCHEDULE 1 CHANGES |

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 1999**
**RATE BASE ADJUSTMENT #5 - WORKING CAPITAL (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE WAR-1**


| LINE NO. | DESCRIPTION | AMOUNT | REFERENCE |
|---|---|---|---|
| 1 | CASH WORKING CAPITAL PER COMPANY | $ 54,098 | COMPANY SCH. B-5, PG. 1 |
| 2 | CASH WORKING CAPITAL PER RUCO | (21,341) | SCH. WAR-1, PG. 2 |
| 3 | CASH WORKING CAPITAL ADJUSTMENT | $ (75,439) | LINE 2 - LINE 1 |
| 4 | MATERIALS & SUPPLIES PER COMPANY | $ 79,985 | COMPANY SCH. B-5, PG. 1 |
| 5 | MATERIALS & SUPPLIES PER RUCO | 79,985 | COMPANY SCH. E-1, PG. 1 |
| 6 | MATERIALS & SUPPLIES ADJUSTMENT | $ - | LINE 5 - LINE 4 |
| 7 | FUEL - COAL AND OIL PER COMPANY | $ 28,185 | COMPANY SCH. B-5, PG. 1 |
| 8 | FUEL - COAL AND OIL PER RUCO | 28,185 | COMPANY SCH. E-1, PG. 1 |
| 9 | FUEL - COAL AND OIL ADJUSTMENT | $ - | LINE 7 - LINE 8 |
| 10 | FUEL - NUCLEAR, NET PER COMPANY | $ 7,466 | COMPANY SCH. B-5, PG. 1 |
| 11 | FUEL - NUCLEAR, NET PER RUCO | 7,466 | COMPANY SCH. E-1, PG. 1 |
| 12 | FUEL - NUCLEAR, NET ADJUSTMENT | $ - | LINE 10 - LINE 11 |
| 13 | PREPAYMENTS PER COMPANY | $ 5,979 | COMPANY SCH. B-5, PG. 1 |
| 14 | PREPAYMENTS PER RUCO | 5,979 | COMPANY SCH. B-5, PG. 1 |
| 15 | PREPAYMENTS ADJUSTMENT | $ - | LINE 11 - LINE 10 |
| 16 | TOTAL WORKING CAPITAL ADJUSTMENT | $ (75,439) | SUM OF LINES 3, 6, 9, 12 & 15 |

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**RATE BASE ADJUSTMENT #5 - WORKING CAPITAL**
**CASH WORKING CAPITAL LEAD/LAG CALCULATION**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE WAR-1**
**PAGE 2 OF 2**

| LINE NO. | DESCRIPTION | (A) TOTAL EXPENSES COMPANY | (B) RUCO ADJUSTMENTS | (C) RUCO ADJUSTED EXPENSES | (D) REVENUE LAG DAYS | (E) EXPENSE LAG DAYS | (F) NET LAG DAYS | (G) CWC FACTOR | (H) WORKING CAPITAL REQUIREMENT |
|---|---|---|---|---|---|---|---|---|---|
| 1 | FUEL FOR ELECTRIC GENERATION: | | | | | | | | |
| 2 | COAL | $ 138,717,000 | $ 8,683,362 | $ 147,400,362 | 41.81069 | 30.86168 | 10.94901 | 0.03000 | $ 4,422,011 |
| 3 | NATURAL GAS | 49,320,000 | 3,082,105 | 52,402,105 | 41.81069 | 41.62912 | 0.18157 | 0.00050 | 26,201 |
| 4 | FUEL OIL | 1,220,000 | 68,351 | 1,288,351 | 41.81069 | 27.40279 | 14.40790 | 0.03947 | 50,851 |
| 5 | NUCLEAR: | | - | | | | | | |
| 6 | AMORTIZATION | 26,740,000 | 1,675,421 | 28,415,421 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 7 | SPENT FUEL | 11,178,000 | 700,369 | 11,878,369 | 41.81069 | 76.37500 | -34.56431 | -0.09470 | (1,124,882) |
| 8 | TOTAL | $ 227,175,000 | $ 14,209,608 | $ 241,384,608 | | | | | $ 3,374,182 |
| 9 | PURCHASED POWER | $ 330,952,000 | $ 20,736,125 | $ 351,688,125 | 41.81069 | 37.83806 | 3.97263 | 0.01088 | $ 3,826,367 |
| 10 | TRANSMISSION BY OTHERS | 10,743,000 | - | 10,743,000 | 41.81069 | 34.02490 | 7.78579 | 0.02133 | 229,148 |
| 11 | TOTAL | $ 341,695,000 | $ 20,736,125 | $ 362,431,125 | | | | | $ 4,055,515 |
| 12 | OTHER OPERATIONS & MAINTENANCE: | | | | | | | | |
| 13 | PAYROLL | $ 218,822,000 | $ (11,124,386) | $ 207,697,614 | 41.81069 | 18.44744 | 23.36325 | 0.06401 | $ 13,294,724 |
| 14 | SEVERANCE | 5,068,000 | (6,972,384) | (1,904,384) | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 15 | PENSION AND OPEB | 45,964,000 | - | 45,964,000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 16 | EMPLOYEE BENEFITS | 17,723,000 | - | 17,723,000 | 41.81069 | 17.02000 | 24.79069 | 0.06792 | 1,203,746 |
| 17 | PAYROLL TAXES | 13,677,000 | - | 13,677,000 | 41.81069 | 13.98000 | 27.83069 | 0.07625 | 1,042,871 |
| 18 | MATERIALS & SUPPLIES | 52,358,000 | - | 52,358,000 | 42 | 29.34000 | 12.47069 | 0.03417 | 1,789,073 |
| 19 | FRANCHISE PAYMENTS | - | - | - | 41.81069 | 68.19607 | -26.38538 | -0.07229 | - |
| 20 | VEHICLE LEASE PAYMENTS | 7,228,000 | - | 7,228,000 | 41.81069 | 38.09947 | 3.71122 | 0.01017 | 73,509 |
| 21 | RENTS | 5,649,000 | - | 5,649,000 | 41.81069 | -31.71012 | 73.52081 | 0.20143 | 1,137,878 |
| 22 | PALO VERDE LEASE | 45,202,000 | - | 45,202,000 | 41.81069 | 53.29167 | -11.48098 | -0.03145 | (1,421,603) |
| 23 | PALO VERDE SALE/LOSS GAIN AMORT. | (4,576,000) | - | (4,576,000) | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 24 | INSURANCE | 2,431,000 | - | 2,431,000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 25 | UNCOLLECTIBLE ACCOUNTS | 2,680,000 | - | 2,680,000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 26 | OTHER | 203,834,000 | (16,587,804) | 187,246,196 | 41.81069 | 37.55000 | 4.26069 | 0.01167 | 2,185,163 |
| 27 | TOTAL | $ 616,060,000 | $ (34,684,573) | $ 581,375,427 | | | | | $ 19,305,362 |
| 28 | DEPRECIATION & AMORTIZATION | $ 331,492,000 | $ (57,141,000) | $ 274,351,000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | $ - |
| 29 | AMORT. OF ELECTRIC PLANT ACQ. ADJ. | - | - | - | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 30 | AMORT. OF PROP. LOSSES & REG. STUDY COSTS | - | - | - | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 31 | TOTAL | $ 331,492,000 | $ (57,141,000) | $ 274,351,000 | | | | | $ - |
| 32 | INCOME TAXES: | | | | | | | | |
| 33 | CURRENT: | | | | | | | | |
| 34 | FEDERAL & STATE | $ 86,606,000 | $ 20,679,400 | $ 107,285,400 | 41.81069 | 60.05000 | -18.23931 | -0.04997 | $ (5,361,051) |
| 35 | DEFERRED | - | - | - | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 36 | TOTAL | $ 86,606,000 | $ 20,679,400 | $ 107,285,400 | | | | | $ (5,361,051) |
| 37 | OTHER TAXES: | | | | | | | | |
| 38 | PROPERTY TAXES | $ 106,189,000 | $ (15,016,227) | $ 91,172,773 | 41.81069 | 212.81731 | -171.00662 | -0.46851 | $ (42,715,356) |
| 39 | SALES TAXES | 3,955,000 | - | 3,955,000 | 0.00000 | 0.00000 | 0.00000 | 0.00000 | - |
| 40 | TOTAL | $ 110,144,000 | $ (15,016,227) | $ 95,127,773 | | | | | $ (42,715,356) |
| 41 | TOTAL | $ 1,713,172,000 | $ (51,216,667) | $ 1,661,955,333 | | | | | $ (21,341,349) |

REFERENCES:
COLUMN (A): COMPANY RESPONSE TO RUCO DATA REQUEST 11.3
COLUMN (B): SUM OF RELEVANT OPERATING ADJUSTMENTS IN RUCO SCHEDULE MDC-5, PAGES 1 AND 2
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COMPANY WORKPAPER LLR_WP2 9/400
COLUMN (E): COMPANY WORKPAPER LLR_WP2 9/400
COLUMN (F): COLUMN (D) - COLUMN (E)
COLUMN (G): COLUMN (F) ÷ 365 DAYS
COLUMN (H): COLUMN (C) x COLUMN (G)

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**OPERATING INCOME ADJUSTMENT #8 - ANNUALIZE PAYROLL (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE WAR-2**

| LINE NO. | | (A) COMPANY TEST YEAR AS FILED | (B) RUCO TEST YEAR ADJUSTMENTS | (C) RUCO TEST YEAR AS ADJUSTED |
|---|---|---|---|---|
| 1 | FUEL FOR ELECTRIC GENERATION: | | | |
| 2 | FUEL HANDLING | $ 2,638 | $ 246 | $ 2,884 |
| 3 | OPERATIONS: | | | |
| 4 | PRODUCTION | $ 63,687 | $ (990) | $ 62,697 |
| 5 | TRANSMISSION | 8,369 | (1,069) | 7,300 |
| 6 | DISTRIBUTION | 26,874 | (3,345) | 23,529 |
| 7 | CUSTOMER ACCOUNTS | 32,162 | (2,550) | 29,612 |
| 8 | CUSTOMER SERVICE & INFO | 914 | 361 | 1,275 |
| 9 | SALES | 17,189 | 307 | 17,496 |
| 10 | ADM. & GENERAL | 45,447 | 1,789 | 47,236 |
| 11 | TOTAL OPERATIONS | $ 194,642 | $ (5,498) | $ 189,144 |
| 12 | MAINTENANCE: | | | |
| 13 | PRODUCTION | $ 40,861 | 2,168 | $ 43,029 |
| 14 | TRANSMISSION | 2,351 | 56 | 2,407 |
| 15 | DISTRIBUTION | 14,393 | 2,395 | 16,788 |
| 16 | ADM. & GENERAL | 4,402 | 1,571 | 5,973 |
| 17 | TOTAL MAINTENANCE | $ 62,007 | $ 6,190 | $ 68,197 |
| 18 | TOTAL OPERATIONS & MAINTENANCE | $ 259,287 | $ 938 | $ 260,225 |
| 19 | PAYROLL ANNUALIZATION ADJUSTMENT PER COMPANY | | | $ 1,031 |
| 20 | PAYROLL ANNUALIZATION ADJUSTMENT PER RUCO | | | $ 938 |
| 21 | RUCO ADJUSTMENT (LINE 20 - LINE 19) | | | $ (93) |

REFERENCES:
COLUMN (A): COMPANY WORKPAPERS DGR_WP15 3/67 THRU 4/67
COLUMN (B): RUCO WORKPAPER WAR-2
COLUMN (C): COLUMN (A) + COLUMN (B)

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**OPERATING INCOME ADJUSTMENT #9 - EMPLOYEE SEVERANCE**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE WAR-3**

| LINE NO. | DESCRIPTION | (A) PER COMPANY WORKPAPER TOTAL | (B) PER COMPANY WORKPAPER APS | (C) PER COMPANY WORKPAPER M&T | (D) PER COMPANY WORKPAPER PIN WEST | (E) PER RUCO AUDIT TOTAL | (F) PER RUCO AUDIT APS | (G) PER RUCO AUDIT M&T | (H) PER RUCO AUDIT PIN WEST | (I) DIFFERENCE |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | TOTAL: | | | | | | | | | |
| 2 | 2002 SEVERENCE | $ (35,691,394) | $ (28,220,834) | $ (259,311) | $ (7,211,249) | $ (35,691,394) | $ (28,220,834) | $ (259,311) | $ (7,211,249) | $ - |
| 3 | NON-APS POWER PLANT PARTICIPANT SHARE | (3,233,633) | (3,233,633) | - | - | (3,233,633) | (3,233,633) | - | - | - |
| 4 | DIFFERENCE - TOTAL (LINE 2 - LINE 3) | $ (32,457,761) | $ (24,987,201) | $ (259,311) | $ (7,211,249) | $ (32,457,761) | $ (24,987,201) | $ (259,311) | $ (7,211,249) | $ - |
| 5 | % TO APS O&M: | | 100.00% | 32.88% (a) | 66.69% (b) | | 100.00% | 32.88% | 66.69% | |
| 6 | APS SHARE: | | | | | | | | | |
| 7 | 2002 SEVERENCE (LINE 2 X LINE 5) | $ (33,115,277) | $ (28,220,834) | $ (85,261) | $ (4,809,182) | $ (33,115,277) | $ (28,220,834) | $ (85,261) | $ (4,809,182) | $ - |
| 8 | NON-APS POWER PLANT PARTICIPANT SHARE (LINE 3 X LINE 5) | (3,233,633) | (3,233,633) | - | - | (3,233,633) | (3,233,633) | - | - | - |
| 9 | DIFFERENCE - APS SHARE (LINE 7 - LINE 8) | $ (29,881,644) | $ (24,987,201) | $ (85,261) | $ (4,809,182) | $ (29,881,644) | $ (24,987,201) | $ (85,261) | $ (4,809,182) | $ - |
| 10 | COMPANY AVERAGE (LINE 9 ÷ 3 YEARS): | $ (9,960,548) | | RUCO AVERAGE (LINE 9 ÷ 10 YEARS): | | $ (2,988,164) | | | | $ 6,972,384 |
| 11 | PRO FORMA (LINE 7 - LINE 10) | $ (23,154,729) | | | | $ (30,127,113) | | | | |
| 12 | RUCO ADJUSTMENT | | | | | | | | | $ (6,972,384) |

REFERENCES:
COLUMNS (A) THRU (D): COMPANY WORKPAPER DGR - WP6 2/4
COLUMNS (E) THRU (H): COMPANY WORKPAPER DGR - WP6 2/4
*COLUMN (I): COLUMN (E) - COLUMN (A)*

NOTES
(a) PER WORKPAPER DGR-WP15 9/67:
$3,052,143 ADJUSTED O&M PAYROLL ÷ $9,281,646 NET PAYROLL = 32.88%

(b) PER WORKPAPERS DGR-WP16 3/4 AND 4/4:
[ ($3,182,263 PNW COMMON + $3,079,537 SHARED SERVICES COMMON ) ÷ $7,211,249 PNW CONSOLIDATED NET PAYROLL ] X [ 30.7% APS GENERAL OPERATIONS COMMON + 46.1% APS COMMERCIAL OPERATIONS COMMON ] =
[ $6,261,800 ÷ $7,211,249 PNW CONSOLIDATED NET PAYROLL ] X [ 76.8% ] = [ 86.83% ] X [ 76.8% ] = 66.69%

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**OPERATING INCOME ADJUSTMENT #12 - INTEREST ON CUSTOMER DEPOSITS (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE WAR-4**

| LINE NO. | DESCRIPTION | (A) PER COMPANY WORKPAPER | (B) PER RUCO AUDIT | (C) DIFFERENCE |
|---|---|---|---|---|
| 1 | CUSTOMER DEPOSIT BALANCE (DECEMBER 31, 2002) | $ 39,795 | $ 39,795 | $ - |
| 2 | TIMES: CONSTANT MATURITY RATE ON 1-YEAR U.S. TREASURY SECURITY | 2.20% | (a) 1.31% | -0.93% |
| 3 | TOTAL INTEREST EXPENSE ON CUSTOMER DEPOSITS | $ 875 | $ 521 | |
| 4 | RUCO ADJUSTMENT | | | $ (354) |

REFERENCES:
COLUMN (A): COMPANY WORKPAPER DGR_WP21 2/3
COLUMN (B): LINE 1 - COMPANY WORKPAPER DGR_WP21 2/3
COLUMN (B): LINE 2 - FEDERAL RESERVE WEBSITE – ONE-YEAR CONSTANT MATURITIES RATE ON JANUARY 2, 2004
COLUMN (C): COLUMN (B) - COLUMN (A)

NOTES
(a) PER WORKPAPER DGR_WP21 3/3:
ONE-YEAR TREASURY CONSTANT MATURITIES RATE EFFECTIVE THE FIRST BUSINESS DAY OF EACH YEAR
AS PUBLISHED ON THE FEDERAL RESERVE WEBSITE

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**OPERATING INCOME ADJUSTMENT #13 - PROPERTY TAXES (000's)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE WAR-5**

| LINE NO. | DESCRIPTION | AMOUNT | REFERENCE |
|---|---|---|---|
| 1 | PLANT IN SERVICE | $ 7,105,595 | (a) DIRECT TESTIMONY ROCKENBERGER |
| 2 | ACCUMULATED DEPRECIATION | (3,042,592) | SCHEDULE MDC-2 |
| 3 | NET PLANT | $ 4,063,003 | LINE 1 + LINE 2 |
| 4 | CWIP @ 50% | 164,545 | COMPANY SCHEDULE E-1 |
| 5 | MATERIALS & SUPPLIES | 79,985 | COMPANY SCHEDULE E-1 |
| 6 | FULL CASH VALUE | $ 4,307,532 | SUM LINES 1 THROUGH 5 |
| 7 | ASSESSED VALUE | $ 1,076,883 | LINE 6 x 25% |
| 8 | TAX RATE | 9.60% | DGR-WP29, PG. 3 |
| 9 | PROPERTY TAXES | $ 103,381 | LINE 7 x LINE 8 |
| 10 | PROPERTY TAX PER COMPANY | 107,141 | DGR-WP29, PG. 3 |
| 11 | ADJUSTMENT | $ (3,760) | LINE 27 - LINE 29 |

NOTES
(a) PER INFORMATION CONTAINED IN ATTACHMENT LLR - 4:
PLANT IN SERVICE NET OF LAND AND TRANSPORTATION VEHICLES

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**OPERATING INCOME ADJUSTMENT #14 - INCOME TAXES (000'S)**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE WAR-6**

| LINE NO. | DESCRIPTION | TOTAL AMOUNT | JURISDICTIONAL AMOUNT | REFERENCE |
|---|---|---|---|---|
| | FEDERAL INCOME TAXES: | | | |
| 1 | OPERATING INCOME BEFORE INCOME TAXES | $ 367,401 | $ 365,720 | SCH. MDC-4 |
| | LESS: | | | |
| 2 | ARIZONA STATE TAX | 18,912 | 18,814 | LINE 11 |
| 3 | INTEREST EXPENSE | 95,993 | 95,722 | NOTE (a) |
| 4 | FEDERAL TAXABLE INCOME | 252,496 | 251,185 | LINE 1 - LINES 2 & 3 |
| 5 | FEDERAL INCOME TAX RATE | 35.00% | 35.00% | TAX RATE |
| 6 | FEDERAL INCOME TAX EXPENSE | 88,374 | 87,915 | LINE 4 X LINE 5 |
| | STATE INCOME TAXES: | | | |
| 7 | OPERATING INCOME BEFORE INCOME TAXES | 367,401 | 365,720 | LINE 1 |
| | LESS: | | | |
| 8 | INTEREST EXPENSE | 95,993 | 95,722 | NOTE (a) |
| 9 | STATE TAXABLE INCOME | 271,408 | 269,999 | LINE 7 - LINE 8 |
| 10 | STATE TAX RATE | 6.968% | 6.968% | TAX RATE |
| 11 | STATE INCOME TAX EXPENSE | 18,912 | 18,814 | LINE 9 X LINE 10 |
| 12 | TOTAL INCOME TAXES | 107,285 | 106,728 | LINE 6 + LINE 11 |
| 13 | INCOME TAXES PER COMPANY | 86,606 | 86,144 | COMPANY SCH. C-1, PG. 2 |
| 14 | ADJUSTMENT | $ 20,679 | $ 20,584 | LINE 12 - LINE 13 |

NOTE (a)
INTEREST SYCHRONIZATION

| | | |
|---|---|---|
| ADJUSTED RATE BASE | $ 3,060,147 | $ 3,051,479 |
| WEIGHTED COST OF DEBT | 3.14% | 3.14% |
| INTEREST EXPENSE | $ 95,993 | $ 95,722 |

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**OPERATING INCOME ADJUSTMENT #15 - SCHEDULE 1 CHANGES**

**DOCKET NO. E-01345A-03-0437**
**SCHEDULE WAR-7**

| LINE NO. | CHARGE | (A) CURRENT CHARGES PER COMPANY | (B) PROPOSED CHARGES PER COMPANY | (C) YE 2002 VOLUME PER COMPANY | (D) IMPACT PER COMPANY | (E) CURRENT CHARGES PER RUCO | (F) PROPOSED CHARGES PER RUCO (a) | (G) YE 2002 VOLUME PER RUCO | (H) IMPACT PER RUCO | (I) DIFFERENCE CURRENT CHARGES | (J) DIFFERENCE PROPOSED CHARGES | (K) DIFFERENCE YE 2002 VOLUME | (L) DIFFERENCE IMPACT |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | TRIP CHARGE | $ - | $ 17.50 | 1,050 | $ 18,375.00 | $ - | $ - | 1,050 | $ - | $ - | $ (17.50) | $ - | $ (18,375.00) |
| 2 | AFTER HOURS CHARGE - REGULAR | $ 50.00 | $ 75.00 | 1,198 | $ 29,950.00 | $ 50.00 | $ 57.50 | 1,198 | $ 8,985.00 | $ - | $ (17.50) | $ - | $ (20,965.00) |
| 2 | AFTER HOURS CHARGE - SPECIAL | $ - | $ 150.00 | 65 | $ 9,750.00 | $ 50.00 | $ 57.50 | 65 | $ 487.50 | $ 50.00 | $ (92.50) | $ - | $ (9,262.50) |
| 3 | TONP @ POLE | $ 87.50 | $ 100.00 | 336 | $ 4,200.00 | $ 87.50 | $ 100.00 | 336 | $ 4,200.00 | $ - | $ - | $ - | $ - |
| 4 | ON-SITE ENERGY EVALUATIONS | $ 50.00 | $ 90.00 | 297 | $ 11,880.00 | $ 50.00 | $ 57.50 | 297 | $ 2,227.50 | $ - | $ (32.50) | $ - | $ (9,652.50) |
| 5 | JOINT SITE MEETINGS | $ 30.00 | $ 70.00 | - | $ - | $ 30.00 | $ 34.50 | - | $ - | $ - | $ (35.50) | $ - | $ - |
| 6 | METER RE-READS | $ 10.00 | $ 20.00 | 268 | $ 2,680.00 | $ 10.00 | $ 11.50 | 268 | $ 402.00 | $ - | $ (8.50) | $ - | $ (2,278.00) |
| 7 | METER TEST - SHOP | $ 25.00 | $ 30.00 | 81 | $ 405.00 | $ 25.00 | $ 28.75 | 81 | $ 303.75 | $ - | $ (1.25) | $ - | $ (101.25) |
| 8 | METER TEST - FIELD | $ 25.00 | $ 100.00 | 28 | $ 2,100.00 | $ 25.00 | $ 28.75 | 28 | $ 105.00 | $ - | $ (71.25) | $ - | $ (1,995.00) |
| 9 | TOTALS (SUM OF LINES 1 THRU 8) | | | | $ 79,340.00 | | | | $ 16,710.75 | | | | |
| 10 | RUCO ADJUSTMENT (SUM OF LINES 1 THRU 8) | | | | | | | | | | | | $ (62,629.25) |

REFERENCES:
COLUMN (A): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (B): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (C): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (D): COMPANY WORKPAPER DGR_WP10 2/2 [ COLUMN (B) - COLUMN (A) ] x COLUMN (C)
COLUMN (E): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (F): TESTIMONY - DR. JOHN STUTZ
COLUMN (G): COMPANY WORKPAPER DGR_WP10 2/2
COLUMN (H): [ COLUMN (F) - COLUMN (E) ] x COLUMN (G)
COLUMN (I): COLUMN (E) - COLUMN (A)
COLUMN (J): COLUMN (F) - COLUMN (B)
COLUMN (K): COLUMN (G) - COLUMN (C)
COLUMN (L): COLUMN (H) - COLUMN (D)

NOTE
(a) THE PROPOSED CHARGES PER RUCO, EXHIBITED IN COLUMN (F), REFLECT THE FULL EFFECT OF AN INCREASE IN CHARGES UNDER THE 15.0% CAP RECOMMENDATION MADE BY RUCO WITNESS DR. JOHN STUTZ.

# REDACTED

**ARIZONA CORPORATION COMMISSION**

**IN THE MATTER**

**of the**
**Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract**

**Docket No. E-01345A-03-0437**

## Direct Testimony of
## David A. Schlissel

## On behalf of
## The Residential Utility Consumer Office

## February 3, 2004

EXHIBIT
RUCO-3
Admitted

**Q. Mr. Schlissel, please state your name, position and business address.**

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

**Q. On whose behalf are you testifying in this case?**

A. I am testifying on behalf of the Residential Utility Consumer Office ("RUCO").

**Q. Please describe Synapse Energy Economics.**

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

**Q. Please summarize your educational background and recent work experience.**

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 24 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the California Public Utilities Commission, the Staff of the Arizona Corporation Commission, the Staff of the Kansas State Corporation Commission, the Arkansas Public Service Commission, municipal utility systems in Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, and

Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

**Q. Mr. Schlissel, have you previously testified before the Arizona Corporation Commission?**

A. Yes. I have testified in Dockets Nos. U-1345-85, U-1345-90-007, and E-01345A-01-0822. I also filed testimony in Docket No. U-1551-93-272 but that case was settled before hearings were held.

**Q. What is the purpose of your testimony.**

A. Synapse was retained by RUCO to evaluate Arizona Public Service Company's ("APS" or "the Company") request that the depreciated cost of the five units built by the Pinnacle West Energy Corporation ("PWEC")[1] be included in its rate base and that the costs related to these units be afforded cost-of-service ratemaking treatment. This testimony presents the results of our evaluation.

**Q. Please explain how Synapse conducted its investigations and analyses in this proceeding.**

A. We first reviewed APS's Application and the testimony and supporting materials appended to the Application. We also submitted discovery to APS and reviewed the materials that were provided in response to RUCO's data requests and to the discovery requests submitted by the other active parties to this proceeding. In particular, we examined the Applicant's economic analyses concerning the five PWEC generating units and the various planning studies prepared by APS since 1995.

We also reviewed materials from ACC Docket No. E-01345A-01-0822 concerning APS's proposed 28 year power purchase agreement with PWEC

[1] Redhawk Units 1 and 2, West Phoenix Unit 4, West Phoenix Unit 5, and Saguaro Combustion Turbine Unit 3.

covering the same five generating units that the Company is seeking to ratebase in this proceeding.

Finally, we reviewed the transmission studies prepared for the ACC Staff as part of the past two biennial transmission reviews.

**Q. Please summarize your findings.**

A. I have found that:

1. The fact that APS has received and is presently receiving power under contract from the PWEC units is not sufficient evidence, on its own, to demonstrate that APS should be allowed to acquire and ratebase the units. Instead, in the current situation, APS must show that acquiring and placing the five PWEC units into rate base is the most economic of the reasonable alternatives available to the Company at this time and will produce economic benefits for ratepayers within a reasonable period of time.

2. PWEC is being compensated for the capacity and energy it is selling to APS pursuant to the contracts entered into as part of last year's Track B capacity solicitation.

3. APS has not provided any evidence showing that the PWEC units represent the most economic capacity it could acquire in the market.

4. Ratebasing the PWEC units would not produce any annual economic benefits for ratepayers until 2011, seven years after they would have been added to APS's rate. By 2011, ratebasing of the PWEC units would have cost ratepayers an additional $187 million in current year dollars, $169 million in present value 2004 dollars.

5. Ratebasing the PWEC units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until sometime around the years 2018 or 2019.

6. Ratebasing the Redhawk units would not produce an annual economic savings for ratepayers until 2011, seven years after they would have been

ratebased. In addition, ratebasing the Redhawk units would not produce a cumulative present value savings for ratepayers, that is, breakeven, until the year 2020 or 2021.

7. Ratebasing West Phoenix Unit 4 would not produce an annual economic savings for ratepayers until the year 2012, eight years after it would have been ratebased. In addition, ratebasing West Phoenix Unit 4 would not produce a cumulative present value savings for ratepayers until significantly beyond the year 2022.

8. Ratebasing West Phoenix Unit 5 would only produce an annual economic savings for ratepayers in two of the first six years that the unit would be in ratebase. Moreover, ratebasing West Phoenix Unit 5 would not produce a cumulative present value savings for ratepayers, that is, breakeven, until the year 2018.

9. Ratebasing the Saguaro CT would produce an annual economic savings for ratepayers in 2007 and a present value cumulative economic savings by 2009.

10. Even if APS is able to produce a study which projects that the PWEC units might be expected to produce an overall net life cycle economic benefit despite large losses in the early years, that showing would not justify the plants as economic investments today. The timing and magnitude of the losses expected in the near future would have to be considered as well. It would be unfair to make the Company's current customers pay substantially higher rates during near-term years when there is only a remote possibility that they or future generations of ratepayers will see an overall savings from the units until two decades in the future, if at all.

11. Available evidence suggests [

]

12. Numerous APS and PWEC planning studies from the years 1998-2002 indicated that the PWEC units were being built to facilitate power sales to areas outside Arizona, not primarily to serve APS load.

13. [

]

14. The PWEC units were built in locations where they could serve APS loads and supply power to markets outside Arizona.

15. It appears that in order to improve its ability to sell power in the regional markets PWEC built a resource mix with more baseload combined cycle capacity and less peaking capacity than would have been needed just to serve the growing APS loads.

16. More than 70 percent of APS's current generation units are baseload capacity. This is a very baseload-heavy capacity mix, especially for a Company that traditionally has had a fairly low load factor due to extreme summer temperatures and the relative lack of a substantial industrial process baseload. Approximately 94 percent, i.e., 1,600 MW, of the PWEC capacity that APS is now seeking to acquire also is baseload combined cycle capacity. Only the 79 MW from the Saguaro CT3 represents peaking capacity.

17. [

]

18. The limited number of hours that APS needs RMR capacity in the Phoenix Valley load pocket and the [ ] that APS currently projects for the West Phoenix and Redhawk units suggest that some of the new capacity needed by APS should have been single cycle turbines instead of baseload combined cycle.

19. There is no capacity crisis requiring the Commission to act at this time to allow APS to acquire the PWEC units and to include them in rate base.

20. The information provided by APS in its January 27 2004 Summary of Responses Received to its Power Supply Request for Proposals about the bids it has received is far too cursory to enable the Commission to evaluate whether the PWEC units represent the most economic capacity that it could acquire in the market. APS has provided no information on the prices and durations of the individual bids. Nor has APS indicated the gas price forecast it has used to develop the range of levelized costs presented in the Summary. This information is essential in order to compare the economic savings and costs from acquiring the PWEC units against the capacity options bid in response to APS's Request for Proposals.

21. For these reasons, the Commission should deny APS's request to acquire and ratebase the PWEC units.

22. Instead of allowing APS to add the PWEC units, the Commission should require that APS immediately undertake the development of a least-cost plan that includes a portfolio of demand-side, generation and transmission options. As part of this plan, APS should be required to undertake a competitive bidding process for power supply contracts (short, medium and long-term) and the purchase of part or all of existing generation facilities. This plan should be developed in order to be in place immediately following the end of the Track B contracts in 2006 or sooner, if possible. PWEC could bid in this competitive process.

23. Planned transmission system upgrades suggest that merchant generators will be able to supply power to APS in the Phoenix load pocket in place of the PWEC units.

**Q. Do you agree with the claim by APS witness Bhatti that the test applied by Commission when determining whether to include Palo Verde in the Company's rate base also should apply to the instant situation with the five PWEC generating units?[2]**

A. No. The current situation is not analogous to that faced by the Commission in Docket No. U-1345-90-007 concerning the Palo Verde nuclear power plants. Palo Verde had been built by APS, a regulated company, and, at the time it was requesting rate base treatment APS already owned shares of each of the three Palo Verde units. The question before the Commission then was how much of APS's share of Palo Verde capacity was used and useful in the test year.

In contrast, APS in this Docket is seeking Commission approval to both acquire and place into rate base the five PWEC units. In this situation, APS must show that acquiring and placing the five PWEC units into rate base is the most economic of the reasonable alternatives available to the Company at this time and will produce economic benefits for ratepayers within a reasonable period of time.

The current situation is analogous to a Company seeking Commission approval to enter into a life-of-asset capacity purchase agreement except that APS wants to acquire the units from its affiliate PWEC and place their cost into rate base. The Commission previously has declined to approve a request by APS to enter into a long-term power purchase agreement with PWEC. APS is now seeking to achieve the same goal by acquiring the units outright from PWEC.

As a result of the deregulation of the wholesale market APS currently has options that were not on the table when then Commission addressed Palo Verde in Docket

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[2] Testimony of Ajit Bhatti, at page 8, line 22, to page 9, line 7.

No. U-1345-90-007 back in 1991. APS's requested ratebasing of the PWEC units must be weighed against these available alternatives.

The PWEC units represent new resources for APS, the regulated utility, and as such, their acquisition should be evaluated in the same way that resources procured by APS from a non-affiliated company would be judged – that is, subject to a prudence standard viewed from today's perspective. The used and useful test, a legitimate regulatory standard, would only apply after a prudence test was satisfied.

Thus, APS must show that the capacity it is seeking to acquire is the most economic capacity now available in the market and that this capacity will produce net economic benefits for ratepayers within a reasonable period of time.

**Q. Do you agree that the PWEC units are actually being used to provide power to APS's customers?**

A. Yes.

**Q. Is PWEC being compensated for the power it is providing to APS?**

A. Yes. PWEC is being fairly compensated for the capacity and energy it is selling to APS pursuant to the contracts entered into as part of last year's Track B capacity solicitation.

**Q. Has APS provided any evidence showing that the PWEC generating units represent the most economic capacity it could acquire in the existing market?**

A. No.

**Q. Have you seen any evidence that the acquisition of the PWEC units will provide net economic benefits for APS's ratepayers within a reasonable number of years?**

A. No. In fact, the evidence we have seen suggests that, if the PWEC units are ratebased, the Redhawk and the West Phoenix Units will not produce net economic savings for ratepayers until a decade or two into the future.

**Q. Please explain.**

A. As shown in Tables 1 through 5 below, we have compared the annual revenue requirements resulting from the ratebasing of the PWEC units and the total annual market revenues associated with these units. These total market revenues represent what it would cost for APS to purchase from the market the same amounts of capacity and energy that would be provided by each of the PWEC units. These comparisons show the net costs/savings from ratebasing the units.

Table 1 shows that:

- Ratebasing the PWEC units would not produce any annual economic benefits for ratepayers until 2011, seven years after they would have been added to APS's rate. By 2011, ratebasing of the PWEC units would have cost ratepayers an additional $187 million in current year dollars, $169 million, in present value 2004 dollars.

- Ratebasing the PWEC units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until sometime around the years 2018 or 2019.

**Table 1: The Economic Costs and Benefits of Ratebasing the PWEC Units**

| | Redhawk Annual Savings/(Costs) Current Year $ ($000) | West Phoenix Unit 4 Annual Savings/(Costs) Current Year $ ($000) | West Phoenix Unit 5 Annual Savings/(Costs) Current Year $ ($000) | Saguaro CT3 Annual Savings/(Costs) Current Year $ ($000) | All Units Annual Savings/(Costs) Current Year $ ($000) | All Units Cumulative Savings/(Costs) Current Year $ ($000) | All Units Annual Savings/Costs PV @ 8.25% ($000) | All Units Cumulative Savings/(Costs) PV @8.25% ($000) | All Units Annual Savings/Costs PV @ 7.07% ($000) | All Units Cumulative Savings/(Costs) PV @7.07% ($000) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2004 | (28,503) | (3,363) | (12,863) | (1,093) | (45,822) | (45,822) | (45,822) | (45,822) | (45,822) | (45,822) |
| 2005 | (66,579) | (7,139) | (28,853) | (1,785) | (104,356) | (150,178) | (96,403) | (142,225) | (97,465) | (143,287) |
| 2006 | (4,622) | (2,237) | 1,461 | (240) | (5,638) | (155,817) | (4,812) | (147,037) | (4,918) | (148,206) |
| 2007 | (9,676) | (1,849) | 5,321 | 576 | (5,628) | (161,445) | (4,437) | (151,474) | (4,585) | (152,791) |
| 2008 | (10,558) | (1,645) | (2,422) | 1,840 | (12,786) | (174,230) | (9,311) | (160,785) | (9,729) | (162,519) |
| 2009 | (9,004) | (1,653) | (2,374) | 1,974 | (11,056) | (185,286) | (7,438) | (168,223) | (7,857) | (170,377) |
| 2010 | (11,076) | (324) | 6,783 | 2,758 | (1,859) | (187,146) | (1,156) | (169,378) | (1,234) | (171,611) |
| 2011 | 5,970 | (491) | 5,917 | 3,030 | 14,427 | (172,719) | 8,283 | (161,096) | 8,943 | (162,668) |
| 2012 | 17,006 | 178 | 7,692 | 3,235 | 28,112 | (144,607) | 14,910 | (146,186) | 16,276 | (146,392) |
| 2013 | 1,668 | 156 | 10,237 | 2,577 | 14,638 | (129,970) | 7,172 | (139,015) | 7,915 | (138,477) |
| 2014 | 25,213 | (2,107) | 12,129 | 3,159 | 38,394 | (91,576) | 17,377 | (121,637) | 19,390 | (119,086) |
| 2015 | 19,881 | 203 | 8,316 | 3,194 | 31,594 | (59,982) | 13,210 | (108,428) | 14,902 | (104,184) |
| 2016 | 21,135 | (678) | 11,028 | 3,223 | 34,707 | (25,275) | 13,405 | (95,022) | 15,290 | (88,894) |
| 2017 | 6,718 | (138) | 8,959 | 2,774 | 18,313 | (6,963) | 6,534 | (88,488) | 7,535 | (81,359) |
| 2018 | 38,499 | 1,724 | 19,129 | 3,601 | 62,953 | 55,990 | 20,750 | (67,738) | 24,192 | (57,168) |
| 2019 | 50,831 | 3,992 | 29,569 | 4,732 | 89,124 | 145,114 | 27,138 | (40,600) | 31,987 | (25,181) |
| 2020 | 64,902 | 6,276 | 37,947 | 6,168 | 115,293 | 260,406 | 32,431 | (8,169) | 38,647 | 13,467 |
| 2021 | 90,961 | 8,193 | 48,064 | 5,896 | 153,113 | 413,519 | 39,787 | 31,617 | 47,936 | 61,402 |
| 2022 | 74,538 | 7,758 | 47,927 | 6,362 | 136,586 | 550,105 | 32,787 | 64,404 | 39,938 | 101,340 |

Tables 2 through 5 show that:

- Ratebasing the Redhawk units would not produce an annual economic savings for ratepayers until 2011, seven years after they would have been

ratebased. In addition, ratebasing the Redhawk units would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until the year 2020 or 2021.

- Ratebasing West Phoenix Unit 4 would not produce an annual economic savings for ratepayers until the year 2012, eight years after it would have been ratebased. In addition, ratebasing West Phoenix Unit 4 would not produce a cumulative present value savings for ratepayers, i.e., breakeven, until significantly beyond the year 2022.

- Ratebasing West Phoenix Unit 5 would only produce an annual economic savings for ratepayers in two of the first six years that the unit would be in ratebase. Moreover, ratebasing West Phoenix Unit 5 would not produce a cumulative present value savings for ratepayers, breakeven, until the year 2018.

- Ratebasing the Saguaro CT would produce an annual economic savings for ratepayers beginning in 2007 and a present value cumulative economic savings by 2009.

**Table 2: The Economic Costs and Benefits of Ratebasing Redhawk Units 1 and 2**

| | Total Market Revenues ($000) | Total Revenue Requirements ($000) | Annual Savings/(Costs) Current Year $ ($000) | Annual Savings/Costs PV @ 8.25% ($000) | Cumulative Savings/(Costs) PV @8.25% ($000) | Annual Savings/Costs PV @ 7.07% ($000) | Cumulative Savings/(Costs) PV @7.07% ($000) |
|---|---|---|---|---|---|---|---|
| **2004** | 91,546 | 120,049 | (28,503) | (28,503) | (28,503) | (28,503) | (28,503) |
| **2005** | 158,993 | 225,572 | (66,579) | (61,505) | (90,008) | (62,183) | (90,686) |
| **2006** | 232,826 | 237,448 | (4,622) | (3,944) | (93,952) | (4,032) | (94,717) |
| **2007** | 240,928 | 250,604 | (9,676) | (7,628) | (101,580) | (7,883) | (102,600) |
| **2008** | 288,579 | 299,137 | (10,558) | (7,689) | (109,269) | (8,034) | (110,634) |
| **2009** | 279,780 | 288,784 | (9,004) | (6,058) | (115,327) | (6,399) | (117,033) |
| **2010** | 274,327 | 285,403 | (11,076) | (6,884) | (122,210) | (7,352) | (124,384) |
| **2011** | 276,394 | 270,424 | 5,970 | 3,428 | (118,783) | 3,701 | (120,683) |
| **2012** | 308,302 | 291,296 | 17,006 | 9,019 | (109,763) | 9,846 | (110,837) |
| **2013** | 307,160 | 305,492 | 1,668 | 817 | (108,946) | 902 | (109,935) |
| **2014** | 330,672 | 305,459 | 25,213 | 11,412 | (97,534) | 12,733 | (97,202) |
| **2015** | 324,324 | 304,443 | 19,881 | 8,312 | (89,222) | 9,378 | (87,824) |
| **2016** | 340,372 | 319,237 | 21,135 | 8,163 | (81,059) | 9,311 | (78,514) |
| **2017** | 363,802 | 357,084 | 6,718 | 2,397 | (78,662) | 2,764 | (75,749) |
| **2018** | 373,173 | 334,674 | 38,499 | 12,690 | (65,972) | 14,794 | (60,955) |
| **2019** | 385,951 | 335,120 | 50,831 | 15,478 | (50,494) | 18,244 | (42,711) |
| **2020** | 413,798 | 348,896 | 64,902 | 18,256 | (32,238) | 21,756 | (20,956) |
| **2021** | 430,499 | 339,538 | 90,961 | 23,636 | (8,601) | 28,478 | 7,522 |
| **2022** | 431,581 | 357,043 | 74,538 | 17,893 | 9,291 | 21,795 | 29,317 |

## Table 3: The Economic Costs and Benefits of Ratebasing West Phoenix Unit 4

| | Total Market Revenues ($000) | Total Revenue Requirements ($000) | Annual Savings/(Costs) Current Year $ ($000) | Annual Savings/Costs PV @ 8.25% ($000) | Cumulative Savings/(Costs) PV @8.25% ($000) | Annual Savings/Costs PV @ 7.07% ($000) | Cumulative Savings/(Costs) PV @7.07% ($000) |
|---|---|---|---|---|---|---|---|
| 2004 | 7,934 | 11,297 | (3,363) | (3,363) | (3,363) | (3,363) | (3,363) |
| 2005 | 14,307 | 21,446 | (7,139) | (6,595) | (9,959) | (6,668) | (10,031) |
| 2006 | 19,982 | 22,219 | (2,237) | (1,909) | (11,868) | (1,952) | (11,983) |
| 2007 | 20,773 | 22,622 | (1,849) | (1,458) | (13,326) | (1,506) | (13,490) |
| 2008 | 23,159 | 24,804 | (1,645) | (1,198) | (14,524) | (1,252) | (14,741) |
| 2009 | 22,454 | 24,107 | (1,653) | (1,112) | (15,636) | (1,175) | (15,916) |
| 2010 | 24,563 | 24,887 | (324) | (201) | (15,837) | (215) | (16,131) |
| 2011 | 23,668 | 24,159 | (491) | (282) | (16,119) | (304) | (16,435) |
| 2012 | 26,569 | 26,391 | 178 | 95 | (16,025) | 103 | (16,332) |
| 2013 | 26,266 | 26,110 | 156 | 76 | (15,948) | 84 | (16,248) |
| 2014 | 29,327 | 31,434 | (2,107) | (954) | (16,902) | (1,064) | (17,312) |
| 2015 | 27,055 | 26,852 | 203 | 85 | (16,817) | 96 | (17,216) |
| 2016 | 29,731 | 30,409 | (678) | (262) | (17,079) | (299) | (17,515) |
| 2017 | 33,614 | 33,752 | (138) | (49) | (17,129) | (57) | (17,572) |
| 2018 | 30,940 | 29,216 | 1,724 | 568 | (16,560) | 663 | (16,910) |
| 2019 | 29,551 | 25,559 | 3,992 | 1,216 | (15,345) | 1,433 | (15,477) |
| 2020 | 29,423 | 23,147 | 6,276 | 1,765 | (13,579) | 2,104 | (13,373) |
| 2021 | 31,469 | 23,276 | 8,193 | 2,129 | (11,451) | 2,565 | (10,808) |
| 2022 | 32,584 | 24,826 | 7,758 | 1,862 | (9,588) | 2,269 | (8,540) |

## Table 4: The Economic Costs and Benefits of Ratebasing West Phoenix Unit 5

| | Total Market Revenues ($000) | Total Revenue Requirements ($000) | Annual Savings/(Costs) Current Year $ ($000) | Annual Savings/Costs PV @ 8.25% ($000) | Cumulative Savings/(Costs) PV @8.25% ($000) | Annual Savings/Costs PV @ 7.07% ($000) | Cumulative Savings/(Costs) PV @7.07% ($000) |
|---|---|---|---|---|---|---|---|
| 2004 | 60,515 | 73,378 | (12,863) | (12,863) | (12,863) | (12,863) | (12,863) |
| 2005 | 102,430 | 131,283 | (28,853) | (26,654) | (39,517) | (26,948) | (39,811) |
| 2006 | 133,516 | 132,055 | 1,461 | 1,247 | (38,270) | 1,275 | (38,536) |
| 2007 | 138,079 | 132,758 | 5,321 | 4,195 | (34,075) | 4,335 | (34,201) |
| 2008 | 130,823 | 133,245 | (2,422) | (1,764) | (35,839) | (1,843) | (36,044) |
| 2009 | 151,192 | 153,566 | (2,374) | (1,597) | (37,436) | (1,687) | (37,731) |
| 2010 | 156,015 | 149,232 | 6,783 | 4,215 | (33,221) | 4,502 | (33,229) |
| 2011 | 157,661 | 151,744 | 5,917 | 3,397 | (29,824) | 3,668 | (29,561) |
| 2012 | 163,714 | 156,022 | 7,692 | 4,080 | (25,744) | 4,454 | (25,107) |
| 2013 | 176,538 | 166,301 | 10,237 | 5,016 | (20,728) | 5,536 | (19,572) |
| 2014 | 168,718 | 156,589 | 12,129 | 5,489 | (15,239) | 6,125 | (13,446) |
| 2015 | 175,390 | 167,074 | 8,316 | 3,477 | (11,762) | 3,923 | (9,524) |
| 2016 | 180,352 | 169,324 | 11,028 | 4,259 | (7,502) | 4,858 | (4,666) |
| 2017 | 188,738 | 179,779 | 8,959 | 3,197 | (4,306) | 3,686 | (979) |
| 2018 | 195,343 | 176,214 | 19,129 | 6,305 | 2,000 | 7,351 | 6,372 |
| 2019 | 203,894 | 174,325 | 29,569 | 9,004 | 11,003 | 10,613 | 16,984 |
| 2020 | 220,655 | 182,708 | 37,947 | 10,674 | 21,677 | 12,720 | 29,704 |
| 2021 | 242,753 | 194,689 | 48,064 | 12,489 | 34,167 | 15,047 | 44,752 |
| 2022 | 234,023 | 186,096 | 47,927 | 11,505 | 45,671 | 14,014 | 58,765 |

**Table 5: The Economic Costs and Benefits of Ratebasing Saguaro CT3**

| | Total Market Revenues ($000) | Total Revenue Requirements ($000) | Annual Savings/(Costs) Current Year $ ($000) | Annual Savings/Costs PV @ 8.25% ($000) | Cumulative Savings/(Costs) PV @8.25% ($000) | Annual Savings/Costs PV @ 7.07% ($000) | Cumulative Savings/(Costs) PV @7.07% ($000) |
|---|---|---|---|---|---|---|---|
| 2004 | 2,799 | 3,892 | (1,093) | (1,093) | (1,093) | (1,093) | (1,093) |
| 2005 | 5,792 | 7,577 | (1,785) | (1,649) | (2,741) | (1,667) | (2,760) |
| 2006 | 8,824 | 9,064 | (240) | (205) | (2,947) | (210) | (2,969) |
| 2007 | 8,453 | 7,877 | 576 | 454 | (2,492) | 469 | (2,500) |
| 2008 | 8,487 | 6,647 | 1,840 | 1,340 | (1,152) | 1,400 | (1,100) |
| 2009 | 8,728 | 6,754 | 1,974 | 1,328 | 176 | 1,403 | 303 |
| 2010 | 9,127 | 6,369 | 2,758 | 1,714 | 1,890 | 1,831 | 2,134 |
| 2011 | 9,414 | 6,384 | 3,030 | 1,740 | 3,630 | 1,878 | 4,012 |
| 2012 | 9,527 | 6,292 | 3,235 | 1,716 | 5,346 | 1,873 | 5,885 |
| 2013 | 8,651 | 6,074 | 2,577 | 1,262 | 6,608 | 1,393 | 7,279 |
| 2014 | 9,127 | 5,968 | 3,159 | 1,430 | 8,038 | 1,595 | 8,874 |
| 2015 | 9,053 | 5,859 | 3,194 | 1,336 | 9,373 | 1,507 | 10,381 |
| 2016 | 8,485 | 5,262 | 3,223 | 1,245 | 10,618 | 1,420 | 11,800 |
| 2017 | 8,082 | 5,308 | 2,774 | 990 | 11,608 | 1,141 | 12,942 |
| 2018 | 8,967 | 5,366 | 3,601 | 1,187 | 12,794 | 1,384 | 14,325 |
| 2019 | 9,954 | 5,222 | 4,732 | 1,441 | 14,235 | 1,698 | 16,024 |
| 2020 | 11,232 | 5,064 | 6,168 | 1,735 | 15,970 | 2,068 | 18,091 |
| 2021 | 11,013 | 5,117 | 5,896 | 1,532 | 17,502 | 1,846 | 19,937 |
| 2022 | 11,159 | 4,797 | 6,362 | 1,527 | 19,030 | 1,860 | 21,797 |

**Q. What are the sources for the revenue requirements figures on Tables 1 through 5?**

A. The annual revenue requirements figures presented in Tables 1 through 5 for the years 2005-2022 are taken directly from APS's response to Data Request LCA 8-237. Unfortunately, APS did not include in this response the revenue requirements for the second half of 2004 during which the PWEC units will be in rate base if the Commission approves the Company's request to acquire and ratebase the units.

Therefore, we have used the fixed costs for 2004 for each of the PWEC units that were provided in APS's response to Data Request LCA 7-219.

**Q. How did you calculate the annual total market revenues presented in Tables 1 through 5?**

A. The total market revenues shown in Tables 1 through 5 are based on the annual amounts of capacity and energy from each PWEC unit multiplied by the respective annual capacity and energy prices.

**Q. What estimates of generation have you used for each of the PWEC units?**

A. We have used APS's projections of annual generation for each of the PWEC units for the years 2005 through 2022 as presented in its response to Data Request LCA

8-237. Because we did not find any projections of the annual generation that the Company currently expects from each of the PWEC units during 2004, we assumed that each of the PWEC would generate approximately 2/3 as much power during the second half of 2004 as APS's 2003 Long Range Forecast projected the unit would generate in 2005.[3]

In addition, we used the individual unit variable fuel costs ($/MWH) that were provided in APS's response to Data Request LCA 8-237 for the year 2005 because we did not have the comparable information for the year 2004.

**Q. What energy market prices have you used in the comparisons shown in Tables 1 through 5?**

A. To be conservative we have used the adjusted energy prices for the years 2005 through 2022 that were provided by APS in its response to Data Request LCA 8-237. We assumed that the energy market prices (in $/MWH) for the generation from each PWEC unit would be the same in 2004 as APS has projected for 2005.

**Q. What capacity prices have you have used in the comparisons shown in Tables 1 through 5?**

A. We used APS's near term capacity price forecasts for the years 2004 and 2005. For the years 2006-2022 we have used the Company's forecast of capacity prices based on the long run marginal costs related to the need to maintain a 15 percent reserve margin in Arizona. APS has explained the derivation of these fundamental capacity prices as follows:

> APS assesses loads and resources of the WECC and each of the sub-regions (WECC Sub-region Supply & Demand Balance was provided in LCA 6-192). Once the plants currently under

[3] The information from APS's 2003 Long Range Forecast that was provided in response to Data Request RUCO 10-8 did not include any generation projections for the PWEC units for 2004. However, the Company's 2002 Long Range Forecast projected that the units would generate about as much energy in 2004 as they would in 2005. We then assumed that because the second half of 2004, during which the PWEC units would be in rate base, would include three of the four peak summer months, that each unit would generate about 2/3 of its annual output during the second half of the year. We also tested to make sure that this assumption did not have a major impact on the results.

construction are completed, a capacity price is added to the energy market price that would be sufficient to incent construction of new generation when the reserve level would drop below 18% in the Desert Southwest sub-region, or 15% in Arizona. When reserve levels are above the 15%, the capacity price is reduced based on a level that supports continued operation of enough existing generation to maintain 15% reserves. The resource plans are developed so that the market is in equilibrium, i.e., it maintains 15% reserve margins once the short term excess goes away. This is represented by the "Fundamental Market Scenario" provided in response to LCA 8-237.[4]

**Q. Isn't it reasonable to expect that there would be some physical and economic "lumpiness" when new large generating units are added by APS?[5]**

A. Yes. It is reasonable to expect that there might be a few years of lumpiness in which the additional costs of ratebasing a new large generating unit would exceed the benefits of adding the unit. However, as Tables 1 through 5 show, ratebasing the West Phoenix and Redhawk units will not provide any overall cumulative savings for ratepayers until the year 2018 or later. This is far more than mere "lumpiness."

**Q. What weight should the Commission give to Company analyses that show that the PWEC units might produce net economic savings over their entire operating lives?**

A. Even if APS is able to produce a study which projects that the PWEC units might be expected to produce an overall net life cycle economic benefit despite large losses in the early years, that showing would not justify the plants as economic investments today. The timing and magnitude of the losses expected in the near future would have to be considered as well. It would be unfair to make the Company's current customers pay substantially higher rates during near-term years when there is only a remote possibility that they or future generations of

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4 APS response to Data Request LCA 19-478(a).

5 Testimony of APS witness Ajit Bhatti, at page 38, lines 1 through 16.

ratepayers will see an overall savings from the units until two decades in the future, if at all.

**Q. Has APS examined the economic costs and benefits of the PWEC units using any other market price forecasts?**

A. Yes. APS examined a scenario in which the base market capacity price forecast is based on overbuild/underbuild ("boom and bust") cycles and wet/dry hydro cycles.[6]

APS also examined an even more severe underbuilding scenario in which no new generation would be built through 2010. As a result capacity prices spiked to about half of the observed prices in 2001. Beginning in 2011, the market would return to overbuild/underbuild cycles.

**Q. Do you believe that it is reasonable to use boom and bust projections of market prices in examining the economic costs and benefits of a proposed capacity acquisition?**

A. No. In theory it seems like a good idea to reflect possible boom and bust capacity cycles in the valuation of a proposed capacity acquisition. However, in practice predicting when the boom and bust phases of the cycle will occur, how long each phase will last, how severe each phase will be and what the market prices will be really is far too speculative to produce reliable results. These important factors simply cannot be predicted with any reasonable degree of certainty.

It is far more reasonable to use the more traditional long run marginal costs to evaluate the economic costs and benefits of a proposed capacity acquisition.

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[6] APS response to Data Request LCA 8-237.

**Q. Have you seen any evidence that suggests that the next capacity shortage will not occur in 2007 as APS and Dr. Hieronymus hypothesize?**[7]

A. Yes. Dr. Hieronymus cites a recent California Energy Commission study as the main support for his conclusion that a new shortage of capacity will reemerge in the Western U.S. by 2007.[8] This study found that although electricity supply resources in California appear to be sufficient for 2004 and 2005, there is an ongoing need to monitor new capacity proposed for the period starting 2006 and beyond. Consequently, the Commission should continue to focus on programs that improve efficiency and reduce demand and to support policies that ensure that new generation is brought to the market.[9]

In his testimony, Dr. Hieronymus cites several factors which he believes will make the capacity situation in California worse than it appears in this recent Energy Commission study. However, he ignores a number of factors which actually make the situation in California far less dire than he would suggest.

First, the California Energy Commission study assumes that only one third of the voluntary conservation achieved in the State during the 2001 electricity crisis will persist in 2003 and that this amount will decline in subsequent years. This is an extremely conservative assumption. It is very reasonable to assume that Californians who conserved energy during the 2001 crisis would again conserve if faced with the prospect of another capacity shortage in 2007 or any subsequent year(s). Such conservation efforts could reduce future electricity demands by 2,700 MW or more over the figures shown in the 2003 California Energy Commission study.

Second, the study notes that California will have about 1,100 MW of Emergency Demand Programs/Interruptible loads that will further add to the State's reserves

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7 Testimony of William H. Hieronymus, at page 59, lines 5 through 7.

8 Testimony of William H. Hieronymus, at pages 62 and 63.

9 *California's 2003 Electricity Supply and Demand Balance and Five-Year Outlook*, available at the California Energy Commission website, www.energy.ca.gov.

in 2007 and subsequent years. The California Public Utilities Commission has established a goal of increasing the amount of demand response in the State to over 1,900 MW by 2007.

Third, the California Energy Commission study assumes dry hydro conditions which it says has a one in five year probability of occurring. This assumption reduces the amounts of power imports available from the Pacific Northwest and from the spot market.

Finally, the California Energy Commission study only includes those power plants deemed as having a 75 percent or greater probability of coming on-line. This essentially means that the study only assumes that the approximately 4,000 MW of power plants that are currently under construction will be built. It does not assume that any of the additional 4,000 MW of approved plants that are currently on hold will be built or that any of the 6,000 MW of plants that are currently undergoing Energy Commission review will be built. This is an extremely conservative assumption especially if the developers of these projects agree with Dr. Hieronymus's conjecture that a new capacity shortage, with significantly higher prices, will reemerge by 2007. Clearly, the prospect of much higher capacity prices in the California market and the rest of the Western U.S. in 2007 will encourage more developers to complete their projects as expeditiously as possible.

**Q. Do you think that the more severe underbuilding scenario examined by APS is more reasonable than the boom/bust cycles scenario?**

A. No. The severe underbuilding scenario examined by APS is simply not credible. Given the very large number of new facilities that are undergoing review in the Western States and the amount of plants that have been announced, it is not reasonable to expect that no additional generation will be added until 2011 once the plants currently under construction are completed.

If APS wanted to examine a severe underbuilding scenario, it should also have looked at a scenario in which there is a more extreme overbuilding of new

generation facilities in the short term leading to a capacity glut that will last further into the future than APS conjectures in its boom and bust cycles scenario.

**Q. Have you seen any evidence that suggests that any party would be interested in selling a generating unit or in making a long-term capacity sale to APS?**

A. Yes. [

][10]

In addition, APS has acknowledged that it is involved in several confidential discussions concerning potential power plant purchases:

> One way to secure long-term supplies in an otherwise dysfunctional market and to avoid the problem of potentially insolvent sellers, is to build or buy power plants. APS has questions about its ability to pursue these options but it is exploring them in any event. Thus, APS entertained representatives from Dome Valley Energy Partner LLC on October 8, 2003 to discuss the overall status of the Wellton Mohawk Generating Facility. No specific detailed and/or substantive discussions involving a firm offer for energy occurred as a result of this meeting. In addition, APS approached and has had brief discussions with two non-affiliated entities concerning the possible purchase of their generating facilities in Arizona. APS is bound by confidentiality agreements with regard to such discussions, which have led to no further communications with these entities. Finally, APS has approached and is currently in confidential discussions with one (non-affiliated) entity concerning that entity's desire to sell a generating facility in Arizona. Those discussions, all analyses in conjunction with those discussions, and even the identify of the potential seller are covered by a confidentiality agreement with such seller.[11]

**Q. Have any power plants in Arizona recently been sold?**

A. Yes. Reliant Energy recently sold the 590 MW Desert Basin plant to SRP for $288.5 million, or about $492 per KW.

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[10] [ ]

[11] APS Response to Data Request LCA 10-269.

**Q. Have you seen any evidence that suggests that the PWEC units were not built "primarily" to serve APS load, as APS witness Bhatti has claimed?**[12]

Yes. Numerous APS and PWEC planning studies indicated that the PWEC units were being built to facilitate power sales to areas outside Arizona. For example:

- APS's "1998 Business Plan – Generation Growth Plan" noted that the "Primary Market Targets" for PWEC generation would be "Phoenix, Yuma, Gila Bend, Saguaro, Cholla, Prescott, S Nevada, California, Northwest, New Mexico, Utah & Colorado."[13]
- [ ][14] Project Hedgehog became the Redhawk units.
- [ ][15]
- A 1999 APS "Planning Scenarios Risk Assessment" revealed that PWEC was planning to add significantly more generation than would be needed just to serve APS loads. For example, PWEC expected to have approximately 8,900 MW of capacity by 2006, significantly above APS's projected load which was in the range of 6,300 MW.[16]
- The Company's September 29, 1999 Pinnacle West Press Release announcing the proposed Redhawk units noted that "The plant will compete in deregulated energy markets of Arizona, California and other western states…"[17] The press release also quoted Pinnacle West Generation Business Unit President William Stewart as stating that "We intend to be a vigorous player in these competitive generation markets. We have a strong record of low-cost, efficient plant operation. We can best serve the public and our shareholders by pursuing these developing markets, particularly in Arizona and the Southwest."

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12 Testimony of Ajit Bhatti, at page 17, line 19, to page 18, line 2.

13 Provided in APS's response to Data Request LCA 11-288, at page 15 of 44.

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15 [ ]

16 Provided in APS's response to Data Request LCA 6-200B, at page 28.

17 Provided in APS's response to Data Request LCA 3-77.

> The same press release also noted that the site for the proposed Redhawk units "was selected because the Palo Verde switchyard is a major transmission hub and provides access to energy markets in Arizona, California and across the Southwest."

This is not to say that Pinnacle West intended to abandon APS's traditional service territory in Arizona. Company management was astute enough to realize that the Phoenix area was one of the fastest growing areas in the West and could provide a strong foundation from which Pinnacle West could compete in other Western region markets.

[ ] For example:

- [ ][18]
- [ ][19]

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- [ ][20]

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[18] [ ]

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[20] [ ]

- [ ][21]
- [ ]

**Q. Do you have any comment on the claim by APS witness Bhatti that the location of the PWEC units demonstrates that they were built at locations where they were needed to serve APS load and with APS customers in mind?[23]**

A. Yes. Mr. Bhatti implies that siting the Redhawk and the West Phoenix units in locations where they could serve APS load was somehow inconsistent or in conflict with siting those units at locations from which they could serve other markets. As I noted earlier, the September 29, 1999 Press Release in which APS announced the Redhawk Project specifically noted that the site for the proposed plant "was selected because the Palo Verde switchyard is a major transmission hub and provides access to energy markets in Arizona, California and across the Southwest."

At the same time, while the West Phoenix units were built in the Phoenix Valley, their power could be exported out of the Phoenix load pocket to Palo Verde. The use of the capacity from the new West Phoenix Units 4 and 5 to serve in-Valley loads also would free up other PWEC generation located outside the load pocket to be sold in other markets.

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21 [ ]

22 [ ]

23 Testimony of Ajit Bhatti, at page 5, lines 8-10, and page 18, lines 5-7.

**Q. APS witness Bhatti makes a number of claims regarding the decision by Pinnacle West management not to sell power from the PWEC units forward to California.[24] Have you seen any evidence that PWEC was not interested in selling power into the California market?**

A. No. Mr. Bhatti has implied that Pinnacle West declined from selling power in California in order to be able to serve APS loads. However, as I have noted above, there is no evidence that PWEC has ever abandoned its interest in selling power into the California markets.

**Q. Does it appear that in order to improve its ability to sell power into the regional markets PWEC built a different resource mix with more baseload combined cycle capacity (and less peaking capacity) than would have been needed just to serve the growing APS loads?**

A. Yes. By the 1990s APS was a company with a generation capacity mix that was more than 70 percent baseload.[25] This was a baseload heavy capacity mix, especially for a Company that traditionally has had a fairly low load factor, i.e., less than 55 percent, due to the extreme summer temperatures and the relative lack of a substantial industrial process baseload.

Given this low load factor, it appears reasonable to expect that if it had been building to meet its own needs, APS, as a regulated company, would have added a significant amount of peaking capacity as part of its generation growth plan. In fact, APS's June 1998 Generation Growth Plan did specifically note that "If construction based on Arizona growth plan only, it would install new CT capacity beginning in 2004 and new combined cycle capacity, or previously installed CTs upgraded, starting in 2006.[26]

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24 For example, see the Testimony of Ajit Bhatti, at page 18, lines 5-7, page 18, lines 16-19, and page 49, lines 20-22.

25 For example, see the [

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26 Provided as document RC01608 in APS's response to Data Request LCA 11-288, at page 6.

However, as a fledgling merchant generator, PWEC's interest was in developing new baseload generation that could compete in other out-of-state markets even if that baseload generation had higher installation costs than the CT capacity that APS would need to serve its growing summer peak loads. Consequently, PWEC developed a generation growth plan that included four new combined cycle units as its first four major new additions (West Phoenix Unit 4, West Phoenix Unit 5, and Redhawk Units 1 and 2). The new Saguaro unit is the only CT that PWEC has added. Thus, approximately, 1,600 MW of the 1,700 MW, or about 94 percent, of the new capacity that APS is seeking to acquire from PWEC is baseload combined cycle capacity. This is far too much for a company that already has a generation mix that is 70 percent baseload. In fact, with the PWEC units, APS's generation would be more than 75 percent baseload.

**Q. Has the Company acknowledged that adding more single cycle turbine capacity would be a better mix with APS's needs?**

A. [

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**Q. Have you seen any other evidence that suggests that single cycle turbine peaking capacity would have been a better match for APS's needs than the combined cycle capacity built by PWEC?**

A. Yes. The limited number of hours that APS needs RMR capacity in the Phoenix load pocket and the relatively low capacity factors that APS currently projects for West Phoenix Unit 4 through 2022 suggest that some of the new capacity that APS needs should be single cycle turbines peaking units instead of baseload combined cycle. This information is presented in Tables 6 and 7 below:

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27 [ ]

**Table 6: Phoenix Area Non-APS RMR Requirements for APS Load[28]**

| Year | Non-APS RMR Hours |
|---|---|
| 2003 | 152 |
| 2004 | 200 |
| 2005 | 230 |

**Table 7: Projected West Phoenix and Redhawk Capacity Factors[29]**

| Year | West Phoenix Unit 4 | West Phoenix Unit 5 | Redhawk |
|---|---|---|---|
| 2005 | 15.1% | 39.1% | 27.4% |
| 2006 | 18.6% | 45.0% | 39.3% |
| 2007 | 18.6% | 44.8% | 39.9% |
| 2008 | 25.3% | 40.4% | 52.0% |
| 2009 | 22.8% | 50.8% | 49.2% |
| 2010 | 25.5% | 51.2% | 46.0% |
| 2011 | 23.0% | 49.0% | 42.6% |
| 2012 | 27.3% | 50.3% | 47.7% |
| 2013 | 27.5% | 55.9% | 46.7% |
| 2014 | 33.1% | 49.9% | 51.1% |
| 2015 | 28.6% | 53.3% | 51.2% |
| 2016 | 33.8% | 54.5% | 53.3% |
| 2017 | 40.2% | 56.1% | 55.9% |
| 2018 | 31.7% | 55.1% | 54.6% |
| 2019 | 25.7% | 54.3% | 53.4% |
| 2020 | 20.7% | 53.4% | 52.1% |
| 2021 | 21.4% | 57.9% | 51.2% |
| 2022 | 23.0% | 55.1% | 52.1% |

These projected capacity factors also suggest that some of the Redhawk capacity should have been single cycle turbines, at least initially.

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28 *APS Reliability Must-Run Analysis 2003-2005*, Table ES3, at page 8, and Table 6A, at page 28.

29 Source: APS response to Data Request LCA 8-237.

**Q. Do you have any comments on the claim by APS witness Bhatti that ratebasing the PWEC units could have been anticipated to yield benefits ranging from approximately $496 million to $615 million in net present value over the life of the projects.[30]**

A. Yes. Mr. Bhatti's retrospective analyses do not provide any insights into the critical question of whether acquiring the PWEC units is the most economic option available to APS at this time. APS did not actually conduct these comparisons during the years 1999 through 2002 and did not acquire the PWEC units during that timeframe. Therefore, Mr. Bhatti's comparisons have no relevance to the current proceeding.

Moreover, many of the studies upon which Mr. Bhatti bases his retrospective comparisons assumed very high capacity factors for the West Phoenix and Redhawk units.[31] This was overly optimistic given the significant number of new combined cycle units that were being proposed for Arizona and the rest of the Western region during the 1999-2002 timeframe. The use of these high capacity factors biased the results of Mr. Bhatti's comparisons in favor of the ratebasing of the PWEC units because it increased the market revenues against which the revenue requirements from ratebasing were being compared.

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30 Testimony of Ajit Bhatti, at page 68, lines 1-10.

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**Q. Is there currently any capacity crisis requiring that the Commission act at this time to allow APS to acquire the PWEC units and to include them in rate base?**

A. No. APS has an existing contract with PWEC for capacity from the units during the months of June, July, August and September through 2006. To the extent that APS needs additional capacity during other, non-summer peak periods, it should be able to acquire that capacity at low prices from PWEC or other sellers. After all, APS's own witness in this Docket, Dr. Hieronymus, has testified that "Near term prices are forecast to be relatively low, reflecting the glut of capacity coming on-line in the western U.S. in 2002-2003 ...."[32] and has noted the "price-depressing effect" of this glut of new capacity.[33]

**Q. Have you reviewed APS's January 27, 2003 Summary of Responses Received to its Power Supply Request for Proposals?**

A. Yes. APS provided the Summary to RUCO which forwarded it to me.

**Q. In your opinion, will the information provided by APS in this Summary enable the Commission to determine whether the PWEC units represent the most economic capacity that APS could acquire at this time?**

A. No. The information provided by APS about the bids it has received is far too cursory to enable the Commission to evaluate whether the PWEC units represent the most economic capacity that it could acquire in the market. APS has provided no information on the prices and durations of the individual bids. Nor has APS indicated the gas price forecast it has used to develop the range of levelized costs presented in the Summary. This information is essential in order to compare the

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32 Testimony of William H. Hieronymus, at page 51, line 23, to page 52, line 1.

33 Testimony of William H. Hieronymus, at page 59, lines 9-13.

economic savings and costs from acquiring the PWEC units against the capacity options bid in response to APS's Request for Proposals.

Moreover, PWEC did not submit a bid. Therefore, it is not possible to evaluate what value PWEC places on the capacity it is seeking to sell to APS.

**Q. Is it reasonable to expect that APS could provide information on the individual bids without compromising the bidding process or seriously prejudicing the negotiation process that may occur as part of the RFP?**

A. Yes. APS could provide the information pursuant to the confidentiality agreements that RUCO and other parties have signed in this proceeding. APS also could white out the names of the individual bidders and the facility-specific information that might reveal the identities of the individual bidders. The possibility that information provided by bidders might be revealed to third parties, if required by the Commission, was clearly contemplated in Section XI, "Confidentiality," of the December 3, 2003 Power Supply Request for Proposals.

**Q. APS's January 27, 2004 Summary notes that none of the PPA proposals involved a fixed-price bid and that all of the proposals would require APS and its customers to bear and/or assume the risk related to natural gas prices and/or transportation. Would this be any different than the risks that ratepayers would bear if the PWEC units are acquired by APS and placed into rate base?**

A. No. For example, I have seen no evidence that if APS acquires the PWEC units and places them into rate base, it will commit to provide the power from those facilities at fixed prices. Instead, the Company's customers will bear the risks associated with natural gas prices. Similarly, I have seen no evidence that APS would refrain from seeking future rate increases to reflect higher than currently projected plant operations & maintenance expenses.

**Q. What is your recommendation to the Commission regarding APS's request to acquire and ratebase the five PWEC units?**

A. The Commission should deny APS's request to acquire and rate base the PWEC units. Instead of allowing APS to add the PWEC units, the Commission should require that APS immediately undertake the development of a least-cost plan that includes a portfolio of demand-side, generation and transmission options. As part of this plan, APS should be required to undertake a competitive bidding process for power supply contracts (short, medium and long-term) and the purchase of part of all of existing generation facilities. This plan should be developed in order to be in place immediately following after the end of the Track B contracts in 2006 or sooner, if possible. PWEC could bid in this competitive process.

**Q. Is it possible that the results of this power supply solicitation could be used to help develop this least-cost plan?**

A. Yes. It is possible that the bids received by APS in response to its December 3, 2003 Power Supply Request for Proposals could be helpful in developing such a least-cost plan. However, PWEC did not submit any bid(s) in response to the latest Power Supply Request for Proposals. Moreover, it does not appear that any of the bids were for short-term or medium-term power supply agreements. Therefore, an additional competitive bidding solicitation may be necessary.

**Q. Is it possible that merchant generators could supply power to APS in the Phoenix load pocket in place of the PWEC units?**

A. Yes. The addition of planned transmission facilities can be expected to increase the ability of merchant generators to send power into the Phoenix load pocket.

For example, Figure 7.5 in the ACC's Second Biennial Transmission Assessment 2002-2011 shows that the import transmission capacity into the Phoenix Valley will increase substantially by 2008 – by more than 1,200 MW. This would enhance the ability of generators outside the Valley to serve loads inside the Valley during what would otherwise be RMR hours.

Consequently, as is shown in Figure 7.4 in the ACC's Second Biennial Transmission Assessment 2002-2011 shows that during the years 2004-2010 there will be substantially more in-Valley generation and transmission capability than will be needed to serve the combined Valley peak loads.

An APS Valley Import Analysis presented in the Rebuttal Testimony of APS witness Cary Deise in Docket No. E-01345A-01-0822 similarly showed that the addition of the planned Palo Verde – Table Mesa 500 kV transmission line in 2008 would significantly reduce APS's Valley Local Generation Requirements.

In addition, new transmission system enhancements may be developed as a result of the Arizona collaborative transmission planning process, in general, and the Central Arizona Transmission planning analyses, in particular.

**Q. Are you prepared to address the questions raised by Commissioner Gleason in his letter of September 5, 2003?**

A. Yes.

**Commissioner Gleason Question No. 1 – How should the Commission calculate the market value of a power plant?**

Answer – With a deregulated wholesale market, the Commission should determine the value of a power plant through a competitive power solicitation.

**Commissioner Gleason Question No. 2 – If the Commission should look at the plant's current market value instead of the original cost to build the plant, how can the Commission determine the market value?**

Answer - The value of a power plant will be determined by the price at which the plant is bid if the plant is the winning bid.

**Commissioner Gleason Question No. 3 – What power plants are on the market that can serve Arizona consumers?**

Answer – [

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In addition, APS has acknowledged that it is involved in several confidential discussions concerning potential power plant purchases.

**Commissioner Gleason Question No. 4 – Has any other state commission faced a situation where a regulated energy utility applied to incorporate merchant assets into its rate base? What did the commission decide?**

Yes. I am aware of two state regulatory commissions which have addressed the situation where a regulated energy utility applied to incorporate merchant assets into its rate base.

The Indiana Utility Regulatory Commission, ("IURC") in December 2002 approved a request by PSI Energy , Inc., for approval to purchase two generating facilities from a merchant affiliate.[35] The IURC's reasoning in approval this application is valuable to this proceeding.

First, the IURC relied heavily on the fact that the utility's resource mix was very heavily weighted towards coal-fired baseload capacity with baseload making up 65 percent of the PSI generation. The IURC specifically found that "PSI's current generating resources are heavily weighted toward baseload capacity while, optimally, the PSI system should be comprised of relatively more peaking capacity." The two units which PSI was seeking approval to acquire from the affiliate were both gas-fired combustion turbine peaking facilities.

Second, the utility, PSI, had conducted a detailed integrated resource planning process, involving the review of more than 4200 alternative resource plans, which identified that acquiring the two peaking facilities was the number one "least cost" plan. As I have noted earlier, APS has presented no evidence in this

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35 Indiana Utility Regulatory Commission, Order in Cause No. 42145, 2002 Ind. PUC LEXIS 544, December 19, 2002.

proceeding that acquiring the PWEC units is the least cost alternative for the Company.

In July 2002, the Public Service Commission of the State of Missouri approved a settlement between the AmerenUE Company, the Staff of the Commission and other parties that, in part, allowed AmerenUE to acquire two combustion turbine peaking generating units from an affiliated company, AEG.[36] Other terms of the settlement approved by the Missouri Commission required the utility to reduce its rates by $110 million over three years and to provide a one-time credit of $40 million to its customers. Unfortunately, the Commission's Order does not address the merits of the request to acquire the two generating facilities from the affiliate except to find that the agreement was in the public interest.

The Federal Energy Regulatory Commission ("FERC") subsequently addressed and approved this same transaction.[37] In May, 2003, FERC set a hearing on the request to transfer the generating units in order "to be certain that the purchase of the Pinckneyville and Kinmundy plants at net book value is consistent with results that would be obtained through a competitive process reflecting the interplay between AmerenUE and independent sellers and has not resulted in under preference being shown to AmerenUE's affiliate, AEG."

In the present case, APS has provided no evidence at all to show that the acquisition of the PWEC units is consistent with any results that would be obtained through a competitive process reflecting the interplay between APS and independent sellers. Moreover, there has been a clear preference shown to APS's affiliate, PWEC. In fact, APS has admitted that there weren't even any negotiations between APS and PWEC.[38]

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36 Public Service Commission of the State of Missouri, Case No. EC-2002-1, 2002 Mo. PSC LEXIS 1036, July 25, 2002.

37 Federal Energy Regulatory Commission, Order Setting Disposition of Facilities Application for Hearing, Docket No. EC03-53-000, 103 F.E.R.C. P61, 128, 2003 FERC LEXIS 819. May 5, 2003.

38 APS's response to Data Request LCA 4-94(b).

The Illinois Commerce Commission ("ICC") also needed to approve the acquisition of the power plants by AmerenUE. The Staff of the ICC filed testimony opposing the acquisition. However, the matter was never resolved as AmerenUE withdrew its application for approval of the asset transfer.[39] Apparently, AmerenUE has decided not to pursue the acquisition of the two generating units.

**Q. Does this complete your testimony at this time?**

A. Yes.

[39] Illinois Commerce Commission, Docket o. 03-0083, 2003 Ill. PUC LEXIS 632, July 23, 2003.

# EXHIBIT DAS-1

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## SUMMARY

I have worked for thirty years as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School

## PROFESSIONAL EXPERIENCE

**Electric System Reliability** - Evaluated whether new transmission lines and generation facilities were needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

**Transmission Line Siting** – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

**Power Plant Operations and Economics** - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Analyzed power plant operating data from the NERC Generating Availability Data System (GADS). Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

**Power Plant Repowering** - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

**Power Plant Air Emissions** – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of $NO_x$, $SO_2$ and $CO_2$. Examined whether new state emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

**Power Plant Water Use** – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proosed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

**Nuclear Power** - Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Evaluated utility decommissioning cost estimates and cost collection plans. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

**Electric Industry Regulation and Markets** - Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Evaluated the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets. Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales and the auctions of power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

**Economic Analysis** - Analyzed the costs and benefits of energy supply options. Examined the economic and system reliability consequences of the early retirement of major electric generating facilities. Evaluated whether new electric generating facilities are used and useful. Quantified replacement power costs and the increased capital and operating costs due to identified instances of mismanagement.

**Expert Testimony** - Presented the results of management, technical and economic analyses as testimony in more than ninety proceedings before regulatory boards and commissions in twenty three states, before two federal regulatory agencies, and in state and federal court proceedings.

**Litigation and Regulatory Support** - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

## TESTIMONY

**Rhode Island Public Utility Commission (Docket No. 3564) – December 2003**
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

**New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003**

The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

**Wisconsin Public Service Commission (Case 6690-UR-115209) - September and October 2003**
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

**Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003**
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

**Arkansas Public Service Commission (Docket 02-248-U) – May 2003**
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

**Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003**
The physical nature of electricity and whether electricity is a tangible product or a service.

**Maine Public Utilities Commission (Docket 2002-665-U) – April 2003**
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

**Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003**
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

**New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003**
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

**New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003**
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

**Arizona Corporation Commission (Docket No. E-01345A-01-0822) – March 2002**
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

**New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002**
Repowering NYPA's existing Poletti Station in Queens, New York.

**Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003**

Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

**Vermont Public Service Board (Case No. 6545) – January 2002**
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

**Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001**
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

**Connecticut Siting Council (Docket No. 208) – October 2001**
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

**New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001**
The market power implications of the proposed merger between Conectiv and Pepco.

**Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001**
Commonwealth Edison Company's management of its distribution and transmission systems.

**New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001**
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

**New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001**
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

**New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001**
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

**Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000**
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

**Illinois Commerce Commission (Docket 00-0361) - August 2000**
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

**Vermont Public Service Board (Docket 6300) - April 2000**
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

**Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000**
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

**Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000**
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

**Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000**
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

**Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999**
Generation, Transmission, and Distribution system reliability.

**Illinois Commerce Commission (Docket 99-0115) - September 1999**
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

**Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999**
Standard offer rates for Connecticut Light & Power Company.

**Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999**
Standard offer rates for United Illuminating Company.

**Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999**
Connecticut Light & Power Company stranded costs.

**Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999**
United Illuminating Company stranded costs.

**Maryland Public Service Commission (Docket 8795) - December 1998**
Future operating performance of Delmarva Power Company's nuclear units.

**Maryland Public Service Commission (Dockets 8794/8804) - December 1998**
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

**Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998**
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

**Arkansas Public Service Commission (Docket 98-065-U) - October 1998**
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

**Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998**
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998**
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

**Illinois Commerce Commission (Docket 97-0015) - May 1998**
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

**Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998**
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

**Illinois Commerce Commission (Docket 97-0018) - March 1998**
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997**
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

**New Jersey Board of Public Utilities (Docket ER96030257) - August 1996**
Replacement power costs during plant outages.

**Illinois Commerce Commission (Docket 95-0119) - February 1996**
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

**Public Utility Commission of Texas (Docket 13170) - December 1994**
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

**Public Utility Commission of Texas (Docket 12820) - October 1994**
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

**Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994**
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

**Public Utility Commission of Texas (Docket 12700) - June 1994**
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

**Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994**
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

**Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994**
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

**Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993**
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

**Public Utility Commission of Texas (Docket 11735) - April and July 1993**
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995**
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

**Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992**
United Illuminating Company off-system capacity sales.

**Public Utility Commission of Texas (Docket 10894) - August 1992**
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

**Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992**
Whether the July 1991 outage of Millstone Unit 3 due tot he fouling of important plant systems by blue mussels was the result of mismanagement.

**California Public Utilities Commission (Docket 90-12-018) - November 1991, March 1992, June and July 1993**
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

**Public Utility Commission of Texas (Docket 9945) - July 1991**
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

**Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991**
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

**New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990**
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

**Public Utility Commission of Texas (Docket 9300) - June and July 1990**
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

**Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989**
Boston Edison's corporate management of the Pilgrim Nuclear Station.

**Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989**
United Illuminating Company's off-system capacity sales.

**Kansas State Corporation Commission (Case 164,211-U) - April 1989**
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

**Public Utility Commission of Texas (Docket 8425) - March 1989**
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

**Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989**
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

**New Mexico Public Service Commission (Case 2146, Part II) - October 1988**
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

**United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988**
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

**Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989**
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

**Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988**
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

**Illinois Commerce Commission (Docket 87-0695) - April 1988**
Illinois Power Company's planning for the Clinton Nuclear Station.

**North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988**
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

**Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987**
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

**North Carolina Utilities Commission (Docket E-2, Sub 526) - June 1987**
Fuel factor calculations.

**New York State Public Service Commission (Case 29484) - May 1987**
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

**Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987**
The reasonableness of certain terms in a proposed Power Supply Agreement.

**Illinois Commerce Commission (Docket 86-0405) - March 1987**
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

**Indiana Public Service Commission (Case 38045) - December 1986**
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

**Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986**
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

**New York State Public Service Commission (Case 28124) - April 1986 and May 1987**
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

**Arizona Corporation Commission (Docket U-1345-85) - February 1986**
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

**New York State Public Service Commission (Case 29124) - January 1986**
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

**New York State Public Service Commission (Case 28252) - October 1985**
A performance standard for the Shoreham nuclear power plant.

**New York State Public Service Commission (Case 29069) - August 1985**
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

**Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985**
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

**Massachusetts Department of Public Utilities (Case 84-152) - January 1985**
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

**Maine Public Utilities Commission (Docket 84-113) - September 1984**
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

**South Carolina Public Service Commission (Case 84-122-E) - August 1984**
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

**Vermont Public Service Board (Case 4865) - May 1984**
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

**New York State Public Service Commission (Case 28347) -January 1984**
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

**New York State Public Service Commission (Case 28166) - February 1983 and February 1984**
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

**U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983**
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

## REPORTS, ARTICLES, AND PRESENTATIONS

*Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities*. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

*Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants*. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

*Determining the Need for Proposed Overhead Transmission Facilities.* A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

*Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station.* An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

*PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002.* An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

*Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants.* A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

*Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities,* on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

*The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability*. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

*Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line.* A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

*ISO New England's Generating Unit Availability Study: Where's the Beef?* A Presentation at the June 29, 2001 Restructuring Roundtable.

*Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability*. A Synapse Report for the Clean Air Task Force. May 2001.

*Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability*. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

*Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market*, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

*Cost, Grid Reliability Concerns on the Rise Amid Restructuring*, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

*Report on Indian Point 2 Steam Generator Issues*, Schlissel Technical Consulting, Inc., March 10, 2000.

*Preliminary Expert Report in Case 96-016613*, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, October 28, 1999.

*Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation*, February 1997.

*Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant*, August 1996.

*Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs*, May, 1996.

*Nuclear Power in the Competitive Environment*, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

*Nuclear Power in the Competitive Environment*, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

*The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations*, a report for the Environmental Law and Policy Center of the Midwest, 1995.

*Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs*, July 15, 1992.

*Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2*, December 1991.

*Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso*, Texas, April 1991.

*Nuclear Power Plant Construction Costs*, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

*Comments on the Final Report of the National Electric Reliability Study*, a report for the New York State Consumer Protection Board, February 27, 1981.

## OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

## WORK HISTORY

2000 - Present: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

## EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

## PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society
- National Association of Corrosion Engineers
- National Academy of Forensic Engineers (Correspondent Affiliate)

**BEFORE THE ARIZONA CORPORATION COMMISSION**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT. | ) | Docket No. E-01345A-03-0437 |

**DIRECT TESTIMONY**

**OF**

**DR. RICHARD A. ROSEN**

**On Behalf of the Arizona**
**Residential Utility Consumer Office**

**Tellus Institute**
**11 Arlington Street**
**Boston, MA 02116-3411**
**Tel: 617/266-5400**

**February 3, 2004**

EXHIBIT
number RUCO-4
Identified

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## I. SUMMARY AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from MIT, a M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president and secretary/treasurer of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resources, and environmental research. Within Tellus Institute, the Electricity Program focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost of capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. As past director of the Energy Group and manager of the Electricity Program, I have had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. I have also reviewed the prudence of many past supply-planning decisions by utilities.

Q. PLEASE PROVIDE A FEW ADDITIONAL DETAILS OF YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling and integrated resource planning has been a major focus of my activities for the past 24 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before

the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna Unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission ("FERC") on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec. In the 1980s, I testified in several cases involving the planning and construction of the Palo Verde nuclear units, before the Arizona Corporation Commission ("Commission" or ACC), as well as before FERC.

Finally, in January 1998, I testified before this Commission on behalf of the Residential Utility Consumer Office ("RUCO") in Docket No. U-0000-94-165 regarding public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; and presentation of the "retail generation service" methodology for computing stranded costs. In September 1998, in Docket No. E-01933A-98-0471, I was the author of comments to the Commission entitled "Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing." In November 1998, I filed testimony before the Commission in Docket Nos. E-

01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473; E-01345A-97-0773; and U-00000C-94-165 on various filings related to the unbundled service tariffs, stranded cost recovery proposal for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals. I filed testimony before the Commission in Docket No. RE-00000C-94-0165 in July 1999 on the status of settlement discussions between RUCO and Citizens Utilities Company-Arizona Electric Division ("CUC-AED"), and summary concerns about CUC-AED's stranded cost recovery plans. In February 2002, I filed testimony before the Commission in Docket No. E-01032C-00-0751 on Citizens Communications Company's Purchased Power and Fuel Adjustment Clause and its wholesale power supply contract with Arizona Public Service. I also testified before the ACC regarding Track A and Track B issues in docket E-00000A-02-0051 et al.

Due to my extensive regulatory experience supporting the public interest, as outlined above, in 1988 I was chosen to serve a three-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the U.S. Department of Justice, the National Association of Regulatory Utility Commissioners (NARUC), the New England Conference of Public Utility Commissioners, the New England

1 Governors Conference, and the National Council on Competition in the Electric
2 Industry.
3 In the last seven years, I have spent most of my time analyzing electric
4 utility restructuring issues. As early as 1996, I testified before the New
5 Hampshire Public Utilities Commission on issues affecting the design of the
6 state's pilot programs (Docket No. 96-150), and I testified before the New York
7 Public Service Commission on stranded costs, market structures, and other issues
8 related to ConEd's, NYSEG's, and RG&E's restructuring plans. I also have
9 worked on or testified on other restructuring issues in Nevada, New Mexico, New
10 Jersey, Illinois, Missouri, Colorado, Pennsylvania, Maryland, Maine, Rhode
11 Island, Utah and Michigan. Finally, I have recently authored a series of comments
12 to FERC on Regional Transmission Organizations and Standard Market Design
13 for several state attorneys general and consumer advocates. Exhibit___(RAR-1)
14 provides a copy of my resume.
15 Q. PLEASE SUMMARIZE THE ISSUES ON WHICH YOU WILL TESTIFY.
16 A. My testimony covers two different sets of issues that affect APS' request for a
17 change in its base rates for Standard Offer Service. The first set of issues deals
18 with how APS should charge its retail customers for the cost of transmission
19 service used to transmit power to retail loads. The second set of issues deals with
20 how APS should charge its retail customers for fuel and purchased power costs,
21 how APS should credit its retail customers for net income earned on wholesale
22 sales, and how the risk of mis-estimates of those future costs in this ratecase
23 should be shared between APS retail ratepayers and stockholders.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THESE TWO MAJOR ISSUE AREAS.

A. With respect to the first issue, I recommend that for several reasons it would be best for APS retail customers if the Arizona Corporation Commission retained jurisdiction over as much of the transmission service required by these customers as it can. The ACC jurisdictional transmission service contrasts with that portion of transmission service provided by APS for the wholesale transmission of power, over which FERC has jurisdiction. I believe that the ACC can and should retain jurisdiction over that portion of transmission service provided by APS to transmit power produced by any power plant that it owns to its own retail customers on a bundled basis. This goal can be achieved if the ACC eliminates the possibility of retail competition after July 1, 2004 for any of APS' retail customers, so that FERC can no longer claim that APS' retail rates are unbundled rates. All other uses of the APS transmission system would need to be charged to either retail or wholesale customers using the FERC approved OATT (Open Access Transmission Tariff) rate, since these uses would involve wholesale transactions.

Pursuant to this recommendation, the appropriate revenue requirement for transmission service for APS retail customers should be computed based on the sharing of regulatory jurisdiction as described above. Doing so will cause the revenue requirements for transmission service to be properly allocated between the ACC jurisdictional and FERC jurisdictional customers.

I also recommend that Mr. Propper's proposal to establish a Transmission Cost Adjustment Clause be rejected, since it does not meet the ACC's own standards justifying an adjustment clause.

With respect to the second main issue, in Decision No. 66567, the Commission has requested comments in this rate case as to how the impact of any mis-estimates in APS' forecasts of the costs of purchased power in the future, relative to the baseline levels approved in this ratecase, should be allocated between retail ratepayers and APS stockholders. I have concluded that most of APS' purchased power costs in the next few years would not be very volatile because they would be incurred primarily under fixed cost contracts. As a consequence, there is no need for APS to adopt a purchased power adjustment clause. Furthermore, any volatility in off-system sales revenues will tend to off-set volatility in purchased power costs, such that net purchased power costs will have a small impact on overall cost volatility.

Thus, my recommendation regarding the second main issue is that the retail ratepayers should only pay for the costs of fuel and purchased power as estimated by APS for their base rates as approved by the ACC in this ratecase. In addition, only the retail ratepayers should be credited with any net wholesale sales income earned on power sales from generating units included in the APS ratebase. If APS finds that it is significantly under-collecting its fuel and purchased power costs incurred for serving retail customers in the future, it can apply for a change in its base rates.

As partial justification for my recommendation that a purchased power adjustment clause is not needed, I completely support the arguments made by Ms. Marylee Diaz Cortez of RUCO in her direct and surrebuttal testimony in ACC Docket No. E-01345A-02-0403 as to why the ACC should not adopt any type of purchased power adjustment clause. Specifically, I agree that approval of APS' proposal for a PSA would require the ACC to reverse its 1989 Decision No. 56450 with respect to these matters. In addition, Ms. Cortez also showed that an up-do-date review of APS' fuel costs per kWh showed fairly modest changes for 2000-2002. Thus, these fuel costs were not sufficiently volatile to justify their inclusion in a fuel adjustment clause, or in a fuel and purchased power adjustment clause.

## II. TRANSMISSION SERVICE JURISDICTION AND RETAIL REVENUE REQUIREMENTS

Q. PLEASE DESCRIBE THE CURRENT SITUATION, AS YOU UNDERSTAND IT, AS TO WHICH REGULATORY AUTHORITIES HAVE JURISDICTION OVER THE TRANSMISSION SERVICE PROVIDED BY APS' TRANSMISSION ASSETS.

A. As I understand the current situation, FERC Order No. 888 made it clear that FERC claims authority over transmission service terms and conditions whenever any vertically integrated electric utility like APS has transmission assets that are either being used to serve wholesale customers directly, or are being used to supply power from third-party (or PWEC) generating units to APS' retail customers. (See 18 CFR 35-28(c)(2).) In addition, in the context of Order No. 888, "wholesale customers" include retail customers once a state has decided to <u>unbundle</u> its retail service due to the onset of retail competition for retail customers. Finally, the US Supreme Court in *New York v. FERC* (decided on March 4, 2002) confirmed that FERC can assert authority over the terms and conditions of all transmission service provided to a utility's retail customers, *if* the state has decided to allow retail competition for those customers, thus unbundling their retail electric rates. (Case No. 00-568)

Q. DO YOU KNOW IF THE ARIZONA CORPORATION COMMISSION HAS PREVIOUSLY TAKEN A POSITION AS TO WHETHER OR NOT IT

FAVORS TRYING TO MAXIMIZE ITS AUTHORITY OVER APS' TRANSMISSION ASSETS IN THE FUTURE?

A. Yes, during the course of FERC Docket No. ER00-3583-001, the ACC expressed the view that the Standard Offer Service that APS was providing to its retail customers was a *bundled* retail service, and, therefore, FERC did not have jurisdiction over the price and terms of the transmission service included as part of its Standard Offer Service. Thus, the ACC appeared to be resisting the extension of FERC authority to include the transmission component of Standard Offer Service prior to the Supreme Court's decision in *New York v. FERC.*

However, in FERC's "Order Denying Rehearing..." of March 16, 2001 in that docket, FERC disagreed with the ACC and declared that Standard Offer Service in Arizona was an unbundled service. This implied, in FERC's view, that Standard Offer Service, such as that provided by APS to its customers, "becomes separate [wholesale] transmission and power sales transactions, [whereby] the resulting transmission transaction falls within the Federal sphere of regulation." (Order, p. 5) As FERC repeated, "once the state commission adopts a system where generation service is available as a separate product, the transmission service is within this Commission's exclusive jurisdiction under the Federal Power Act." (Order, p. 5)

Q. WHAT ARE THE ADVANTAGES OF THE ARIZONA CORPORATION COMMISSION MAINTAINING THE MAXIMUM DEGREE OF AUTHORITY OVER TRANSMISSION SERVICE FOR RETAIL CUSTOMERS IN ARIZONA?

A. In my opinion, there are several existing as well as potential advantages for Arizona retail consumers to have the ACC maintain the maximum level of regulatory authority possible over the transmission assets in Arizona used to serve the retail customers of Arizona's vertically integrated electric utilities. The first advantage is that the ACC is more likely than FERC to carefully attend to whether or not the price of the transmission component of electric rates is as just and reasonable for electric retail customers as conditions change. Secondly, maximizing its authority over transmission will help the ACC to be able to assure retail customers (native load) that they get first priority in the use of APS' transmission assets to serve their needs, both from a system reliability and economic standpoint. This is justified since the relevant transmission lines were built to primarily serve native load, and since the lines have been paid for primarily through retail rates. For example, the ACC would be able to set rules as to the Firm Transmission Rights (FTRs) that Arizona utilities will have available for the purpose of using their own transmission assets to serve retail loads, including sufficient FTRs to provide transmission capacity reserves in order to maintain adequate levels of system reliability.

Thirdly, if the ACC maintains a maximum level of jurisdiction over the retail use of transmission assets within Arizona, this will very likely help to provide continued legal protection to prevent Arizona electric utilities from having to join a Regional Transmission Organization (RTO), which is a problematic creation of FERC's. It may very well be in the interest of Arizona's electric ratepayers not to have Arizona utilities join an RTO, because of the many

negative characteristics of such an organization, especially the Standard Market Design that FERC has so far insisted on for all RTOs. In my opinion, the ACC should do everything in its power to keep Arizona's electric utilities from being forced to participate in an RTO (as opposed to a cost-based regional power pool), especially if it includes FERC's proposed Standard Market Design. In this regard, over the last two years, I have drafted many sets of comments to FERC on this and related issues that have been signed by the consumer advocates and/or attorneys general of New Mexico, Utah, Colorado, and Rhode Island, as well as by other consumer protection organizations.

Fourthly, I believe that if the ACC retains jurisdiction over the bundled retail component of transmission service in Arizona, thus helping to avoid RTO membership for Arizona's electric utilities, this will also prevent the adoption by FERC of the additional returns on equity for these transmission assets (so-called "financial incentives") that FERC has proposed allowing for utilities that do join RTOs. Not having to pay for those unneeded financial incentives, as proposed by FERC, will directly save retail ratepayers money.

Q. BECAUSE OF THE POTENTIAL BENEFITS OF MAINTAINING ACC JURISDICTION OVER THE RETAIL USE OF THE TRANSMISSION ASSETS OF ARIZONA's ELECTRIC UTILITIES, WHAT DO YOU RECOMMEND THAT THE ACC DO TO PREVENT FERC FROM HAVING COMPLETE REGULATORY CONTROL OVER THOSE ASSETS?

A. In light of the current legal situation affecting the transmission assets of vertically integrated electric utilities, I recommend to the ACC that they repeal the

Commission's competition rules that established retail competition for retail customers in Arizona. I believe that if the ACC repeals these rules prior to July 1, 2004, then FERC Order No. 888 and the resulting Open Access Transmission Tariff (OATT) that resulted from this order, will no long apply to Arizona's electric utilities with respect to the bundled retail use of their transmission assets for the purpose of transmitting power from their own power plants to retail customers. If this is done prior to July 1, 2004, then APS' Standard Offer Service will cease to exist as an unbundled service, and traditional bundled retail service will again be the only type of electric service offered to retail customers. The ACC will, then, be free to set the revenue requirements for the bundled retail component of transmission service as it sees fit as part of this ratecase.

Q. IN ITS RATECASE FILING DID APS TAKE A POSITION ON THE JURISDICTIONAL ISSUES DISCUSSED ABOVE?

A. Yes, Mr. Robinson stated on page 15 of his direct testimony that FERC rules required APS to use the FERC OATT rates for pricing all components of Standard Offer transmission service. Because of this, Mr. Robinson removed *all* of the assets and costs associated with APS' transmission system from his revenue requirements calculations in this ratecase, as a pro forma adjustment. In their place, Mr. Robinson charged all APS' retail customers for all the transmission service provided to them using the OATT rates. In addition, Mr. Robinson's response to RUCO data request 13.1 pointed to FERC's decision in Docket No. ER00-3583-000, et al. as justification for APS' position on transmission pricing.

Q. IF THE ACC AGREES WITH YOUR RECOMMENDATION THAT IT RETAIN JURISDICTION OVER THE RETAIL USE OF APS' TRANSMISSION ASSETS BY ENDING RETAIL COMPETITION IN ARIZONA, OR AT LEAST FOR APS, HOW SHOULD APS CALCULATE THE REVENUE REQUIREMENTS FOR RETAIL TRANSMISSION SERVICE IN THIS RATECASE?

A. If the ACC retains authority over the bundled retail use of APS' transmission system assets, then APS should calculate the revenue requirements of this ACC jurisdictional service in two steps. The first step is to allocate the appropriate amount of transmission system asset costs (both fixed costs and expenses) to ACC jurisdictional customers, on a monthly basis for the test year, corresponding to the retail use of the transmission system for the purpose of transmitting power from generating units owned by APS (including the PWEC units if purchased by APS) to APS' retail customers. In other words, the appropriate numerical values for the use of the transmission system (in megawatts) to serve the coincident monthly peak retail demand, and monthly energy flows (in MWH) to serve retail customers directly from APS' owned generating units, should be used to determine what fraction of the fixed and variable costs, respectively, associated with the entire APS transmission system should remain in the ACC jurisdictional revenue requirement analysis directly.

The second step necessary to compute the total revenue requirements for APS' use of its transmission system for the purpose of serving bundled retail load is to use the OATT rates to determine the cost of serving the remainder of the

APS retail load on a month-to-month basis that is not supplied directly from APS' owned generating units. The revenue requirement results for each of these two steps should, then, be added together to obtain the total revenue requirements for transmission service for APS' retail customers.

Q. WHAT IS THE REGULATORY BASIS FOR THE FIRST STEP IN THE CALCULATION OF RETAIL REVENUE REQUIREMENTS THAT YOU HAVE OUTLINED ABOVE?

A. Again, the first step represents the bundled retail use of transmission service to transmit power from APS' owned generating units directly to retail customers. This component of transmission service would be part of the new bundled retail service provided by APS to all of its retail customers, and it would be completely under the jurisdiction of the state public utility commission. If retail competition is ended by July 1, 2004, then, there is no aspect of this type of use of the transmission system that represents a wholesale transaction, and, therefore, it would not be under FERC's jurisdiction.

Q. WHAT IS THE REGULATORY BASIS FOR THE SECOND STEP IN YOUR CALCULATION OF TRANSMISSION REVENUE REQUIREMENT FOR RETAIL CUSTOMERS?

A. In contrast, the use of APS' transmission system as described in step #2 above to supply additional amounts of power to retail customers from wholesale purchases, whether from PWEC plants, or from third-party plants, would represent a wholesale transaction. Thus, these two types of wholesale uses of the APS transmission system would be under FERC's jurisdiction according to both FERC

Order No. 888 and the Federal Power Act. That is why the results of the second step in the calculation of transmission revenue requirements for retail customers using the FERC OATT tariff rates must be included when calculating the total cost of transmission service for retail customers.

In addition, there is a third type of use of the APS transmission system that does not contribute to retail revenue requirements. APS' transmission system will also provide for the delivery of wholesale purchases of power to APS' wholesale customers (such as coop and wheeling-through customers), and these wholesale customers should also pay their fair portion of the total wholesale and retail revenue requirements for all transmission service under the FERC OATT rates. In summary, then, the three components of APS' total transmission revenue requirements are for:

1. retail service directly from APS' plants (ACC jurisdictional);
2. retail service from APS' wholesale contracts for purchases and sales of power (FERC jurisdictional);
3. service to wholesale customers from other wholesale contracts, or for wheeling through the APS system (FERC jurisdictional).

Q. DID YOU REQUEST THAT APS MAKE A CALCULATION OF THE ACC JURISDICTIONAL (RETAIL) TRANSMISSION SERVICE REVENUE REQUIREMENTS USING THE METHODOLOGY THAT YOU DESCRIBED ABOVE IN YOUR FIRST STEP?

A. Yes, in RUCO data request 15.1, I requested that APS make the revenue requirement calculation as described above in the first and second steps in the

form of a change to the retail revenue requirements that they were claiming in this case in Mr. Robinson's direct testimony which was based on 100 percent use of the OATT wholesale tariff rate for this purpose. Unfortunately, Mr. Propper's response was not helpful in terms of computing the relevant revenue requirement, since it appears that he did not understand the requested calculation. (See answer to RUCO 15.1.)

Q. ON PAGE 18 OF MR. PROPPER'S TESTIMONY HE PROPOSES THE ADOPTION OF A TRANSMISSON COST ADJUSTMENT CLAUSE. DO YOU AGREE WITH MR. PROPPER'S PROPOSAL FOR SUCH A CLAUSE?

A. No, I do not believe there is any reason for the ACC to adopt a Transmission Cost Adjustment Clause for APS retail customers. As discussed below, the main criteria that the ACC has previously accepted for justifying the adoption of adjustment clauses is that the relevant costs are significant and volatile. Yet, Mr. Propper provides no evidence at all in his testimony in this case that the retail component of transmission service costs meets these Commission criteria. He does not show that there is likely to be any significant degree of volatility in those costs, on a cents-per-kWh basis. In fact, it is very unlikely that actual transmissions costs per kWh would vary significantly from the baseline costs per kWh as set in the ratecase, since transmission costs are less than 10 percent of revenue requirements, and because they will tend to be proportional to sales. Thus, the adoption of a Transmission Cost Adjustment Clause has not been sufficiently justified in Mr. Propper's testimony, and I recommend that the request for such a clause be denied.

## III. THE PURCHASED POWER ADJUSTMENT CLAUSE

Q. PLEASE SUMMARIZE THE CURRENT STATUS OF RETAIL COMPETITION IN ARIZONA AND DESCRIBE THE IMPACT OF THIS SITUATION ON THE NEED FOR A PURCHASED POWER ADJUSTMENT CLAUSE.

A. Currently, retail competition does not functionally exist in Arizona. My understanding is that no significant number of APS' retail customers have ever chosen to purchase their electric generation supplies directly from a third- party provider, and none are doing so presently. Furthermore, it is my understanding that for many reasons RUCO will be recommending to the ACC that the Electric Competition Rules be modified in a manner to end retail competition in Arizona as an option for the retail customers of APS prior to July 1, 2004. In addition, I have just made the same recommendation above, in order that the ACC can retain jurisdiction over as much of the APS transmission system as possible.

It is especially true that if retail competition is ended in Arizona prior to July 1, 2004, then Ms. Diaz Cortez's testimony on behalf of RUCO in Docket No. E-01345A-02-0403 will retain all of its original relevance and force as to why a purchased power adjustment clause for APS should not be implemented. As Ms. Diaz Cortez pointed out, that aspect of the original settlement agreement of 1999 to consider establishing a purchased power adjustment clause would no longer have much relevance if retail competition proved to be ineffective, or was ended. This is because such a clause was presumed useful only when APS was

purchasing 100 percent (or a very high fraction) of its power supplies on a wholesale basis, and was not providing any significant fraction of the power demanded by its retail customers from its own power plants. In that situation, purchased power costs would completely dominate fuel costs. However, since it is clear now that APS will still generate much of the power supply needs of its retail customers from generating units that it owns for the foreseeable future, an adjustment clause for purchased power alone is far less necessary than was originally thought to be the case.

In addition, in the interim, the Track B power procurement process has been concluded. This means that the additional power requirements of APS that can not be generated from its own power plants will be purchased under contract pricing arrangements that will not be subject to as high a degree of price volatility as spot market purchased power might be. Furthermore, it would seem that only a very small fraction of the net power supply needs of APS customers could be prudently served from spot market power purchases anyway. Accordingly, only a very small fraction of APS' purchased power costs might be volatile. If, then, APS' off-system sales of power that will occur at market prices are netted against its projected power purchases at market prices, changes in the cost of the one will tend to off-set changes in the cost of the other. Thus, the ACC only needs to focus on the potential price volatility of these net power purchases, since market price fluctuations will tend to affect both sales and purchases similarly.

I relied on the APS forecasts for wholesale purchases and sales used for setting their proposed base rates in this ratecase to perform such a calculation. Mr.

Robinson's Workpaper number DGR-WP13, page 2, indicates that only about $10 million in *net* power purchases, out of about $584 million in total fuel and purchased power costs for 2003, can be expected. This calculation implies that the cost of net power purchases is likely to be so small that even if this cost were volatile a purchased power adjustment clause would not be justified. (Note that this workpaper assumes that the PWEC generating units are not included in the APS ratebase.) In addition, when considering whether or not a purchased power adjustment clause is needed, another important factor to consider is how the average net cost of purchased power changes on a multi-year average basis between ratecases, and not just how much volatility exists in this quantity from year to year. This is important because one year's increase in actual purchased power costs relative to base rate costs can be off-set by another year's decrease in such costs relative to base rates.

In light of all these considerations, it will not be necessary for the ACC to implement a purchased power adjustment clause for APS in order to reduce the average degree of risk faced by APS stockholders to reasonable levels between ratecases. Furthermore, not implementing a purchased power adjustment clause will provide APS management with a very strong incentive to minimize both its purchase power and fuel costs jointly. Finally, denying the PSA will not create the problems associated with piecemeal regulation that the ACC itself cited in Decision No. 56450.

Q. IN THE ACC'S RECENT DECISION NO. 66567 REGARDING APS' PROPOSAL FOR VARIOUS ADJUSTMENT MECHANISMS, THE ACC

STATED THAT THE PROPER TREATMENT OF ANY WHOLESALE MARKET CREDITS EARNED BY APS SHOULD BE DEALT WITH AS PART OF THE CURRENT RATECASE (P. 16). HOW WOULD YOUR PROPOSAL NOT TO IMPLEMENT ANY PURCHASED POWER ADJUSTMENT MECHANISM FOR APS BEGINNING IN JULY 2004 AFFECT THIS ISSUE?

A. If the ACC adopts my proposal to have no purchased power adjustment mechanism for APS' retail rates, then the ACC should also simply require APS to flow all projected net income from wholesale sales made from APS' owned generating units or purchased power contracts to the retail ratepayers, with no portion of this net income going to wholesale customers. This net income from wholesale sales should be forecast by APS on a consistent basis with its forecasts of all other fuel and purchased power costs, as they claim to have done in the ratecase filing. However, if the actual future net income from wholesale sales differs from the forecast amount on a test year basis, then just as for fuel and purchased power costs forecast to serve retail load, any differences in net income from wholesale sales relative to the baseline forecast would not be recovered from (or charged to) retail customers.

Q. HOW DID APS TREAT NET INCOME FROM WHOLESALE SALES IN ITS FORECASTS OF ITS NET COSTS OF PURCHASED POWER WHEN CALCULATING RETAIL REVENUE REQUIREMENTS IN THIS RATECASE FILING?

A. According to Mr. Robinson's Attachment DGR-5, page 8, it appears as if he credited the total Company revenue requirements with "normalized off-system revenue – 2003," as opposed to just crediting the ACC jurisdictional revenue requirements with this revenue as I have recommended above. This implies that the net off-system revenues are being shared between APS' retail and wholesale customers, which is not appropriate since APS' owned power supplies were built to serve retail load. If this is correct, APS should modify its revenue allocation methodology to credit all of its net revenues from off-system sales to ACC jurisdictional retail customers only.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

TELLUS INSTITUTE
*Resource and Environmental Strategies*

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## Education

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| Ph.D. | Physics, Columbia University, 1974 |
| M.A. | Physics, Columbia University, 1969 |
| B.S. | Physics and Philosophy, M.I.T., 1966 |

## Experience

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| 1998-2001 | Director of Energy Group, Tellus Institute |
| 1997-present | Manager of Electricity Group, Tellus Institute. |
| 1993-1997 | Director of Energy Group, Tellus Institute. |
| 1991-present | Director of Planning, Tellus Institute. |
| 1977-present | Energy Group. Responsibility for a broad range of research on integrated resource planning energy conservation; electric generation planning issues; and modeling studies of long-range energy demand, utility system reliability, energy demand curtailment, and environmental externalities and energy planning. |
| 1978-1980 | Consultant to Brookhaven National Laboratory. |
| 1979 | Consultant to the National Academy of Sciences, Puerto Rico Energy Study Committee. |
| 1976-1978 | Assistant Physicist, Economic Analysis Division, National Center for the Analysis of Energy Systems, Brookhaven National Laboratory. |
| 1974-1976 | National Research Council - National Academy of Sciences Resident Research Fellow, Goddard Institute for Space Studies, New York. |

1973 Instructor, Putney - Antioch Graduate School.

**Testimony**

| Agency | Case or Docket No. | Date | Topic |
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| Arizona Corporation Commission | E-00000A-02 0051 et al. | November 2002 | Track B issues |
| | | November 2002 | Rebuttal Testimony in above dockets |
| Public Service Commission of Wisconsin | 05-CE-117, 05-CE-130, 05-AE-109 (Tellus 02-070) | August 2002 | Review components of Phase I of proposed Power The Future investment plan; recommend changes in assumptions and methodology to improve WEPCO's Application for both Phase I and Phase II |
| | | September 2002 | Surrebuttal testimony in above dockets |
| Arizona Corporation Commission | E-00000A-02-0051 (Tellus 02-072) | May 2002 | Market Power in the Context of Deregulated Electricity Markets |
| Arizona Corporation Commission | E-04345A 01-0822 (Tellus 01-199) | March 2002 | Arizona Public Service Company's Request for a Variance of Certain Requirements of A.A.C. R14-2-1606 |
| Arizona Corporation Commission | E-01032C-00-0751 (Tellus 00-172) | February 2002 | Citizens Communications Company wholesale purchased power costs |
| United States District Court for the Southern District of Ohio – Eastern Division | C2-99-1181 (Tellus 00-205) | November 2001 | Evaluation of whether Ohio Edison should have forecasted that 11 activities undertaken at W.H. Sammis plant would cause net emissions increases exceeding the allowable Clean Air Act thresholds for $SO_2$, $NO_X$, and $PM_{10}$ at the time the activities occurred |
| | | August 2002 | Supplemental Expert Testimony in above docket. |
| Colorado Public | 00A-600E | March | Review of evidence filed by Public Service |

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| Utilities Commission | (Tellus 00-204) | 2001 | Company of Colorado in support of a proposed transmission line and high voltage DC converter between Lamar, CO and Holcomb, KS |
| Wisconsin Public Service Commission | 05-CE-113 (Tellus 99-207) | Nov. 2000 | Review and critique of Application supporting construction of Arrowhead-Weston transmission line |
| | | Dec. 2000 | Sur-rebuttal Testimony in above docket |
| Colorado Public Utilities Commission | 99A-549E Phase I (Tellus 00-128) | Nov. 2000 | Review of the adequacy of PSCo's selection of the electric generation resource bids that it has chosen for its final IRP plan |
| Colorado Public Utilities Commission | 00A-007E (Tellus 00-021) | March 2000 | Review of methodologies on which PSCo's summer peak demand and sales forecasts are based, and recommendations how its load forecasting could, and should, be improved |
| New Hampshire Public Utilities Commission | DE99-099 (Tellus 99-136) | Dec. 1999 | Discussion of the Transition Service Energy Charges that might be applied in New Hampshire |
| New Hampshire Public Utilities Commission | DE 99-099 (Tellus 99-136) | Nov. 1999 | Non-rate design aspects of the proposed Settlement Agreement between PSNH and the State of New Hampshire |
| Delaware Public Service Commission | 99-457 (Tellus 99-145) | Nov. 1999 | Analysis of the stranded cost-related issues in the Delaware Electric Cooperative, Inc.'s filing and sponsoring of an estimate of stranded costs for the DEC |
| | | Dec. 1999 | Rebuttal testimony |
| Federal Energy Regulatory Commission | EC97-56-000 ER97-4669-000 (Tellus 97-230) | Sept. 1999 | Description of, and results of, an independent analysis of market power performed to demonstrate potential impact on regional electricity prices of proposed KCPL/Western Resources merger, and to illustrate several key aspects of how market power analysis for a merger should be done |
| Arizona Corporation | RE-00000C- | July | The status of settlement discussions between |

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| Commission | 94-0165 (Tellus 98-147) | 1999 | Residential Utility Consumer Office (RUCO) and Citizens Utilities Company-Arizona Electric Division, and summary of concerns about CUC-AED's stranded cost recovery plans |
| Public Utilities Commission of New Hampshire | DR 96-150 (Tellus 98-237) | June 1999 | Clarification of the regulatory policy implications of the New Hampshire Supreme Court decision of December 23, 1998, as it applies to the future recovery of stranded costs in the rates that the PUC will set for Public Service of New Hampshire |
| Missouri Public Service Commission | Case No. EM-97-515 (Tellus 97-230) | April 1999 | Review and critique of the analyses of market power specific to the proposed merger of Kansas City Power & Light Company and Western Resources, performed by Dr. Robert Spann on behalf of the Applicants. Also a description of, and the results of, an independent analysis of market power performed in order to demonstrate the potential impact on regional electricity prices of the proposed merger. |
| Arizona Corporation Commission | E-01933A-98-0471; E-01933A-97-0772; E-01345A-98-0473 E-01345A-97-0773 and U-00000C-94-165. (Tellus 98-147) | November 1998 | Analysis of various filings related to the unbundled service tariffs, stranded cost recovery proposals for Arizona Public Service and Tucson Electric Power Company, and various other aspects of their restructuring proposals |
| New Mexico Public Utility Commission | 2867/2868 (Tellus 98-195) | November 1998 | Application of Residential Electric Incorporated for a CCN to provide electric service and its request that Public Service of New Mexico offer transmission, distribution, and customer-related services, at unbundled rates |
| Public Utilities Commission of Nevada | 98-7023 (Tellus 98-111) | November 1998 | Analysis of stranded generation costs of Sierra Pacific Power Co. and the Nevada Power Co.; analysis of conditions under which competitive wholesale power markets could be created in Nevada, particularly given the severe transmission constraints in the state |

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| Maine Public Utility Commission | 97-580 (Tellus 98-007) | May 1998 | Central Maine Power's proposed Standby rates and related policy issues |
| | | August 1998 | Surrebuttal testimony in above docket |
| Maine Public Utility Commission | 97-580 (Tellus 98-007) | April 1998 | Alternative estimate of value of stranded costs of Central Maine Power Company based on three changes to their methodology, and alternative estimate of CMP's non-utility generation stranded costs arising from the Regional Waste Systems purchased power contract |
| New Hampshire Public Utilities Commission | DR 98-012 (Tellus 98-019) | April 1998 | Proposed Offer of Settlement in the Granite State Electric Company restructuring docket |
| New Mexico Public Utility Commission | 2761 (Tellus 97-135) | April 1998 | Investigation of the potential of using market pricing for the unbundled generation portion of rates in a way that will allow Public Service Company of New Mexico to realize the fair market value of its generation plant over the long run, beginning with the test year 1996 |
| New Hampshire Public Utilities Commission | DE97-251 (Tellus 98-019) | March 1998 | Evaluation of whether or not the proposed transfer of the generating assets and purchased power agreements of the New England Power Company to USGenNE is in the public interest for the citizens of New Hampshire |
| Arizona Corporation Commission | U-0000-94-165 (Tellus 97-289) | Jan. 1998 | Public policy recommendations on key issues related to calculation, sharing, and recovery of stranded costs; presentation of "retail generation service" methodology for computing stranded costs |

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| | | Feb. 1998 | Sur-Rebuttal testimony in above docket |
| New Jersey Office of Administrative Law | BPU EO9707-0465 OAL PUC-7309-97 BPU EO9707-0464 OAL PUC-7310-97<br><br>Tellus (97-203/A4) | Jan. 1998 | The importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Rockland Electric Company) |
| | | March 1998 | Sur-rebuttal Testimony in above docket |
| New Jersey Office of Administrative Law | BPU E097070 456 OAL PUC 7311-97 (Tellus 97-203/A6) | Nov. 1997 | Importance of pricing retail generation services for use in the appropriate methodology for making stranded cost calculations (Atlantic City Electric) |
| New Jersey Office of Administrative Law | BPU EO9707 0459 OAL PUC-7308-97 BPU E09707 0458 OAL PUC-7307-97<br><br>(Tellus 97-203/A3) | Nov. 1997 | Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Jersey Central Power & Light dba GPU Energy) |
| New Jersey Office of Administrative Law | BPU E09707 0462 OAL PUC-7347-97 BPU EO9707 0461 OAL PUC-7348-97 | Nov. 1997 | Pricing of retail generation services relative to the appropriate methodology for making stranded cost calculations (Public Service Electric & Gas Company) |

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| | (Tellus 97-203/A1) | | |
| | | Jan. 1998 | Sur-rebuttal testimony in above dockets |
| Public Utility Commission of Texas | 473-96-2285 and 16705 Tellus 97-046) | Sept. 1997 | Competitive issues |
| Michigan Public Service Commission | U-11283 (Tellus 97-093) | May 1997 | Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test |
| Michigan Public Service Commission | U-11337 (Tellus 97-093) | May 1997 | Recommendations on key policy issues related to determining the appropriate division between transmission and local distribution facilities, and the appropriate cost allocations, as required under FERC Order No. 888 using FERC's seven-point test |
| New York Public Service Commission | 96-E-0898 (Tellus 97-009) | May 1997 | Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Rochester Gas and Electric Corp., and public policy recommendations on key issues related to market structure, market power, and the likelihood of RG&E's proposed retail access program actually leading to competition |
| New York Public Service Commission | 96-E-0897 (Tellus 97-009) | April 1997 | Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of Consolidated Edison Company of New York, Inc., and public policy recommendations related to market structure and market power |
| New York Public Service Commission | 96-E-0891 (Tellus 97-009) | February 1997 | Public policy recommendations on key issues related to stranded costs, a preliminary range of estimates of the stranded generation costs of New York State Electric and Gas Company, and public policy recommendations on key issues related to market structure and market power |

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| Missouri Public Service Commission | EM-96-149 (Tellus 96-214) | Nov. 1996 | Various issues related to market power |
| Federal Energy Regulatory Commission | EC96-10-000 (Tellus 96-050F) | Sept. 1996 | Review of the joint application of Baltimore Gas & Electric Company and Potomac Electric Power Company for approval of their proposed merger and organization |
| Maryland Public Service Commission | 8725 (Tellus 96-050) | July 1996 | Review of the joint application of BGE and PEPCO for approval of their proposed merger and reorganization |
| Illinois Commerce Commission | 95-0551 (Tellus 95-302) | March 1996 | Review of joint application of Central Illinois PSC, CIPSCO Incorporated, and Union Electric Company for approval of their proposed merger and reorganization |
| Vermont Public Service Board | 5724 (Tellus 94-064) | July 1994 | Review of Central Vermont Public Service's planning for its power supply resources over the past 5 years and its management of its resource portfolio |
| Illinois Commerce Commission | 94-0065 (Tellus 94-112A) | June 1994 | Assessment of the extent to which Byron 2, Braidwood 1 and Braidwood 2 nuclear units may be considered used and useful for ratemaking purposes by Commonwealth Edison, and recommendation of an appropriate ratemaking treatment of the units based on this assessment |
| | | July 1994 | Rebuttal Testimony in above docket |
| Kansas Corporation Commission | 180,056-U | February 1994 | Oral Testimony (no written testimony) on establishment of IRP rules for electric and gas utilities |
| Public Utilities Commission of Hawaii | 7257 (Tellus 93-144A3) | December 1993 | Critique of HECO IRP plan. Recommendations re: better and simpler approach to taking environmental externalities into account in integrated resource planning |
| Arkansas Public Service Commission | 93-132-U (Tellus 93-148) | November 1993 | Review application of Arkansas Electric Cooperative Corporation (AECC) for a certificate of public convenience and necessity for the |

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| | | | construction, ownership, operation, and maintenance of a hydro-electric generating facility at Dam No. 2 ("H.S. #2") on the Arkansas River |
| | | January 1994 | Sur-Rebuttal Testimony in above docket |
| Public Utilities Commission of Georgia | 4152-U (Tellus 93-100) | August 1993 | Review of ratemaking aspects of the Clean Air Act Compliance plans of Georgia Power Company and Savannah Electric and Power Company |
| Pennsylvania Public Utility Commission | A-110300 F. 051 (Tellus 92-026) | July 1993 | Critique of certain aspects of the Joint Applicants' filing with respect to whether the Joint Applicants have satisfied the requirements of the Pennsylvania PUC's siting regulation |
| Public Utilities Commission of Ohio | 91-635-EL-FOR 92-312-EL-FOR 92-1172-EL-FOR (Tellus 92-165) | April 1993 | Comments and recommendations re: Cincinnati Gas & Electric Company's integrated resource plan submitted in the Company's 1992 Electric Long Term Forecast Report |
| Georgia Public Service Commission | 4133-U, 4136-U (Tellus 92-078) | October 1992 | Review of the need for new capacity on the Georgia Power Company, Savannah Electric & Power Company, and Southern Company system over the next three years, 1992-1995 |
| Public Utilities Commission of Ohio | 92-708-EL-FOR 92-1123-EL-FOR (Tellus 92-041A) | September 1992 | Comment on Centerior Energy Corporation's integrated resource plan and Clean Air Act compliance plan submitted in the Company's Long Term Forecast Report; specific recommendations for action on behalf of the Company to improve components of its resource and Clean Air Act compliance planning process |
| Public Service Commission of the State of Georgia | 4131-U, 4136-U (Tellus 91-266) | June 1992 | Adequacy of the 1992 Integrated Resource Plans of Georgia Power Company (GPC) and Savannah Electric Power Company (SEPCO) |

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| U.S. Bankruptcy Court - Manchester, NH | BK-91-11336 Chapter 11 | March 1992 | Adequacy of bankruptcy plan filed by New Hampshire Electric Cooperative, Inc. |
| Public Utilities Commission of Ohio | 91-410-EL-AIR (Tellus 91-082) | December 1991 | Ratemaking treatment of Cincinnati Gas & Electric Company's 39.63% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO) |
| Public Utilities Commission of Ohio | 92-418-EL-AIR (Tellus 91-091) | December 1991 | Ratemaking treatment of Columbus Southern Power Company's 24.20% share in the Zimmer plant under the jurisdiction of the Public Utilities Commission of Ohio (PUCO) |
| Maine Public Utilities Commission | 89-193, 89-194, 89-195 (ESRG 89-189B & 90-039) | August 1990 | Review of Bangor Hydro-Electric Company's solicitation of bids with a request for proposals dated July 24, 1989, and its approach to the evaluation of the respondents' bids. |
| New Hampshire Public Utilities Commission | DF 89-085 (ESRG 90-051) | July 1990 | Assessment of Eastern Utilities Associates' Plan to acquire UNITIL Corporation: Issues Affecting NH Consumers |
| | | September 1990 | Supplemental Testimony in above docket. |
| Florida Public Service Commission | 891345-EI (ESRG 90-017) | April 1990 | Rate base treatment of Gulf Power Company's 63-MW ownership share of the Scherer 3 generating unit. |
| Michigan Public Service Commission | U-9458 (ESRG 89-158) | February 1990 | Implications of excess capacity on the Indiana Michigan system for the costs that should be included in the Company's 1990 PSCR plan. |
| Vermont Public Service Board | 5330 (ESRG 89-078) | December 1989 | Presentation of results of ESRG Study: *The Role of Hydro-Quebec Power in a Least-Cost Energy Resource Plan for Vermont.* |
| | | February 1990 | Further Testimony in above Docket |

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| | | February 1990 | Surrebuttal Testimony in above Docket |
| Pennsylvania Public Utility Commission | R-891364 (ESRG 89-90A) | October 1989 | Recommendations regarding the proper ratemaking treatment for PECo's Limerick 2 nuclear unit. |
| Florida Public Service Commission | 881167-EI (ESRG 89-034) | May 1989 | Ratebase Treatment of Gulf Power Scherer 3 Capacity |
| Federal Energy Regulatory Commission | ER88-630-000 (ESRG 88-153) | April 1989 | Pass Through of Performance Incentive Program Charges by New England Power Company |
| Public Service Commission of the District of Columbia | Formal Case No. 877 (ESRG 88-128D) | February 1989 | Evaluation of the Need and Justification for 210 MW CTs at Benning Road Site Proposed by PEPCO |
| | (ESRG 88-128E) | March 1989 | Rebuttal Testimony |
| Michigan Public Service Commission | U-8871 (ESRG 88-32) | April 1988 | Review of the Appropriate Avoided Costs for the CPCo System |
| | (ESRG 88-32A) | August 1988 | Rebuttal Testimony |
| Maine Public Utilities Commission | 87-268 (ESRG 30A) | April 1988 | Review Related to the Staff's Evaluation of the Desirability of the Purchase of Power from Hydro Quebec Proposed by Central Maine Power |
| | 87-268 (ESRG 87-30A1) | August 1988 | Supplemental Testimony |
| Pennsylvania Public Utility Commission | M-870111, G-870087 G-870088 (ESRG 88-01) | February 1988 | Review of Pennsylvania Power Company's Requested Recovery of Purchased Power Costs |

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| Michigan Public Service Commission | U-7830 (ESRG 85-35E) | December 1987 | Review of the Application of Consumers Power Company to Recover Its Midland Investment |
| Pennsylvania Public Utility Commission | R-870651 (ESRG 87-50D) | October 1987 | Investigation into Whether Perry 1 and Beaver Valley 2 Capacity Is Economically Used and Useful on the Duquesne System. |
| Federal Energy Regulatory Commission | ER-86-694-001 | September 1987 | Analysis of NEPOOL's PIP Program on Behalf of Maine Public Utilities Commission |
| Maine Public Utilities Commission | 86-85 | June 1987 | Investigation of Reasonableness of Rates |
| | | August 1987 | Surrebuttal |
| Maryland Public Service Commission | 7972 | February 1987 | Investigation by the Commission of the Justness and Reasonableness of the Rates of Potomac Electric Power Company |
| Arizona Corporation Commission | U-1345-85-367 (Tellus 86-42B) | February 1987 | Concerning the Prudence of Palo Verde Investment |
| Michigan Public Service Commission | U-8578 (Tellus 86-055A) | January 1987 | Power Supply Cost Recovery Plan for Detroit Edison |
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| Pennsylvania Public Utility Commission | R-860378 (Tellus 85-083A) | September 1986 | Economics of Duquesne Light Company's Share of Perry 1 |
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| | | November 1986 | Surrebuttal |
| | | March 1987 | Supplemental |
| Michigan Public Service Commission | U-8348 | July 1986 | Palisades Performance Standards |
| Michigan Public Service Commission | U-8291 | April 1986 | Power Supply Cost Recovery Plan for Detroit Edison |
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| Division of Public Utilities, Dept. of Business Regulation | 85-2011-01 85-999-08 | January 1986 | Construction of a Transmission Line and Transmission Facilities in Southwestern Utah |
| New York Public Service Commission | 28252 | October 1985 | Shoreham - Rate Moderation |
| | | January 1986 | Surrebuttal |
| Missouri Public Service Commission | ER-85-128 EO-85-185 EO-85-224 (Tellus 83-089) | June 1985 | Wolf Creek Excess Capacity and the Prudency of Company Planning |
| Federal Energy Regulatory Commission | ER-84-560-000 (Tellus | April 1985 | Callaway Excess Capacity and a Review of Union Electric Planning |

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| State Corporation Commission of the State of Kansas | 120-924-U<br>142-098-U<br>142-099-U<br>142-100-U | April 1985 | General Investigation by the Commission of the Projected Costs and Related Matters of the Wolf Creek Nuclear Generation Facility at Burlington, Kansas |
| Michigan Public Service Commission | U-8042 | February 1985 | Power Supply Cost Recovery Plan for Consumers Power Company |
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| Massachusetts Department of Public Utilities | 84-49, 84-50, 84-140, 627, 1656 & 1957 | January 1985 | Economics of Completing Seabrook 1 for Four Massachusetts Utilities |

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1999 *Funding for Energy-Related Public Benefits: Needs and Opportunities With and Without Restructuring.* A report to the Governor's Office of Energy Conservation. Tellus Study No. 98-002/C2. May. Co-author.

1998 *New England Tracking System (NETS).* A report of the New England Governors' Conference, Inc. Tellus Study No. 97-063. October. Project manager.

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1997 *Restructuring the Electric Industry in Delaware*. A Draft Report by the Delaware Public Service Commission Staff. PSC Docket No. 97-229. Tellus Study No. 96-099. November. Co-author. Final Draft Report.

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1995 *Promoting Environmental Quality in a Restructured Electric Industry.* A Report to: The National Association of Regulatory Utility Commissioners. Tellus Study No. 95-056. December. Co-author.

1995 *Power Pools and Least-Cost Compliance with the Clean Air Act.* A Report to: the Pew Charitable Trusts. Tellus Study No. 94-113. October. Principal investigator.

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1995 *Order on Application for Reconsideration, Formal Case No. 813, Order No. 10590.* Public Service Commission of the District of Columbia. Tellus No. 94-051. March.

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1995 In the Matter of a Notice of Inquiry to Consider Section III of the Energy Policy Act of 1992 - Integrated Resource Planning and Energy Efficiency Investments in Power Generation and Supply for Electric Utilities. Docket No. 94-342-U. Prepared for: Arkansas Public Service Commission. Tellus No. 92-153A4. January. Co-author.

1994 *Competition and the Tennessee Valley Authority.* White paper prepared for TVA's Board of Directors. Tellus Study No. 94-096. October. Co-author. Draft.

1994-1995 Independent Advisors to the Tennessee Valley Authority's Board of Directors during the Utility's Development of its First Integrated Resource Plan. Tellus Study No. 94-096. May 1994-December 1995. Project manager.

1994 *Report on Notice of Advanced Rulemaking Relating to Commission Review of Siting and Construction of Electric Transmission Lines.* Submitted to: Pennsylvania Office of

Consumer Advocate. Docket No. L-00940091. Tellus Study No. 94-223. December. Co-author.

1994 "Comments in Response to Edison Electric Institute's Petition for Statement of Policy on the Ratemaking Treatment of the Costs Associated with $SO_2$ Emissions Allowances." Docket No. PL95-1-000. Federal Energy Regulatory Commission. Tellus Study No. 94-113. November. Co-author.

1994 *Electric Transmission Pricing.* A report to: American Wind Energy Association. Tellus Study No. 94-39. September. Co-author.

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1993 A Report to: The Public Service Commission of the State of Delaware Regarding Docket 39: PURPA Standards as Amended by the Energy Policy Act of 1992. Tellus Study No. 93-054. August. Co-author.

1993 *IRP Concepts and Approaches.* Report to Hydro-Quebec and the Public Interest Groups and Associations. Tellus Study No. 92-155. July. Project manager.

1993 *Proposed Rules Governing Integrated Resource Planning for Electric and Natural Gas Utilities Regulated by the State of Kansas.* In collaboration with Kansas Corporation Commission Staff. Tellus Study No. 92-105. June. Project manager.

1993 *Preliminary Study on Integrated Resource Planning for the Consumers' Gas Company Ltd.* Prepared for Consumers Gas Company, Ltd. Tellus No. 91-001. Project Co-manager. May. Not publicly available.

1992 *Sales Forecasts and Price Changes for New Hampshire Electric Cooperative.* Prepared for: Members Committee of New Hampshire Electric Cooperative. Tellus Project No. 91-173. January. Principal investigator.

1991 *America's Energy Choices: Investing in a Strong Economy and a Clean Environment.* In collaboration with the Union of Concerned Scientists, the American Council for an Energy Efficient Economy, the Natural Resources Defense Council, and the Alliance to Save Energy. Tellus Study No. 90-067. September. Co-author.

1990 *Environmental Impacts of Long Island's Energy Choices: The Environmental Benefits of Demand-Side Management.* Tellus No. 90-028A. September. Co-author.

1990 *Assessment of the Eastern Utilities Associates' Plan to Acquire UNITIL Corporation: Issues Affecting New Hampshire Consumers.* Exhibit 2 to Tellus No. 90-051. July. Project manager.

1990 *Comments on Pacific Power and Utah Power Resource and Market Planning Program.* On behalf of Committee of Consumer Services, Utah Department of Commerce. ESRG No. 90-050A. April. Author.

1990 *The Northeast Utilities Plan for Public Service Company of New Hampshire: Issues Affecting New Hampshire Consumers.* A report to: State of New Hampshire, Office of the Consumer Advocate. ESRG No. 90-019. March. Reviewer.

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1989 *Rhode Island's Options for Electric Generation.* A Policy Statement of the Energy Coordinating Council. ESRG No. 89-004. July. Co-author.

1989 *Update of 1985 Study on the Economics of Closing vs. Operating Shoreham.* ESRG Report No. 89-051. March. Principal investigator.

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1988 *An Evaluation of Central Maine Power Company's Proposed Purchase of Power from Hydro Quebec.* A Report to the Maine Public Utilities Commission Staff. ESRG Report No. 87-30. April. Principal investigator.

## Other Publications

2000 "Electricity Market Regulation in Germany and the USA—History and Prospects," in *Electricity Restructuring and the Environment – A U.S.-German Dialogue.* The Heinrich Böll Foundation, Washington, DC. Co-author.

1992 "Bill Indexing," chapter in: *Regulatory Incentives for Demand Side Management*, edited by S. Nadel, et al. Published by ACEEE/NYSERDA. With David Moskovitz.

## Papers and Presentations

2002 "Why the Deregulation of the Electric Industry Will Inevitably Lead to Higher Prices and Lower Economic Efficiency." Washington, DC. September 28.

2002 "How IRP Principles Can Help Explicate Electric Utility Restructuring Issues." A presentation to the NARUC Energy Resource & Environment Committee, NARUC Summer Meeting – Portland, OR. July 30.

2002 "FERC's Standard Market Design: One of the Key Reasons Why Electric Deregulation Will Fail." NASUCA Summer Meeting – Austin, TX , June 16.

2002 NASUCA Seminar on Market Power Issues in the Northeast - Albany, NY, February.

2001 "Just and Reasonable Rates vs. Price Caps at FERC," Backgrounder. June 19.

2001 The Progressive Pro-Consumer Solution to Today's Electricity Crisis: Just and Reasonable Rates. Preliminary proposal to Progressive Caucus, U.S. House of Representatives. May 16. Co-author.

2001 "The Arrowhead-Weston Transmission Line – Issues and Lessons." Presented to: NWCC Upper Midwest Transmission Workshop, Minneapolis, MN. May 1.

2001 "Short- and Long-Term Solutions to Deal with Market Power." Presented at NRRI Market Power Conference, Columbus, OH. April 11.

2001 "Why We Need an ICAP Market in New England." Presented to Massachusetts Electric Restructuring Roundtable, Boston, MA. February 16.

2000 *Can Electric Utility Restructuring Meet the Challenges It Has Created?* A Tellus Institute White Paper. November.

2000 "Electric Restructuring in Crisis: The Implications of Market Power." Pace Conference on Electricity Restructuring. White Plains, NY. November 10.

2000 "Presentation on Market Power Issues Raised by the Proposed NU/Con Edison Merger," to Connecticut DPUC. August 3.

2000 "The Bumpy Launch May Never Stop." NASUCA Conference, Portland, ME. June 5-6. With F. Sverrisson.

1999 "Nothing in the Pipeline?" Some Economic and Environmental Effects of the Proposed Natural Gas Pipeline and Generating Facilities in Southwestern Vermont. With F. Sverrison.

1999 "A Comparison of Studies by U.S. DOE and Stone & Webster on the Effect of Electric Restructuring in Colorado." Presented at Tenth National Energy Services Conference, Tucson, Arizona. December 6-8. With F. Sverrisson.

1999 "The Emperor's New Clothes: Fatal Flaws of the HHI," presented at Pricing Power Products & Services Conferences, Chicago, IL. October 14-15.

1999 "A Better Approach to Market Power Analysis," presented at Annual NECPUC Conference, Bretton Woods, NH. May 25. Revised July 1999. Co-author.

1999 "The Emperor's New Clothes: Fatal Flaws of the HHI," presented at Annual NECPUC Conference, Bretton Woods, NH. May 25.

1999 "Market Power in Colorado." Electricity Advisory Panel. Denver, CO. May.

1998 "Market Power and Mergers," presented at NASUCA Annual Meeting, Orlando, FL. November.

1998 "Breaking Up is Hard to Do, Unless You Have the Power." Presentation to NASUCA Annual Meeting. November 10.

1997 "How Do You Compute Stranded Costs?" A talk to ELCON. Washington, DC. October 30.

1997 "An Overview of Key Issues in Electric Industry Restructuring," presented to the Colorado Office of Consumer Counsel. June 26. Co-author.

1997 "Letting Retail Competition Succeed," presented at 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Co-author.

1997 "A Critique of FERC's New Merger Guidelines: Implications for Analyzing Market Power, Mergers & Deregulation," distributed at 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Co-author.

1997 "A Critique of FERC's New Merger Guidelines: Implications for Analyzing Market Power, Mergers & Deregulation," 1997 NASUCA Mid-year Meeting, Charleston, SC. June 9-11. Panelist.

1997 "Market Power, Mergers, and Deregulation: A Critique of FERC's New Merger Guidelines," The National Regulatory Research Institute *Quarterly Bulletin*. May.

1997 "A Whitepaper On Stranded Costs and Market Structures in the U.S. Electricity Industry," prepared for: The American Association of Retired Persons. Tellus No. 97-009. April. Draft.

1997 "A Point/Counterpoint Analysis of Major Restructuring Issues." Co-author.

1996 "Leveraging" - The Key to the Exercise of Market Power in a Poolco. NARUC and NASUCA Summer Meetings. June. Co-author.

1995 "The Status of Regulatory Policy Affecting the Restructuring of the Electric Utilities Industry." Presentation to: Wheelabrator Technologies, Inc. September.

1995 Presentation to Maine Public Service Company on Behalf of Wheelabrator Sherman to explain Tellus' Calculation of Estimates of Total Avoided Costs for Wheelabrator Sherman Power through 2015. August. Co-author.

1994 "Nine Fallacies in Computing Avoided Costs." Distributed at: The Annual NARUC/ NASUCA Conference, Reno, NV. November. Co-author.

1994 "Apples and Oranges: Using Multi-Attribute Analysis in a Collaborative Process to Address Value Conflicts in Electric Facility Siting." Presented at: Ninth National Association of Regulatory Utility Commissioners (NARUC) Biennial Regulatory Information Conference, Columbus, Ohio, September 8. Co-author.

1993 "How Should Electric Utilities Allocate Their Free EPA-Granted Allowances Among Retail and Wholesale Customers? An Unresolved Issue of Clean Air Act Compliance. Prepared for distribution at: The NARUC/NASUCA 1993 Annual Meetings, New York, NY. November 14. Co-author.

1993 "Integrated Resource Planning and Clean Air Act Compliance: Elements of Consistency." Prepared for Distribution at: The NARUC Energy Conservation Committee 1993 Winter Meeting, Washington, DC. February. Co-author.

1991 "The Clean Air Act Amendments of 1990 and Utility Least Cost Planning: Issues for State Regulators," for distribution at the NARUC Conservation Committee, 1991 Winter Meeting, Washington, D.C. February. Co-author.

1991 "Sustainable Development and the Future of Electric Utilities," for the Energy Conservation Coalition Electric Utility Industry Vision Paper Project, Washington, DC. February.

1989 "Six Fallacies in Computing Avoided Costs," delivered at the NARUC Least Cost Planning Conference, Charleston, S.C. September.

1988 "Ratemaking and Conservation: The Tune Should Fit the Dance," distributed at the NARUC Committee on Energy Conservation Meeting, San Francisco. October 30.

1987 "Electric Utility System Reliability and Reserves" (ESRG Paper). September. Co-author.

1986 "Risk Sharing and the `Used and Useful' Criterion in Utility Ratemaking" (ESRG Paper). September. Co-author.

1986 "Risk Sharing, Excess Capacity, and the "Used and Useful" Criterion." Presented to the Fifth Biennial Regulatory Information Conference sponsored by the National Regulatory Research Institute in Columbus, Ohio. September.

List of other Publications and Presentations prior to 1985 available upon request.

## Related Professional Activities

Elected to Three-Year Term as a member of the Research Advisory Committee of The National Regulatory Research Institute, October 1, 1988 - September 30, 1991. Term extended through June 1992.

**Invited Speaker**

2001 "Status of Electricity Deregulation Today." Consumers' Assembly – Washington, DC. March 8.

1997 "Evaluating the Competitive Effect of Electric and Gas Utility Mergers Under Retail Competition." Panel - "Merger and Acquisitions: Implications of the Convergence of Electric and Gas Industries," *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, New Mexico State University, Santa Fe, NM. March 11.

1996 "NASUCA's Filing on the CRT NOPR at FERC," NASUCA Annual Conference. November.

1996 "Independent System Operators," NASUCA meeting, Chicago, IL. June.

1995 "Preserving Environmental Quality Under Electric Restructuring," NARUC Energy Conservation Committee meeting, New Orleans, LA. November.

1994 "Electricity Transmission Pricing," presented at NARUC Committee on Energy Conservation, Annual Meeting, Reno, NV. November. Co-author.

1994 Sixth Natural Gas Industry Forum, Quebec City. September 25-28.

1993 The National Energy Summit, in conjunction with the Multi-Media Energy Education Project of the Jefferson Energy Foundation - "Balancing Energy-Environment-Economy ($E^3$)", Washington, DC. June. Panelist.

1992 "Natural Gas Planning: An IRP Case Study." Presented at: The NARUC Conference on Integrated Resource Planning, Burlington, Vermont, September 13-16. Co-author.

1992 Fourth Natural Gas Industry Forum, Montreal. September.

1992 American Gas Association Long Range Forecasting for Integrated Resource Planning Seminar - "How Externalities and Supply Costs Affect IRP." March.

1991 Edison Electric Institute -- Strategic Planning Committee - "Incorporating Environmental Externalities into Integrated Resource Planning." December.

1990 NARUC Energy Conservation Committee Meeting, Orlando, Florida - "Rate Impacts of Demand-Side Management Programs." November.

1990 NARUC and NASUCA Joint Annual Meeting, Orlando, Florida - "Environmental Externalities and Integrated Resource Planning." November.

10/03

IN THE MATTER OF

**ARIZONA PUBLIC SERVICE COMPANY**

BEFORE THE

**ARIZONA CORPORATION COMMISSION**

**DOCKET NO. E-01345A-03-0437**

DIRECT TESTIMONY

OF

**STEPHEN G. HILL**

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 3, 2004

EXHIBIT

RUCO-5

Submitted

DIRECT TESTIMONY

OF

STEPHEN G. HILL

**ARIZONA PUBLIC SERVICE COMPANY**

DOCKET NO. E-01345A-03-0437

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## INTRODUCTION / SUMMARY

Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A. My name is Stephen G. Hill. I am self-employed as a financial consultant, and principal of Hill Associates, a consulting firm specializing in financial and economic issues in regulated industries. My business address is P.O. Box 587, Hurricane, West Virginia, 25526 (e-mail: sghill@compuserve.com).

Q. BRIEFLY, WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. After graduating with a Bachelor of Science degree in Chemical Engineering from Auburn University in Auburn, Alabama, I was awarded a scholarship to attend Tulane Graduate School of Business Administration at Tulane University in New Orleans, Louisiana. There I received a Master's Degree in Business Administration. More recently, I have been awarded the professional designation "Certified Rate of Return Analyst" by the Society of Utility and Regulatory Financial Analysts. This designation is based upon education, experience and the successful completion of a comprehensive examination. I have also recently been asked to be on the Board of Directors of that national organization. A more detailed account of my educational background and occupational experience appears in Appendix A.

Q. HAVE YOU TESTIFIED BEFORE THIS OR OTHER REGULATORY COMMISSIONS?

A. Yes, I have appeared previously before this Commission on many occasions. In addition, I have testified on cost of capital, corporate finance and capital market issues in more than 210 regulatory proceedings before the following regulatory bodies: the West Virginia Public Service Commission, the Texas Public Utilities Commission, the Oklahoma State Corporation Commission, the Public Utilities Commission of the State of California, the Public Service Commission of the State of Maine, the Maryland Public Service Commission, the Public Utilities Commission of the State of Minnesota, the Ohio Public Utilities Commission, the Insurance Commissioner of the State of Texas, the North Carolina Insurance Commissioner, the Rhode Island Public Utilities Commission, the City

Council of Austin, Texas, the Missouri Public Service Commission, the South Carolina Public Service Commission, the Public Utilities Commission of the State of Hawaii, the New Mexico Corporation Commission, the State of Washington Utilities and Transportation Commission, the Georgia Public Service Commission, the Public Service Commission of Utah, the Illinois Commerce Commission, the Kansas Corporation Commission, the Indiana Utility Regulatory Commission, the Virginia Corporation Commission, the Montana Public Service Commission, the Pennsylvania Public Utilities Commission, the Public Service Commission of Wisconsin, the Vermont Public Service Board, the Federal Communications Commission and the Federal Energy Regulatory Commission. I have also testified before the West Virginia Air Pollution Control Commission regarding appropriate pollution control technology and its financial impact on the company under review and have been an advisor to this Commission on matters of utility finance.

Q. ON BEHALF OF WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Residential Utility Consumer Office (RUCO).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony, I present the results of studies I have performed related to the establishment of an appropriate return on equity and overall cost of capital for the electric utility operations of Arizona Public Service Company (APS, the Company), a subsidiary of Pinnacle West Capital Corp. (PWC, Pinnacle West, the Parent). In addition to my testimony regarding the Company's current cost of capital, I review the cost of capital testimony provided by Dr. Charles Olson and discuss the shortcomings contained therein.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, Exhibit_(SGH-1) consists of 12 Schedules and provides the analytical support for the conclusions reached regarding the overall cost of capital for Arizona Public Service Company presented in the body of the testimony. This Exhibit was prepared by me and is correct to the best of my knowledge and belief. Also, I have provided four Appendices

("A" through "D"), which contain additional detail regarding certain aspects of my narrative testimony in this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND FINDINGS CONCERNING THE RATE OF RETURN THAT SHOULD BE UTILIZED IN SETTING RATES FOR APS's ARIZONA ELECTRIC UTILITY OPERATIONS IN THIS PROCEEDING.

A. My testimony is organized into four sections. First, I discuss the cost of capital standard as a measure of the return to be allowed for regulated industries, and review the current economic environment in which the equity return estimate is made. Second, I review the capital structure requested by APS for ratemaking purposes in comparison to capital structures employed by the Company historically as well as those existing in the utility industry today. From that review, I develop a capital structure appropriate for ratemaking purposes.

Third, I evaluate the cost of equity capital for similar-risk utility operations using Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Modified Earnings-Price Ratio (MEPR), and Market-to-Book Ratio (MTB) analyses. Fourth, I comment on the pre-filed cost of capital testimony submitted by Company witness, Dr. Charles Olson.

I have estimated the equity capital cost of electric utility companies to fall in a range of 9.25% to 9.75%. Within that range, I estimate the equity cost of the Company's Arizona utility operations to be at the mid-point of a reasonable range of equity costs for fully-integrated electric utilities—9.50%. Applying that equity capital cost to a capital structure which is reasonable for ratemaking purposes produces an overall cost of capital of 7.43% (Exhibit_(SGH-1), Schedule 12). That overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.28 times. That level of pre-tax coverage is very similar to the 3.3 times interest coverage for APS for 2002, as reported by Moody's in its August 8, 2003 ratings report on APS (provided in response to RUCO 1-5). According to Standard & Poor's, that level of pre-tax interest coverage falls at the mid-point of a range of pre-tax interest coverages that will support a bond rating range of "A" to

"BBB" for a utility of average risk[1]. Therefore, the equity return I recommend is sufficient to support the Company's current bond rating. Therefore, the equity return I recommend fulfills the requirement of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

Q. WHY SHOULD THE COST OF CAPITAL SERVE AS A BASIS FOR THE PROPER ALLOWED RATE OF RETURN FOR A REGULATED FIRM?

A. The Supreme Court of the United States has established, as a guide to assessing an appropriate level of profitability for regulated operations, that investors in such firms are to be given an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in the unregulated sector for assuming the same degree of risk. The Bluefield and Hope cases provide the seminal decisions [Bluefield Water Works v. PSC, 262 US 679 (1923); FPC v. Hope Natural Gas Company, 320 US 591 (1944)]. These criteria were restated in the Permian Basin Area Rate Cases, 390 US 747 (1968). However, the Court also makes quite clear in Hope that regulation does not guarantee profitability and, in Permian Basin, that, while investor interests (profitability) are certainly pertinent to setting adequate rates, those interests do not exhaust the relevant considerations.

As a starting point in the rate-setting process, then, the cost of capital of a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. Since financial theory holds that investors will not provide capital for a particular investment unless that investment is expected to yield their opportunity cost of capital, the correspondence of the cost of capital with the Court's guidelines for appropriate earnings is clear.

[1] Standard & Poor's, Utilities & Perspectives, Utility Financial Targets Are Revised, June 21, 1999. Business position '4", pre-tax interest coverage for "A" rating = 3.3x – 4.0x, for "BBB" rating = 2.2x – 3.3x.

# I. ECONOMIC ENVIRONMENT

Q. WHY IS IT IMPORTANT TO REVIEW THE ECONOMIC ENVIRONMENT IN WHICH AN EQUITY COST ESTIMATE IS MADE?

A. The cost of equity capital is an expectational, or *ex ante*, concept. In seeking to estimate the cost of equity capital of a firm, it is necessary to gauge investor expectations with regard to the relative risk and return of that firm, as well as that for the particular risk-class of investments in which that firm resides. Because this exercise is, necessarily, based on understanding and accurately assessing investor expectations, a review of the larger economic environment within which the investor makes his or her decision is most important. Investor expectations regarding the strength of the U.S. economy, the direction of interest rates and the level of inflation (factors that are determinative of capital costs) are key building blocks in the investment decision. They should be reviewed by the analyst and the regulatory body in order to assess accurately investors' required return—the cost of equity capital to the regulated firm.

Q. WHY DO YOU BELIEVE AN EQUITY RETURN IN THE RANGE OF 9.25% TO 9.75% IS REASONABLE FOR AN ELECTRIC UTILITY IN TODAY'S ECONOMIC ENVIRONMENT?

A. Although there was an upward movement in interest rate levels during 1999 and 2000, that movement reversed course during 2001 and continued a decline to much lower levels in 2002 and 2003. The overall level of fixed-income capital costs has been relatively low by historical standards for several years, and is especially low at the current time. Also, there are examples in the marketplace for equities that indicate that investor return requirements are low by historical standards.

A recent A.G. Edwards report on the gas utility industry[2] indicates that market return expectations for utility stocks are well below historical earned returns. That investor service publication reports that, for a sample of 20 large and small gas distributors, the

[2] A.G. Edwards, "Gas Utilities Quarterly Review," October 3, 2003.

median total return expectation (dividend yield plus expected growth—a DCF-type calculation) is only 8.7%.

Those data confirm that my 9.25%-9.75% equity return range for the electric utility operations under consideration here is reasonable. In addition, those data represent information to which investors are exposed in the equity marketplace for rate-regulated companies and underscore the fact that, currently, investor return requirements for that type of equity investment are low by historical standards.

Q. ARE THERE OTHER INDICATIONS THAT CAPITAL COSTS ARE AT HISTORICALLY LOW LEVELS?

A. Yes. Another indication of the reason investors are willing to buy and hold stocks that offer what seem to be "low" returns is shown in Exhibit__(SGH-1), Schedule 1, page 1, which depicts Moody's A-rated utility bond yields from 1984 through November, 2003. Page 1 of Schedule 1 shows that interest rates and capital costs remain very low relative to the interest rate levels that existed in the mid-1980s, and have continued a strong downward trend begun in 2000.

Also, page 2 of Schedule 1 (Exhibit__(SGH-1)), which presents the year-average Moody's A-rated bond yields for each year over the past 34 years (1969-2003), shows that A-rated bond yields thus far in 2003 are below the bond yield levels seen in the U.S. in the late 1960s. Also, the most recent average A-rated utility bond yield, 6.02%[3], falls well below the lower range of interest rates that have existed over the past 30 years (See Schedule 1, page 2). Simply put, a fundamental reason that the current cost of common equity capital for electric utility operations of 9.25% to 9.75% is reasonable is that fixed-income capital cost rates are lower than they have been in more than thirty years.

The above data indicate that capital costs, with the recent credit loosening by the Federal Reserve Bank (the Fed), remain at low levels and generally support the efficacy of my range of equity capital costs. However, it is important to note here that equity capital cost rates and bond yields do not move in lock-step fashion over time. In fact, the

[3] Value Line *Selection & Opinion*, most recent six weekly editions (10/24/03-11/28/03, inclusive), 20/30-year A-rated utility bond yield averages.

variability of that return differential is a fundamental reason why risk premium type analyses—which attempt to quantify the additional return over bond yields required by equity investors—are not reliable as primary indicators of equity capital cost. Therefore, it is necessary to perform an independent cost of equity capital analysis, rather than to simply "index" the cost of capital to current interest rates.

Q. PLEASE BRIEFLY DESCRIBE THE INTEREST RATE CHANGES THAT HAVE OCCURRED IN THE U.S. ECONOMY OVER THE PAST FEW YEARS AND HOW THEY IMPACT CAPITAL COST RATE EXPECTATIONS FOR THE FUTURE.

A. The substantial interest rate decline that occurred following the historically-high interest rates in the early 1980s spurred increased economic activity in the U.S. The rate of growth in the U.S. Gross Domestic Product (GDP) began to increase at a rapid rate by the end of 1987 and showed signs of continuing to gain strength. That increased economic activity, in turn, led to increased inflation expectations (a rapid rate of economic growth creates shortages in labor and materials, driving up the price of those factors of production, which ultimately results in higher prices in all sectors of the economy). The expectation of increased inflation, in turn, caused the Fed to act aggressively to slow down what was widely believed to be an overheating economy. The very sharp interest rate rise that followed in late 1987 and 1988, shown on Exhibit__(SGH-1), page 1 of Schedule 1, succeeded in damping down the economy, reducing inflationary pressures, and allowing interest rates to fall again.

Since that time, the interaction between the Federal Reserve's moves to expand or restrain the money supply and burgeoning inflation has been a primary influence in the U.S. macro-economy and the level of interest rates. Overall, as inflation has remained calm and economic activity has been moderate, interest rates have trended downward, but that general downward direction has been interrupted when investors (and/or the Fed) believed that falling interest rates would spur too-rapid economic growth. Rapid economic growth has, historically, created unwanted inflation. Investors, anticipating that higher inflation and interest rates might be the result of rapid economic expansion, have reacted to positive economic news (e.g., increasing GDP growth rates, lower unemployment) or negative

inflation news (e.g., increasing commodity prices, factory capacity or labor shortages) by bidding down debt prices and driving up interest rates. That is precisely the economic situation that fueled the more recent interest rate peaks from 1994 through the 2000/2001 period (see Exhibit__(SGH-1), Schedule 1, page 1).

As shown on page 2 of Schedule 1, single-A rated utility debt yielded about 7.6%, on average, in 1999, while, in 2000, equivalently rated debt was priced to yield approximately 8.2%, on average. That cost rate increase was due, primarily, to investors' concerns regarding the continued strength of the recent U.S. economic expansion and the potential for increased inflation caused by what was perceived to be a rapid (inflationary) level of growth. However, that rapid rate of economic growth did not come to pass, and the interest rate increases engineered by the Federal Reserve in 2000 to slow down a rapidly growing economy worked a little too well, resulting in declining economic growth. Then, in response to an economy that was slowing down, the Fed elected to increase the supply of money by dramatically lowering the Federal Funds rate (the rate at which money center banks can lend funds on an overnight basis—a fundamental building block of capital costs in the U.S.). In order to revive what became a slowing economy, the Fed lowered short-term interest rates eleven times in 2001 (and again in early November 2002 as well as at mid-year 2003).

As Value Line notes in its most recent Quarterly Review regarding economic growth, inflation and the interest rate environment, the current expectation is that the Federal Reserve's recent monetary loosening will, during 2003 and 2004, begin to revive the economy. Importantly, with regard to the estimation of capital costs, inflation is expected to be moderate and interest rates will continue in the future at moderate levels preserving a favorable capital cost environment:

> **Economic Growth**: Clearly, the U.S. economic outlook is brighter than it was at the time of our last "Quarterly Economic Review." Importantly, the business revival is no longer being underpinned solely by the consumer and the federal government. The more broadly configured expansion is not also being helped by increases in capital spending and by a nascent recovery in the heretofore slumping technology sector. The projected 4% current-quarter growth rate should be sufficient, moreover, to induce many companies to start hiring again, while the recent ratcheting up in corporate

earnings should give businesses the means to support a stepped-up page in new hiring [charts omitted]. This more inclusive business expansion is also likely to support some additional increases in industrial production and factory utilization in 2004 [chart omitted].

Still, although the consumer may be ready to pass the baton to others in the coming quarters, we believe that the retail and housing sectors will continue to hold their own [charts omitted]. Exports, which have also shown improvement of late, in spite of the lack of strong growth among several of our trading partners, should provide additional support in the months ahead. The sharp decline in the value of the dollar against the currencies of other countries should continue to make corporations here more competitive on a global basis....All told, we believe that economic growth will remain just above the estimated 4% current-quarter level in 2004 and modestly below that pace over the succeeding 3 to 5 years.

**Inflation**: Here, the news continues to be consistently good. True, there has been a measurable increase in raw materials costs, while oil prices remain near their highs of the past two years. Of course, not all of the raw materials price hikes are being passed on to users, so actual inflation is somewhat less than the quotations for some commodities would suggest. In fact, the Federal Reserve Board, which serves as the nation's inflation watchdog, continues to believe that deflation—or actually falling prices—is a greater threat than inflation at this point. Clearly, Japan's unfortunate recent experience with deflation has caught the Fed's attention. Our sense, though, is that steadily rising costs, in such categories as medical care, housing, and education, along with stubbornly high energy prices and the likely strength of the U.S. economy going forward will prevent deflation from securing a foothold on these shores. Our projections call for consumer price inflation to remain around 2% through next year and to hold in a comfortable 2% to 2.5% range, for the most part, during the succeeding 3 to 5 years. [Chart omitted].

**Interest Rates**: The Federal Reserve Board, which has helped orchestrate the current business upturn with the lowest interest rates in a generation, appears to have finally finished its job. This should not imply that we thing the lead band would hesitate to provide an additional monetary boost should the current expansion falter or deflation become a reality. However, it does suggest that the Fed's next move will be to tighten the monetary reigns, most likely by mid-2004. Such a rate adjustment probably would be modest, with the bank not figuring to disturb the overall monetary stability now in place, unless future budget deficits balloon unexpectedly. Unless that happens, we think rates will hold relatively near current levels through the latter years of this

> decade, barring serous deviations from the projected rates of business growth or inflation, or a major upheaval abroad. [Chart omitted]. (The Value Line Investment Survey, *Selection & Opinion*, November 28, 2003, pp. 2618-2620.)

In that most recent Quarterly Economic Review, cited above, Value Line projects long-term Treasury bond rates will average 4.9% through 2003 and 5.5% through 2004. The recent six-week average 30-year T-bond yield is 5.2% (data from Value Line, *Selection & Opinion*, six weekly editions, October 24, through November 28, 2003). Therefore, the indicated expectation with regard to interest rates is that they are likely to will move somewhat higher in coming years but remain within a range that Value Line terms "near current levels."

Q. ARE THERE OTHER REASONS THAT COMMON EQUITY CAPITAL COSTS ARE LOWER TODAY THAN THEY HAVE BEEN IN THE PAST?

A. Yes. The recently enacted change in the Federal tax law lowered the tax rate on dividends. Under the old tax law, dividends were taxed at rates that were approximately 30%[4]; now dividends are taxed at no more than 15%. The result of that tax cut is that a greater percentage of dividends are kept by investors, and dividend-paying stocks such as utilities have become more valuable than they were before the change in the tax law. In other words, because investors can now keep more of their dividends from their utility investment, they are willing to pay more for those same stocks, resulting in a lower cost of equity capital.

The impact of the tax change on the stock prices of utilities has been recognized by investor advisory services:

> "Tax Reform Has Resulted in a Fundamental Shift in The Group's Trading Range. We estimate the reduction in dividend and capital gains taxes should result in a 10%

[4] Prior to the tax law change, federal income tax rates were 10%,15%,27%,30%,35%,or 38.6% depending upon the relevant income bracket. Under the newly passed law, the 27% drops to 25%, the 30% to 28%, the 35% to 33% and the 38.6% to 35%. Since the old 27% tax bracket applied to married couples with a combined income of no more than $47,450, it is reasonable to say that the dollar weighted dividends paid to most individual investors were in brackets of between 27% and 38.6%.

> increase in the average gas utility stock price. Prior to tax reform, the median gas utility P/E [price/earnings ratio] traded in a range of 11.5X to 14.5X. With the tax reduction, we believe the new trading range in now 12.5X to 16.0X." (A. G. Edwards, Gas Utilities Quarterly Review, October 3, 2003, p. 5)

A simple example will facilitate understanding how the tax law change has lowered the cost of equity. Assume a utility with a dividend of $0.50, a stock price of $10, and a long-term investor-expected growth rate of 5.5%. A simple DCF estimate of the cost of equity for that utility would be 10.5%, comprised of a dividend yield of 5.0% ($0.50/$10} and a growth rate of 5.5%. When the tax law changed, investors increase the price they are willing to provide for that stock by 10% (as noted in the AG Edwards report cited above), to $11 per share [10$/share x 1.10 = $11/share]. Due to that re-valuation of the stock to $11/share, the dividend yield now becomes 4.5% [$0.50/$11 = 4.545%, rounded to 4.5%]. Because the tax law does not affect the company or its utility operations, its anticipated long-term growth does not change; it remains at 5.5%. The new cost of equity, however, is 10% (4.5% dividend yield + 5.5% growth rate), roughly 50 basis points below the pre-tax change cost of equity capital. Therefore, another factor contributing to the relatively low cost of common equity capital for utilities in the current capital markets is the recent dividend tax law change.

## II. CAPITAL STRUCTURE

Q. WITH WHAT CAPITAL STRUCTURE DOES APS REQUEST RATES BE SET IN THIS PROCEEDING?

A. Although Company witness Olson discusses the use of "alternative" capital structures, depending on whether or not the Pinnacle West Energy Corporation (PWEC) generation assets are allowed into rate base, the Company has filed its rate request based on one capital structure—an adjusted test-year end capital structure consisting of 50.23% common equity and 49.77% long-term debt.

However, although the Company indicates that its ratemaking capital structure is based on capital changes through June of 2003, it is not. According to the Company's

published balance sheets (available in its quarterly Securities and Exchange Commission filings), APS increased its long-term debt accounts by more than $400 Million by June of 2003. According to Moody's, APS issued the additional debt in May 2003 (RUCO-1-5, Moody's Investors Service, September 2, 2003). That increased debt amount, which was related to APS's funding the debt of PWEC as allowed by this Commission, was not included in the Company's ratemaking capital structure.

Schedule D-1 in the Company's filing shows a long-term debt balance (adjusted through June 15, 2003) of $2.140 Billion. However the Company's second quarter S.E.C. Form 10-Q reports a long-term debt amount of $2.684 Billion.

Q. IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE SIMILAR TO THE MANNER IN WHICH IT HAS RECENTLY BEEN CAPITALIZED?

A. No. The Company's requested ratemaking capital structure is different from the manner in which it has been capitalized recently. Page 1 of Schedule 2 attached to my testimony shows that over the five quarters from September, 2002, through September, 2003, APS has been capitalized, on average, with 47.65% common equity, 52.23% long-term debt and 0.11% short-term debt. Also, following the Company's most recent debt issuance in May of 2003, the capital structure has averaged 45.14% common equity and 54.86% long-term debt.

Q. HOW HAS THE COMPANY'S PARENT, PINNACLE WEST, BEEN CAPITALIZED OVER THE SAME TIME PERIOD?

A. As shown on page 2 of Schedule 2, Pinnacle West's capital structure over the past five quarters has consisted of 44.53% common equity, 52.89% long-term debt and 2.58% short-term debt. Pinnacle West has been capitalized with less equity and more debt than requested by APS in its ratemaking capital structure. That capital structure inter-relationship is significant because Pinnacle West, with its unregulated competitive operations, has a higher risk profile than its regulated utility subsidiary, APS. Companies that have higher business risk are optimally capitalized with more equity and less debt than less risky companies, according to long-accepted tenets of modern corporate finance. However, in

this proceeding APS, the regulated firm with *lower* operating risk, is requesting that its rates be set with a common equity ratio which is *higher* than that utilized by its operationally riskier parent. If this Commission were to utilize the Company's requested equity-heavy ratemaking capital structure, it would allow financial cross-subsidization of PWC's unregulated operations by APS's regulated ratepayers.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY FINANCIAL CROSS-SUBSIDIZATION AND WHY THIS COMMISSION SHOULD BE AWARE OF THAT ISSUE.

A. Cross-subsidization of a company's unregulated operations by its regulated operations can occur in many forms. For example, the unregulated firm could provide services to the utility at above-market rates or, conversely, the utility could provide services to its unregulated affiliates at rates below that which would prevail in an arms-length transaction. This Commission is familiar with those issues and has addressed them on many occasions.

Financial cross-subsidization occurs when the capital structure of the utility operation provides financial strength to the holding company, which, in turn, allows the parent to capitalize its unregulated operations with more debt and less equity (i.e., more cheaply) than they would otherwise be able to do. In other words, the utility (and, thereby, utility ratepayers) shoulders some of the financial risk of the unregulated affiliates by allowing the latter to be capitalized in a manner which would not prevail in a stand-alone situation.

Pinnacle West's unregulated operations are riskier operations than its regulated electric utility operations. That fact is recognized in the financial community. Regarding two factors which negatively affect Pinnacle West's financial strength, Standard & Poor's noted recently:

> "• Increasing amount of consolidated operations coming from unregulated businesses. In 2003 unregulated operations are expected to account for 15% of flow of funds from operation, although some of this is the result of expected asset sales at SunCor, and
> • Execution risk at SunCor where management has undertaken an aggressive effort to accelerate asset sales to permit SunCor to make an annual cash distribution to PWCC of between $80 million to $100 million annually during 2003

through 2005." (Standard & Poor's Ratings Direct, Pinnacle West Capital Corporation, April 8, 2003)

One way that Pinnacle West can maintain a strong financial profile and offset the increased risks of its unregulated operations, is to maintain a high common equity ratio for the capital structure of its regulated utility operation while simultaneously financing its unregulated operations with a higher percentage of debt capital than would otherwise be possible. That is the essence of financial cross-subsidization. The tangible result of that action is a common equity ratio for Pinnacle West that is below that of APS. It would not be reasonable, therefore, for this Commission to set rates for APS using the Company's requested common equity ratio which is substantially in excess of the equity capitalization of its riskier parent.

Q. IS THE COMPANY'S REQUESTED COMMON EQUITY RATIO—50%—SIMILAR TO THE AVERAGE EQUITY RATIO EXISTING IN THE ELECTRIC UTILITY INDUSTRY TODAY?

A. No. The ratemaking capitalization requested by Arizona Public Service Company for ratemaking purposes contains considerably more common equity and less debt capital than that utilized by the electric industry, on average. Because common equity capital, from a ratepayers' perspective (i.e., pre-tax), is twice as costly as debt capital, a capital structure like that requested by APS will be far more expensive that the capital structure used, on average, in the electric utility industry.

As shown on page 3 of Schedule 2, the average common equity ratio of the electric industry, as reported in the November 2003 edition of C.A. Turner's Utility Reports is 40%. For investment grade electrics (i.e., those that have bond ratings of "BBB" or above), the average common equity ratio is also 40%. C.A. Turner's also indicates that for combination utilities—electric and gas—the average common equity ratio is 37% of total capital. For investment grade combination utilities the average common equity ratio is slightly higher—39%.

Page 4 of Schedule 2 shows that the electric companies which were selected by Company witness Olson as similar in risk to APS have a median common equity ratio of

38%. In addition, the median common equity ratio of the electric companies I selected as similar in risk to APS have a median common equity ratio of 39.50%.

The evidence available in the marketplace as well as the similar-risk sample companies selected by Dr. Olson and myself, indicate that the capital structure requested for ratemaking purposes by APS contains a level of equity capital far above that used, on average, in the electric utility industry. Those data show that APS requests that its rates be set with a capital structure which is far more expensive capital structure than that which exists, on average, for electric utility operations.

Q. DO YOU BELIEVE IT IS NECESSARY FOR THE COMMISSION TO ALLOW THE PWEC GENERATION ASSETS INTO APS 's REGULATED RATE BASE IN ORDER TO SET RATES FOR THIS COMPANY USING A CAPITAL STRUCTURE CONSISTING OF APPROXIMATELY 45% COMMON EQUITY AND 55% DEBT?

A. No, for several reasons. First, the Company's current (i.e., known-and-measurable) capital structure is comprised of approximately 45% equity and 55% debt, not the 50%/50% capitalization on which it rate request is based. Regardless of whether or not the debt in the capital structure finances rate base, that debt is the financial responsibility of APS, and, in turn, it's ratepayers. APS's income stream will be encumbered by that debt and the Company's ratepayers will be called on to provide the interest costs associated with that debt.

Second, the Company clearly had the capability to assume the additional leverage without affecting its financial risk, as noted by Standard & Poor's: "The ratings on APS reflect the company's financial condition, which is sufficiently resilient to withstand the impact of the new debt at the current rating level." (S&P Ratings Direct, May 7, 2003, RUCO-1-5). Therefore, the Company had the ability to be financed more cost-effectively (i.e., with more debt and less equity) than the capital structure with which it requests its rates be set in the instant proceeding, and that opportunity should have been utilized to finance its Arizona jurisdictional utility plant, regardless of the status of the PWEC assets.

Third, ignoring the actual amount of debt on APS's balance sheet (i.e., utilizing a 50% equity/50% debt capital structure for ratesetting purposes) would require the

Company's Arizona ratepayers to provide an equity return as well as the taxes that must be paid on that return instead of a debt return on that portion of whatever rate base is approved in this proceeding. From a ratepayer perspective common equity is roughly twice as expensive as debt. Therefore, effectively substituting equity capital for debt capital in the ratemaking capital structure would cause the capital costs included in rates to overstate the Company actual capital costs, leading to rates which are not cost-based.

Fourth, the Company's requested capital structure is substantially different from the manner in which the electric industry is capitalized. APS requests its rates be set in this case using a 50% common equity ratio, while the electric utility industry, on average is capitalized with about 40% common equity.

Fifth, the Company's current actual capital structure (containing 45% common equity) is still more equity-rich that the industry generally, and more equity rich than the similar-risk sample groups chosen by Company witness Olson and myself to estimate APS's cost of equity capital. In that regard, a ratemaking capital structure based on APS's current actual capital structure would afford the Company lower financial risk than that realized by the electric industry generally and the similar-risk sample groups used to estimate the Company's cost of equity capital.

Q. HAS THIS COMMISSION SET RATES FOR COMPANIES UNDER ITS PURVIEW USING CAPITAL STRUCTURES THAT ARE DIFFERENT THAT THE ACTUAL, BOOKED CAPITAL STRUCTURE?

A. Yes. For many years this Commission has set rates for the Arizona jurisdictional operations of Southwest Gas using a hypothetical capital structure containing a different amount of common equity than the company actually carried on its books. Setting rates on that company's actual, booked capital structure, which contained a low common equity ratio, could have had the effect of exacerbating the company's financial risk. Increased financial risk could have lead to further financial difficulty for Southwest Gas and, ultimately, a higher overall cost of capital. Therefore, the Commission elected to set rates using a common equity ratio lower than other similar-risk firms but above that company's actual, booked common equity ratio.

This Commission utilized the same logic with Tucson Electric Power when that company was emerging from bankruptcy. It set rates using a nominal or hypothetical capital structure in order to preserve that company's financial strength during its recovery from Chapter 11 proceedings.

In the instant proceeding, as in the cases cited above, the Commission is faced with an applicant utility which has an actual capital structure which is not cost-effective. The only difference in APS's case is that the Company is over-capitalized, i.e., is requesting that its rates be set on a capital structure that is too expensive to be commensurate with the risk of its operations, rather than under-capitalized. Given this Commission's prior position on the use of ratemaking capital structures, an even-handed approach in this proceeding would be to set rates for APS using a more cost-effective yet financially safe capital structure—one with less common equity capital than that requested by APS. Therefore, the use of a hypothetical capital structure containing 45% common equity and 55% debt is reasonable from the standpoints of financial economy and financial strength, and is consistent with this Commission's prior position regarding the use of ratemaking capital structures different from the actual booked capital structure of the applicant utility.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND FOR RATEMAKING PURPOSES IN THIS PROCEEDING?

A. For the reasons outlined above, the Company's rates should be set using a capital structure with approximately 45% common equity and 55% debt. Regardless of the disposition of the PWEC assets, the Commission should reject the Company's requested 50% equity/50% debt capital structure and set rates using a more cost-effective but financially safe capital structure consisting of 45% common equity and 55% debt.

Q. ARE THERE OTHER CAPITAL STRUCTURE ISSUES WHICH YOU BELIEVE SHOULD BE BROUGHT TO THE ATTENTION OF THIS COMMISSION?

A. Yes. As I noted in my discussion of the economy, debt cost rates are currently at historic lows. Short-term debt costs are at especially low levels. For example, Pinnacle West was able to borrow $50 Million in August 2003 at a cost rate of only 1.43%. That is, indeed,

very low cost capital. Given that the object of any financial manager is to finance the operations of the firm in the most cost-effective, fiscally sound manner possible, the use of moderate amounts of very low-cost short term debt should be part of that strategy in today's capital markets.

Q. IS IT REASONABLE TO INCLUDE SHORT-TERM DEBT IN A RATEMAKING CAPITAL STRUCTURE?

A. Yes. First, it is not possible to specifically identify the source of monies spent on utility construction projects, or any other corporate expense, for that matter. Dollars enter the corporate treasury from many sources—retained earnings, common equity infusions, dividend reinvestment, as well as long-term and short-term debt issuances. However, once those dollars are in the corporate treasury they are indistinguishable from one another. For that reason it is not possible, when monies are paid out of the treasury (for office supplies, transformers or anything else), to discern precisely where those dollars come from. Therefore, it is not possible to reliably claim that construction is funded *only* by short-term debt (as the Company does in its filing, e.g., Schedule D-1). The only logical assumption is that construction, as indeed are all corporate expenses, is funded by a variety of investor-supplied sources as well as internally generated funds.

Second, short-term debt is investor-supplied capital and is a quantifiable part of the capital mix utilized by utility operations. The use of an average level of short-term debt in a ratemaking capital structure, then, recognizes the capital mix employed by utility management and more accurately represents the Company's actual cost of capital. Moreover, it simply does not make good financial sense to avoid use of the cheapest form of capital available.

Third, bond rating agencies, in calculating the debt-to-capital and interest coverage ratios include short-term debt and the interest on short-term debt, respectively, in those calculations. It is reasonable to assume, then, that those data are important in estimating the financial health of a firm and are important to investors. Although the level of short-term debt fluctuates from time to time, it has been my experience that short-term debt is a

permanent part of utility capital structures over the long term and should be considered for ratemaking purposes.

Fourth, because short-term debt carries a lower cost rate than other forms of capital, failure to consider the Company's use of that type of capital would result in an overstatement of the Company's overall cost of capital. The Company's requested overall return, which does not account for the amount of short-term debt expected to be used by the Company, is flawed in that manner, i.e., it overstates the Company's actual overall cost of capital.

Q. HAVE YOU EXAMINED THE COMPANY'S AND PINNACLE WEST'S USE OF SHORT-TERM DEBT?

A. Yes. Page 5 of Schedule 2 shows the average daily balances of Short-term debt for both Pinnacle West and APS from January 2001 through the most recent month available—August 2003. For Pinnacle West, over that entire historical time period the monthly average amount of short-term debt outstanding was approximately $200 Million. That level declined to an average of about $150 Million in 2003.

The historical short-term debt usage data for APS reveals an unusual pattern which appears to be designed to coincide with the current rate case proceeding. The Company apparently elected to stop using short-term debt at the end of 2002—the end of the historical test year. In fact, the Company reports a $0 balance of short-term debt on its December 31, 2002 balance sheet but shows an average daily balance of $13 Million of short-term debt for December 2003 in its response to RUCO-1-6. That means, simply, that APS utilized short-term debt in December 2002, but elected to eliminate that form of financing on the last day of 2002—the end of the test year in this proceeding. Pinnacle West continues to finance its operations with short-term debt, but APS appears to have ceased using that most inexpensive form of capital in anticipation of this rate proceeding[5].

It appears that the Company is purposely eliminating short-term debt from its investor-supplied capital mix in order to affect the outcome of this rate proceeding. The

[5] Because short-term debt appears on the balance sheet of Pinnacle West, but not on the balance sheet of its regulated subsidiary—APS, we must assume that Pinnacle West is continuing to finance its unregulated operations with short-term debt.

company can "game" the regulatory process and effectively raise the equity return it is allowed in this rate proceeding by convincing this Commission to omit short-term debt from the ratemaking capital structure and then, following the rate case, begin again to utilize short-term debt in its capital mix. The use of short-term debt will cause the Company's overall cost of capital to fall below that determined absent consideration of short-term debt, and the residual will impact the bottom line in the form of higher net income and a higher return on equity than allowed.

In the current interest rate environment, in my view, it is not reasonable to finance utility operations without the use of any short-term debt. To do so would forego an opportunity to more cost-effectively capitalize utility operations. Therefore, regardless of the pattern of the Company's use of short-term debt, I believe it is reasonable and prudent to include a modest amount of short-term debt in the ratemaking capital structure.

Q. HOW HAVE YOU DETERMINED YOUR RECOMMENDED RATEMAKING CAPITAL STRUCTURE?

A. Page 1 of Schedule 2 shows that over the most recent two quarters, APS's total capital has averaged $4.836 Billion. Of that amount, 45.14% was common equity and 54.86% of that is debt. In adjusting that debt amount to include short-term debt on a pro-forma basis, it is reasonable to assume that $50 Million of that total debt amount on a ratemaking basis will be short-term debt. The Company monthly-average amount of short term debt from January 2001 through August 2003 was $48.5 Million, even with zero balances in 2003.

Page 6 of Schedule 2 shows that, with that adjustment to the Company's actual average debt balance, the pro-forma ratemaking capital structure consists of 45.14% common equity, 58.83% long-term debt and 1.03% short-term debt. The cost rate of long-term debt at June 30, 2003, 5.77%, is provided by the Company in response to RUCO 1-2. The cost of short-term debt, 3.0%, is a forward-looking estimate which accounts for the expected increase in short-term debt cost rates. The most recent available cost rate of long-term debt available to Pinnacle West is 1.43% (see Schedule 2, page 5).

Q. DOES THIS CONCLUDE YOUR DISCUSSION OF CAPITAL STRUCTURE?

A. Yes, it does.

## III. METHODS OF EQUITY COST EVALUATION

### DISCOUNTED CASH FLOW MODEL

Q. PLEASE DESCRIBE THE DISCOUNTED CASH FLOW (DCF) MODEL YOU USED TO ARRIVE AT AN ESTIMATE OF THE COST RATE OF COMMON EQUITY CAPITAL FOR THE COMPANY IN THIS PROCEEDING.

A. The DCF model relies on the equivalence of the market price of the stock (P) with the present value of the cash flows investors expect from the stock, providing the discount rate equals the cost of capital. The total return to the investor, which equals the required return according to this theory, is the sum of the dividend yield and the expected growth rate in the dividend.

The theory is represented by the equation,

$$k = D/P + g, \qquad (1)$$

where "k" is the equity capitalization rate (cost of equity, required return), "D/P" is the dividend yield (dividend divided by the stock price) and "g" is the expected sustainable growth rate.

Q. WHAT GROWTH RATE (g) DID YOU ADOPT IN DEVELOPING YOUR DCF COST OF COMMON EQUITY FOR THE ELECTRIC UTILITIES?

A. The growth rate variable in the traditional DCF model is quantified theoretically as the dividend growth rate investors expect to continue into the indefinite future. The DCF model is actually derived by 1) considering the dividend a growing perpetuity, that is, a payment to the stockholder which grows at a constant rate indefinitely, and 2) calculating the present value (the current stock price) of that perpetuity. The model also assumes that the company whose equity cost is to be measured exists in a steady state environment, i.e., the payout

ratio and the expected return are constant and the earnings, dividends, book value and stock price all grow at the same rate, forever. As with all mathematical models of real-world phenomena, the DCF theory does not exactly "track" reality. Payout ratios and expected equity returns do change over time. Therefore, in order to properly apply the DCF model to any real-world situation and, in this case, to find the long-term sustainable growth rate called for in the DCF theory, it is essential to understand the determinants of long-run expected dividend growth.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THE DETERMINANTS OF LONG-RUN EXPECTED DIVIDEND GROWTH?

A. Yes, in Appendix B, I provide an example of the determinants of a sustainable growth rate on which to base a reliable DCF estimate. In addition, in Appendix B, I show how reliance on earnings or dividend growth rates alone, absent an examination of the underlying determinants of long-run dividend growth, can produce inaccurate DCF results.

Q. DID YOU USE A SUSTAINABLE GROWTH RATE APPROACH TO DEVELOP AN ESTIMATE OF THE EXPECTED GROWTH RATE FOR THE DCF MODEL?

A. Yes. I have calculated both the historical and projected sustainable growth rate for a sample of electric utility firms with similar-risk operations. To supplement the sustainable growth rate analysis, I have also analyzed published data regarding both historical and projected growth rates in earnings, dividends, and book value for all the companies under study.

Q. WHY HAVE YOU USED THE TECHNIQUE OF ANALYZING THE MARKET DATA OF SEVERAL COMPANIES?

A. I have used the "similar sample group" approach to cost of capital analysis because it yields a more accurate determination of the cost of equity capital than does the analysis of the data of one individual company. Any form of analysis, in which the result is an estimate, such as growth in the DCF model, is subject to measurement error, i.e., error induced by the measurement of a particular parameter or by variations in the estimate of the technique chosen. When the technique is applied to only one observation (e.g., estimating the DCF

growth rate for a single company) the estimate is referred to, statistically, as having "zero degrees of freedom." This means, simply, that there is no way of knowing if any observed change in the growth rate estimate is due to measurement error or to an actual change in the cost of capital. The degrees of freedom can be increased and exposure to measurement error reduced by applying any given estimation technique to a sample of companies rather than one single company. Therefore, by analyzing a group of firms with similar characteristics, the estimated value (the growth rate and the resultant cost of capital) is more likely to equal the "true" value for that type of operation.

Q. HOW WERE THE FIRMS SELECTED FOR YOUR ANALYSIS?

A. In selecting a sample of electric firms to analyze, I screened all the electric utility firms followed by Value Line. I selected companies from that group that had a continuous financial history and had at least 70% of operating revenues generated by electric utility operations. In addition, I eliminated companies that were in the process of merging or being acquired <u>and</u> had realized an upward stock price shift due to that activity or companies that had omitted dividends. Also, the companies in the selected sample had to own generation assets and have a bond rating ranging from "BBB" to "A+". The sample group selection screening process I utilized in shown in detail on Schedule 3 attached to this testimony.

Twelve electric utilities passed the screening process, including Pinnacle West, APS' parent. The companies included in the sample group are: Central Vermont Public Service (CV), Energy East Corp. (EAS), FirstEnergy Corp. (FE), Southern Company (SO), Ameren Corp. (AEE), Cleco Corp. (CNL), DPL, Inc. (DPL), Empire District Electric (EDE), Entergy Corp. (ETR), Great Plains Energy (GXP), Hawaiian Electric (HE), and Pinnacle West Capital Corp. (PNW). [Note: In the Schedules accompanying this testimony, the sample group companies are referred to by their stock ticker symbols, designated above in parentheses.]

Q. HOW HAVE YOU CALCULATED THE DCF GROWTH RATES FOR THE SAMPLE OF COMPARABLE COMPANIES?

A. Schedule 4 pages 1 through 4, shows the retention ratios, equity returns, sustainable growth rates, book values per share and number of shares outstanding for the comparable companies for the past five years. Also included in the information presented in Schedule 4, are Value Line's projected 2003, 2004 and 2006-2008 values for equity return, retention ratio, book value growth rates and number of shares outstanding.

In evaluating these data, I first calculate the five-year average sustainable growth rate, which is the product of the earned return on equity (r) and the ratio of earnings retained within the firm (b). For example, Schedule 4, page 2, shows that the five-year average sustainable growth rate for Southern Company (SO) is 3.37%. The simple five-year average sustainable growth value is used as a benchmark against which I measure the company's most recent growth rate trends. Recent growth rate trends are more investor-influencing than are simple historical averages. Continuing to focus on SO, we see that sustainable growth in 2002 was about 4%—above the average growth for the five-year period, indicating an increasing trend in growth. By the 2006-2008 period, Value Line projects SO's sustainable growth will reach a level above the recent five-year average—about 5%. These data would indicate that investors expect SO to grow at a rate in the future above the growth rate that has existed, on average, over the past five years[6].

It is important to note that, while the five-year projections are given consideration in estimating a proper growth rate because they are available to and are used by investors, they are not given sole consideration. Without reviewing all the growth rate data available to investors, both projected and historic, sole reliance on projected information may be misleading. Value Line readily acknowledges to its subscribers the subjectivity necessarily present in estimates of the future:

> We have greater confidence in our year-ahead ranking system, which is based on proven price and earnings momentum, than in 3- to 5-year projections. (Value Line Investment Survey, Selection and Opinion, June 7, 1991, p.854).

[6] I have included the details of my growth rate analyses for SO as an example of the methodology I use in determining the DCF growth rate for each company in the industry sample. A description of the growth rate analyses of each of the companies included in my sample group is set out in Appendix C. Schedule 5, page 1, of Exhibit_(SGH-1) attached to this testimony shows the internal, external and resultant overall growth rates for all the companies analyzed.

Another factor to consider is that SO's book value growth is expected to increase substantially, increasing at a 5% level over the next five years, after decreasing at a 1% rate historically (Southern Company divested its unregulated generation operation two years ago). Also, as shown on Schedule 5, page 2, Southern Company's dividend growth rate, which was only 1.5% historically, is expected to increase to 3% in the future. While this confirms that future growth is likely to be greater than historical growth, the projected dividend growth is below the sustainable growth rate projections. Earnings growth rate data available from Value Line indicate that investors can expect a higher growth rate in the future (6.5%) than has existed over the past five years (2.0%). However, Zack's and Thomson Financial (investor advisory services that poll institutional analysts for growth earnings rate projections) project lower earnings growth rate for SO over the next five years —4.5% and 5.0%, respectively.

SO's projected sustainable growth, book value, dividend and projected earnings growth indicates that investors can expect higher growth than has occurred, on average, in the past. Those projections are moderated somewhat by an expectation of dividend growth below the level of earnings growth projections. A long-term sustainable growth rate of 5.0% is a reasonable expectation for SO.

Q. IS THE INTERNAL (b x r) GROWTH RATE THE FINAL GROWTH RATE YOU USE IN YOUR DCF ANALYSIS?

A. No. An investor's sustainable growth rate analysis does not end upon the determination of an internal growth rate from earnings retention. Investor expectations regarding growth from external sources (sales of stock) must also be considered and examined. For SO, page 2 of Schedule 4 shows that the number of outstanding shares increased at about a 0.6% rate over the most recent five-year period. Value Line expects the number of shares outstanding to increase more rapidly through the 2006-2008 period, bringing the share growth rate to about a 1.5% rate by that time. An expectation of annual share growth of 1.25% is reasonable for this company.

Because a goal of regulation, in duplicating the strictures of the competitive

marketplace, is to allow a utility to recover no more than its cost of capital, it is reasonable to assume that the market price/book value ratio would, over the long-term horizon of the DCF model, have a tendency toward unity. However, the market price/book value ratio is unlikely to reach 1.0 overnight and, on average, utilities will continue to issue stock at prices above book value. In addition, Professor Myron Gordon, often referenced as the "father" of DCF in regulation, indicates that the DCF can overstate the cost of common equity capital when allowed returns exceed the cost of capital[7] (i.e., when market prices are substantially above book value as they are currently). Finally, although I have selected electric utility firms for analysis which derive the majority of their revenues from electric utility operations, those firms are not "pure play" utilities—they do have some other operations. Those other operations, therefore, are likely to have an upward impact on the market price and the market-to-book ratio of those companies.

I believe, therefore, that a reasonable estimate of investors' expectations for utility price/book ratios is that it will range between current levels and 1.0. I have used the average as an estimate of investors' expectations for the future. For our example company, Southern Company, the result of combining expected internal (b x r = 5.00%) and external growth rates (1.25%) yields an investor-expected long-term growth rate of 5.81% (see Exhibit__(SGH-1), Schedule 5, page 1 of 2).

Q. HAVE YOU CHECKED THE REASONABLENESS OF YOUR GROWTH RATE ESTIMATES AGAINST OTHER, PUBLICLY AVAILABLE, GROWTH RATE DATA?

A. Yes. Page 2 of Schedule 5 shows the results of my DCF sustainable growth rate analysis as well as 5-year historic and projected earnings, dividends and book value growth rates from Value Line, earnings growth rate projections from Zack's (and Thomson Financial), the average of Value Line and Zack's growth rates and the 5-year historical compound growth rates for earnings, dividends and book value for each company under study.

For the electric utility sample group, Schedule 5, page 2, shows that my DCF growth rate estimate for those companies is 4.79%. That long-term growth rate estimate is

[7] Gordon, M.J., The Cost of Capital to a Public Utility, MSU Public Utilities Studies, East Lansing, Michigan, 1974, pp. 9, 10.

higher than Value Line's average projected earnings, dividend and book value growth rate (3.33%) and much higher than the historical average of those same parameters (2.17%). In addition, my DCF growth rate estimate for the electric companies is also somewhat lower than Zack's projected earnings growth rate estimate (5.13%), but above both Value Line's projected growth rate estimate (3.63%) and Thomson Financial's projected growth rate (4.08%). My DCF growth rates for these companies may be conservative on the high side, when compared to available published information.

Q. DOES THIS CONCLUDE THE GROWTH RATE PORTION OF YOUR DCF ANALYSIS?

A. Yes, it does.

Q. HOW HAVE YOU CALCULATED THE DIVIDEND YIELDS?

A. I have estimated the next quarterly dividend payment of each firm analyzed and annualized them for use in determining the dividend yield. If the quarterly dividend of any company were expected to be raised in the quarter following that in which the most recent dividend was declared, I increased the current quarterly dividend by (1+g). For the electric companies in the sample group, a dividend adjustment was unnecessary for most of the companies under study because they either recently raised their dividend or were not projected to raise the dividend in 2004. A dividend adjustment was required for two companies in the sample, Central Vermont Public Service (CV), and Energy East (EAS).

The next quarter annualized dividends were divided by a recent daily closing average stock price to obtain the DCF dividend yields. I use the most recent six-week period to determine an average stock price in a DCF cost of equity determination because I believe that period of time is long enough to avoid daily fluctuations and recent enough so that the stock price captured during the study period is representative of current investor expectations.

Schedule 6 indicates that the average dividend yield for the sample group of electric utility companies is 4.89%. It is interesting to note that Value Line's most recent year-ahead dividend yield projection for the companies in my sample group averaged 4.92%—very

similar to the dividend yield I use in my analysis (Value Line, *Summary & Index,* November 28, 2003). That indicates that the dividend yield used in my DCF analysis is reasonable, and is representative of investor expectations.

Q. WHAT IS YOUR COST OF EQUITY CAPITAL ESTIMATE FOR THE ELECTRIC UTILITY COMPANIES, UTILIZING THE DCF MODEL?

A. Schedule 7 shows that the average DCF cost of equity capital for the entire group of electric utilities studied is 9.69%.

## CORROBORATIVE EQUITY COST ESTIMATION METHODS

Q. IN ADDITION TO THE DCF, WHAT OTHER METHODS HAVE YOU USED TO ESTIMATE THE COST OF EQUITY CAPITAL FOR ARIZONA PUBLIC SERVICE COMPANY?

A. To support and temper the results of my DCF analysis, I have used three additional econometric methods to estimate the cost of equity capital for a group of firms similar in investment risk to APS. The three methodologies are: 1) the Capital Asset Pricing Model (CAPM), 2) the Modified Earnings-Price Ratio (MEPR) analysis, and 3) the Market-to-Book Ratio (MTB) analysis. The similar risk sample group of firms analyzed with these three methods is the same as that selected for the DCF analysis, discussed previously. The theoretical details of each of those analyses is contained in Appendix D, attached to this testimony. The actual calculations and data supporting the results of each of these models is shown in the attached Schedules.

Schedule 8 attached to this testimony shows the detail regarding the CAPM analysis, which indicates a cost of capital for electric companies ranging from 8.33% to 9.47%. Schedule 10 shows the data and calculations regarding the Modified Earnings Price Ratio (MEPR) analysis, which indicates a current cost of equity capital for companies like APS ranging from 9.16% to 9.49%. Schedule 11 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital of 9.59% (near-term) to 9.30% (long-term).

## SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF SIMILAR-RISK ELECTRIC COMPANIES.

A. My analysis of the cost of common equity capital for the sample group of electric utility companies is summarized in the table on the following page.

| METHOD | COST OF EQUITY |
|---|---|
| DCF | 9.69% |
| CAPM | 8.33%/9.47% |
| MEPR | 9.16%/9.49% |
| MTB | 9.59%/9.30% |

The DCF result noted above, which is my primary indication of the cost of equity capital, is 9.69%. Averaging the lowest and the highest results of the corroborative analyses (CAPM, MEPR, and MTB) produces an equity cost rate range of 8.93% to 9.52%—a range that is entirely below the DCF result. In fact, only the upper end of the range of corroborative results are near the DCF result; all of the other corroborative analyses indicate that my DCF results may overstate the actual cost of common equity of electric utilities. Therefore, weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company facing similar risks as that group of electric utility companies ranges from 9.25% to 9.75%. Within that range, a reasonable point-estimate for the cost of common equity capital for APS would be a the mid-point of that range, or 9.50%.

Q. DOES YOUR EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR FLOTATION COSTS?

A. No, it does not.

Q. CAN YOU PLEASE EXPLAIN WHY AN EXPLICIT ADJUSTMENT TO THE COST OF EQUITY CAPITAL FOR FLOTATION COSTS IS UNNECESSARY?

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, there is no information in the evidence presented by the Company in this case that indicates that it anticipates a public stock offering. Absent such an offering, the Company will not incur flotation costs going forward and should not be reimbursed for a cost it will not incur. Moreover, any attempt to collect equity financing costs incurred in prior periods would amount to retro-active ratemaking.

Second, flotation cost adjustments are usually predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at to or below its book value. For example, as Company witness Olson noted in his Direct Testimony in this case:

> "The market-to-book ratio should be set high enough to permit equity financing with net proceeds equal to or in excess of book [value] under most market conditions, otherwise dilution will take place." (Olson Direct, p. 25, ll. 4-6)

In the current market environment for electric utility common stock, Pinnacle West stock is selling at roughly a 20% premium to its book value. Therefore, even if we assume as Dr. Olson does, that 3% of the stock price is an out-of-pocket cost for the Company, every time a new share of Pinnacle West stock is sold, all shareholders realize an *increase* in the per share book value of their investment. No dilution occurs, even without any flotation cost allowance.

For example, assume that Pinnacle West had one share of stock outstanding with a market price of $1.20 and a book value of $1.00. Assume also the parent company issued another share of stock at the current market price of $1.20 and actually paid out-of-pocket flotation costs of 4¢ (approximating Olson's average 3% flotation cost estimate). The monies received from the stock issuance, $1.16 (the $1.20 market price less the 4¢ flotation cost), would be added to the Company's common equity. That $1.16 added to the

original $1.00 of common equity on the books, indicates a total common equity balance for Pinnacle West after the stock issuance of $2.16. That book balance of common equity divided by the two outstanding shares produces a per share book value of $1.08 [$2.16 ÷ 2]. In other words, the stockholders' investment value is increased when new stock is issued, not decreased, because the amount that market value exceeds book value is substantially more than any anticipated flotation costs. Therefore, there is no need to "compensate" stockholders for a hypothetical dilution of book value that will not exist.

Third, assuming *arguendo* the need for an issuance expense adjustment to the cost of equity, the majority of the issuance expenses incurred in any public offering are "underwriter's fees" or "discounts". Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

Moreover, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that knowledge, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs which accounts for investor expectations regarding stock sales at market prices in excess of book value, and any further explicit adjustment for issuance expenses is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary[8]. There are other transaction costs which, when properly considered,

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[8] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the Wall Street Journal, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs which, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs which lower the required return (brokerage fees) should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. WHAT IS THE OVERALL COST OF CAPITAL FOR APS's ELECTRIC UTILITY OPERATIONS, BASED ON AN ALLOWED EQUITY RETURN OF 9.50%?

A. Schedule 12 attached to my testimony shows that an equity return of 9.50%, operating through an appropriate ratemaking capital structure and embedded capital cost rates, produces an overall return of 7.43% for APS. Schedule 12 also shows that an 7.43% overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.28 times. According to Moody's Investors Service (ratings report on APS, August 8, 2003), APS's pre-tax interest coverage in 2002 was 3.3 times. Because the Company was able to maintain it's bond rating over the past year its is reasonable to believe that the equity return I recommend is sufficient to support APS's current bond rating. Also, according to Standard & Poor's published bond rating benchmarks the pre-tax interest coverage afforded by the equity return I recommend will support a bond rating in the range of "A" to "BBB", which brackets the Company's current bond rating. Therefore, the equity return I recommend fulfills the legal requirement of Hope and Bluefield of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract

capital.

## IV. COMPANY COST OF CAPITAL TESTIMONY

Q. WHAT METHODS HAS COMPANY WITNESS OLSON USED TO DETERMINE EQUITY CAPITAL COSTS IN THIS PROCEEDING?

A. Company witness Olson testifies that he based his recommendation on the results of his DCF analysis, which he checks with a risk premium analysis. The Company witness' DCF methodology is flawed and produces results which are overstated due to his use of stale stock price and growth rate data. In addition, his sole reliance on projected earnings growth rates causes his DCF results to be overstated. Had the Company witness relied on other growth rate data available to investors, his results would approximate those I present in my testimony.

Although Dr. Olson's DCF produces overstated results, they are far more reasonable results than his Risk Premium analysis, which significantly overstates the Company's cost of equity capital. As I discuss in more detail below, Dr. Olson's Risk Premium analysis does not serve as a reasonable check of his DCF analysis because 1) it is based on very long-term return data not necessarily representative of current risk/return relationships and 2) it is based on a measure of return appropriate for all stocks, not utility stocks, which are considerably less risky than the broad market measure used by the Company witness.

I will discuss the infirmities in Dr. Olson's DCF analysis initially, and then discuss the witness' Risk Premium analysis.

Q. WHAT ARE YOUR COMMENTS REGARDING COMPANY WITNESS OLSON'S DCF ANALYSIS?

A. Although he does not show the results in the attachments to his testimony, Dr. Olson's DCF results range from 9.89% to 14.67% for his sample group of electric companies, and 10.05% for Pinnacle West. Dr. Olson's DCF result for his sample group is overstated because 1) he relied on results for one of his sample companies that is a statistical outlier,

2) he used stock price and growth rate data which are not representative of current capital costs, 3) he increased the divided for next period growth whether or not such an adjustment was warranted and 4) he relied only on projected per share earnings growth rate data to determine the long-term sustainable growth called for in DCF theory, even though he testifies that investors use other measures of growth.

Q. WHICH DCF RESULT OBTAINED BY DR, OLSON IS A STATISTICAL OUTLIER?

A. Dr. Olson's Attachments CEO-6 and CEO-7 show the dividend yield and growth rate for each of his sample companies. Those data indicate the DCF results for his sample group of companies shown in Table I below.

TABLE I.

DR. OLSON'S DCF ANALYSIS RESULTS

| COMPANY | DIVIDEND YIELD | GROWTH RATE | DCF RESULT |
|---|---|---|---|
| CINergy | 5.39% | 4.50% | 9.89% |
| IDACORP | 7.67% | 7.00% | **14.67%** |
| OGE Energy Corp. | 6.95% | 3.50% | 10.45% |
| PPL Corp. | 4.18% | 5.90% | 10.08% |
| Progress Energy | 5.24% | 5.00% | 10.24% |
| Public Serv. Ent. | 6.08% | 5.00% | 11.08% |
| | | Average without IDACORP | 10.35% |
| | | Standard Deviation without IDACORP | 0.46% |
| | | Avg + 3 St. Deviation Units | 11.72% |

Table I shows that the DCF result for one of Dr. Olson's sample companies, IDACORP, is significantly different from the average of the other companies. The average simple DCF cost of equity of the other companies in Dr. Olson's sample group is 10.35%. The standard deviation of those average results (i.e., without IDACORP) is 0.46%. Adding three times that standard deviation ( 3 x 0.46%) to the average DCF result of the other companies indicates that the upper bound of a statistically reliable DCF estimate would be 11.72%[9].

[9] Assuming a normally distributed sample, 99.9% of the observations fall within three standard deviations of the mean or average of the sample.

Obviously, Dr. Olson's DCF result for IDACORP falls well outside of that range of reasonableness (termed a statistical outlier) and should not be relied on as an indicator of the cost of equity capital of APS in this proceeding. As shown in Table I, eliminating IDACORP from his sample of firms causes Dr. Olson's average DCF equity cost estimate to fall to 10.35%. However, as I show below, that estimate is stale and newer information indicates that the cost of equity of Dr. Olson's sample group is considerably lower.

Q. YOU MENTIONED PREVIOUSLY THAT DR. OLSON'S DCF DATA ARE STALE, AND SERVE TO OVERSTATE THE CURRENT COST OF EQUITY CAPITAL, EVEN USING HIS METHODOLOGY. CAN YOU PLEASE EXPLAIN YOUR COMMENTS?

A. Yes. As shown in Table II, below, using Dr. Olson's DCF methodology and current data the overall average DCF cost of capital for his sample group is 9.15%, and 9.80% for Pinnacle West Capital producing an overall average of 9.24%. That result is roughly 100 basis points below his DCF equity cost range excluding IDACORP shown in Table I, above, and 200 basis points below the low end of his equity return recommendation in this proceeding (11.25%).

TABLE II.

DR. OLSON'S DCF ANALYSIS, UPDATED

| COMPANY | DIVIDEND YIELD* | GROWTH RATE | DCF RESULT |
|---|---|---|---|
| CINergy | 5.20% | 4.00% | 9.20% |
| IDACORP | 4.20% | 5.00% | 9.20% |
| OGE Energy | 5.70% | 3.00% | 8.70% |
| PPL Corp. | 4.00% | 5.00% | 9.00% |
| Progress Energy | 5.40% | 4.00% | 9.40% |
| P.S. Ent. Group | 5.40% | 4.00% | 9.40% |
| AVERAGE | 4.98% | 4.17% | **9.15%** |
| Pinnacle West | 4.80% | 5.00% | 9.80% |

OVERALL AVERAGE DCF RESULT = **9.24%**

* Value Line Summary & Index 11/28/03, proj. year-ahead yield.
* Projected 5-year earnings growth, Thomson Financial (12/9/03).

Value Line's current year-ahead divided yield projections for those companies[10] (which encompasses expected dividend increases and current stock prices) average 4.98%—about 100 basis points less than Dr. Olson's reported yield for those same companies (5.92%). The current projected earnings growth rates for his sample companies is 4.17%, well below the 5.0% to 5.5% he uses in his original DCF analysis. Therefore, a more current cost of equity result, using Dr. Olson's own DCF analysis would approximate 9.25%, not the 11.07 to 11.58% he reports at page 22 of his Direct Testimony in this proceeding.

Q. WHAT DCF GROWTH RATE METHODOLOGY DID WITNESS OLSON USE?

A. As shown on Schedule CEO-7 attached to Dr. Olson's testimony, the only growth rate data he relied on in determining his DCF growth rate was projected earnings growth. Dr. Olson elects to adopt that methodology in this proceeding even though he testifies at page 18 of his testimony that in addition to stock price data, investors are likely to have access to "past and present dividends, past and present earnings." Moreover, he states at line 20 on page 18 of his Direct, "[h]owever, it is not reasonable to expect that past trends are ignored" by investors. I agree. Dr. Olson's DCF analysis which totally ignores "past trends" does not provide a reasonable basis for estimating the current cost of equity capital.

Q. HAS DR. OLSON CONSISTENTLY USED A DCF GROWTH RATE METHODOLOGY THAT RELIES ONLY ON PROJECTED EARNINGS PER SHARE GROWTH?

A. No. Dr. Olson and I have testified in many rate cases together over the years and only recently has he begun to rely solely on projected earnings growth rate data in determining his DCF growth rate. In prior proceeding in which he and I have been involved (e.g., Montana Public Service Commission Docket No. D95.9.128, Montana Power Company), Dr. Olson has relied on 10-year and 5-year historical growth rates in earnings, dividends and book value, sustainable ('b x r") growth as well as projected earnings growth rates.

As shown in my Schedule 4, page 2 of 2, the historical and projected growth in dividends and book value are below the projected earnings growth rates for electric utilities.

[10]The Value Line Investment Survey, *Summary & Index*, November 28, 2003.

It is reasonable to assume, therefore, that had Dr. Olson considered those data in addition to the projected earnings growth of his sample group (as he has done in the past) his DCF result would have been lower than that which he presents in his testimony in this proceeding and lower even than the DCF shown in Table II, above.

Q. WHAT ARE YOUR COMMENTS ON THE EXCLUSIVE USE OF PROJECTED EARNINGS GROWTH RATES IN A DCF ESTIMATE OF THE COST OF EQUITY CAPITAL?

A. In my view, earnings growth rate projections are widely available, are used by investors and therefore deserve consideration in an informed, accurate assessment of the investor expected growth rate to be included in a DCF model. I do not believe, however, that projected earnings growth rates should be used as the *only* source of a DCF growth estimate as Dr. Olson has elected to do in this case. In other words, projected earnings growth rates are influential in, but not the only factor that is determinative of, investor expectations.

Q. PLEASE EXPLAIN WHY EXCLUSIVE RELIANCE ON ANALYSTS' PROJECTED EARNINGS GROWTH RATES IN A DCF EQUITY COST ESTIMATE CAN PRODUCE UNRELIABLE RESULTS.

A. First, it is important to realize that projected growth rates may over- or understate growth that can be sustained over time by the companies under review. This is important because sustainable growth is required in an accurate DCF assessment of the cost of equity capital. The efficacy of projected earnings growth rates in any specific DCF analysis can only be determined through a study of the underlying fundamentals of growth—something which Company witness Olson fails to do with his exclusive reliance on analysts' earnings growth rate projections.

Second, there is often associated with the exclusive use of analysts' projected earnings growth rates an erroneous notion of "consensus," i.e., that projected earnings growth rates are precisely what investors are using to estimate return requirements and that those estimates closely agree. As shown in the table below, which shows detailed statistics

from Zack's' most recently available growth rates for the companies in my sample group (many of which are also in Dr. Olson's sample group), what is often called a "consensus" earnings growth expectation are, in reality, quite divergent.

Finally, as evidenced in financial news headlines, the sell-side institutional analysts that are polled by Zack's and similar services sometimes offer relatively "rosy" expectations for the stock they follow—even when the analyst's actual expectations for the stock are not so sanguine. Simply put, some analysts are simply overstating growth expectations to make the stocks look better. Although claims are often made that the opinions of sell-side analysts are not affected by the profits made by the other parts of the business that actually trade those securities, the recent event in the marketplace underscore that concern. Therefore, while what is known as the "Cinderella effect" (analysts' overstating stock expectations) is not a new phenomenon, the recent concern in the financial markets regarding this issue underscores the need for caution in the use of earnings growth expectations in estimating the cost of equity capital.

Q. DON'T WITNESSES WHO RELY EXCLUSIVELY ON EARNINGS GROWTH PROJECTIONS CITE ACADEMIC STUDIES WHICH SHOW ANALYSTS' EARNINGS GROWTH ESTIMATES TO BE "SUPERIOR" TO OTHER GROWTH RATE ESTIMATION METHODS?

A. Yes, however, while such studies do show that projected growth rates are superior to simple, mechanical averages of historical growth rates, they do not in any way suggest that projected earnings growth rates, alone, are determinative of investor expectations. What those studies actually do is make a good case for the consideration of analysts' growth rate forecasts in a reasoned examination of investor growth rate expectations. I agree with that premise, and that is how I use analysts' forecasts in my DCF analyses, i.e., as part of an analysis of growth rate expectations. Those studies do not, however, provide a rationale for an *exclusive* reliance in earnings growth rate projections. Certainly analysts' growth rate projections can influence investor expectations, but it is unreasonable to conclude, as Dr. Olson appears to do in this case, that they determine those expectations exclusively.

Q. DOES THAT CONCLUDE YOUR COMMENTS REGARDING DR. OLSON'S DCF ANALYSIS?

A. Yes, it does.

Q. WHAT ARE YOUR COMMENTS ON THE MECHANICS OF THE RISK PREMIUM METHODOLOGY?

A. A fundamental precept on which the risk premium methodology is based holds that the higher risk of stocks over bonds requires an incrementally higher return for those stocks in order for investors to be compensated for assuming the higher risk (e.g., see Olson Direct, pp. 16). Although that is generally true, it is most important to realize that, given a current bond yield of 6% for A-rated utilities, an equity return of 7%, 9% or even 25% would fulfill the requirement of providing "a premium" over debt costs. The real issue with a risk premium analysis is determining with any precision the return premium that investors require to invest in stocks rather than bonds. It is not a directly observable phenomenon and must be estimated.

There are two other fundamental tenets on which risk premium-type analyses are grounded which, when examined, indicate that this equity cost estimation methodology should not be given primary consideration in setting allowed rates of return. First, since risk premium analyses look backward in time[11], they assume "past is prologue." In other words, the investors' expectations for the future are assumed to mirror the average results they have experienced in the past. Second, implicit in the use of an average historical return premium of equities over debt is the assumption that the risk premium is constant over time because only one value is used to represent the risk premium expectation of investors. Neither of these assumptions on which the risk premium analysis rests is true.

The relative risk differentials between bonds and stocks are different now than they have been over the 72-year period from which Dr. Olson draws his risk premium data. The Ibbotson data indicate that, beginning in the 1970's, bond returns became substantially more volatile than they had been an anytime previously and, further, showed return

[11] Witness Olson notes at page 22 of his Direct that the data on which his Risk Premium analyses are from Ibbotson Associates Stocks, Bonds, Bills and Inflation: 2003 Yearbook, which studies return differentials from 1926 through 2002.

volatility similar to that of common stocks. It follows, then, that the investor-required return differential between stocks and bonds has been substantially different (smaller) over the past 30 years than it was prior to that time due to the increased volatility which is now inherent in the bond market. In other words, the very long-term return differentials between stocks and bonds used by Dr. Olson do not capture the current expected return differential.

Second, risk premiums are not static and vary significantly from period to period. The Ibbotson data on which Mr. Olson's risk premium is based indicate that common stock annual returns have ranged from +54% to -43%, while bond returns have ranged from +42% to -9%. Therefore, the assumption implicit in the Risk Premium analysis that risk premiums are static over time and that historical average results are equivalent to current expectations is simply not a reasonable basis on which to estimate current equity capital cost rates.

The practical impact of the volatility of historical risk premium data is that with the selection of any particular period over which to average the historical data, virtually any risk premium result can be produced. In addition, the use of historical earned return data (such as that published by Ibbotson Associates) to estimate current equity capital costs has been questioned in the financial literature:

> There are both conceptual and measurement problems with using I&S [Ibbotson and Sinquefield] data for purposes of estimating the cost of capital. Conceptually, there is no compelling reason to think that investors expect the same relative returns that were earned in the past. Indeed, evidence presented in the following sections indicates that relative expected returns should, and do, vary significantly over time. Empirically, the measured historic premium is sensitive both to the choice of estimation horizon and to the end points. These choices are essentially arbitrary, yet they can result in significant differences in the final outcome. ("The Risk Premium Approach to Measuring a Utility's Cost of Equity," Brigham, Shome and Vinson, Financial Management, Spring 1985, p. 34.)

Q. DO YOU HAVE OTHER SPECIFIC COMMENTS REGARDING MR. OLSON'S RISK PREMIUM ANALYSIS?

A. Yes, in addition to the general infirmities of such an analysis, outlined above, Mr. Olson's risk premium analysis is flawed by the fact that it produces a cost of equity that is not applicable to an electric utility operation. For example, Mr. Olson takes the Ibbotson Associates total return difference between common stocks and corporate bonds over the 1926-2002 period (6%) and adds that historical risk premium to the corporate bond rate prevailing at the time he performed his analysis (6.4%). That analysis produces a cost of capital for common stocks of 12.6% (Olson Direct, p. 23). However, that cost of capital estimate is based on Ibbotson's historical returns for the stock market as proxied by the S&P 500 index—an index of unregulated industrial firms. Dr. Olson makes an ad hoc adjustment to that result to account for the lower risk APS, and, based on a risk premium analysis estimates the equity capital cost of APS to range from 12% to 12.5%. However, as he, himself, notes that 40 basis point decrement is not based on quantifiable data.

If the Ibbotson historical risk premium of 6% used by Mr. Olson were adjusted for the difference in risk between the S&P 500 (the basis for Ibbotson's risk premium) and electric utility stocks, a more accurate estimate of the Company's cost of equity might ensue. For example, if the 6% risk premium were adjusted by a electric utility beta coefficient (0.67, see Exhibit_(SGH-1), Schedule 8) a more appropriate risk premium above bond yields for electric utilities would be 4.02% (6% x 0.67). That risk premium added Dr. Olson's bond yield of 6.4% would produce an equity cost estimate for APS of 10.04%—well below the 12.0%-12.5% he indicates is produced by his Risk Premium analysis[12]. Clearly, Dr. Olson's Risk Premium results is based primarily on the historical returns of unregulated industrial firms and is not adjusted in any quantifiable fashion or sufficiently to represent the risk differential between unregulated industrial firms and electric utility operations.

The purpose of this proceeding is to set rates for the utility operations of Arizona Public Service Company, not an average competitive industrial firm. Therefore, Mr.

[12] There is evidence published recently that risk premiums obtained from the Ibbotson studies are exaggerated. Moreover, those more recent studies show that a more normal risk premium between stocks and bonds ranges from 2% to 3% (Siegel, J., Stocks for the Long Run, 1994, Irwin, Chicago IL, p. 20). In that regard a risk premium at lower end of that range, 2%, which would be appropriate for less-risky utilities, added to Dr. Olson's 6.4% utility bond yield would produce a cost of equity estimate of 8.4%—below the lower end of my range of equity cost estimates for APS

Olson's risk premium analyses which rely on risk premiums based primarily on historical earned return data derived from unregulated, competitive industrial enterprises is not appropriate for ratesetting purposes. The results of Mr. Olson's risk premium analyses overstate the cost of capital of APS.

Q. DOES THIS COMMISSION RELY ON A RISK PREMIUM-TYPE ANALYSES IN SETTING ALLOWED EQUITY RETURNS?

A. No. It has been my experience that this Commission has, in the past, placed primary emphasis on the DCF methodology of estimation equity capital costs and does not place great weight on risk premium-type analyses.

Q. DOES THIS CONCLUDE YOUR COMMENTS ON DR. OLSON'S COST OF CAPITAL TESTIMONY?

A. Yes, it does.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY, MR. HILL?

A. Yes, it does.

## APPENDIX A

EDUCATION AND EMPLOYMENT HISTORY
OF
STEPHEN G. HILL

EDUCATION

Auburn University - Auburn, Alabama - Bachelor of Science in Chemical Engineering (1971); Honors - member Tau Beta Pi national engineering honorary society, Dean's list, candidate for outstanding engineering graduate; Organizations - Engineering Council, American Institute of Chemical Engineers

Tulane University - New Orleans, Louisiana - Masters in Business Administration (1973); concentration: Finance; awarded scholarship; Organizations - member MBA curriculum committee, Vice-President of student body, academic affairs

Continuing Education - NARUC Regulatory Studies Program at Michigan State University

EMPLOYMENT

West Virginia Air Pollution Control Commission (1975)
Position: Engineer ; Responsibility: Overseeing the compliance of all chemical companies in the State with the pollution guidelines set forth in the Clean Air Act.

West Virginia Public Service Commission-Consumer Advocate (1982)
Position: Rate of Return Analyst ; Responsibility: All rate of return research and testimony promulgated by the Consumer Advocate; also, testimony on engineering issues, when necessary.

Hill Associates (1989)
Position: Principal; Responsibility: Expert testimony regarding financial and economic issue in regulated industries.

PUBLICATIONS

"The Market Risk Premium and the Proper Interpretation of Historical Data," Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, Volume I, pp. 245-255.
"Use of the Discounted Cash Flow Has Not Been Invalidated," Public Utilities Fortnightly, March 31, 1988, pp. 35-38.

MEMBERSHIPS

American Institute of Chemical Engineers; Society of Utility and Regulatory Financial Analysts (Certified Rate of Return Analyst, Member of the Board of Directors)

## APPENDIX B

Q. PLEASE PROVIDE AN EXAMPLE WHICH DESCRIBES THE DETERMINANTS OF LONG-TERM SUSTAINABLE GROWTH.

A. Assume that a hypothetical regulated firm had a first period common equity or book value per share of $10, the investor-expected return on that equity was 10% and the stated company policy was to pay out 60% of earnings in dividends. The first period earnings per share are expected to be $1.00 ($10/share book equity x 10% equity return) and the expected dividend is $0.60. The amount of earnings not paid out to shareholders ($0.40), the retained earnings, raises the book value of the equity to $10.40 in the second period. The table below continues the hypothetical for a five year period and illustrates the underlying determinants of growth.

TABLE A.

| | YEAR 1 | YEAR 2 | YEAR 3 | YEAR 4 | YEAR 5 | GROWTH |
|---|---|---|---|---|---|---|
| BOOK VALUE | $10.00 | $10.40 | $10.82 | $11.25 | $11.70 | 4.00% |
| EQUITY RETURN | 10% | 10% | 10% | 10% | 10% | - |
| EARNINGS/SH. | $1.00 | $1.040 | $1.082 | $1.125 | $1.170 | 4.00% |
| PAYOUT RATIO | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | - |
| DIVIDENDS/SH. | $0.60 | $0.624 | $0.649 | $0.675 | $0.702 | 4.00% |

We see that under steady-state conditions, the earnings, dividends and book value all grow at the same rate. Moreover, the key to this growth is the amount of earnings retained or reinvested in the firm and the return on that new portion of equity. If we let "b" equal the retention ratio of the firm (1 – the payout ratio) and let "r" equal the firm's expected return on equity, the DCF growth rate "g" (also referred to as the internal or sustainable growth rate ) is equal to their product, or

$$g = br. \qquad \text{(i)}$$

Professor Myron Gordon, who developed the Discounted Cash Flow technique and first

introduced it into the regulatory arena, has determined that Equation (i) embodies the underlying fundamentals of growth and, therefore, is a primary measure of growth to be used in the DCF model. Professor Gordon's research also indicates that analysts' growth rate projections are useful in estimating investors' expected sustainable growth.

I should note here that the above hypothetical does not allow for the existence of external sources of equity financing, i.e., sales of common stock. Stock financing will cause investors to expect additional growth if the company is expected to issue new shares at a market price that exceeds book value. The excess of market over book would inure to current shareholders, increasing their per share equity value. Therefore, if the company is expected to continue to issue stock at a price that exceeds book value, the shareholders would continue to expect their book value to increase and would add that growth expectation to that stemming from earnings retention or internal growth. Conversely, if a company were expected to issue new equity at a price below book value, that would have a negative effect on shareholder's current growth rate expectations. In such a situation, shareholders would perceive an overall growth rate less than that produced by internal sources (retained earnings). Finally, with little or no expected equity financing or a market-to-book ratio near unity, investors would expect the sustainable growth rate for the company to equal that derived from Equation (i), "g = br." Dr. Gordon[1] identifies the growth rate which includes both expected internal and external financing as:

$$g = br + vs, \qquad \text{(ii)}$$

where,

g = DCF expected growth rate,
r = return on equity,
b = retention ratio,
v = fraction of new common stock sold that accrues to the current shareholder,
s = funds raised from the sale of stock

[1]Gordon, M.J., The Cost of Capital to a Public Utility, MSU Public Utilities Studies, East Lansing, Michigan, 1974, pp., 30–33.

as a fraction of existing equity.

Additionally,

$$v = 1 - BV/MP, \qquad \text{(iii)}$$

where,

MP = market price,
BV = book value.

I have used Equation (iii) as the basis for my examination of the investor expected long-term growth rate (g) in this proceeding.

Q. IN YOUR PREVIOUS EXAMPLE, EARNINGS AND DIVIDENDS GREW AT THE SAME RATE (br) AS DID BOOK VALUE. WOULD THE GROWTH RATE IN EARNINGS OR DIVIDENDS, THEREFORE, BE SUITABLE FOR DETERMINING THE DCF GROWTH RATE ?

A. No, not necessarily. Rates of growth derived from earnings or dividends alone can be unreliable due to extraneous influences on those parameters such as changes in the expected rate of return on common equity or changes in the payout ratio. That is why it is necessary to examine the underlying determinants of growth through the use of a sustainable growth rate analysis.

If we take the hypothetical example previously stated and assume that, in year three, the expected return on equity rises to 15%, the resultant growth rate for earnings and dividends far exceeds that which the company could sustain indefinitely. The potential error in using those growth rates to estimate "g" is illustrated in the following table.

TABLE B.

| | YEAR 1 | YEAR 2 | YEAR 3 | YEAR 4 | YEAR 5 | GROWTH |
|---|---|---|---|---|---|---|
| BOOK VALUE | $10.00 | $10.40 | $10.82 | $11.47 | $12.157 | 5.00% |
| EQUITY RETURN | 10% | 10% | 15% | 15% | 15% | 10.67% |
| EARNINGS/SH. | $1.00 | $1.040 | $1.623 | $1.720 | $1.824 | 16.20% |
| PAYOUT RATIO | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | - |
| DIVIDENDS/SH. | $0.60 | $0.624 | $0.974 | $1.032 | $1.094 | 16.20% |

What has happened is a shift in steady-state growth paths. For years one and two, the sustainable rate of growth (g=br) is 4.00%, just as in the previous hypothetical. Then, in the last three years, the sustainable growth rate increases to 6.00% (g=br = 0.4x15%). If the regulated firm were expected to continue to earn a 15% return on equity and retain 40% of its earnings, then a growth rate of 6.0% would be a reasonable estimate of the long-term sustainable growth rate. However, the compound annual growth rate for dividends and earnings exceeds 16% which is the result only of an increased equity return rather than the intrinsic ability of the firm to grow continuously at a 16% annual rate. Clearly, this type of estimate of future growth cannot be used with any reliability at all. In the case of the hypothetical, to utilize a 16% growth rate in a DCF model would be to expect the company's return on common equity to increase by 50% every five years into the indefinite future. This would be a ridiculous forecast for any regulated firm and underscores the importance of utilizing the underlying fundamentals of growth in the DCF model.

It can also be demonstrated that a change in our hypothetical regulated firm's payout ratio makes the past rate of growth in dividends an unreliable basis for predicting "g". If we assume our regulated firm consistently earns its expected equity return (10%) but in the third year, changes its payout ratio from 60% to 80% of earnings, the results are shown in the table below.

TABLE C.

| | YEAR 1 | YEAR 2 | YEAR 3 | YEAR 4 | YEAR 5 | GROWTH |
|---|---|---|---|---|---|---|
| BOOK VALUE | $10.00 | $10.40 | $10.82 | $11.036 | $11.26 | 3.01% |
| EQUITY RETURN | 10% | 10% | 10% | 10% | 10% | - |
| EARNINGS/SH. | $1.00 | $1.040 | $1.082 | $1.104 | $1.126 | 3.01% |
| PAYOUT RATIO | 0.60 | 0.60 | 0.80 | 0.80 | 0.80 | 7.46% |
| DIVIDENDS/SH. | $0.60 | $0.624 | $0.866 | $0.833 | $0.900 | 10.67% |

What we see here is that, although the company has registered a high dividend growth rate (10.67%), it is, again, not at all representative of the growth that could be sustained indefinitely, as called for in the DCF model. In actuality, the sustainable growth rate has declined from 4.0% the first two years to only 2.0% (g=br = 0.2x10%) during the last three years due to the increased payout ratio. To utilize a 10% growth rate in a DCF analysis of this hypothetical regulated firm would 1) assume the payout ratio of the firm would continue to increase 33% every five years into the indefinite future, 2) lead to the highly implausible result that the firm intends to consistently pay out more in dividends than it earns and 3) grossly overstate the cost of equity capital.

# APPENDIX C
# SAMPLE COMPANY GROWTH RATE ANALYSES

## ELECTRIC UTILITIES

**CV – Central Vermont Public Service** - CV's sustainable growth rate has averaged only 0.8% over the most recent five year period (1998-2002), including a set-back with substantially negative growth in 1998, due to purchased power contract difficulties. Absent that negative growth, the company's average historical sustainable growth is 2%. Also, the company's sustainable growth in the most recent year, about 4%, indicates an increasing growth trend. VL expects CV's sustainable growth to rise above that historical growth rate level and reach 4.6% by the 2006-2008 period. CV's book value growth rate is expected to be 2% over the next five years, a significant increase from the 0.5% rate of growth experienced over the past five years, but far below internal growth projections. Also, CV's earnings per share are projected to increase at a 7.5% (VL) rate—above the indicated sustainable growth rate—but its dividends are expected to show 3% growth over the next five years, moderating long-term sustainable growth expectations. Over the past five years, CV's earnings growth was negative (giving rise to the expectation for much higher growth in the future) while its dividends increased at only a 1% rate. Investors can reasonably expect a sustainable growth rate in the future to be higher than the past; a growth rate of **4.75%** is reasonable for CV.

Regarding share growth, CV's shares outstanding increased at a 0.6% rate over the past five years. The growth the number of shares is projected by VL to increase at about a the same rate – 0.6% -- between 2002 and the 2006-08 period. An expectation of share growth of **0.6%** for this company is reasonable.

**EAS –Energy East Corp** - EAS's sustainable growth rate averaged about 6.5% for the five-year historical period, with a substantial growth rate decrease in the most recent year. Value Line projects more moderate growth from 2003 through 2006-08 period at a level near 4%. However, EAS's book value growth during the most recent five years (4%) is expected to increase to a 5% rate in the future. EAS's earnings per share are projected to increase at a 1% (VL) to 5.0% (Zack's) or 6.0% (Thomson Financial) rate, but its dividends are expected to grow at a 4.0% rate, moderating earnings growth expectations. Historically EAS's earnings have shown 8% growth, while its dividends increased at a 5.5% rate. Investors can reasonably expect a sustainable growth rate lower than that established historically; **4.5%** is a reasonable expectation for this company.

Regarding share growth, EAS's shares outstanding grew at approximately an 3.5% rate over the past five years due to an equity issuance in 2002. Prior to that equity issuance the number of shares outstanding had declined at a 2.5% rate. The number of shares is expected to grow at approximately a 0.7% rate through 2006-08. An expectation of share growth of **1%** for this company is reasonable.

**FE – FirstEnergy Corp.** - FE's sustainable growth rate averaged 4.3% over the five-year historical period. VL projects that the internal growth will be stable through 2006-08, bringing sustainable growth to 4.33%. FE's book value, which increased at a 6.5% rate during the most recent five years, is expected to decline to a 4.5% rate in the future, very similar to the sustainable growth projection. FE's earnings per share are projected to increase at a 2% (VL) to 4.0% (Zack's and

Thomson Financial) rate, and its dividends are expected to grow at a 2% rate, moderating long-term growth expectations. Historically FE's earnings grew at an 6% rate, according to Value Line and its dividends showed essentially no growth. On a compound growth rate basis using 2003 projections as the final year, FE's earnings grew at a –0.52% rate historically. The projected sustainable growth, earnings and book value growth rate data indicate that investors can expect the growth from FE in the future to be similar to or lower than that which has existed in the past. Investors can reasonably expect a sustainable growth rate of **4.5%** for FE.

Regarding share growth, FE's shares outstanding showed a 5.8% increase over the past five years. Further, after showing similar growth from 2002 to 2003, FE's growth rate in shares outstanding is expected to fall to about a 1.5% rate of increase through 2006-08. Those projections indicate that future share growth will be below past averages. An expectation of share growth of **2%** for this company is reasonable.

**SO – Southern Company** - SO's sustainable growth rate has averaged 3.37% over the most recent five year period. VL expects SO's sustainable growth to rise above that historical growth rate level and reach approximately 5% by the 2006-2008 period. SO's book value growth rate is expected to be 5% over the next five years, up dramatically from the -1% rate of growth experienced over the past five years. Also, SO's earnings per share are projected to increase at a 4.6% (Zack's), 5.0% (Thomson Financial) to 5.5% (VL) rate—bracketing the indicated sustainable growth rate. However, its dividends are expected to grow at 3%. Over the past five years, SO's earnings growth was 2% according to Value Line (only 1.35% on a compound basis ) while its dividends increased at a 1.5% rate. Investors can reasonably expect a higher sustainable growth rate in the future — **5%** for SO is reasonable.

Regarding share growth, SO's shares outstanding increased at approximately a 0.6% rate over the past five years. The number of shares is expected to grow at a 1.46% rate through 2006-08. An expectation of share growth of **1.25%** for this company is reasonable.

**AEE – Ameren Corp.** - AEE's sustainable growth rate averaged only about 2% over the most recent five-year period, with a poor year in the most recent year. Absent the most recent year AEE's sustainable growht averaged 2.35% with an increasing trend. VL projects, by the 2006-08 period, sustainable growth will approximate 2.3%-a-some improvement over the actual five-year average. AEE's projected book value also indicates improvement -- book value grew at a 1.5% rate during the most recent five years but is expected to rise at an 3.5% rate in the future, according to Value Line. Value Line projects a rate of earnings increase for AEE of 1%, while Thomson Financial projects 3% and Zack's projects 2.9%. Dividends are expected to grow at a 0.5% rate, moderating long-term growth expectations somewhat. Historically AEE's earnings grew at a 2.5% rate while its dividends increased at a 0.5% rate. Therefore, Investors can reasonably expect a long-term sustainable growth rate from this company of **3.0%.**

Regarding share growth, AEE's shares outstanding grew at a 2.94% rate over the past five years. The five-year average level of share growth is expected to decrease at approximately 2% annually through 2006-08. An expectation of share growth of **2.5%** for this company is reasonable.

**CNL – Cleco Corp.** - CNL's sustainable growth rate averaged 5.03% for the five-year period, with the results in the most recent year, approximating that average. VL expects sustainable growth to continue at about a 5% level through the

2006-08 period. CNL's book value growth is expected to continue to increase at a 3%, below the historical level of 5.5%. CNL's earnings per share is projected to show no growth over the next five years, and its dividends are expected to grow at only a 0.5% rate. Historically CNL's earnings increased at a 6.5% rate and its dividends increased at a 2.5% rate of growth, according to Value Line. Investors can reasonably expect sustainable growth from CNL to be below past averages, a sustainable internal growth rate of **4.75%** is reasonable for this company.

Regarding share growth, CNL's shares outstanding grew at approximately a 1.1% rate over the past five years. The growth in the number of shares is expected by VL to be 0.6% through 2006-08. An expectation of share growth of **0.75%** for this company is reasonable.

**DPL – DPL Inc.** - DPL's sustainable growth rate has averaged 5.1% over the most recent five year period with negative results in the most recent year. Absent the 2002 results, DPL's average growth was 7.2%. VL expects DPL's sustainable growth to rise above that historical growth rate level to 9% by the 2006-2008 period. DPL's book value growth rate is expected to be 6% over the next five years, up dramatically from the -3% rate of growth experienced over the past five years. Also, DPL's earnings per share is projected to increase at a 6% (VL) to 4.5% (Zack's) to 4% (Thomson Financial) rate—all well below the indicated internal growth rate. Also, its dividends are expected to grow at only 0.5%, moderating long-term growth rate expectations. Over the past five years, DPL's earnings growth was 3% while its dividends increased at a 1.5% rate. Investors can reasonably expect a sustainable growth rate in the future of **5.75%** for DPL.

Regarding share growth, DPL's shares outstanding decreased at approximately a 6% rate over the past five years. The number of shares outstanding in 2006-2008 is expected to be the same as that existing in 2002—therefore no growth is expected in the future. An expectation of share growth of **0%** for this company is reasonable.

**EDE – Empire District Electric** - EDE's sustainable internal growth rate averaged –0.79% over the five-year historical period, with several negative growth years. VL projects EDE's sustainable growth to rise to a level of almost 3% through 2006-08. Also, EDE's book value growth rate is expected to continue in the future at 3%, double the historical level of 1.5%, pointing to increasing growth for this company. EDE's earnings per share are projected to increase at 9% to 10% according to VL & Zack's, respectively while the analysts' surveyed by Thomson Financial (IBES) project earnings growth at 3.0%, a substantial difference. EDE's dividends are expected to remain at a constant level over the next five years (i.e., showing 0% growth). Sustainable growth has been relatively inconsistent for this company, historically and is expected to trend upward in the future to near the 3% level. Dividend growth has been non-existent. Also Value Line's earnings growth projection is skewed upward by their inclusion of the company's 2001 earnings in is "base" three-year period. From 2003 through the mid-point of the 2006-2008 period, Value Line's projected earnings per share indicate a 4% growth rate. investors can reasonably expect a sustainable growth rate of **3.5%** from EDE.

Regarding share growth, EDE's shares outstanding grew at about a 7% rate over the past five years, due primarilyi to a large equity issuance in 2002. The level of share growth is expected by VL to drop to 1% through 2006-08. An expectation of share growth of **2.5%** for this company is reasonable.

**ETR – Entergy Corp.** - ETR's internal sustainable growth rate has averaged 4.81% over the most recent five year period (1998-2002), with results in 2000 through 2002 above the historical growth rate level, indicating an increasing trend.

That higher level of growth is expected to be sustained in 2003 and to rise to approximately 5.2% by the 2006-2008 period. ETR's book value growth rate is expected to be 6.5% over the next five years—an substantial increase from the 3.5% rate of growth experienced over the past five years also pointing to higher growth expectations for the future. ETR's earnings per share are projected to increase at a rate of from 5.5% (VL) to 6.1% (Zack's) to 6.0% (Thomson Financial). After showing negative growth historically ETR's dividends are expected to grow at a high 8.5%, supporting higher sustainable growth expectations. Over the past five years, ETR's earnings grew at a 7% rate while its dividends showed –6.5% growth. Investors can reasonably expect a sustainable growth rate in the future to be higher than past averages, **6.00%** is reasonable for for ETR.

Regarding share growth, ETR's shares outstanding grew at a –2.5% rate over the past five years. The number of shares outstanding is projected by VL to rise at approximately a 0.75% rate through 2006-08. An expectation of share growth of **0.25%** for this company is reasonable.

**GXP – Great Plain Energy** - GXP's sustainable growth rate has averaged only 0.7% over the most recent five year period, with two negative years. VL expects GXP's sustainable growth to rise above that historical growth rate level to about 4.8% by the 2006-2008 period. GXP's book value growth rate is expected to be 3.5% over the next five years, above the –1.0% rate of growth experienced over the past five years. GXP's earnings per share are projected to increase at a rate of 4.5% (VL) to 4.0% (Zack's) to 4.0% (Thomson Financial). However, like many other electric companies, its dividends are expected to grow at only 0.5%. Over the past five years, GXP's earnings growth was 1.5% while its dividends increased at a 1% rate. Investors can reasonably expect a sustainable growth rate in the future of **4.25%** for GXP.

Regarding share growth, GXP's shares outstanding increased at approximately a 2.8% rate over the past five years due to an equity issuance in 2002—for the four years prior, there was no growth. That rate of increase is expected to slow in the future with number of shares outstanding in 2006-2008 is expected to remain essentially constant. An expectation of share growth of **0.5%** for this company is reasonable.

**HE – Hawaiian Electric** - HE's sustainable growth rate has averaged 1.77% over the most recent five year period (1998-2002), with higher growth in the two most recent years, indicating an increasing trend. However, VL expects HE's sustainable growth to moderate from that historical growth rate level to reach 1.5% by the 2006-2008 period. However, HE's book value growth rate is expected to be 3.5% over the next five years, a significant increase from the 1.5% rate of growth experienced over the past five years. Also, HE's earnings per share are projected to increase at a 2.8% (Thomson Financial) to 2.9% (Zack's) rate—while Value Line expects no growth in per share earnings for HE. The company's dividends are expected to show no growth over the next five years. Over the past five years, HE's earnings grew at a relatively slow rate (2.5%--giving rise to the expectation for much higher growth in the future) while its dividends increased at only a 0.5% rate. Investors can reasonably expect a sustainable growth rate in the future of **3.0%** for HE.

Regarding share growth, HE's shares outstanding grew at a 3.5% rate over the past five years. The number of shares is projected by VL to increase at about a 1.2% between 2002 and the 2006-08 period. An expectation of share growth of **2.25%** for this company is reasonable.

**PNW – Pinnacle West Capital Corp** - PNW's sustainable growth rate averaged about 6% for the five-year historical period, with a growth rate in the most recent year below historical averages, indicating a declining trend. Value Line projects that growth moderation to continue and a sustainable growth rate by the 2006-08 period at a level near 3.5%. Also, PNW's book value growth during the most recent five years (5%) is expected to moderate to a 3% rate in the future, confirming slower growth expectations. PNW's earnings per share are projected to increase at a 0.5% (VL) to 5.3% (Zack's) to 5.0% (Thomson Financial). However, its dividends are expected to grow at a 5.5% rate, similar to some earnings growth expectations. Historically PNW's earnings have shown 5% growth, while its dividends increased at an 8.5% rate. Investors can reasonably expect a sustainable growth rate lower than that established historically, but not as high as the earnings growth projected by analysts; **4.5%** is a reasonable expectation for this company.

Regarding share growth, PNW's shares outstanding grew at approximately a 1.8% rate over the past five years. The number of shares is expected to grow at approximately a 0% rate through 2006-08. An expectation of share growth of **0.5%** for this company is reasonable.

## APPENDIX D

## CORROBORATIVE EQUITY CAPITAL COST ESTIMATION METHODS

### CAPITAL ASSET PRICING MODEL

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL (CAPM) YOU USED TO ARRIVE AT AN ESTIMATE FOR THE COST RATE OF THE COMPANY'S EQUITY CAPITAL.

A. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (systematic) risk of a security. Systematic risk refers to the risk associated with movements in the macro-economy (the economic "system") and, thus, cannot be eliminated through diversification by holding a portfolio of securities. The beta coefficient ($\beta$) is a statistical measure which is an attempt to quantify the non-diversifiable risk of the return on a particular security against the returns inherent in general stock market fluctuations. The formula is expressed as follows:

$$k = r_f + \beta(r_m - r_f), \qquad \text{(i)}$$

where "k" is the cost of equity capital of an individual security, "$r_f$" is the risk-free rate of return, "$\beta$" is the beta coefficient, "$r_m$" is the average market return and "$r_m - r_f$" is the market risk premium. The CAPM is used in my analysis, not as a primary cost of equity analysis, but as a check of the DCF cost of equity estimate. Although I believe the CAPM can be useful in testing the reasonableness of a cost of capital estimate, certain theoretical shortcomings of this model (when applied in cost of capital analysis) reduce its usefulness.

Q. CAN YOU EXPLAIN WHY YOU APPLY THE CAPM ANALYSIS WITH CAUTION?

A. Yes. The reasons why the CAPM should be used in cost of capital analysis with caution

are set out below. It is important to understand that my caution with regard to the use of the CAPM in a cost of equity capital analysis does not indicate that the model is not a useful description of the capital markets. Rather, it recognizes that in the practical application of the CAPM to cost of capital analysis there are problems that can cause the results of that type of analysis to be less reliable than other, more widely accepted models such as the DCF.

The CAPM was originally designed as a point-in-time tool for selecting stock portfolios that matched a particular investor's risk/return preference. Its use in rate of return analysis to estimate multi-period return expectations for one stock or one type of stock, rather than a diversified portfolio of stocks, takes the model out of the context for which it was intended. Also, questions regarding the fundamental applicability of the CAPM theory and the accuracy of beta have arisen recently in the financial literature.

Over the past few years there has been much comment in the financial literature over the strength of the assumptions that underlie the CAPM and the inability to substantiate those assumptions through empirical analysis. Also, there are problems with the key CAPM risk measure that indicate that the CAPM analysis is not a reliable primary indicator of equity capital costs.

Cost of capital analysis is a decidedly forward-looking, or *ex-ante*, concept. Beta is not. The measurement of beta is derived completely with historical, or *ex-post*, information. Therefore, the beta of a particular company, because it is usually derived with five years of historical data, is slow to change to current (i.e., forward-looking) conditions, and some price abnormality that may have happened four years ago could substantially affect beta while, currently, being of little actual concern to investors. Moreover, this same shortcoming which assumes that past results mirror investor expectations for the future plagues the market risk premium in an ex-post, or historically-oriented CAPM.

Also, a recent study performed for the Center for Research in Security Prices at the University of Chicago Graduate School of Business shows that the assumed linear relationship between beta, risk and return (i.e., beta varies directly with risk and return) simply does not appear to exist in the marketplace. As Value Line reported in its Industry

Review published in March of 1992:

> Two of the most prestigious researchers in the financial community, Professors Eugene F. Fama and Kenneth R. French from the University of Chicago have challenged the traditional relationship between Beta and return in a recent paper published by the Center for Research in Security Prices. In this study, the duo traced the performance of thousands of stocks over 50 years, but found no statistical support for the hypothesis that the relationship between volatility and return is significantly different from random. Indeed, professor Fama concluded, 'The fact is that Beta, as the sole variable explaining returns on stocks, is dead.' These findings support previous studies that have called into question the real-world applicability of the CAPM Beta, including papers by Keim (Financial Analysts Journal, 1986), and Roll (Journal of Financial Economics, 1977). Never before, however, has the lack of a statistically significant relationship between beta and return been so rigorously and dramatically established. (Value Line Industry Review, March 13, 1992, p. 1-8.)

Fama and French have continued their investigation of the CAPM since their 1992 article and have postulated that a more accurate CAPM would use two additional risk measures in addition to beta. Their three-factor CAPM uses relative size as measured by market value of the firm's stock compared to that of the market index and relative book value-to-market value ratio compared to that of the market index as additional measures of risk[1]. The continuing research of Fama and French indicate that their three-factor CAPM is theoretically superior to the "standard" CAPM which relies on betas as the sole indicator of relative risk, producing results which more closely mimic historical experience.

However, it is important to note that while those authors tout the superiority of their three-factor CAPM to the single-beta CAPM on theoretical grounds, they recognize that there are significant problems with any type of asset pricing model when it comes to

[1] Fama and French postulate that firm size and book-to-market ratio effectively proxy the risk-return characteristics of earnings-price ratios and sales growth, the latter having been determined to have more explanatory power with regard to relative risk and return than beta alone.

using the model to estimate the cost of equity capital. In "Industry Costs of Equity" a working paper published by the Center for Research in Security Prices (Revised October 1996), Fama and French point out quite clearly that the volatility inherent in the historical data is such that a cost of equity estimate produced by <u>any</u> asset pricing model -- whether the traditional CAPM or their three-factor CAPM -- is subject to wide error:

> We do not take a stance on which is the right asset pricing model. Instead we use both the CAPM and our three-factor model to estimate industry costs of equity (CE's). Our goal is to illustrate in detail two problems that plague CE estimates from any asset pricing model.
>
> The first problem is imprecise estimates of risk loadings [betas or beta-equivalents for other risk measures]. Estimates of CAPM and three-factor risk loadings for industries would be precise if the loadings were constant. We find however, that there is strong variation through time in the CAPM and three-factor risk loadings of industries. As a result, if we are trying to measure an industry's current risk loadings and cost of equity, estimates from full sample (1963-1994) regressions are not more accurate than the imprecise estimates from regressions that use only the latest three years of data. And industries give an understated picture of the problems that will arise in estimating risk loadings for individual firms and investment projects.
>
> The second problem is imprecise estimates of factor risk premiums. For example, the price of risk in the CAPM is the expected return on the market portfolio minus the risk-free interest rate, $E(R_M)-R_f$. The annualized average excess return on the Center for Research in Security Prices (CSRP) value-weighted market portfolio of NYSE, AMEX and NASDAQ stocks for our 1963-1994 sample period is 5.16%; its standard error is 2.71%. Thus, if we use the historical market premium to estimate the expected premium, the traditional plus-and-minus-two-standard-error interval ranges from less than zero to more than 10.0%.
>
> Our message is that uncertainty of this magnitude about risk premiums, coupled with the uncertainty about risk loadings, implies woefully imprecise estimates of the cost of equity. (Fama, French, "Industry Costs of Equity," Center for Research in Security Prices at the University of Chicago Graduate School of Business (First Draft March 1994, Revised October 1996), pp. 1-2)

While this relatively recently published conclusion as to the imprecision of equity cost estimates produced by CAPM-type models does not negate the risk/return basis of asset pricing, it does definitely call for a more accurate measure with which asset returns can be more reliably indexed. However, unless and until such an index is published and widely accepted in the marketplace, CAPM cost of equity capital estimates should be relegated to a supporting role or informational status. Therefore, for the reasons set out above, I use the CAPM for informational purposes and do not rely on that methodology as a primary equity capital cost estimation technique.

Q. WHAT VALUE HAVE YOU CHOSEN FOR A RISK-FREE RATE OF RETURN IN YOUR CAPM ANALYSIS?

A. As the CAPM is designed, the risk-free rate is that short-term rate of return investors can realize with certainty. The nearest analog in the investment spectrum is the 13-week U. S. Treasury Bill. Although longer-term Treasury bonds have equivalent default risk to T-Bills, those longer-term government securities carry maturity risk that the T-Bills do not have. When investors tie up their money for longer periods of time, as they do when purchasing a long-term Treasury, they must be compensated for future investment opportunities forgone as well as the potential for future changes in inflation. Investors are compensated for this increased investment risk by receiving a higher yield on T-Bonds.

As I noted in my previous discussion of the macro-economy, due to a sluggish economy, the Fed has acted vigorously over the past year to lower short-term interest rates. Over the most recent six-week period, T-Bills have produced an average yield of only 0.94% (data from Value Line *Selection & Opinion*, six most recent weekly editions[2]).

Q. DO YOU BELIEVE THE USE OF A LONG-TERM TREASURY BOND RATE IS APPROPRIATE IN THE CAPM?

[2] Current T-Bill yield, six-week average yield from Value Line Selection & Opinion (10/24/03-11/28/03).

A. No. Although the selection of a long- or short-term Treasury security as the risk free rate of return to be used in the CAPM is often one of the areas of contention in applying the model in cost of capital analysis, the use of a normalized short-term T-Bill rate is the more theoretically correct parameter. However, the T-Bill yield can be influenced by Federal Reserve policy, and, as noted above, the Fed's current stance regarding economic stimulation has caused the current level of T-Bills to fall to historic lows. Therefore, for purposes of analysis in this proceeding I will use both the T-Bill and long-term Treasury bond yields for the risk-free rate in the CAPM. Also, along with those measures of the risk-free rate I use the corresponding measures of market risk premiums.

Q. WHAT HAVE YOU CHOSEN AS THE MARKET RISK PREMIUM FOR THE CAPM ANALYSIS?

A. In their 2003 edition of Stocks, Bonds, Bills and Inflation, R.G. Ibbotson Associates indicates that the average market risk premium between stocks and T-Bills over the 1926–2002 time period is 8.4% (based on an arithmetic average), and 6.4% (based on a geometric average). For long-term Treasuries, the market risk premiums are 6.4% (based on an arithmetic average) and 4.7% (based on a geometric average). I have used these values to estimate the market risk premium in the CAPM analysis. The geometric mean is based on compound returns over time and the arithmetic mean is based on the average of single-period returns.

Q. WHAT VALUES HAVE YOU CHOSEN FOR THE BETA COEFFICIENTS IN THE CAPM ANALYSIS?

A. Value Line reports beta coefficients for all the stocks it follows. Value Line's beta is derived from a regression analysis between weekly percentage changes in the market price of a stock and weekly percentage changes in the New York Stock Exchange Composite Index over a period of five years. The average beta coefficient of the sample group of gas distribution companies is 0.66.

Q. WHAT IS YOUR RECOMMENDED COST OF EQUITY CAPITAL FOR THE SAMPLE OF ELECTRIC COMPANIES USING THE CAPITAL ASSET PRICING MODEL ANALYSIS?

A. Schedule 8 shows that the average Value Line beta coefficient for the group of electric companies under study is 0.67. The overall arithmetic average market risk premium of 8.4% would, upon the adoption of a 0.67 beta, become a sample group premium of 5.64% (0.67 x 8.4%). That non-specific risk premium added to the risk-free T-Bill rate of 0.94%, previously derived, yields a common equity cost rate estimate of 6.58%. Schedule 8 also shows that using an average long-term T-bond yield (5.18%) the CAPM produces equity cost estimates of 8.33% (geometric) and 9.47% (arithmetic).

In the current market environment, the CAPM result based on the current T-Bill produces a very low cost of equity estimate that is, in my view, below the Company's long-term cost of equity capital. The T-Bill CAPM results, currently, do not produce a return which is above the Company's debt costs and, thus, are not reliable as an indicator of the cost of equity.

The CAPM results which employ the long-term Treasury yields (8.33%/9.47%) are more reasonable in the current economic environment as an estimate of the Company's cost of equity capital. Those results are below the DCF results derived previously, indicating that 1) even long-term capital costs are currently quite low and 2) my DCF equity cost estimate may be higher than the companies' actual cost of equity capital.

## MODIFIED EARNINGS-PRICE RATIO ANALYSIS

Q. PLEASE DESCRIBE THE MODIFIED EARNINGS-PRICE RATIO (MEPR) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL.

A. The earnings-price ratio is calculated simply as the expected earnings per share divided by the current market price. In cost of capital analysis, the earnings-price ratio (which is one portion of this analysis) can be useful in a corroborative sense, since it can be a good indicator of the proper range of equity costs when the market price of a stock is near its

book value. When the market price of a stock is *below* its book value, the earnings-price ratio *overstates* the cost of equity capital. Schedule 9 contains mathematical support for this concept. The opposite is also true, i.e.; the earnings-price ratio *understates* the cost of equity capital when the market price of a stock is *above* book value.

Under current market conditions, the electric firms under study have an average market-to-book ratio of 1.67 and, therefore, the average earnings-price ratio alone would understate the cost of equity for the sample group. However, it is important to emphasize that I do not use the earnings-price ratio alone as an indicator of equity capital cost rates. Because of the relationship among the earnings-price ratio, the market-to-book ratio and the investor-expected return on equity, I have modified the standard earnings-price ratio analysis by including expected returns on equity for the companies under study. It is that modified analysis, the MEPR analysis, that I will use to assist in estimating an appropriate range of equity capital costs in this proceeding.

Q. PLEASE EXPLAIN THE RELATIONSHIP AMONG THE EARNINGS-PRICE RATIO, THE EXPECTED RETURN ON EQUITY AND THE MARKET-TO-BOOK RATIO.

A. When the investor-expected return on equity for a company exceeds the investor-required return (the cost of equity capital), the market price of the firm will tend to exceed its book value. As explained above, when the market price exceeds book value, the earnings-price ratio understates the cost of equity capital. Therefore, when the expected equity return (ROE) exceeds the cost of equity capital, the earnings-price ratio will understate that cost rate.

Also, in situations where the expected equity return is below what investors require for that type of investment, market prices fall below book value. Further, when market-to-book ratios are below 1.0, the earnings-price ratio overstates the cost of equity capital. Thus, the expected rate of return on equity and the earnings-price ratio tend to move in a countervailing fashion about the cost of equity capital. When market-to-book ratios are above one, the expected equity return exceeds and the earnings-price ratio understates the cost of equity capital. When market-to-book ratios are below one, the

expected equity return understates and the earnings-price ratio exceeds the cost of equity capital. Further, as market-to-book ratios approach unity, the expected return and the earnings price ratio approach the cost of equity capital. Therefore, the average of the expected book return and the earnings price ratio provides a reasonable estimate of the cost of equity capital.

These relationships represent general rather than precisely quantifiable tendencies but are useful in corroborating other cost of capital methodologies. The Federal Energy Regulatory Commission, in its generic rate of return hearings, found this technique useful and indicated that under the circumstances of market-to-book ratios exceeding unity, the cost of equity is bounded above by the expected equity return and below by the earnings-price ratio (e.g., 50 Fed Reg, 1985, p. 21822; 51 Fed Reg, 1986, pp. 361, 362; 37 FERC ¶ 61,287). The mid-point of these two parameters, therefore, produces an estimate of the cost of equity capital which, when market-to-book ratios are different from unity, is far more accurate than the earnings-price ratio alone.

Q. WHAT ARE THE RESULTS OF YOUR EARNINGS-PRICE RATIO ANALYSIS OF THE COST OF EQUITY FOR THE SAMPLE GROUP?

A. Schedule 10 shows the Thomson Financial projected 2004 per share earnings for each of the firms in the sample groups. Recent average market prices (the same market prices used in my DCF analysis), Value Line's projected 2003 return on equity and 2006-2008 equity returns for each of the companies are also shown.

The average earnings-price ratio for the electric sample group, 7.14%, is below the cost of equity for those companies due to the fact that their average market-to-book ratio is currently above unity. The sample electric companies' 2003 expected book equity return averages 11.17%. That return rate is above the companies' cost of equity capital, again due to the fact that the market prices for those firms are above their book values. For the entire sample group, then, the mid-point of the earnings-price ratio and the current equity return is 9.16%.

Schedule 10 also shows that the average expected book equity return over the next three- to five-year period is 11.83%. The midpoint of these two boundaries of equity

capital cost for the whole group, i.e., the long-term projected return on book equity (11.83%) and the current earnings-price ratio (7.14%) is 9.49%, and provides another forward-looking estimate of the equity capital cost rate of an electric utility firm. The results of this MEPR analysis also indicate that the DCF equity cost estimate previously derived may be overstated (i.e., too high).

## MARKET-TO-BOOK RATIO ANALYSIS

Q. PLEASE DESCRIBE YOUR MARKET-TO-BOOK (MTB) ANALYSIS OF THE COST OF COMMON EQUITY CAPITAL FOR THE SAMPLE GROUP.

A. This technique of analysis is a derivative of the DCF model that attempts to adjust the capital cost derived with regard to inequalities that might exist in the market-to-book ratio. This method is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method. However, the MTB analysis is useful in a corroborative sense. The MTB seeks to determine the cost of equity using market-determined parameters in a format different from that employed in the DCF analysis. In the DCF analysis, the available data is "smoothed" to identify investors' long-term sustainable expectations. The MTB analysis, while based on the DCF theory, relies instead on point-in-time data projected one year and five years into the future and, thus, offers a practical corroborative check on the traditional DCF. The MTB formula is derived as follows:

Solving for "P" from Equation (1), the standard DCF model, we have

$$P = D/(k-g). \qquad \text{(ii)}$$

But the dividend (D) is equal to the earnings (E) times the earnings payout ratio, or one minus the retention ratio (b), or

$$D = E(1-b). \qquad \text{(iii)}$$

Substituting Equation (iii) into Equation (ii), we have

$$P = \frac{E(1-b)}{k-g} \quad . \qquad \text{(iv)}$$

The earnings (E) are equal to the return on equity (r) times the book value of that equity (B). Making that substitution into Equation (iv), we have

$$P = \frac{rB(1-b)}{k-g} \quad . \qquad \text{(v)}$$

Dividing both sides of Equation (v) by the book value (B) and noting from Equation (iii) in Appendix B that g = br+sv,

$$\frac{P}{B} = \frac{r(1-b)}{k-br-sv} \quad . \qquad \text{(vi)}$$

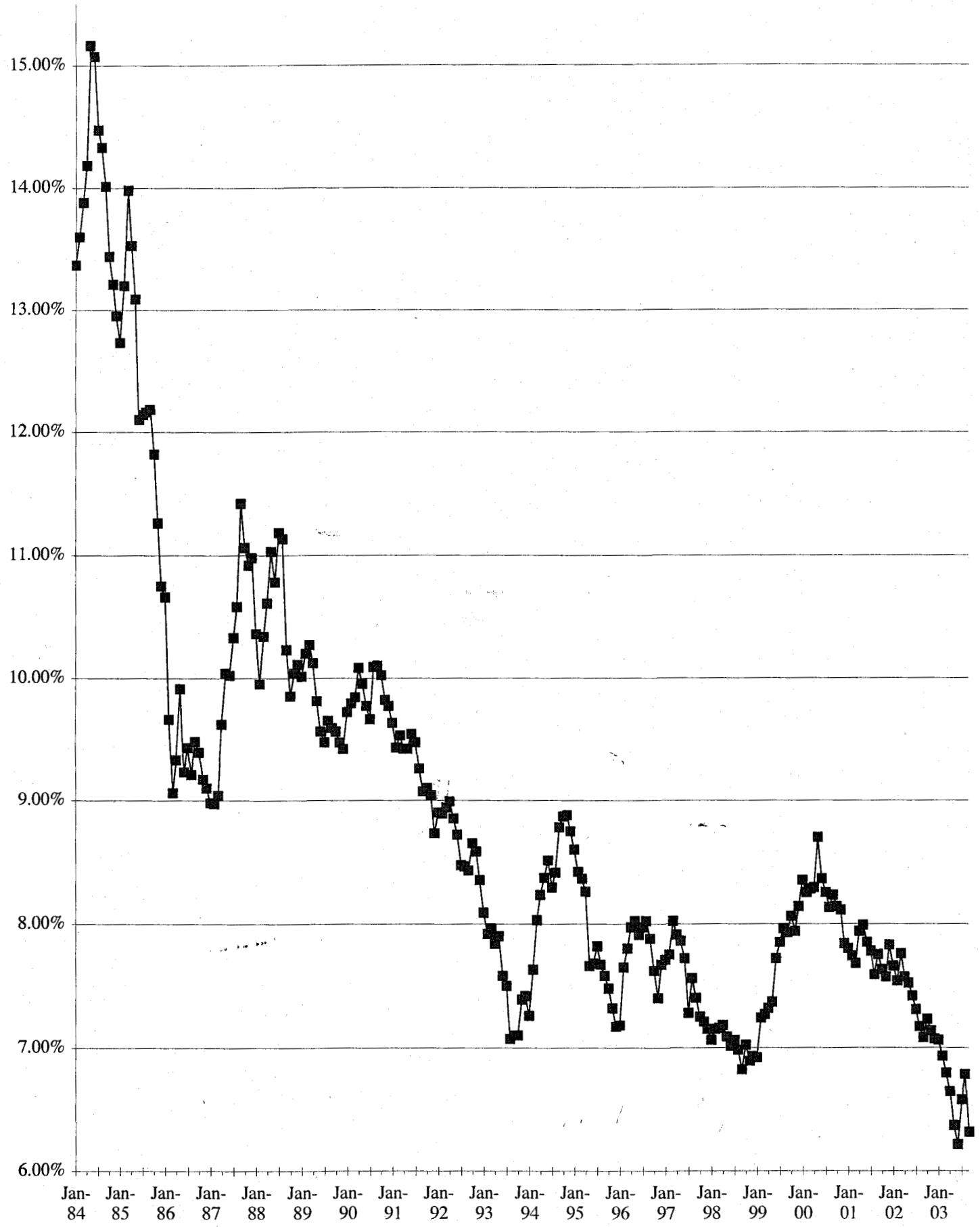
Finally, solving Equation (vi) for the cost of equity capital (k) yields the MTB formula:

$$k = \frac{r(1-b)}{P/B} + br + sv. \qquad \text{(vii)}$$

Equation (vii) indicates that the cost of equity capital equals the expected return on equity multiplied by the payout ratio, divided by the market-to-book ratio plus growth. Schedule 11 shows the results of applying Equation (vii) to the defined parameters for the electric utility firms in the comparable sample. Page 1 of Schedule 11 utilizes current year (2003) data for the MTB analysis while Page 2 of Schedule 11 utilizes Value Line's 2006-2008 projections.

The MTB cost of equity for the entire sample of electric utility firms, adjusted for a current average market-to-book ratio of 1.67 is 9.59% using the current year data and 9.30% using projected three- to five-year data.

**ARIZONA PUBLIC SERVICE COMPANY**
Moody's A-Rated Utility Bond Yields

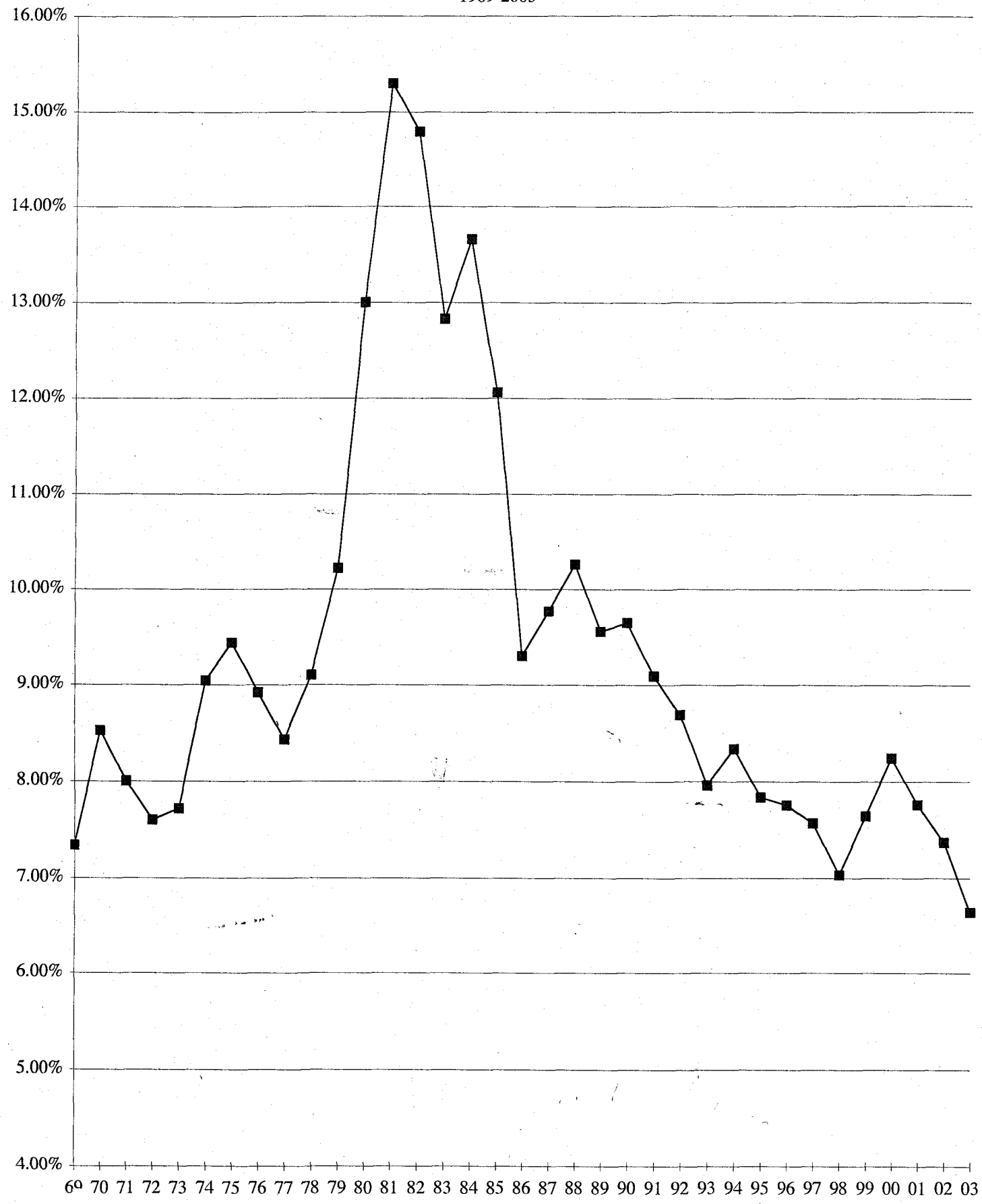



All data from Mergent (Moody's) Bond Record.

**ARIZONA PUBLIC SERVICE COMPANY**

Moody's A-rated Utility Bond Yields

1969-2003




All data from Moody's.

# ARIZONA PUBLIC SERVICE COMPANY
# HISTORICAL CAPITAL STRUCTURE

**AMOUNT (000)**

| Type of Capital | Sep-02 | Dec-02 | Mar-03 | Jun-03 | Sep-03 | **5 Quarter Average** | **June/Sept. Average** |
|---|---|---|---|---|---|---|---|
| Common Equity | $2,237,790 | $2,159,312 | $2,139,364 | $2,155,473 | $2,210,965 | **$2,180,581** | **$2,183,219** |
| Long-term Debt | $2,201,156 | $2,220,843 | $2,222,045 | $2,684,044 | $2,622,717 | **$2,390,161** | **$2,653,381** |
| Short-term Debt | $25,300 | $0 | $0 | $0 | $0 | **$5,060** | **$0** |
| TOTAL | $4,464,246 | $4,380,155 | $4,361,409 | $4,839,517 | $4,833,682 | **$4,575,802** | **$4,836,600** |

**PERCENTAGE**

| Type of Capital | Sep-02 | Dec-02 | Mar-03 | Jun-03 | Sep-03 | **5 Quarter Average** | **June/Sept. Average** |
|---|---|---|---|---|---|---|---|
| Common Equity | 50.13% | 49.30% | 49.05% | 44.54% | 45.74% | **47.65%** | **45.14%** |
| Long-term Debt | 49.31% | 50.70% | 50.95% | 55.46% | 54.26% | **52.23%** | **54.86%** |
| Short-term Debt | 0.57% | 0.00% | 0.00% | 0.00% | 0.00% | **0.11%** | **0.00%** |
| TOTAL | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | **100.00%** | **100.00%** |

Data from company response to RUCO-1.1, Third Quarter 2003 S.E.C. Form 10-Q.

# ARIZONA PUBLIC SERVICE COMPANY
# PINNACLE WEST CAPITAL CORPORATION
## HISTORICALCAPITAL STRUCTURE

**AMOUNT (000)**

| Type of Capital | Sep-02 | Dec-02 | Mar-03 | Jun-03 | Sep-03 | **Average** |
|---|---|---|---|---|---|---|
| Common Equity | $2,662,530 | $2,686,153 | $2,658,706 | $2,737,228 | $2,803,376 | **$2,709,599** |
| Long-term Debt | $3,139,358 | $3,162,718 | $3,130,243 | $3,368,712 | $3,289,880 | **$3,218,182** |
| Short-term Debt | $317,811 | $102,183 | $207,667 | $65,802 | $90,011 | **$156,695** |
| TOTAL | $6,119,699 | $5,951,054 | $5,996,616 | $6,171,742 | $6,183,267 | **$6,084,476** |

**PERCENTAGE**

| Type of Capital | Sep-02 | Dec-02 | Mar-03 | Jun-03 | Sep-03 | **Average** |
|---|---|---|---|---|---|---|
| Common Equity | 43.51% | 45.14% | 44.34% | 44.35% | 45.34% | **44.53%** |
| Long-term Debt | 51.30% | 53.15% | 52.20% | 54.58% | 53.21% | **52.89%** |
| Short-term Debt | 5.19% | 1.72% | 3.46% | 1.07% | 1.46% | **2.58%** |
| TOTAL | 100.00% | 100.00% | 100.00% | 100.00% | 100.00% | **100.00%** |

Data from company response to RUCO-1.1, Third Quarter 2003 S.E.C. Form 10-Q.

# ARIZONA PUBLIC SERVICE COMPANY
# ELECTRIC UTILITY INDUSTRY COMMON EQUITY RATIOS

| ELECTRIC COMPANIES | EQUITY RATIO |
|---|---|
| ALLETE | 54% |
| American Electric Power | 39% |
| Black Hills Corp. | 44% |
| Central Vermont P.S. | 54% |
| Cleco Corporation | 30% |
| DPL, Inc. | 26% |
| DQE, Inc. | 27% |
| Edison International | 22% |
| El Paso Electric Co. | 44% |
| Empire District Electric | 41% |
| FirstEnergy Corp. | 33% |
| FPL Group | 42% |
| Great Plains Energy | 40% |
| Green Mountain Power | 47% |
| Hawaiian Electric Industries | 25% |
| IDACORP | 42% |
| Maine & Maritimes Corp. | 59% |
| OGE Energy | 36% |
| Otter Tail Power | 49% |
| Pinnacle West Capital Corp. | 44% |
| Progress Energy Inc. | 38% |
| Southern Co. | 39% |
| UIL Holdings | 48% |
| Westar Energy | 26% |
| **AVERAGE** | **40%** |
| Investment Grade Average | 40% |

| COMBINATION GAS & ELECTRIC COMPANIES | EQUITY RATIO |
|---|---|
| AES Corp. | 1% |
| Allegheny Energy | 55% |
| Alliant Energy | 38% |
| Ameren Corp. | 45% |
| Aquilla | 35% |
| Avista Corp. | 40% |
| CenterPoint Energy | 11% |
| CH Energy Group | 61% |
| CINergy Crop. | 41% |
| CMS Energy Corp. | 14% |
| Consolidated Edison | 48% |
| Constellation Energy | 39% |
| Dominion Resources | 39% |
| DTE Energy Company | 36% |
| Duke Energy | 38% |
| Dynegy | 19% |
| Energy East Corp. | 36% |
| Entergy Corp. | 50% |
| Excelon Corp. | 34% |
| Florida Pub. Utilities | 44% |
| MDU Resources | 58% |
| MGE Resources | 50% |
| NiSource Inc. | 38% |
| Northeast Utilities | 33% |
| NSTAR | 37% |
| Pepco Holdings | 31% |
| PG&E Corp. | 24% |
| PNM Resources | 48% |
| PPL Corp. | 27% |
| Public Service Ent. Group | 24% |
| Puget Energy | 92% |
| SCANA Corp. | 38% |
| SEMPRA Energy | 36% |
| Sierra Pacific Resources | 24% |
| TECO Energy | 25% |
| TXU Corp. | 27% |
| Unitil Corp. | 33% |
| Unisource Energy | 20% |
| Vectren Corp. | 40% |
| Wisconsin Energy Corp. | 35% |
| WPS Resources | 44% |
| Xcel Energy Inc. | 39% |
| **AVERAGE** | **37%** |
| Investement Grade Average | 39% |

Data from C.A. Turners Utility Reports, November 2003.

**ARIZONA PUBLIC SERVICE COMPANY**
**EQUITY RATIO OF ELECTRIC UTILITY SAMPLE GROUPS**

**OLSON**

| COMPANY | COMMON EQUITY RATIO |
|---|---|
| CINergy | 41.00% |
| IDACORP | 42.00% |
| OGE Energy | 36.00% |
| PPL Corp. | 27.00% |
| Progress Energy | 38.00% |
| P.S. Ent. Group | 24.00% |
| Pinnacle West Capital Corp. | 44.00% |
| AVERAGE | **36.00%** |
| MEDIAN | **38.00%** |

**HILL**

| COMPANY | COMMON EQUITY RATIO |
|---|---|
| Central Vermont Public Service | 54.00% |
| Energy East Corp. | 36.00% |
| FirstEnergy Corp. | 33.00% |
| Southern Company | 39.00% |
| Ameren Corp. | 45.00% |
| Cleco Corp. | 30.00% |
| DPL Inc. | 26.00% |
| Empire District Electric | 41.00% |
| Entergy Corp. | 50.00% |
| Great Plains Energy | 40.00% |
| Hawaiian Electric | 25.00% |
| Pinnacle West Capital Corp. | 44.00% |
| AVERAGE | **38.58%** |
| MEDIAN | **39.50%** |

# ARIZONA PUBLIC SERVICE COMPANY
## SHORT-TERM DEBT

| PINNACLE WEST | | | ARIZONA PUBLIC SERVICE | | |
|---|---|---|---|---|---|
| DATE | AMOUNT | COST RATE | DATE | AMOUNT | COST RATE |
| Jan-01 | $44,608,333 | 7.70% | Jan-01 | $44,608,333 | 7.70% |
| Feb-01 | $77,495,000 | 0.07% | Feb-01 | $17,495,000 | 7.51% |
| Mar-01 | $118,041,667 | 6.56% | Mar-01 | $35,608,333 | 6.56% |
| Apr-01 | $137,711,667 | 5.82% | Apr-01 | $97,411,667 | 5.60% |
| May-01 | $183,485,033 | 4.66% | May-01 | $84,468,667 | 4.81% |
| Jun-01 | $217,783,333 | 4.35% | Jun-01 | $101,908,333 | 4.45% |
| Jul-01 | $273,751,533 | 4.12% | Jul-01 | $108,160,000 | 4.23% |
| Aug-01 | $74,275,000 | 4.17% | Aug-01 | $66,326,667 | 4.19% |
| Sep-01 | $120,385,000 | 3.67% | Sep-01 | $114,480,000 | 3.68% |
| Oct-01 | $79,105,000 | 3.28% | Oct-01 | $17,843,333 | 4.44% |
| Nov-01 | $202,378,667 | 2.75% | Nov-01 | $0 | 0.00% |
| Dec-01 | $293,425,233 | 2.92% | Dec-01 | $94,197,733 | 3.16% |
| Jan-02 | $423,833,833 | 2.44% | Jan-02 | $161,791,967 | 2.39% |
| Feb-02 | $353,629,845 | 2.36% | Feb-02 | $156,663,333 | 2.32% |
| Mar-02 | $103,095,589 | 2.49% | Mar-02 | $31,126,667 | 3.01% |
| Apr-02 | $167,110,356 | 2.36% | Apr-02 | $4,083,333 | 8.21% |
| May-02 | $219,855,834 | 2.22% | May-02 | $55,548,333 | 2.42% |
| Jun-02 | $294,859,482 | 2.17% | Jun-02 | $132,009,400 | 2.16% |
| Jul-02 | $352,592,110 | 2.10% | Jul-02 | $144,716,667 | 2.11% |
| Aug-02 | $314,406,627 | 2.11% | Aug-02 | $57,576,667 | 2.32% |
| Sep-02 | $319,818,817 | 2.25% | Sep-02 | $9,776,667 | 4.49% |
| Oct-02 | $297,242,960 | 1.86% | Oct-02 | $990,000 | 2.00% |
| Nov-02 | $190,971,117 | 2.28% | Nov-02 | $4,567,667 | 2.99% |
| Dec-02 | $202,781,560 | 1.99% | Dec-02 | $13,023,333 | 2.63% |
| Jan-03 | $180,781,360 | 2.22% | Jan-03 | $0 | 0.00% |
| Feb-03 | $149,104,330 | 1.89% | Feb-03 | $0 | 0.00% |
| Mar-03 | $229,855,293 | 1.86% | Mar-03 | $0 | 0.00% |
| Apr-03 | $226,767,360 | 1.96% | Apr-03 | $0 | 0.00% |
| May-03 | $191,334,007 | 2.19% | May-03 | $0 | 0.00% |
| Jun-03 | $45,547,383 | 2.29% | Jun-03 | $0 | 0.00% |
| Jul-03 | $72,724,327 | 1.42% | Jul-03 | $0 | 0.00% |
| Aug-03 | $65,367,877 | 1.43% | Aug-03 | $0 | 0.00% |
| 2003 AVERAGE | $145,185,242 | 1.91% | 2003 AVERAGE | $0 | 0.00% |
| TWO-YEAR AVERAGE | $212,373,915 | 2.27% | TWO-YEAR AVERAGE | $41,599,796 | 2.01% |
| TOTAL PERIOD AVERAGE | $194,503,923 | 2.87% | TOTAL PERIOD AVERAGE | $48,574,441 | 2.92% |

Data from Company response to RUCO 1.6.

**ARIZONA PUBLIC SERVICE COMPANY**
**RATEMAKNG CAPITAL STRUCTURE**

| Type of Capital | AMOUNT [000] | PERCENT | COST RATE* | WT. AVG. COST RATE |
|---|---|---|---|---|
| Common Equity | $2,183,219 | 45.14% | - | - |
| Long-term Debt | $2,603,381 | 53.83% | 5.77% | 3.11% |
| Short-term Debt | $50,000 | 1.03% | 3.00% | 0.03% |
| TOTAL CAPITAL | $4,836,600 | 100.00% | | - |

*Data from Company response to RUCO 1-2, embedded debt cost at 6/30/03.
Most recent cost of short-term debt for PWCC = 1.43%, use 3.00% for ratemaking purposes.

# ARIZONA PUBLIC SERVICE COMPANY
# ELECTRIC UTILITY SAMPLE GROUP SELECTION

| | Company Name | Revenues % Electric | Pending Merger? | Recent Div. Cut? | Generation Assets? | Stable Book Value? | Bond Rating S&P | Bond Rating Moody's | Select |
|---|---|---|---|---|---|---|---|---|---|
| | SCREEN | ≥70 | no | no | yes | yes | A+ to BBB | | |
| EAST | | | | | | | | | |
| e+g | Alegheny Energy | 58 | no | yes | yes | no | B+ | Baa1 | |
| e+g | CH Energy | 57 | no | no | yes | yes | A | A2 | |
| e | Central Vermont P. S. | 100 | no | no | yes | yes | BBB+ | - | √ |
| e+g | Consolidated Edison | 70 | no | no | no | yes | A | A1 | |
| e+g | Constellation Energy | 26 | no | yes | yes | yes | A | A1 | |
| e | DQE, Inc. | 88 | no | yes | no | no | BBB- | Baa1 | |
| e+g | Dominion Resources | 43 | no | no | yes | yes | A- | A2 | |
| e+g | Duke Energy | 25 | no | no | yes | no | BBB+ | Baa2 | |
| e+g | Energy East Corp. | 72 | no | no | yes | yes | BBB+ | A3 | √ |
| e+g | Excelon Corp. | 67 | no | no | yes | no | A | A2 | |
| e | FPL Group | 86 | no | no | yes | yes | A | Aa3 | |
| e | FirstEnergy Corp. | 78 | no | no | yes | yes | BBB | A3 | √ |
| e | Green Mountain Power | 100 | no | yes | yes | no | BBB | Baa1 | |
| e+g | Northeast Utilities | 68 | no | yes | yes | yes | A- | A3 | |
| e+g | NSTAR | 82 | no | no | no | yes | A | A1 | |
| e+g | PPL Corporation | 68 | no | yes | yes | no | A- | Baa1 | |
| e+g | Pepco Holdings, Inc. | 52 | no | yes | yes | no | A- | A2 | |
| e | Progress Energy | 81 | yes | no | yes | yes | BBB | A2 | |
| e+g | Public Service Ent. Gp. | 57 | no | no | yes | yes | A- | A3 | |
| e+g | SCANA Corp. | 43 | no | no | yes | yes | A- | A1 | |
| e | Southern Company | 82 | no | no | yes | yes | A+ | A1 | √ |
| e+g | TECO Energy | 56 | no | no | yes | yes | BBB- | A3 | |
| e | UIL Holdings Corp. | 64 | no | no | no | yes | - | A3 | |
| CENTRAL | | | | | | | | | |
| e | ALLETE | 33 | no | no | yes | yes | A | Baa1 | |
| e+g | Alliant Energy | 64 | no | no | yes | yes | A | A2 | |
| e+g | Ameren Corp. | 88 | no | no | yes | yes | A- | A1 | √ |
| e | American Eelectric Power | 35 | no | no | yes | yes | BBB | A3 | |
| e+g | Aquila, Inc. | 45 | no | yes | yes | yes | B | B3 | |
| e+g | CMS Energy Corp. | 9 | no | yes | yes | no | BBB- | Baa3 | |
| e+g | CenterPoint Energy | 25 | no | yes | yes | no | BBB | Baa2 | |
| e+g | Cinergy Corp. | 62 | no | no | yes | yes | BBB+ | A3 | |
| e | Cleco Corporation | 77 | no | no | yes | yes | BBB+ | A3 | √ |
| e | DPL Inc. | 99 | no | no | yes | no | BBB | Baa1 | √ |
| e+g | DTE Energy | 19 | no | no | yes | yes | A- | A2 | |
| e | Empire District Electric | 94 | no | no | yes | yes | BBB | Baa1 | √ |
| e+g | Entergy Corp. | 81 | no | no | yes | yes | BBB | Baa2 | √ |
| e | Great Plains Energy | 52 | no | no | yes | yes | BBB | A1 | √ |
| e+g | MGE Energy | 61 | no | no | yes | yes | AA- | Aa3 | |
| e+g | NiSource Inc. | 14 | no | yes | yes | yes | BBB | Baa2 | |
| e | OGE Energy Corp. | 44 | no | no | yes | yes | BBB+ | Baa2 | |
| e | Otter Tail Corp. | 43 | no | no | yes | yes | A- | A2 | |
| e+g | TXU Corp. | 24 | no | no | no | yes | BBB | Baa2 | |
| e+g | Vectren Corp. | 71 | no | no | yes | no | A- | A3 | |
| e+g | WPS Resources | 22 | no | no | yes | yes | AA- | Aa1 | |
| e | Westar Energy | 84 | no | yes | yes | no | BBB- | Ba1 | |
| e+g | Wisconsisn Energy | 49 | no | yes | yes | yes | A- | Aa2 | |
| WEST | | | | | | | | | |
| e+g | Avista Corp. | 90 | no | yes | yes | no | BBB- | Baa3 | |
| e | Black Hills Corp. | 21 | no | no | yes | yes | BBB | Baa1 | |
| e | Edison International | 74 | no | yes | yes | no | BB | Ba2 | |
| e | El Paso Electric | 99 | no | yes | yes | yes | BBB- | Baa3 | |
| e | Hawaiian Electric | 78 | no | no | yes | yes | BBB+ | Baa1 | √ |
| e | IDACORP, Inc. | 92 | no | yes | yes | yes | A | A2 | |
| e+g | MDU Resources Group | 8 | no | no | yes | yes | A- | A2 | |
| e+g | PG&E Corp. | 65 | yes | yes | yes | no | CC | B1 | |
| e+g | PNM Resources | 74 | no | no | yes | yes | BBB- | Baa3 | |
| e | Pinnacle West Capital | 70 | no | no | yes | yes | A- | A3 | √ |
| e+g | Puget Energy, Inc. | 62 | no | yes | yes | yes | BBB | Baa2 | |
| e+g | Sempra Energy | 45 | no | yes | yes | yes | A+ | A1 | |
| e+g | Sierra Pacific Resources | 94 | no | yes | yes | no | BB | Ba2 | |
| e+g | UniSource Energy | 95 | no | yes | yes | yes | BBB- | Ba2 | |
| e+g | Xcel Energy, Inc. | 58 | no | yes | yes | yes | BBB+ | A3 | |

e= electric company; e+g=combination electric and gas company

Data from Value Line Ratings & Reports, September 5, October 3, November 14, 2003; CA Turner's Utility Reports November 2003

**ARIZONA PUBLIC SERVICE COMPANY**
**DCF GROWTH RATE PARAMETERS**
INSURANCE COMPANIES

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **CV** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | -3.8889 | 01.1% | -4.28% | 15.63 | 11.46 | |
| 1999 | 0.3125 | 08.0% | 2.50% | 16.05 | 11.47 | |
| 2000 | 0.2281 | 06.9% | 1.57% | 16.57 | 11.51 | |
| 2001 | 0.0538 | 05.8% | 0.31% | 15.81 | 11.61 | |
| 2002 | 0.4286 | 09.3% | 3.99% | 16.83 | 11.74 | |
| AVERAGE GROWTH | | | 0.82% | 0.50% | | 0.61% |
| 2003 | 0.4133 | 08.5% | 3.51% | | 12.00 | 2.21% |
| 2004 | 0.4065 | 09.0% | 3.66% | | 12.00 | -0.50% |
| 2006-2008 | 0.4378 | 10.5% | 4.60% | 2.00% | 12.10 | 0.61% |

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **EAS** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.4834 | 11.3% | 5.46% | 13.61 | 125.89 | |
| 1999 | 0.5602 | 15.8% | 8.85% | 12.84 | 109.34 | |
| 2000 | 0.5749 | 13.8% | 7.93% | 14.59 | 117.66 | |
| 2001 | 0.5400 | 13.1% | 7.07% | 15.26 | 116.72 | |
| 2002 | 0.3600 | 08.0% | 2.88% | 16.97 | 144.97 | |
| AVERAGE GROWTH | | | 6.44% | 4.00% | | 3.59% |
| 2003 | 0.4118 | 09.5% | 3.91% | | 146.00 | 0.71% |
| 2004 | 0.4057 | 09.5% | 3.85% | | 147.00 | 0.70% |
| 2006-2008 | 0.4200 | 09.5% | 3.99% | 5.00% | 150.00 | 0.68% |

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **FE** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.2308 | 09.9% | 2.28% | 18.77 | 237.07 | |
| 1999 | 0.4000 | 12.5% | 5.00% | 19.63 | 232.45 | |
| 2000 | 0.4424 | 12.9% | 5.71% | 20.72 | 224.53 | |
| 2001 | 0.4718 | 08.9% | 4.20% | 24.86 | 297.64 | |
| 2002 | 0.4094 | 10.5% | 4.30% | 23.92 | 297.64 | |
| AVERAGE GROWTH | | | 4.30% | 6.50% | | 5.85% |
| 2003 | 0.2105 | 07.5% | 1.58% | | 315.00 | 5.83% |
| 2004 | 0.4545 | 10.5% | 4.77% | | 315.00 | 2.87% |
| 2006-2008 | 0.4333 | 10.0% | 4.33% | 4.50% | 315.00 | 1.14% |

**ARIZONA PUBLIC SERVICE COMPANY**
**DCF GROWTH RATE PARAMETERS**

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **SO** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.2254 | 12.2% | 2.75% | 14.02 | 698.63 | |
| 1999 | 0.2678 | 13.6% | 3.64% | 13.82 | 666.00 | |
| 2000 | 0.3333 | 12.3% | 4.10% | 15.67 | 682.00 | |
| 2001 | 0.1677 | 14.0% | 2.35% | 11.42 | 699.00 | |
| 2002 | 0.2649 | 15.1% | 4.00% | 12.15 | 716.00 | |
| AVERAGE GROWTH | | | 3.37% | -1.00% | | 0.62% |
| 2003 | 0.2486 | 14.0% | 3.48% | | 730.00 | 1.96% |
| 2004 | 0.2718 | 14.5% | 3.94% | | 740.00 | 1.66% |
| 2006-2008 | 0.3277 | 15.5% | 5.08% | 5.00% | 770.00 | 1.46% |

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **AEE** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.0993 | 12.6% | 1.25% | 22.27 | 137.22 | |
| 1999 | 0.0961 | 12.5% | 1.20% | 22.52 | 137.22 | |
| 2000 | 0.2372 | 14.3% | 3.39% | 23.30 | 137.22 | |
| 2001 | 0.2551 | 14.0% | 3.57% | 24.26 | 138.05 | |
| 2002 | 0.0451 | 09.9% | 0.45% | 24.93 | 154.10 | |
| AVERAGE GROWTH | | | 1.97% | 1.50% | | 2.94% |
| 2003 | 0.1241 | 11.0% | 1.37% | | 163.00 | 5.78% |
| 2004 | 0.1533 | 11.0% | 1.69% | | 164.80 | 3.41% |
| 2006-2008 | 0.2061 | 11.0% | 2.27% | 3.50% | 170.20 | 2.01% |

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **CNL** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.2768 | 12.7% | 3.52% | 9.07 | 44.97 | |
| 1999 | 0.3025 | 12.9% | 3.90% | 9.44 | 44.88 | |
| 2000 | 0.4178 | 14.9% | 6.23% | 10.04 | 44.99 | |
| 2001 | 0.4238 | 14.6% | 6.19% | 10.69 | 44.96 | |
| 2002 | 0.4079 | 13.1% | 5.34% | 11.77 | 47.04 | |
| AVERAGE GROWTH | | | 5.03% | 5.50% | | 1.13% |
| 2003 | 0.3077 | 12.5% | 3.85% | | 47.35 | 0.66% |
| 2004 | 0.3571 | 13.0% | 4.64% | | 47.65 | 0.65% |
| 2006-2008 | 0.4000 | 12.5% | 5.00% | 3.00% | 48.50 | 0.61% |

**ARIZONA PUBLIC SERVICE COMPANY**
**DCF GROWTH RATE PARAMETERS**

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **DPL** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.2419 | 13.6% | 3.29% | 8.58 | 161.26 | |
| 1999 | 0.3037 | 14.0% | 4.25% | 9.20 | 157.80 | |
| 2000 | 0.3691 | 22.9% | 8.45% | 6.80 | 127.77 | |
| 2001 | 0.4598 | 27.8% | 12.78% | 6.31 | 126.50 | |
| 2002 | -0.3056 | 10.8% | -3.30% | 6.38 | 126.50 | |
| AVERAGE GROWTH | | | 5.10% | -3.00% | | -5.89% |
| 2003 | 0.2480 | 17.5% | 4.34% | | 126.50 | 0.00% |
| 2004 | 0.2769 | 17.5% | 4.85% | | 126.50 | 0.00% |
| 2006-2008 | 0.4703 | 19.5% | 9.17% | 6.00% | 126.50 | 0.00% |

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **EDE** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.1634 | 11.3% | 1.85% | 13.43 | 17.11 | |
| 1999 | -0.1327 | 08.8% | -1.17% | 13.48 | 17.37 | |
| 2000 | 0.0519 | 09.8% | 0.51% | 13.65 | 17.60 | |
| 2001 | -1.1695 | 03.9% | -4.56% | 13.58 | 19.76 | |
| 2002 | -0.0756 | 07.8% | -0.59% | 14.59 | 22.57 | |
| AVERAGE GROWTH | | | -0.79% | 1.50% | | 7.17% |
| 2003 | 0.1467 | 10.0% | 1.47% | | 23.00 | 1.91% |
| 2004 | 0.1467 | 09.5% | 1.39% | | 23.20 | 1.39% |
| 2006-2008 | 0.2686 | 10.5% | 2.82% | 3.00% | 23.80 | 1.07% |

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **ETR** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.3243 | 07.4% | 2.40% | 28.79 | 246.83 | |
| 1999 | 0.4667 | 07.7% | 3.59% | 28.81 | 247.08 | |
| 2000 | 0.5892 | 09.7% | 5.72% | 31.89 | 219.60 | |
| 2001 | 0.5844 | 09.3% | 5.44% | 33.78 | 220.73 | |
| 2002 | 0.6359 | 10.9% | 6.93% | 35.24 | 222.42 | |
| AVERAGE GROWTH | | | 4.81% | 3.50% | | -2.57% |
| 2003 | 0.6145 | 11.0% | 6.76% | | 228.40 | 2.69% |
| 2004 | 0.5614 | 10.0% | 5.61% | | 229.00 | 1.47% |
| 2006-2008 | 0.5422 | 09.5% | 5.15% | 6.50% | 230.80 | 0.74% |

**ARIZONA PUBLIC SERVICE COMPANY**
**DCF GROWTH RATE PARAMETERS**

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **GXP** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.1323 | 13.1% | 1.73% | 14.41 | 61.91 | |
| 1999 | -0.3175 | 09.0% | -2.86% | 13.97 | 61.91 | |
| 2000 | 0.1902 | 13.8% | 2.63% | 14.88 | 61.91 | |
| 2001 | -0.0440 | 12.6% | -0.55% | 12.59 | 61.91 | |
| 2002 | 0.1863 | 13.6% | 2.53% | 13.58 | 69.20 | |
| AVERAGE GROWTH | | | 0.70% | -1.00% | | 2.82% |
| 2003 | 0.1902 | 14.5% | 2.76% | | 69.20 | 0.00% |
| 2004 | 0.2279 | 14.5% | 3.30% | | 69.20 | 0.00% |
| 2006-2008 | 0.3200 | 15.0% | 4.80% | 3.50% | 69.20 | 0.00% |

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **HE** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.1622 | 11.4% | 1.85% | 25.75 | 32.12 | |
| 1999 | 0.1419 | 11.0% | 1.56% | 26.31 | 32.21 | |
| 2000 | 0.0236 | 09.8% | 0.23% | 25.43 | 32.99 | |
| 2001 | 0.2226 | 11.6% | 2.58% | 26.11 | 35.60 | |
| 2002 | 0.2346 | 11.3% | 2.65% | 28.43 | 36.81 | |
| AVERAGE GROWTH | | | 1.77% | 1.50% | | 3.47% |
| 2003 | 0.1143 | 09.5% | 1.09% | | 38.00 | 3.23% |
| 2004 | 0.1298 | 09.5% | 1.23% | | 38.25 | 1.94% |
| 2006-2008 | 0.1733 | 09.0% | 1.56% | 3.50% | 39.00 | 1.16% |

| COMPANY | INTERNAL GROWTH | | | | EXTERNAL GROWTH | |
|---|---|---|---|---|---|---|
| **PNW** | RETENTION RATIO | EQUITY RETURN | "g" | BOOK VALUE ($/SHARE) | SHARES OUTST (MILLIONS) | SHARE GROWTH |
| 1998 | 0.5684 | 11.2% | 6.37% | 25.50 | 84.83 | |
| 1999 | 0.5818 | 12.2% | 7.10% | 26.00 | 84.83 | |
| 2000 | 0.5731 | 11.9% | 6.82% | 28.09 | 84.83 | |
| 2001 | 0.5842 | 12.5% | 7.30% | 29.46 | 84.83 | |
| 2002 | 0.3557 | 08.0% | 2.85% | 29.44 | 91.26 | |
| AVERAGE GROWTH | | | 6.09% | 5.00% | | 1.84% |
| 2003 | 0.3216 | 08.5% | 2.73% | | 91.30 | 0.04% |
| 2004 | 0.3900 | 09.5% | 3.71% | | 91.30 | 0.02% |
| 2006-2008 | 0.3545 | 09.5% | 3.37% | 3.00% | 91.30 | 0.01% |

Data from Value Line Ratings & Reports Sept. 5, oct. 3, Nov. 14, 2003.

**ARIZONA PUBLIC SERVICE COMPANY**

**DCF GROWTH RATES**

| COMPANY | br | + | sv=g*((M/B+1)/2-1) | | = | g |
|---|---|---|---|---|---|---|
| CV | 4.75% | + | 0.60% | (( 1.36 + 1)/2-1) | = | 4.86% |
| EAS | 4.50% | + | 1.00% | (( 1.28 + 1)/2-1) | = | 4.64% |
| FE | 4.50% | + | 2.00% | (( 1.38 + 1)/2-1) | = | 4.88% |
| SO | 5.00% | + | 1.25% | (( 2.29 + 1)/2-1) | = | 5.81% |
| AEE | 3.00% | + | 2.50% | (( 1.67 + 1)/2-1) | = | 3.84% |
| CNL | 4.75% | + | 0.75% | (( 1.62 + 1)/2-1) | = | 4.98% |
| DPL | 5.75% | + | 0.00% | (( 2.72 + 1)/2-1) | = | 5.75% |
| EDE | 3.50% | + | 2.50% | (( 1.45 + 1)/2-1) | = | 4.06% |
| ETR | 6.00% | + | 0.25% | (( 1.40 + 1)/2-1) | = | 6.05% |
| GXP | 4.25% | + | 0.50% | (( 2.24 + 1)/2-1) | = | 4.56% |
| HE | 3.00% | + | 2.25% | (( 1.50 + 1)/2-1) | = | 3.56% |
| PNW | 4.50% | + | 0.50% | (( 1.18 + 1)/2-1) | = | 4.54% |

Average Market-to-Book Ratio = 1.67

| | | |
|---|---|---|
| CV | = | Central Vermont Public Service |
| EAS | = | Energy East Corp. |
| FE | = | FirstEnergy Corp. |
| SO | = | Southern Company |
| AEE | = | Ameren Corp. |
| CNL | = | Cleco Corp. |
| DPL | = | DPL Inc. |
| EDE | = | Empire District Electric |
| ETR | = | Entergy Corp. |
| GXP | = | Great Plains Energy |
| HE | = | Hawaiian Electric |
| PNW | = | Pinnacle West Capital Corp. |

g*= expected growth in number of shares outstanding

**ARIZONA PUBLIC SERVICE COMPANY**

**GROWTH RATE COMPARISON**

| | | Value Line Projected | | | Zack's | Value Line Historic | | | Zack's & VL | 5-yr Compound Hist. | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| COMPANY | br + sv | EPS | DPS | BVPS | EPS | EPS | DPS | BVPS | AVGS. | EPS | DPS | BVPS |
| CV | 4.86% | 7.50% | 3.00% | 2.00% | n/a | -3.00% | 1.00% | 0.50% | 1.83% | 52.81% | 0.00% | 1.81% |
| EAS | 4.64% | 1.00% | 4.00% | 5.00% | 5.00% | 8.00% | 5.50% | 4.00% | 4.64% | 2.40% | 5.09% | 5.40% |
| FE | 4.88% | 2.00% | 2.00% | 4.50% | 6.00% | 6.00% | 0.00% | 6.50% | 3.86% | -0.52% | 0.00% | 5.73% |
| SO | 5.81% | 6.50% | 3.00% | 5.00% | 4.60% | 2.00% | 1.50% | -1.00% | 3.09% | 1.35% | 0.74% | -1.65% |
| AEE | 3.84% | 1.00% | 0.50% | 3.50% | 2.90% | 2.50% | 0.50% | 1.50% | 1.77% | 0.56% | 0.00% | 3.42% |
| CNL | 4.98% | 0.00% | 0.50% | 3.00% | n/a | 6.50% | 2.50% | 5.50% | 3.00% | 3.03% | 2.13% | 2.77% |
| DPL | 5.75% | 6.00% | 0.50% | 6.00% | 4.50% | 3.00% | 1.50% | -3.00% | 2.64% | 0.16% | 0.00% | -4.40% |
| EDE | 4.06% | 9.00% | 0.00% | 3.00% | 10.00% | -3.50% | 0.00% | 1.50% | 2.86% | -0.40% | 0.00% | 2.17% |
| ETR | 6.05% | 5.50% | 8.50% | 6.50% | 6.10% | 7.00% | -6.50% | 3.50% | 4.37% | 13.33% | 1.30% | 5.85% |
| GXP | 4.56% | 4.50% | 0.50% | 3.50% | 4.00% | 1.50% | 1.00% | -1.00% | 2.00% | 1.64% | 0.24% | -0.36% |
| HE | 3.56% | 0.00% | 0.00% | 3.50% | 2.90% | 2.50% | 0.50% | 1.50% | 1.56% | -1.11% | 0.00% | 2.51% |
| PNW | 4.54% | 0.50% | 5.50% | 3.00% | 5.30% | 5.00% | 8.50% | 5.00% | 4.69% | -2.20% | 7.06% | 3.48% |
| | | 3.63% | 2.33% | 4.04% | | 3.13% | 1.33% | 2.04% | | 5.92% | 1.38% | 2.23% |
| AVERAGES | 4.79% | | 3.33% | | 5.13% | | 2.17% | | 3.03% | | 3.18% | |

Thomson Financial (IBES) 5-year earnings growth projections: CV-n/a; EAS- 4.0%; FE-4.0%; SO-5.0%; AEE-3.0%, CNL-n/a; DPL-4.0%; EDE-3.0%; ETR-6.0%, GXP-4.0%; HE-2.8%; PNW-5.0%. Average = 4.08%.

**ARIZONA PUBLIC SERVICE COMPANY**

**STOCK PRICE, DIVIDENDS, YIELDS**

| COMPANY | AVG. STOCK PRICE 11/21/02-1/3/03 (PER SHARE) | | ANNUALIZED DIVIDEND (PER SHARE) | DIVIDEND YIELD |
|---|---|---|---|---|
| CV | $23.28 | * | $0.92 | 3.96% |
| EAS | $22.65 | * | $1.05 | 4.62% |
| FE | $34.11 | | $1.50 | 4.40% |
| SO | $29.55 | | $1.40 | 4.74% |
| AEE | $44.11 | | $2.54 | 5.76% |
| CNL | $16.86 | | $0.90 | 5.34% |
| DPL | $18.62 | | $0.94 | 5.05% |
| EDE | $21.68 | | $1.28 | 5.90% |
| ETR | $53.69 | | $1.80 | 3.35% |
| GXP | $31.76 | | $1.66 | 5.23% |
| HE | $45.14 | | $2.48 | 5.49% |
| PNW | $37.02 | | $1.80 | 4.86% |
| | | | AVERAGE | **4.89%** |

*Dividend increase expected in next quarter. Current dividend multiplied by (1+g), from Schedule 5.

**ARIZONA PUBLIC SERVICE COMPANY**

**DCF COST OF EQUITY CAPITAL**

| COMPANY | DIVIDEND YIELD Schedule 6 | GROWTH RATE Schedule 5 | DCF COST OF EQUITY CAPITAL |
|---|---|---|---|
| CV | 3.96% | 4.86% | 8.82% |
| EAS | 4.62% | 4.64% | 9.26% |
| FE | 4.40% | 4.88% | 9.27% |
| SO | 4.74% | 5.81% | 10.54% |
| AEE | 5.76% | 3.84% | 9.60% |
| CNL | 5.34% | 4.98% | 10.32% |
| DPL | 5.05% | 5.75% | 10.80% |
| EDE | 5.90% | 4.06% | 9.97% |
| ETR | 3.35% | 6.05% | 9.40% |
| GXP | 5.23% | 4.56% | 9.79% |
| HE | 5.49% | 3.56% | 9.06% |
| PNW | 4.86% | 4.54% | 9.41% |
| | | AVERAGE | **9.69%** |
| | | STANDARD DEVIATION | **0.61%** |

**ARIZONA PUBLIC SERVICE COMPANY**

**CAPM COST OF EQUITY CAPITAL**

**k = rf + B (rm - rf)**

**T-BILLS**

[rf]* = 0.94%
[rm - rf]† = 6.40% (geometric mean)
[rm - rf]† = 8.40% (arithmetic mean)
average beta = 0.67

k = 0.94% + 0.67 (6.4%/8.40%)
k = 0.94% + 4.29%/5.64%
k = 5.23% / 6.58%

**T-BONDS**

[rf]* = 5.18%
[rm - rf]† = 4.70% (geometric mean)
[rm - rf]† = 6.40% (arithmetic mean)
average beta = 0.67

k = 5.18% + 0.67 (5.40%/7.00%)
k = 5.18% + 3.15%/4.29%
k = 8.33% / 9.47%

*Current T-Bill & T-Bond yields, six-week avg. yield from Value Line Selection & Opinion (10/24/03-11/28/03)
†Geometric and arithmetic market risk premiums from Ibbotson Associates 2003 SBBI Yearbook, p. 28.

**ARIZONA PUBLIC SERVICE COMPANY**

PROOF

If book value exceeds market price,
the market-to-book ratio is less than 1.0,
and the earnings-price ratio exceeds the cost of capital.

MP = market price
BV = book value
i = cost of equity capital
r = earned return
E = earnings

1. At MP = BV, $i = r = \frac{E}{MP}$ .

2. E = rBV.

3. Then, $\frac{E}{MP} = \frac{rBV}{MP}$ .

4. When BV > MP, i.e., $\frac{BV}{MP} > 1$, then,

   a. $\frac{E}{MP} > r$, since $\frac{E}{MP} = \frac{rBV}{MP} > r$, because $\frac{BV}{MP} > 1$;

   b. $i > r$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} > 1$, then $i > r$; and

   c. $\frac{E}{MP} > i$, since at $\frac{BV}{MP} = 1$, $i = \frac{E}{MP} = \frac{rBV}{MP}$, but if $\frac{BV}{MP} > 1$, then $\frac{E}{MP} > i$, because,

      1) $\frac{BV}{MP} > 1$, through MP decreasing, and, if so, $\frac{E}{MP}$ increases, therefore, $\frac{E}{MP} > i$, or

      2) $\frac{BV}{MP} > 1$, through BV increasing, and, if so, given E = rBV, $\frac{E}{MP}$ increases, therefore, $\frac{E}{MP} > i$.

5. Ergo, $\frac{E}{MP} > i > r$, the cost of capital exceeds the earned return.

**ARIZONA PUBLIC SERVICE COMPANY**

**MODIFIED EARNINGS-PRICE RATIO ANALYSIS**

| COMPANY | Zack's Projected 2004 Earnings (Per Share) | Market Price (Per share) | Earnings-Price Ratio | Current R.O.E. 2003 | Projected R.O.E. 2006-2008 |
|---|---|---|---|---|---|
| CV | $1.55 | $23.28 | 6.66% | 8.50% | 10.50% |
| EAS | $1.73 | $22.65 | 7.64% | 9.50% | 9.50% |
| FE | $2.91 | $34.11 | 8.53% | 7.50% | 10.00% |
| SO | $1.97 | $29.55 | 6.67% | 14.00% | 15.50% |
| AEE | $2.98 | $44.11 | 6.76% | 11.00% | 11.00% |
| CNL | $1.15 | $16.86 | 6.82% | 12.50% | 12.50% |
| DPL | $1.32 | $18.62 | 7.09% | 17.50% | 19.50% |
| EDE | $1.37 | $21.68 | 6.32% | 10.00% | 10.50% |
| ETR | $4.22 | $53.69 | 7.86% | 11.00% | 9.50% |
| GXP | $2.07 | $31.76 | 6.52% | 14.50% | 15.00% |
| HE | $3.11 | $45.14 | 6.89% | 9.50% | 9.00% |
| PNW | $2.96 | $37.02 | 7.99% | 8.50% | 9.50% |
| | | AVERAGE | 7.14% | 11.17% | |
| | | CURRENT M.E.P.R. | | **9.16%** | |
| | | AVERAGE | 7.14% | | 11.83% |
| | | PROJECTED M.E.P.R. | | **9.49%** | |

**ARIZONA PUBLIC SERVICE COMPANY**

**MARKET-TO-BOOK RATIO ANALYSIS**

k = R.O.E.(1-b)/(M/B) + g
[2002]

| COMPANY | | | | | | | | | MARKET-TO-BOOK COST OF EQUITY |
|---|---|---|---|---|---|---|---|---|---|
| CV | k= 08.5% | (1- | 0.4133 )/ | 1.36 | + | 4.86% | = | | 8.52% |
| EAS | k= 09.5% | (1- | 0.4118 )/ | 1.28 | + | 4.64% | = | | 9.01% |
| FE | k= 07.5% | (1- | 0.2105 )/ | 1.38 | + | 4.88% | = | | 9.18% |
| SO | k= 14.0% | (1- | 0.2486 )/ | 2.29 | + | 5.81% | = | | 10.40% |
| AEE | k= 11.0% | (1- | 0.1241 )/ | 1.67 | + | 3.84% | = | | 9.60% |
| CNL | k= 12.5% | (1- | 0.3077 )/ | 1.62 | + | 4.98% | = | | 10.32% |
| DPL | k= 17.5% | (1- | 0.2480 )/ | 2.72 | + | 5.75% | = | | 10.59% |
| EDE | k= 10.0% | (1- | 0.1467 )/ | 1.45 | + | 4.06% | = | | 9.95% |
| ETR | k= 11.0% | (1- | 0.6145 )/ | 1.40 | + | 6.05% | = | | 9.07% |
| GXP | k= 14.5% | (1- | 0.1902 )/ | 2.24 | + | 4.56% | = | | 9.79% |
| HE | k= 09.5% | (1- | 0.1143 )/ | 1.50 | + | 3.56% | = | | 9.17% |
| PNW | k= 08.5% | (1- | 0.3216 )/ | 1.18 | + | 4.54% | = | | 9.44% |
| | | | | | | | | AVERAGE | **9.59%** |
| | | | | | | | | STANDARD DEVIATION | **0.64%** |

Note: Equity returns and retention ratios based on Value Line current year projections.

**ARIZONA PUBLIC SERVICE COMPANY**

**MARKET-TO-BOOK RATIO ANALYSIS**

k = R.O.E.(1-b)/(M/B) + g
[2005-2007]

| COMPANY | | | | | | | | MARKET-TO-BOOK COST OF EQUITY |
|---|---|---|---|---|---|---|---|---|
| CV | k= 10.5% | (1- 0.4378 )/ | 1.36 | + | 4.86% | = | | 9.19% |
| EAS | k= 09.5% | (1- 0.4200 )/ | 1.28 | + | 4.64% | = | | 8.95% |
| FE | k= 10.0% | (1- 0.4333 )/ | 1.38 | + | 4.88% | = | | 9.00% |
| SO | k= 15.5% | (1- 0.3277 )/ | 2.29 | + | 5.81% | = | | 10.36% |
| AEE | k= 11.0% | (1- 0.2061 )/ | 1.67 | + | 3.84% | = | | 9.06% |
| CNL | k= 12.5% | (1- 0.4000 )/ | 1.62 | + | 4.98% | = | | 9.61% |
| DPL | k= 19.5% | (1- 0.4703 )/ | 2.72 | + | 5.75% | = | | 9.55% |
| EDE | k= 10.5% | (1- 0.2686 )/ | 1.45 | + | 4.06% | = | | 9.36% |
| ETR | k= 09.5% | (1- 0.5422 )/ | 1.40 | + | 6.05% | = | | 9.15% |
| GXP | k= 15.0% | (1- 0.3200 )/ | 2.24 | + | 4.56% | = | | 9.11% |
| HE | k= 09.0% | (1- 0.1733 )/ | 1.50 | + | 3.56% | = | | 8.52% |
| PNW | k= 09.5% | (1- 0.3545 )/ | 1.18 | + | 4.54% | = | | 9.75% |
| | | | | | | | AVERAGE | **9.30%** |
| | | | | | | | STANDARD DEVIATION | **0.47%** |

Note: Equity returns and retention ratios based on Value Line three- to five-year projections.

**ARIZONA PUBLIC SERVICE COMPANY**
**OVERALL COST OF CAPITAL**

| Type of Capital | PERCENT | COST RATE | WT. AVG. COST RATE |
|---|---|---|---|
| Common Equity | 45.14% | 9.50% | 4.29% |
| Long-term Debt | 53.83% | 5.77% | 3.11% |
| Short-term Debt | 1.03% | 3.00% | 0.03% |
| TOTAL CAPITAL | 100.00% | | 7.43% |

PRE-TAX INTEREST COVERAGE = 3.28X

*Assuming the Company experiences, prospectively, an income tax rate of 40%, the pre-tax overall return would be 10.28% [7.43%-(3.11%+0.03%) = 4.29% /(1-40%) = 7.15%+(3.11%+0.03%)]. That pre-tax overall return, 10.28%, divided by the weighted cost of debt (3.11%+0.03%), indicates a pre-tax interest coverage of 3.28 times.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | ) | Docket No. E-A 01345A-03-0437 |

**DIRECT TESTIMONY**

**OF**

**DR. JOHN STUTZ**

**On Behalf of the Arizona**
**Residential Utility Consumer Office**

**Tellus Institute**
**11 Arlington Street**
**Boston, MA 02116-3411**
**Tel: 617/266-5400**

**February 3, 2004**

EXHIBIT
RUCO-6
Admitted

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## 1. INTRODUCTION

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

A. My name is John K. Stutz. My business address is the Tellus Institute (Tellus), 11 Arlington Street, Boston, Massachusetts 02116-3411. I am a vice president at Tellus.

**Q. WHAT IS TELLUS?**

A. Tellus is a non-profit organization. It provides research and consulting services to clients in the public and private sectors in the areas of energy, environmental policy, solid waste management, water resource planning, and sustainable development.

**Q. PLEASE DESCRIBE YOUR EDUCATION AND EMPLOYMENT HISTORY.**

A. I received a B.S. from the State University of New York at Stonybrook in 1965 and a Ph.D. from Princeton University in 1969. Both degrees are in mathematics. After completing my Ph.D., I taught and did research at the Massachusetts Institute of Technology, the State University of New York at Albany where I received tenure, and Fordham University where I held the position of associate professor of mathematics and was co-director of the program in mathematics and economics. I left Fordham to join Tellus where I have been employed since 1976.

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

A. I have extensive experience in the utility industry, particularly as an expert witness. Since 1977 I have appeared before the Federal Energy Regulatory Commission (FERC) as well

as Public Utility Commissions in 39 states, the District of Columbia, and three provinces in Canada. In total, I have appeared in 179 proceedings as shown in Schedule JS-1. Most of my appearances have been in electric utility proceedings. However, I have also testified on gas and telecommunications matters.

In addition to my utility-related activities, since 1988 I have worked regularly for the United States Environmental Protection Agency (EPA), the Organisation for Economic Cooperation and Development (OECD), and various state and local agencies. This work has focused on solid waste management and its impact on the environment.

**Q. PLEASE DESCRIBE YOUR BACKGROUND IN UTILITY RATEMAKING.**

A. My first appearance as an expert witness on ratemaking was in 1979. Since then, I have appeared as a witness on ratemaking in 121 proceedings, as shown in Schedule JS-1. My testimony has addressed a variety of topics, including marginal costs, embedded cost-of-service studies (COSS), service quality standards, and numerous aspects of rate design. Since the early 1980s, I have testified regularly on behalf of the Rhode Island Division of Public Utilities and Carriers on electric ratemaking issues.

My articles and comments on utility-related subjects have appeared in the *Public Utilities Fortnightly, The Electricity Journal*, and elsewhere. My paper with Thomas Austin is cited, in the second edition of Bonbright's *Principles of Public Utility Rates*, as a source of information on electric ratemaking in general and COSS in particular. I was the lead author of *Aligning Rate Design Policies with Integrated Resource Planning*, a report commissioned and published by the National Association of Regulatory Utility

Commissioners (NARUC). As NARUC's preface states, Tellus was selected to prepare this report largely because of my expertise.

**Q. PLEASE SUMMARIZE YOUR EXPERIENCE IN ARIZONA.**

A. My first appearance in Arizona was in 1986. Since then I have testified a total of four times in the state. All of my testimony in Arizona has addressed ratemaking. Three of my four appearances were in APS rate cases.

## 2. SUMMARY AND RECOMMENDATIONS

**Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. My testimony addresses the ratemaking proposals put forward by Arizona Public Service Company (APS or the Company). I will focus primarily on the COSS presented by Mr. Propper, and on the changes in residential class revenue responsibility and rate design he proposes based, in part, on that study. I will also address the changes in Service Schedules proposed by Mr. Rumolo. Dr. Richard Rosen, another witness appearing on behalf of the Residential Utility Consumer Office (RUCO), will address APS' proposals related to the treatment of transmission and fuel and purchased power costs.

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

A. This section presents a summary of my testimony and recommendations. My detailed testimony is presented in the following sections. Section 3 discusses APS' ratemaking proposals. In response to those proposals, Sections 4 to 7 deal with ratemaking principles, COSS methods and results, revenue requirements and rate design. Section 8 addresses APS' proposed changes in the Service Schedules.

**Q. WHAT ARE THE KEY POINTS OF YOUR TESTIMONY?**

A. My key points are presented below. For convenience they are grouped to correspond to the sections of my detailed testimony.

**APS Proposals**

- The range of impacts (i.e., increases and decreases) among and within the residential rates produced by APS' ratemaking proposals is substantial. Increases for some small customers are 3.6 to 4.6 times the residential average.
- There are substantial changes in the customer, kWh and kW charges, which adversely affect the price signals sent by APS' residential rates.

**Ratemaking Principles**

- Bonbright's *Criteria of a Sound Rate Structure* identifies equity and efficiency as primary concerns in ratemaking.
- Mr. Propper only addresses one aspect of equity: cost tracking. Efficiency is never mentioned or discussed.

**COSS Methods and Results**

- APS' proposed treatment of transmission substantially reduces the returns produced by residential rates.
- In choosing allocators for use in his COSS, Mr. Propper has overemphasized demand and neglected energy. As a result, the residential rates of return produced by Mr. Propper's preferred COSS are unrealistically low, compared to other reasonable COSS.

**Revenue Requirements**

- APS' allocation of increases among the residential rates is inconsistent with the pattern of rates of return from the Company's preferred COSS.
- Rates of return produced using a more reasonable choice of allocators support equal increases for all the residential rates.

**Rate Design**

- Mr. Propper's redesign of the residential rates combines selective application of cost tracking with changes based on judgment. The resulting customer impacts are inconsistent with rate stability and are inequitable.
- The price signals created by the residential rates proposed by Mr. Propper discourage conservation and load management, and so are contrary to Bonbright's criterion of efficiency.

**Service Schedules**

- APS proposed new trip charge and its proposed increases in existing fees reaching 300 percent are contrary to Bonbright's criterion of rate stability.
- APS has proposed line extension allowance that would increase the up-front cost for a 1,000 foot extension by $6,500.
- The proposed change in economic feasibility analysis would make all electric developments more attractive. This conflicts with stated public policy.

**Q. WHAT ARE YOUR RECOMMENDATIONS?**

A. My recommendations are the following:

- APS' proposal to eliminate rates E-10 and EC-1 should be rejected.
- All residential rates should receive the average increase (or decrease) allowed by the Commission for APS as a whole.
- Increases (or decreases) should be accommodated by uniform changes in

usage (i.e., per kWh and kW) and customer charges.

- Customer charges should be stated on a monthly, not a daily basis.
- APS proposed new trip charge should be rejected. Increases in other Schedule 1 charges should be limited to 15 percent.
- The line extension allowance for residential customers should be set at $6,000.
- APS' proposed change in usage assumptions for use in economic feasibility analysis for real estate developments should be rejected.

## 3. APS PROPOSALS

**Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S CUSTOMER MIX.**

A. APS divides its retail customers into five major classes: Residential, General Service, Irrigation, Outdoor Lighting, and Dusk-to-Dawn Lighting. Information on the number of customers, total usage and average usage per customer for each major class is provided in Schedule JS-2. As that schedule shows, the residential customers are more numerous and have much lower average usage than those in any of the other major classes.

**Q. PLEASE EXPLAIN WHAT YOU MEAN BY RATEMAKING.**

A. Ratemaking is the process by which a utility's required revenues are translated into the charges which customers pay. Ratemaking involves two steps: development of revenue requirements for individual rates, and the design of charges to recover those requirements.

**Q. PLEASE DESCRIBE APS' GENERAL RATEMAKING APPROACH.**

A. As Mr. Wheeler, APS' lead witness, explains, APS has assigned the proposed increase on an equal percentage basis to all of the Company's major customer classes. However, specific rates receive greater or lesser than average increases, and individual customers experience larger or smaller than average impacts, based on the Company's ratemaking proposals.

**Q. PLEASE DISCUSS THE AVERAGE INCREASES PROPOSED FOR APS' RESIDENTIAL RATES.**

A. In addition to two rates for discounted service for which no changes are proposed, APS has five residential rates. As shown on Schedule JS-3, two rates, E-12 and ET-1, account for 80 percent of the customers and about 75 percent of the residential usage. APS' proposed average increases by rate are also shown on Schedule JS-3. APS has proposed average increases varying from 6.6 to 15.5 percent. For rates E-12, ECT-1R and ET-1 these increases reflect Mr. Propper's choices concerning class revenue responsibility. Mr. Propper recommends that E-10 and EC-1 rates be replaced by E-12 and ECT-1R, respectively. The increases for E-10 and EC-1 reflect the proposed elimination.

**Q. PLEASE DESCRIBE APS' PROPOSED CHANGES IN THE CHARGES INCLUDED IN RESIDENTIAL RATES.**

A. APS has proposed three key changes:

- Customer charges are stated on a daily rather than a monthly basis. Charges for rates E-12, E-10 and EC-1 increase substantially.
- For rates E-12 and E-10, the summer kWh charges are simplified and flattened.
- For rates ECT-1R, ET-1 and EC-1, the ratio of summer on- to off-peak kWh charges is reduced. In the winter, separate on- and off-peak charges are eliminated.

Schedule JS-4 shows the magnitude of the key changes. Schedule JS-5 lists all of the changes proposed by APS for each individual rate.

**Q. DO YOU HAVE ANY COMMENTS ON APS' RATE DESIGN PROPOSALS?**

A. Yes, I do. The changes APS has proposed are numerous and significant. The impacts they create differ significantly within and among rate classes. The variation in impacts within rates is particularly large.

Schedule JS-6 shows the highest and lowest impacts, by season, for customers on each rate. Comparison with Schedule JS-3 shows that the variation within rates is substantially greater than the variation among rate schedules. Schedule JS-7 provides information on the distribution of impacts by usage level within individual rates. The rates with the largest proposed increases—E-12, E-10, and EC-1—all assign the largest increases to customers at the lowest usage levels.

**Q. WHAT QUESTIONS ARE RAISED BY APS' RATEMAKING PROPOSALS?**

A. APS' proposed changes raise three sets of questions.

- What principles has APS relied upon to support its proposed changes? Are APS' proposals consistent with the principles it adopted, and with the principles that should guide ratemaking?
- Are APS' proposed average increases reasonable in light of its own COSS results and the results of other reasonable studies?
- Are the impacts of APS' proposed changes in rate design equitable? Do they adversely affect the price signals sent by APS' residential rates?

The following sections of my testimony address these questions.

## 4. RATEMAKING PRINCIPLES

**Q. WHAT GENERAL PRINCIPLES SHOULD GUIDE RATEMAKING?**

A. Bonbright's *Criteria of a Sound Rate Structure*, reproduced in Schedule JS-8, provide an appropriate general framework for ratemaking. Among his eight criteria, Bonbright identifies three as primary:

- Opportunity to earn a fair rate of return.
- Equity in the apportionment of costs.
- Efficiency in pricing.

In addition, rate stability, another of Bonbright's criteria, is generally accepted as quite important.

**Q. WHAT IS MEANT BY EQUITY?**

A. Equity in ratemaking is described in Bonbright's criterion No. 6. It requires fairness in the apportionment of the total cost of providing service among different customers. "Apportionment" refers to the division of the costs, among rates by the setting of revenue requirements, and among customers within a rate by the charges included in that rate. To test whether an apportionment is fair, two points are generally considered:

- Are differences in apportionment based on differences in the cost to serve?
- If differences in apportionment are made clear to ratepayers, are they likely to be accepted?

Customer acceptance is an important aspect of ratemaking. Bonbright indicates this by including public acceptability among the practical attributes of a sound rate structure listed in his criterion No 1.

**Q. WHAT IS MEANT BY RATE STABILITY?**

A. Rate stability is described in Bonbright's criterion No. 5. It requires that changes in rates result in the minimum of unexpected changes seriously adverse to existing customers. In practice, rate stability is generally interpreted to mean that rates should change gradually.

**Q. ARE EQUITY AND RATE STABILITY RELATED?**

A. Yes. That relationship is made clear in the following description of an equitable distribution, provided by Payton Young in *Equity in Theory and Practice* (Princeton University Press, 1994).

> As we have seen, the perceived equity of a distribution depends on the particulars of the case: on the nature of the goods being divided, on the salient characteristics of the claimants, on their values and beliefs, and on precedent—on what is normal, customer, and expected in situations of that sort.

In stating that the perceived equity of a distribution depends, in part, on the distribution being what is normal, customary and expected, Dr. Young echoes Bonbright's comment that "the best tax is an old tax."

1 **Q. WHAT IS MEANT BY EFFICIENCY?**

2 A. Efficiency in ratemaking is described in Bonbright's criterion No. 8. It requires rates to
3 be effective in discouraging waste while promoting all justified types and amounts of use.
4 The key to efficiency lies in sending the ratepayer a **price signal** which elicits a balanced
5 response. In addressing efficiency, one needs to consider the way in which customers are
6 likely to respond to the individual charges in a rate, and to the rate as a whole.

7

8 **Q. HOW ARE EQUITY, EFFICIENCY, REVENUE SUFFICIENCY AND RATE**
9 **STABILITY ADDRESSED IN THE RATEMAKING PROCESS?**

10 A. Equity is the primary consideration when responsibility for a utility's required revenues is
11 apportioned among the rates. Once an equitable division has been made, efficiency and
12 equity in intra-class apportionment have to be balanced in the design of customer,
13 demand and energy charges applicable to each rate. Rates are designed to recover the
14 share of required revenues allocated to each rate, thus addressing revenue sufficiency. To
15 address stability, changes in both revenue requirements and the charges included in rates
16 are made gradually.

17

18 **Q. WHAT PRINCIPLES GUIDED THE DEVELOPMENT OF APS' RATEMAKING**
19 **PROPOSALS?**

20 A. Mr. Propper did not identify a set of principles that guided the development of his
21 ratemaking proposals. However, he did identify three overall objectives which he "kept in
22 mind":

23 1. Meeting APS' revenue requirement.

2. Improving cost tracking.

3. Unbundling in conformance with the Commission's rules.

Mr. Propper describes "cost tracking" as setting class revenue requirements to produce the system average return and developing customer, demand and energy charges based directly on the unit costs produced by the Company's COSS. COSS tracking is central to Mr. Propper's ratemaking approach. However, Mr. Propper does depart from cost tracking in order to give weight to other factors, particularly rate stability.

Mr. Propper's unbundling proposals focus on the customer charges. Mr. Propper has proposed significant increases in some customer charges in order to fully recover costs for certain services, including billing and metering, which could be provided by parties other than APS.

**Q. DO YOU HAVE ANY COMMENTS ON APS' GENERAL RATEMAKING APPROACH?**

A. Yes, I have two comments:

- While Mr. Propper does not say much about equity, one aspect of equity—charging customers what it costs to serve them—is addressed by his emphasis on cost tracking. The issues with Mr. Propper's treatment of equity via cost tracking are threefold: (1) his preferred COSS does not provide a reasonable standard for cost responsibility; (2) his tracking is highly selective; and (3) there is more to equity than cost tracking. Customer acceptance is also involved.

- Mr. Propper fails to address, or even mention, pricing efficiency as part of his ratemaking process. In light of the substantial changes he has proposed in design of the residential rates, this is a serious omission.

In the remainder of my testimony, I will focus on equity and efficiency, which Bonbright identifies as primary, and on rate stability, which I and Mr. Propper both find to be important. I will not address revenue sufficiency because any rates approved by the Commission will, of course, be designed to recover the required revenues approved by the Commission.

## 5. COSS METHODS AND RESULTS

**Q. PLEASE DESCRIBE THE ROLE COSS PLAY IN RATEMAKING.**

A. Ratemaking involves the setting of revenue requirements and then the development of customer, energy and demand charges applicable to each rate. A COSS produces rates of return which provide part of the basis for setting revenue requirements for each rate. It also produces unit costs that provide part of the basis for setting the charges included in rates.

**Q. HOW IS A COSS ORGANIZED?**

A. The major steps in a COSS are functionalization, classification, and allocation. To begin, expenses and the costs associated with rate-based items are grouped into functional categories (generation, transmission, distribution, etc.). Next, costs in each of these functional categories are classified as being related to energy usage, peak demand, or the number of customers served by the utility. Finally, based on their classification, costs are allocated among the rate classes using allocation factors.

There is broad agreement among analysts that the three-step procedure of funtionalization, classification and allocation is the proper approach to allocate costs among customer classes. Differences emerge over the classification and allocation of certain costs. Here I will focus on APS' classification and allocation of generation and distribution related costs.

**Q. PLEASE EXPLAIN YOUR APPROACH TO THE DEVELOPMENT OF A COSS.**

A. The development of a COSS involves choices concerning classification and allocation. It is tempting to think that there is, in each instance, one right choice, and that any other choice is therefore completely wrong. Such a perspective will inevitably distort any serious discussion of COSS development. No COSS is perfect, or even nearly so. However, there are better and worse ways to classify and allocate costs. The goal is to develop a COSS which reflects causal relationships as fully and correctly as possible in its classification and allocation choices.

**Q. HOW DO COSS TREAT COST CAUSATION?**

A. In a COSS, cost causation is based on **relative use**. Customers are assigned costs associated with the share of utility services and equipment used to serve them. This approach reflects cost causation because, over the long run, utilities construct, maintain, and operate facilities and provide services based as closely as possible on the number of customers they serve, and the demand and usage they face.

**Q. IS RELATIVE USE CONSISTENT WITH BONBRIGHT'S CRITERIA OF EQUITY AND EFFICIENCY?**

A. Yes. Assigning customers responsibility for the cost of the services and facilities used to serve them, is, on its face, equitable. Rates which assign customers costs based on relative use send customers correct "price signals" concerning the cost associated with their presence on the system, and their demand and consumption. Transmitting this information is consistent with the notion of efficient consumption described in Bonbright's criterion No. 8.

**Q. PLEASE DISCUSS THE COSS PRODUCED BY APS.**

A. APS produced two COSS. The first COSS treated transmission as APS had treated it in the past. This study was adjusted to reflect the new treatment of transmission proposed by APS. This produced a second, adjusted study, which Mr. Propper has relied upon for ratemaking purposes.

**Q. DO APS' TWO COSS PRODUCE SIMILAR RESULTS?**

A. No. Unitized rates of return produced by Mr. Propper's preferred study and by the initial, unadjusted COSS are shown in the first two columns of Schedule JS-9. Note the following:

- While the average residential return is similar for both studies, the returns for specific rates are quite different. In particular, the returns for the two rates Mr. Propper proposes to eliminate are above the residential average in the unadjusted study.
- The return for all other (i.e., non-jurisdictional) is substantially lower in the unadjusted study than in Mr. Propper's preferred study.

Dr. Rosen has recommended that APS proposed treatment of transmission be rejected. Consideration of the Company's COSS results supports that view. The results of a COSS should reflect cost causation, not jurisdictional issues as is the case in the APS preferred COSS.

**Q. LEAVING ASIDE THE TRANSMISSION ISSUES, DOES APS' PREFERRED COSS FULLY REFLECT COST CAUSATION?**

A. No. APS allocation of generation and distribution costs is based solely on demand. To reflect cost causation, these costs should be classified as energy and demand related, and allocated on the basis of energy as well as demand.

**Q. HOW DOES APS ALLOCATE GENERATION-RELATED COSTS?**

A. The Company allocates these costs using the 4CP method. The only support for the Company's use of this method is the following statement by Mr. Propper:

> Production related and Transmission related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load. Correspondingly, they are allocated on the basis of the average of the system peak demands occurring in the months of June, July, August, and September.

**Q. DO YOU HAVE ANY COMMENTS ON MR. PROPPER'S STATEMENT?**

A. Yes, I do. In response to discovery, Mr. Propper agreed that APS does not acquire generation assets and incur the associated costs solely to meet the coincident demand in the four summer months. However, he did not identify the other factors that affect APS' decisions in this area.

**Q. DO OTHER WITNESSES ADDRESS APS' GENERATION PLANNING PROCESS?**

A. Yes, they do. Mr. Bhatti, the Company's Vice President of Resource Planning, describes APS' approach to system planning as follows:

> The primary goals of APS Resource Planning are to provide our customers with an adequate supply of reliable power at a **reasonable cost** and at a reasonable level of risk. (emphasis added)

**Q. HOW IS THE ISSUE OF COST REFLECTED IN THE CHOICE OF GENERATION AND TRANSMISSION RESOURCES?**

A. Utility planners can choose different types of generating plants to meet customer loads. Peaking plants offer the advantage of lower capital costs but they are generally more expensive to run. Baseload plants, on the other hand, are more costly to build but have lower running costs. The choice of plant additions requires detailed analysis. However, underlying that analysis is the simple point that utility planners will only build more expensive baseload plants if they produce sufficient operating cost savings to outweigh their higher capital costs. Thus, the additional cost of baseload plants is justified by potential energy cost savings. The same is true for transmission lines. Both their role in meeting peak demand and their capacity to reduce costs by providing access to economic energy sources is considered.

If APS only considered peak demands, then peaking plants would predominate in its generation mix because they are the cheapest plants to build to meet a given demand. However, as Mr. Wheeler, APS' lead witness points out, the APS generation mix contains 44 percent coal as well as 31 percent nuclear units. The cost of coal and nuclear plants cannot be justified solely to meet peak demand.

**Q. HOW DO THESE PLANNING CONSIDERATIONS AFFECT THE CLASSIFICATION AND ALLOCATION OF GENERATION- RELATED COSTS?**

A. Generating plants are built to meet peak demand, with adequate reserves, and to produce energy at least cost. For investments made to provide energy cost effectively, it is the customer's energy consumption, not their peak demand, that is relevant. Accordingly, generation-related costs should be classified as energy and demand related. Peak demand and energy consumption should be reflected in their allocation.

**Q. DOES CONSIDERATION OF RELATIVE USE SUPPORT THE ALLOCATION OF GENERATION-RELATED COSTS BASED ON DEMAND AND ENERGY?**

A. Yes. Customers rely on APS' generation and transmission facilities to meet their peak demands and to provide electricity in all the hours. Allocating generation-related costs based solely on demand during the hours of coincident peak demand in June, July, August, and September does not reflect customers' relative use of the system.

**Q. HOW DOES THE FAILURE TO ALLOCATE GENERATION RELATED COSTS BASED ON ENERGY AND DEMAND AFFECT COSS RESULTS?**

A. The basic effect is to overstate the cost of serving low load factor customers and understate the cost of serving high load factor customers. This point is illustrated in the example presented in Schedule JS-10.

**Q. PLEASE DESCRIBE THE EXAMPLE USED IN SCHEDULE JS-10.**

A. The example is based on a simple, hypothetical electric utility that has two customers, A and B. A has a constant demand of 100 MW during the period 10 a.m. to 2 p.m. During the remainder of the day its demand is zero. B has a demand of 100 MW all day. These demands are assumed to be the same, 365 days per year, year in and year out. The utility serves its two customers from two generating units; a 100 MW peaker and a 100 MW baseload unit. The plant (i.e., capital) costs and the production costs assumed for the two units are shown in the top position of Schedule JS-10. For simplicity, the example assumes that each of the units can run at 100 percent of capacity with 100 percent reliability at all times.

**Q. PLEASE EXPLAIN THE COSTS SHOWN IN THE BOTTOM HALF OF SCHEDULE JS-10.**

The bottom half of Schedule JS-10 shows the generation costs allocated to A and B under various assumptions. The schedule begins by establishing bounds on the cost to serve A and B: it would cost **at most** $.08 per kWh to serve A using only the peaker, and **at least** $.05 per kWh to serve B using only the baseload unit. Next the schedule shows the result of applying APS' 4CP method to this example. The cost allocated to A is $.147 per kWh, much more than the cost to serve A using the peaker alone. The cost assigned to B is $.039, less than the cost to serve B from the baseload unit alone. Finally, the schedule shows the result of classifying varying parts of the plant cost as energy-related and allocating it on the basis of usage rather than peak demand. This change in classification eventually moves the costs allocated to A and B into the $.05 to $.08 per kWh range.

**Q. PLEASE DISCUSS THE RESULTS SHOWN IN SCHEDULE JS-10.**

A. Customer A has a very low load factor, 16.7 percent. B has a 100 percent load factor, the highest possible. The assumption of very different load factors makes the consequences of using different cost allocation methods quite clear. Classification of generation related costs as both energy and demand related results in an equitable cost allocation to customers with differing load factors. Mr. Propper's 4CP method results in a clearly inequitable allocation.

**Q. HOW WOULD THE RESULTS OF MR. PROPPER'S PREFERRED COSS CHANGE IF GENERATION RELATED COSTS WERE ALLOCATED ON THE BASIS OF ENERGY AND DEMAND?**

A. To address this point I requested that APS rerun Mr. Propper's preferred COSS with the 4CP allocator replaced by the average of 4CP and energy. The results are shown in the third column of Schedule JS-9. Allocating generation-related costs based on energy and demand increases the rate of return for all the residential rates.

**Q. TURNING TO A NEW TOPIC, PLEASE DISCUSS THE ALLOCATION OF DISTRIBUTION-RELATED COSTS.**

A. Distribution-related costs are the capital costs and operations and maintenance expenditures associated with the transformers, poles, and wires that allows electricity from the transmission system to reach the customer's service drop. Historically, the allocation of these costs has attracted less attention than the allocation of generation-

related costs. When one focuses on these costs, an issue come to light: should one classify these costs as demand- and energy-related, as was done for generation-related costs? In my view, distribution costs should be classified as energy and demand related and allocated accordingly.

Classification of part of distribution costs as energy-related is consistent with the principle of relative use. A customer's use of the distribution system is not limited to the few hours of the year when the customer's demand contributes to peak demand. Customers make more or less continuous use of the distribution system to obtain electricity. This being the case, energy and demand should be reflected in the allocation of distribution related costs.

**Q. IS IT POSSIBLE TO INTRODUCE ENERGY USE INTO THE ALLOCATION OF DISTRIBUTION COSTS?**

A. Yes. To introduce energy, one can average APS allocators based solely on demand with energy. The results of that change are shown in the final column of Schedule JS-9. Allocating both generation and distribution related costs based on energy and demand produces further increases in the residential rates of return.

**Q. PLEASE SUMMARIZE THE RESULTS SHOWN IN SCHEDULE JS-9.**

A. The results in Schedule JS-9 show three things. First, the results in columns 1 and 2 show that rejecting APS' proposed treatment of transmission, based on the recognition that jurisdictional changes should not be allowed to distort the causal relationships in COSS, would result in higher rates of return for residential rates. The results in columns

3 and 4 show that using energy and demand to allocate generation and distribution costs will also raise residential rates of return. Taken as a whole, the results in Schedule JS-9 show that the returns for the residential rates are better than those shown in Mr. Propper's preferred study.

Second, the results in Schedule JS-9 support rejection of Mr. Propper's proposal that Rates E-10 and EC-1 be eliminated because they produce low rates of return and so may create a burden on other customers. In fact, as the results in columns 1 and 2 of Schedule JS-9 show, the low returns are due to Mr. Propper's transmission-related adjustments to the COSS. In his unadjusted study, these classes produce returns above the residential average. 14.6 percent of APS' residential customers take service on these two rates. Eliminating them would impose increases substantially above the residential average on these customers. A jurisdictional shift in costs does not provide an adequate justification for the imposition of such a burden.

Finally, I would draw the Commission's attention to the dramatic variation in all other (i.e. non-jurisdictional) returns shown in Schedule JS-9. If one accepts the point that energy and demand are relevant to the allocation of generation-related costs, then non-jurisdictional sales are not even covering their full cost, let alone producing a contribution to APS return. The Commission may want to look more closely, to see whether non-jurisdictional sales are priced appropriately.

## 6. REVENUE RESPONSIBILITY

**Q. PLEASE DESCRIBE APS' PROPOSED CHANGES IN REVENUE RESPONSIBILITY.**

A. APS has proposed roughly equal increases for all of the major customer classes including residential. However, for the individual residential rates, a wide range of average increases are proposed. Mr. Propper does not explain how the specific increases proposed were developed. The only rationale offered for the proposed increases is improved cost tracking.

**Q. ARE MR. PROPPERS PROPOSED INCREASES CONSISTENT WITH COST TRACKING?**

A. No, they are not consistent with cost tracking, even if one accepts Mr. Propper's preferred COSS results. For the residential rates, Schedule JS-11 shows the increases proposed by Mr. Propper, and the rates of return, produced by Mr. Propper's preferred COSS. To make it easier to see how the increases and returns vary, each is expressed as a percentage of the residential average. Note the following:

- Rate ECT-1R produces essentially the same return as residential customers as a whole, but receives a much lower than average increase.
- Rates ET-1 and EC-1 produce essentially the same rate of return, but receive substantially different increases.

- Rate EC-1 produces a better (i.e., higher) return than Rate E-10, but receives a greater increase.

The data in Schedule JS-11 do not show cost tracking at the rate level. Indeed, the increases proposed by APS are so far from cost tracking that one must consider them to be essentially the product of "judgment" rather than cost tracking.

**Q. WHAT DO YOU RECOMMEND?**

A. I recommend that all residential rate schedules receive the average change approved by the Commission for APS as a whole. The "change" could be an increase or a decrease, depending on the Commission's decision concerning the Company's required revenues.

**Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

A. The considerations of rate stability and continuity that Mr. Propper relied upon to support uniform increases for the major customer classes are equally applicable at the rate level. Their application supports my proposal. My proposal is also supported by the results in Schedule JS-9. As the results show, which rates produce returns above or below the residential average varies depending on which COSS one considers. In that situation a uniform change is reasonable.

## 7. RATE DESIGN

**Q. PLEASE BRIEFLY REVIEW THE CHANGES IN RESIDENTIAL RATE DESIGN PROPOSED BY APS.**

A. APS proposes three key changes in residential rate design:

- A shift to daily customer charges and substantial increases in some of those charges;
- Flattening of summer season inclining block charges;
- Reduction or elimination of on- to off-peak differentials in energy (i.e. per kWh) charges.

These changes were discussed earlier, in Section 3 of my testimony. Together with other minor changes in rate design, they create impacts on individual customers which vary greatly within each residential rate, as shown in Schedules JS-6 and 7.

**Q. HOW DID MR. PROPPER DEVELOP HIS PROPOSED CHARGES?**

A. The point of departure for Mr. Propper was his preferred COSS. In his testimony, he states that, if the cost-of-service study were the only consideration for setting rates, the charges in all rates would be the unit costs from the COSS, expressed as demand, energy, and customer charges. However, his proposed charges depart from the unit costs, in part, so that the increases that individual customers experience can be moderated to the extent Mr. Propper finds "reasonable."

1 **Q. WHAT ISSUES ARE RAISED BY MR. PROPPER'S RATE DESIGN**
2 **PROPOSALS?**
3 A. The customer impacts associated with Mr. Propper's proposals raise issues of rate
4 stability and equity. The changes in the price signals due to his changes raise questions of
5 efficiency.
6
7 **Q. PLEASE DISCUSS THE RATE STABILITY AND EQUITY ISSUES.**
8 A. In considering rate stability and equity, it is important to recognize that Mr. Propper's
9 proposals rest substantially on **judgment**. Consider Rate E-12. As shown in Schedule
10 JS-5, two key changes are proposed for this rate. First, there is the increase in the
11 customer charge, which Mr. Propper bases directly on unit cost data from the COSS.
12 Second, there is the change in the first and second block charge. That reflects
13 "simplification," not improved cost tracking. A mixture of judgment and cost tracking
14 accounts for APS' redesign of the other residential rates. As I showed earlier, Mr.
15 Propper's proposals concerning revenue responsibility rest primarily on judgment, not
16 cost tracking. Once one pulls together the two steps in ratemaking—setting revenue
17 responsibility and designing the rates—one sees that APS' residential ratemaking as a
18 whole rests substantially on judgment. Judgment is not sufficient justification for Mr.
19 Propper's proposals, given the impacts that the proposals create.
20 Mr. Propper's proposals result in increases of up to 44.3 percent for some
21 customers and decreases of up to 3.8 percent for others. Variations of this magnitude are
22 contrary to any reasonable notion of rate stability. Because they are due in large part to

judgment rather than cost tracking, they are also inequitable, and are likely to be perceived as such.

**Q. WHY ARE APS' PROPOSALS LIKELY TO BE PERCEIVED AS INEQUITABLE?**

A. A key feature of APS' proposals is the very high increases they create for small residential customers, and the decreases they provide for very large customers. Were customers informed of APS' proposals, particularly for the treatment of small customers, they would be unlikely to find them acceptable. To appreciate this point it is useful to apply the **6:00 News Test**. Simply imagine that the 6:00 PM TV news included the following item:

- Today APS announced that it will share a proposed $85 million increase in the cost of residential electric service by assigning small residential customers 3.6 to 4.6 times the average increase. This will allow the Company to provide large residential customers with a decrease.

In my opinion, the public is likely to see the arrangement described as unacceptable.

**Q. PLEASE DISCUSS THE ISSUE OF EFFICIENCY.**

A. The key to efficiency lies in sending the ratepayer a price signal which elicits a balanced response. In addressing efficiency, one needs to consider the way in which customers are likely to respond to the individual charges in a rate, and to the rate as a whole. The proposed dramatic increases in customer charges send the customer a price signal to

ignore their level and pattern of usage. The other changes proposed by Mr. Propper send similar price signals:

- The flattening of the summer inclining block charges on rates E-12 and E-10 sends the message that increases in usage are less important than they were before.
- The elimination of the winter on- and off-peak charges and the lowering of the summer on-to-off-peak differential sends customers on rates ET-1 and ECT-1R the message that load shifting is less important than previously.

The price signals sent by Mr. Propper's proposed residential rates may adversely affect customer investment in conservation or load management.

**Q. PLEASE EXPLAIN YOUR COMMENT ABOUT CUSTOMER CHARGES.**

A. In response to an increase in the customer charge, the ratepayers' only option is to pay the higher amount. In contrast, an increase in a charge per kWh or kW provides an opportunity for increased savings for a customer who invests in more efficient equipment or changes consumption patterns.

In considering this point, it is useful to consider the following **Gas Station Example**. Suppose that Arizona "redesigned" gasoline pricing so that there was a fixed charge, say $5, for all gasoline purchases, and a discount on price per gallon. Would such a change help discourage wasteful use while promoting all justified usage, thus making pricing more efficient in the sense Bonbright uses the term? In my opinion, the answer is "no." Instead, increased usage would appear attractive and the impulse to

avoid wasteful usage would be undercut. Increasing customer charges dramatically, as APS proposes for rates E-12, E-10, and EC-1, is likely to have the same effect as the change in gasoline pricing in my example: increased usage will become more attractive and the impulse to avoid waste will be undercut.

**Q. IS THE ADEQUACY OF CUSTOMER INVOLVEMENT IN CONSERVATION AND LOAD MANAGEMENT A REASONABLE CONCERN?**

A. Yes. It is important to understand that now, as in the past, the concern is under-, not over-involvement in conservation and load management. This is made clear in *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, prepared for NARUC by Richard Cowart in 2001. As Mr. Wheeler points out on pages 48 to 50 of his testimony, APS has a number of programs and joint efforts that are designed to inform customers about energy conservation and load management opportunities, and to promote energy efficiency.

**Q. WHY ARE THESE APS PROGRAMS AND EFFORTS RELEVANT HERE?**

A. It would be inappropriate to make changes in the design of APS' residential rates, such as those proposed by Mr. Propper, which could undercut APS efforts to promote efficiency. To underline this point, I would direct the Commission's attention to the graph of current and anticipated APS load growth provided in Mr. Wheeler's Attachment SMW-2. In the face of the rapid growth shown there, is it reasonable to redesign residential rates to send price signals to ratepayers to reduce their energy conservation and load management efforts? In my view, the answer is "no".

1

2 **Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ABOUT APS'**

3 **PROPOSED CHANGES IN CUSTOMER CHARGES?**

4 A. Yes, I do. on page 17 Mr. Propper noted that it may be necessary to "revisit" the

5 customer charges proposed in this case. In response to RUCO 16.23 he

6 acknowledged that this might result in changes in the currently proposed charges.

7 Those changes could not be estimated at this time. Under these circumstances,

8 changing charges substantially now is not compatible with Bonbright's criterion

9 of rate stability.

10 I would also like to comment on Mr. Propper's proposal to change

11 customer charges from a monthly to a daily basis. APS' residential rates are

12 currently quite complex, containing multi-block kWh charges, demand charges

13 and/or time-of-use energy charges. Adding a variable customer charge will

14 simply make it that much harder for customers to discern the price signals sent by

15 these rates. This will make the rates less efficient. In addition, changing to a

16 daily customer charge is contrary to Bonbright's practical criterion of simplicity,

17 and to Mr. Propper's own goal, stated in a response to RUCO 16.17, of

18 developing rates that can be understood by customers.

19

20 **Q. DO YOU HAVE ANY COMMENTS ABOUT RATES E-12 AND E-10?**

21 A. Yes, I do. In order to appreciate how customers might respond to the price signals

22 provided by these rates, it is useful to look at the average cost of electricity on these rates,

23 currently and with APS' proposed changes. Schedule JS-12 provides this information. To

facilitate comparison between average costs before and after APS' proposed changes, the average costs are indexed by dividing by the average cost for 200 kWh per month, the lowest level of usage APS addresses in its bill impact studies.

The graphs in Schedule JS-12 show that APS' proposal enhances the **quantity discount** present in APS' current rates. A quantity discount is created whenever the average cost per kWh declines as usage increases. In the summer, the decline in average costs for the proposed rates is much greater than for the current rates. Thus, the proposed rates offer larger quantity discounts to more of those served on E-12 and E-10. In the winter, the effects are similar, but less dramatic. 52.6 percent of APS' residential customers are served on rates E-12 and E-10. I would ask the Commission whether it finds it reasonable to provide customers served on these rates with enhanced quantity discounts, encouraging greater use particularly in the summer. In my view, the answer is "no."

**Q. HOW DO YOU RECOMMEND APS RESIDENTIAL RATES BE REDESIGNED?**

A. I recommend uniform increases in all usage (i.e., per kWh and kW) and customer charges. This approach avoids the issues of rate stability and equity, and of efficiency created by APS' proposals.

- All customers on a rate will be affected equally. The extreme impacts on small customers due to APS proposal will be avoided.
- The rates will send the same price signals as are sent by APS' current rates. Adverse impacts on conservation and load management will be avoided.

1 **Q. DO YOU HAVE ANY FINAL COMMENTS ON THE CHARGES INCLUDED IN**
2 **APS' RATES?**
3 A. Yes, I do. Under the heading of "other cost elements" Mr. Propper addresses a number
4 of charges including the Systems Benefit Charge (SBC) and the Returning Customer
5 Direct Assignment Charge (RCDAC). The Company has been directed by the
6 Commission to address the level of these charges in this proceeding, but has yet to do so.
7 I simply wish to note that I may respond to this portion of the Company's testimony once
8 it is available.

## 8. SERVICE SCHEDULES

**Q. PLEASE BRIEFLY DISCUSS APS SERVICE SCHEDULES.**

**A.** APS' service schedules address the general terms and conditions for utility service and policies on specific issues such as line extensions. I will address certain changes Mr. Rumolo has proposed in Schedules 1 and 3.

**Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 1.**

A. APS is proposing a new trip charge to be assessed when an APS employee attempts to provide a customer-requested service, but is unable to provide it for a variety of reasons. APS also proposes to increase certain existing charges, to reflect current costs.

**Q. DO YOU HAVE ANY COMMENTS ON MR. RUMOLO'S PROPOSED CHANGES TO SCHEDULE 1?**

A. Yes, I do. Mr. Rumolo has proposed the addition of a new fee and increase in existing fees as part of an effort to improve cost tracking. As in other aspects of ratemaking, one must balance the desire for better cost tracking against other legitimate concerns reflected in Bonbright's criteria. Mr. Rumolo's proposals require adjustment to strike this balance.

The criterion of rate stability, particularly the minimization of unexpected changes seriously adverse to existing customers, is particularly relevant when considering the proposed changes in Schedule 1. The new, $17.50 trip charge is certainly an unexpected and adverse change. Further, as shown in Schedule JS-13, a number of proposed increases in existing charges far exceed the average increase in residential rates.

Increases in the range of 80 to 300 percent are certainly adverse to those who will pay them, and are likely to be unexpected as a result of a proceeding in which the average residential increased proposed by APS is less than 10 percent.

**Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE PROPOSED CHANGES IN SCHEDULE 1 CHARGES?**

A. I recommend that the new trip charge be rejected and that the increases in existing charges be capped at 15 percent. A fifteen percent increase will send a price signal that costs are increasing, while insuring that customer impacts are reasonable. In making this recommendation I note that insuring reasonable impacts was one of Mr. Propper's rate design goals.

**Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO SCHEDULE 3.**

A. Schedule 3 is APS' line extension policy. The current policy has three main elements: (1) a 1000 foot free allowance for residential extensions, (2) a revenue test for extensions over 1,000 feet when the cost is under $25,000, and (3) an economic feasibility analysis when the cost exceeds $25,000 or the extension is not subject to the footage allowance or revenue test. Under APS' proposal, the footage allowance is replaced by a $3,500 allowance. If the cost exceeds $3,500, but is under $25,000, the customer will be required to make a non-refundable payment to cover the excess. Line extensions costing over $25,000 will be evaluated based on an economic feasibility analysis.

APS is also proposing changes to its current economic feasibility analysis for new real estate developments. In addition to using only distribution revenue and expenses in

the analysis, APS is changing the underlying usage assumption. Currently, APS assumes that the customers in a new development are all-electric. Instead, APS proposes to run the economic analysis under a dual-fuel or all-electric basis, depending on the specifics of the development.

**Q. WILL APS' PROPOSED CHANGE IN LINE EXTENSION POLICY HAVE A SUBSTANTIAL EFFECT ON RESIDENTIAL CUSTOMERS' COSTS?**

A. Yes, it will. As Mr. Rumolo notes, the cost of a typical 1000-foot overhead extension, provided without a customer payment, today, is approximately $10,000. Thus the proposed change could add up to $6,500 to the cost a customer faces for a long line extension.

**Q. DO YOU HAVE ANY COMMENTS ON THE PROPOSED CHANGE IN THE LINE EXTENSION POLICY FOR RESIDENTIAL CUSTOMERS?**

A. Yes, I do. APS' proposed change to a dollar allowance is reasonable. The issue is at what level should the allowance be set. In considering this point, the nature of APS' service territory needs to be considered. As Mr. Wheeler points out, APS serves a large, sparsely populated area in addition to the urbanized Valley region. On average, APS serves just 19 customers per square mile. In contrast, SRP and Tucson Electric Power – the other two large Arizona electric utilities – serve 233 and 282 customers per square mile, respectively. Mr. Rumolo's suggestion of an allowance similar to that provided by other Arizona utilities is not supported by Mr. Wheeler's remarks.

1 **Q. WHAT ALLOWANCE DO YOU RECOMMEND?**

2 A. I recommend a $6,000 allowance. $6,000 is roughly half way between the approximately
3 $10,000 cost of a 1,000 foot overhead extension, and the average current APS investment
4 per customer of $1,500 cited by Mr. Rumolo. The $6,000 balances the desire to limit the
5 impact of the allowance on current average cost against the need for rate stability.

6

7 **Q. DO YOU HAVE ANY COMMENTS ON THE PROPOSED CHANGE IN THE**
8 **ECONOMIC FEASIBILITY ANALYSIS?**

9 A. Yes, I do. The change proposed by Mr. Rumolo will reduce the up-front cost of an all-
10 electric development, compared to an otherwise comparable dual-fuel development. I
11 would simply ask the Commission if this is the price signal that is appropriate to send to
12 developers, and to customers seeking new homes in APS' service territory. In
13 considering this point, it may be useful to reflect a public policy concerning dual-fuel
14 capacity, stated in Title 40, Section F of the Arizona Statutes, which states the following:

15 F. Except as provided in subsection G of this section, during the
16 initial construction of a residential structure, electric and natural gas
17 facilities at a minimum shall be installed in and to the structure in a
18 manner that provides the retail energy consumer ultimately residing in the
19 structure with the capability to choose between electricity and natural gas
20 as an energy source for each appliance application.

21 I would ask the Commission to consider whether approving an economic
22 feasibility test which could lower the "up front" cost of all electric developments
23 is consistent with the requirement to provide choice between gas and electricity.

In my view, the answer is "no." If APS wished to change its economic feasibility analysis, it should be required to do so in a fashion that does not make all electric developments more attractive.

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

A. Yes, it does.

# SUMMARY OF EXPERIENCE
## Dr. Stutz's Testimony Before Regulatory Commissions

| | Ratemaking | Planning | | Ratemaking | Planning |
|---|---|---|---|---|---|
| Alabama | 1 | | Minnesota | 2 | |
| Arizona | 4 | | Mississippi | 1 | |
| Arkansas | 1 | | Nevada | 4 | 3 |
| Canada | 9 | | New Jersey | 7 | |
| Colorado | 5 | 4 | New York | | 5 |
| Connecticut | 3 | 3 | New Mexico | 6 | |
| Delaware | 2 | | New Hampshire | 2 | |
| District of Columbia | 1 | | North Carolina | 3 | |
| FERC | | 3 | Ohio | 5 | 1 |
| Florida | 1 | 3 | Oregon | 1 | |
| Georgia | | 1 | Pennsylvania | 2 | 4 |
| Hawaii | | 1 | Rhode Island | 20 | 3 |
| Illinois | 1 | 3 | South Carolina | 1 | |
| Iowa | 1 | | Tennessee | 1 | |
| Kansas | 1 | | Texas | 7 | 1 |
| Kentucky | 1 | | Utah | 2 | |
| Louisiana | 2 | | Vermont | 3 | 1 |
| Maine | 11 | 5 | Virginia | 1 | |
| Maryland | 2 | | Washington | | 1 |
| Massachusetts | 1 | 4 | West Virginia | 3 | |
| Michigan | 2 | 12 | Wisconsin | 1 | |
| | | | | Total Ratemaking 121 | Total Planning 58 |

# OVERVIEW OF APS' MAJOR CUSTOMER CLASSES

| | Customer | | Usage | | Average Use |
|---|---|---|---|---|---|
| | Number (Thousands) | Percent of Total | Level (GWH) | Percent of Total | Per Customer (kWh per Month) |
| Residential | 814.7 | 88.9 | 10,587 | 45.1 | 1,083 |
| General Service | 100.2 | 10.9 | 12,706 | 54.2 | 10,566 |
| Irrigation | .3 | 0.0 | 31 | .1 | 7,741 |
| Outdoor Lighting | 1.0 | .1 | 101 | .4 | 8,809 |
| Dusk-to-Dawn Lighting | NA | NA | 38 | .2 | NA |
| Total - Retail | 916.2 | 100.0 | 23,462 | 100.0 | 2,134 |

## AVERAGE INCREASE BY RATE

| | Customers (Percent of Total) | Usage (Percent of Total) | Avg. Use Per Month (kWh) | Average Increase (Percent) | Percent of Residential Average |
|---|---|---|---|---|---|
| Redesigned Rates: | | | | | |
| E-12 | 46.0 | 30.1 | 708 | 6.6 | 68 |
| ECT-1R | 5.3 | 11.4 | 2,335 | 7.0 | 72 |
| ET-1 | 34.0 | 44.6 | 1,420 | 11.2 | 115 |
| Rates Proposed For Elimination | | | | | |
| E-10 | 11.6 | 8.5 | 797 | 14.6 | 150 |
| EC-1 | 3.1 | 5.4 | 1,899 | 15.5 | 159 |
| All Residential | 100.0 | 100.0 | 1,083 | 9.7 | 100 |

Note: The residential rates in this and the following schedules appear in ascending order, based on the average increases proposed by APS.

## KEY CHANGES IN CHARGES PROPOSED BY APS
## (Percent Change)

| | Level of Customer Charges | Ratio of Summer kWh Block Charges | | Ratio of On- to Off-Peak KWh Charges | |
|---|---|---|---|---|---|
| | | Second to First | Third to First | Summer | Winter |
| Redesigned Rates: | | | | | |
| E-12 | 64.4 | -39 | -23 | NA | NA |
| ECT-1R | 0 | NA | NA | -9.4 | -29.7 |
| ET-1 | -1.6 | NA | NA | -36.0 | -61.0 |
| Rates Proposed For Elimination | | | | | |
| E-10 | 64.4 | -38 | -11 | NA | NA |
| EC-1 | 50.0 | NA | NA | 63.0 | 0 |

## CHANGES PROPOSED BY APS: RATE E-12

| | Charges | | Percent |
|---|---|---|---|
| | **Current** | **Proposed** | **Change** |
| Customer ($ per Month) | 7.50 | 12.33 | 64.4 |
| Energy (¢ per kWh) | | | |
| Summer | | | |
| First 400 kWh | 7.376 | 8.764 | 18.8 |
| Next 400 kWh | 10.281 | 8.764 | -14.8 |
| Additional kWh | 11.991 | 11.006 | -8.2 |
| Winter | | | |
| All kWh | 7.394 | 7.105 | -3.9 |
| Ratio of Summer kWh Block Charges | | | |
| Second to First | 1.39:1 | 1.0:1 | -39 |
| Third to First | 1.63:1 | 1.26:1 | -22 |

# CHANGES PROPOSED BY APS: RATE ETC-1R

| | Charges | | Percent |
|---|---|---|---|
| | **Current** | **Proposed** | **Change** |
| Customer ($ per Month) | 15.00 | 15.00 | 0 |
| Demand ($ per kW) | | | |
| Summer | 11.33 | 11.16 | -1.5 |
| Winter | 8.11 | 8.12 | 0.1 |
| Energy (¢ per kWh) | | | |
| Summer | | | |
| All – Demand Cap | 8.912 | NA | NA |
| On-Peak | 4.572 | 5.279 | 15.5 |
| Off-Peak | 2.543 | 3.248 | 27.7 |
| Winter | | | |
| All – Demand Cap | 6.488 | NA | NA |
| On-Peak | 3.618 | 3.069 | -15.2 |
| Off-Peak | 2.543 | 3.069 | 20.7 |
| Ratio: On-to Off-Peak Energy Charges | | | |
| Summer | 1.80:1 | 1.63:1 | -9.4 |
| Winter | 1.42:1 | 1.00:1 | -29.7 |

## CHANGES PROPOSED BY APS: RATE ET-1

| | Charges | | Percent |
|---|---|---|---|
| | **Current** | **Proposed** | **Change** |
| Customer ($ per Month) | 15.00 | 14.76 | -1.6 |
| Energy (¢ per kWh) | | | |
| Summer | | | |
| On-Peak | 12.815 | 12.326 | -3.8 |
| Off-Peak | 4.129 | 6.209 | 50.4 |
| Winter | | | |
| On-Peak | 10.656 | 6.882 | -64.6 |
| Off-Peak | 4.129 | 6.882 | 66.7 |
| Ratio: On-to Off-Peak Energy Charges | | | |
| Summer | 3.10:1 | 1.99:1 | -36.0 |
| Winter | 2.58:1 | 1.0:1 | -61.0 |

## CHANGES PROPOSED BY APS: RATE E-10

| | Charges | | Percent |
|---|---|---|---|
| | Current | Proposed | Change |
| Customer ($ per Month) | 7.50 | 12.33 | 64.4 |
| Energy (¢ per kWh) | | | |
| Summer | | | |
| First 400 kWh | 6.682 | 8.764 | 31.2 |
| Next 400 kWh | 9.189 | 8.764 | -4.6 |
| Additional kWh | 9.440 | 11.006 | 16.6 |
| Winter | | | |
| All kWh | 7.609 | 7.105 | -7.6 |
| Ratio of Summer kWh Block Charges | | | |
| Second to First | 1.38:1 | 1.0:1 | -38 |
| Third to First | 1.41:1 | 1.26:1 | -11 |

## CHANGES PROPOSED BY APS: RATE EC-1

| | Charges | | Percent |
|---|---|---|---|
| | **Current** | **Proposed** | **Change** |
| Customer ($ per Month) | 10.00 | 15.00 | 50.0 |
| Demand ($ per kW) | | | |
| Summer | 9.84 | 11.16 | 13.4 |
| Winter | 7.06 | 8.12 | 15.0 |
| Energy (¢ per kWh) | | | |
| Summer | | | |
| All – Demand Cap | 7.872 | NA | |
| On-Peak | 3.827 | 5.279 | 37.9 |
| Off-Peak | 3.827 | 3.248 | -15.1 |
| Winter | | | |
| All – Demand Cap | 5.640 | NA | NA |
| On-Peak | 3.176 | 3.069 | -3.4 |
| Off-Peak | 3.176 | 3.069 | -3.4 |
| Ratio: On-to Off-Peak Energy Charges | | | |
| Summer | 1.0:1 | 1.63:1 | 63 |
| Winter | 1.0:1 | 1.0:1 | 0 |

# IMPACTS ON INDIVIDUAL CUSTOMERS

| | Percent Impacts on Individual Customers | | | | Impacts as Percent of Residential Average Increase | |
|---|---|---|---|---|---|---|
| | ----- Summer ----- | | ------ Winter ------ | | | |
| | High | Low | High | Low | Maximum | Minimum |
| Redesigned Rates: | | | | | | |
| E-12 | 35.3 | -3.7 | 20.2 | -1.1 | 364 | -38 |
| ECT-1R | 12.8 | 4.3 | 5.0 | 1.9 | 132 | 20 |
| ET-1 | 13.3 | 6.4 | 12.5 | 5.3 | 137 | 56 |
| Rates Proposed For Elimination | | | | | | |
| E-10 | 44.3 | 18.2 | 17.9 | -3.8 | 457 | -39 |
| EC-1 | 18.2 | 10.5 | 17.4 | 4.0 | 187 | 41 |
| All Residential | 35.3 | -3.7 | 20.2 | -3.8 | 457 | -39 |

# IMPACTS BY CUSTOMER SIZE - RATES WITH ENERGY CHARGES

| Usage (kWh per Month) | Percent Change | | | | | |
|---|---|---|---|---|---|---|
| | E-12 | | E-10 | | ET-1 | |
| | Summer | Winter | Summer | Winter | Summer | Winter |
| 200 | 35.3 | 20.2 | 44.3 | 17.9 | 6.4 | 5.3 |
| 600 | 13.4 | 6.7 | 24.1 | 4.1 | 10.4 | 9.2 |
| 1300 | 1.3 | 2.0 | 17.4 | -0.6 | 12.1 | 11.0 |
| 3000 | -3.7 | -1.1 | 18.2 | -3.8 | 13.3 | 12.5 |

## IMPACTS BY CUSTOMER SIZE - RATES WITH ENERGY AND DEMAND CHARGES

| Customer Characteristics | | | Percent Change | | | |
|---|---|---|---|---|---|---|
| | | | ECT-1R | | EC-1 | |
| Demand (kW) | Load Factor (Percent) | Usage (kWh) | Summer | Winter | Summer | Winter |
| 3 | 20 | 438 | 4.3 | 1.9 | 18.2 | 17.4 |
| 3 | 75 | 1,643 | 11.3 | 4.3 | 13.6 | 8.4 |
| 15 | 20 | 2,190 | 5.3 | 2.5 | 13.0 | 10.4 |
| 15 | 75 | 8,213 | 12.8 | 5.0 | 10.5 | 4.0 |

## CRITERIA OF A SOUND RATE STRUCTURE

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

6. Fairness of the specific rates in the appointment of total costs of service among the different customers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

Source: James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

# UNITIZED RATES OF RETURN PRODUCED BY DIFFERENT COSS

| | Study Relied on by APS | APS' Initial Unadjusted Study | Gen. Costs: Energy-and -Demand Allocation | G & D Costs: Energy-and -Demand Allocation |
|---|---|---|---|---|
| Redesigned Rates: | | | | |
| E-12 | .88 | .86 | .95 | .97 |
| ECT-1R | .70 | .74 | .70 | .70 |
| ET-1 | .61 | .55 | .74 | .77 |
| Rates Proposed For Elimination | | | | |
| E-10 | .52 | .74 | .59 | .61 |
| EC-1 | .59 | .80 | .65 | .64 |
| All Residential | .69 | .70 | .78 | .80 |
| ACC Jurisdiction | 1.00 | 1.00 | 1.00 | 1.01 |
| All Other | 1.33 | .89 | -.37 | -.37 |

# AN EXAMPLE SHOWING THE COSTS PRODUCED BY DIFFERENT ALLOCATION METHODS

## 1. GENERATION-RELATED COSTS BY UNIT

| | Plant ($ per kW-yr) | Production ($ per kWh) |
|---|---|---|
| **Peaker** | $30 | $.06 |
| **Baseload** | $350 | $.01 |

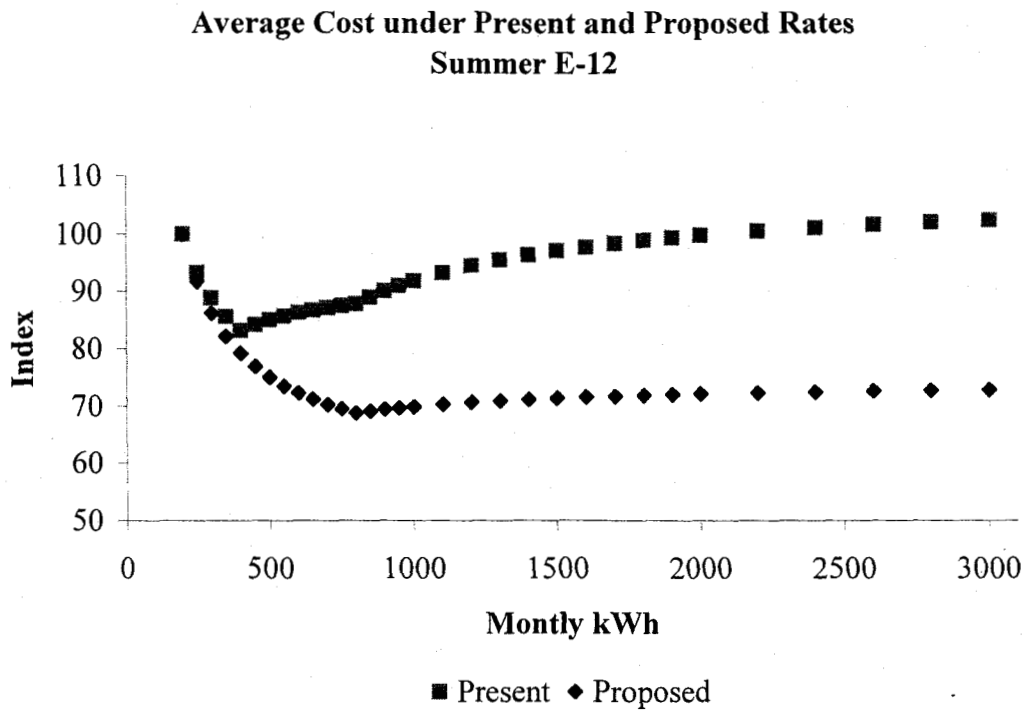
## 2. GENERATION-RELATED COSTS BY CUSTOMER
(Plant and Production, $ per kWh)

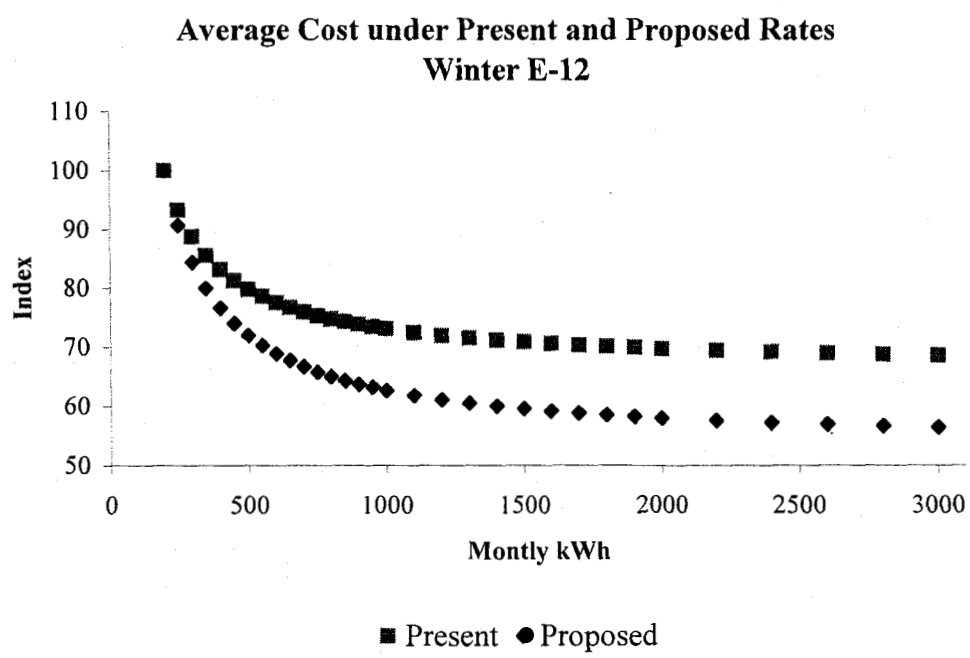
| | A Served by Peaker B by Baseload | 4CP Used by APS | Average of 4CP and kWh Usage 20% Usage | 50% Usage | 80% Usage |
|---|---|---|---|---|---|
| A | 0.0800 | 0.1473 | 0.1287 | 0.1008 | 0.0729 |
| B | 0.0500 | 0.0388 | 0.0419 | 0.0466 | 0.0512 |

## RESIDENTIAL INCREASES AND RATES OF RETURN
**(Percent of Residential Average)**

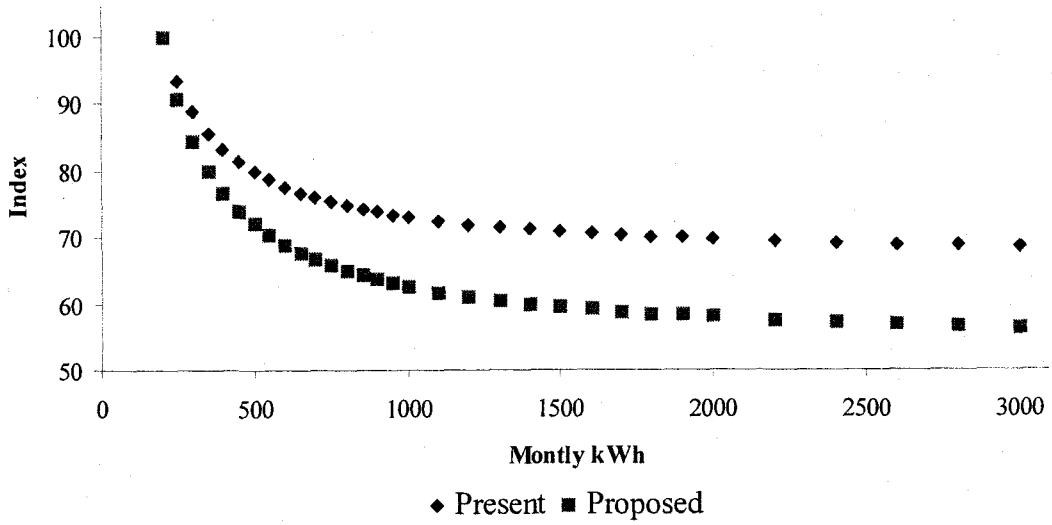
| | Increase Proposed | Rate of Return |
|---|---|---|
| Redesigned Rates: | | |
| E-12 | 68 | 127 |
| ECT-1R | 72 | 101 |
| ET-1 | 115 | 87 |
| Rates Proposed For Elimination | | |
| E-10 | 151 | 75 |
| EC-1 | 160 | 86 |
| All Residential | 100 | 100 |

# AVERAGE COST UNDER PRESENT AND PROPOSED RATES

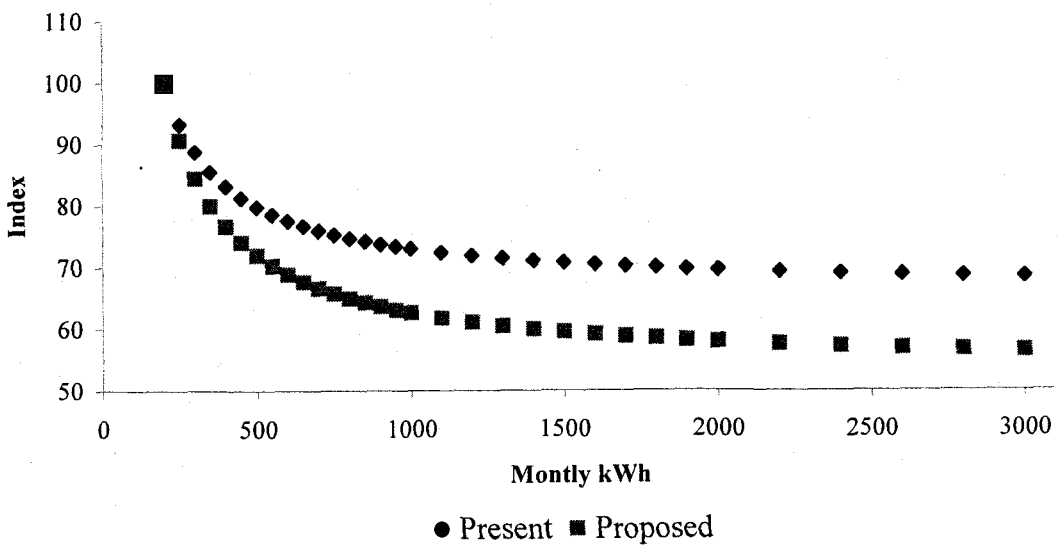


**Average Cost under Present and Proposed Rates**
**Summer E-10**




**Average Cost Index under Present and Proposed Rates**
**Winter E-12**



Schedule JS-13

## PROPOSED CHANGES IN CHARGES FOR SPECIFIC SERVICES

| Service | Charge | | Change | |
|---|---|---|---|---|
| | Current | Proposed | Amount | Percent |
| Trip Charge | None | $17.50 | $17.50 | NA |
| Services Outside Normal Business Hours: | | | | |
| Metric Read, Turn On, or Install Service | $50.00 | $75.00 | $25.00 | 50 |
| Other Services | $50.00 | $100.00 | $100.00 | 200 |
| Reconnection at Pole | $87.50 | $100.00 | $12.50 | 14.3 |
| On Site Energy Evaluation | $50.00 | $90.00 | $40.00 | 80.0 |
| Joint Site Visit: | | | | |
| Metro | $30.00 | $70.00 | $40.00 | 133.3 |
| Outside | $75.00 | $70.00 | -$5.00 | -6.6 |
| After 30 mins. | $30/hour | Actual | NA | NA |
| Meter Test: | | | | |
| Shop | $25.00 | $30.00 | $5.00 | 20 |
| Field | $25.00 | $100.00 | $75.00 | 300 |

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

# CROSS REBUTTAL TESTIMONY

OF

MARYLEE DIAZ CORTEZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MARCH 30, 2004

EXHIBIT

RUCO-7

Admitted

## INTRODUCTION

Q. Please state your name.

A. My name is Marylee Diaz Cortez.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony in this docket on February 3, 2004 on behalf of the Residential Utility Consumer Office.

Q. What is the purpose of your cross rebuttal testimony?

A. The purpose of my cross rebuttal testimony is to respond to the positions taken by parties other than APS in their direct testimonies. Later, when I file surrebuttal testimony, I will address APS' rebuttal positions. Given the number of other parties in this docket and the respective number of witnesses that have filed direct testimony, my cross rebuttal will not respond to each and every position taken. Thus, the absence of cross rebuttal on any given witness or position should not be construed to mean agreement with that position.

## DEMAND-SIDE MANAGEMENT

Q. Have you reviewed the testimony of Staff witness Barbara Keene regarding demand side management?

A. Yes.

Q. Do you agree with Staff's position regarding demand side management?

A. No. First, while Staff, in general, supports the use of demand side management to meet load growth, it has not proposed a specific level of funding. Second, RUCO does not agree with Staff's proposed method of funding APS's demand side management programs.

Q. Please discuss your first objection to the Staff's position on demand side management.

A. The Staff has not proposed a specific level of funding for DSM programs. While the Staff supports the continuation of existing demand side management programs, it recommends that funding should be capped at $4 million a year, which is even less than $6 million than is currently embedded in rates. RUCO believes that Arizona should take an aggressive approach to DSM, and, that to do so, adequate levels of funding are necessary. The use of DSM to address load growth is desirable because it is beneficial to all affected parties. It allows the Company to grow and increase its customer base, without the need for long expensive power plant construction projects. This lowers stockholder risk, mitigates upward pressure such construction projects would have on electric rates, as well as detrimental effects the operation of additional generation would have on the environment. Ratepayers can also benefit from DSM programs through their ability to control and/or cut consumption and thereby lower their energy bills. There is much to be gained from an

aggressive approach to demand side management. However, if not adequately funded, these benefits cannot be realized. The Staff's recommended level of funding is simply not sufficient to realize any meaningful results.

Q. Please discuss your second objection to the Staff's DSM recommendations.

A. The Staff recommends that the DSM programs be funded through an adjustment mechanism. This adjustment mechanism would be an additional charge per Kwh consumed, and would appear as a separate item on customer bills.

Q. Why is the Staff recommending that DSM be funded through an adjustor mechanism?

A. Staff claims the use of an adjustor mechanism to recover DSM costs is desirable because it would allow APS the flexibility to adjust funding levels as necessary and provide incentives for APS to initiate programs at any time, rather than just in rate cases.

Q. Do you agree with the Staff's recommendation?

A. No. RUCO supports the recovery of its recommended level of DSM through base rates.

Q. What are the reasons behind your recommendation?

A. RUCO recommends base rate recovery of DSM for the following reasons:

1) Separately identified surcharges on bills can mistakenly be perceived to be additional taxes by customers;

2) The DSM expenses will be a fixed amount under RUCO's proposal ($35 million) and thus, does not meet the criteria of volatile and widely fluctuating for automatic adjustment;

3) Base rate treatment coupled with a balancing account insures that APS will expend the allotted funds on DSM or will be required to refund the difference directly to ratepayer.

Q. Will RUCO's recommended DSM funding method also achieve the objectives cited by Staff?

A. Yes. RUCO's proposed funding through base rates will allow APS 100% recovery of all DSM expenditures up to $35 million and allows APS flexibility to initiate new programs at any time, the two objectives cited by Staff.

Q. Please summarize your objections to the Staff DSM recommendation.

A. First, the $4 million in funding is not sufficient to achieve any meaningful change in APS load. Second, DSM expenditures do not meet the criteria for automatic adjustment mechanisms. Further, the appearance of additional line item charges on utility bills unduly raises customer

concerns, particularly concerns of additional taxation. RUCO believes its recommended approach to DSM and DSM funding will promote good programs with meaningful results.

Q. Does this conclude your cross rebuttal testimony?

A. Yes.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | ) | Docket No. E-A 01345A-03-0437 |

**CROSS REBUTTAL**

**OF**

**DR. JOHN STUTZ**

**On Behalf of the Arizona Residential Utility Consumer Office**

**Tellus Institute**
**11 Arlington Street**
**Boston, MA 02116-3411**
**Tel: 617/266-5400**

**March 30, 2004**

EXHIBIT
RUCO-8
Admitted

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1. SUMMARY AND RECOMMENDATIONS ..... 1

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Schedule JS-14 Recommended Revenue Spreads

## 1. SUMMARY AND RECOMMENDATIONS

**Q. PLEASE STATE YOUR NAME AND ADDRESS.**

A My name is John K. Stutz. My business address is the Tellus Institute (Tellus), 11 Arlington Street, Boston, Massachusetts 02116-3411.

**Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Yes, I did.

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

A. My testimony responds to the testimony of Ms. Lee Smith, Ms. Erinn Andreasen, and Ms. Barbara Keene on behalf of ACC Staff, and to the testimony of Mr. Steven Baron, Mr. Dennis Goins, and Mr. Kevin Higgins on behalf of various intervenors. (In what follows I will refer to Messrs. Baron, Goins and Higgins jointly as "the Intervenors"),

**Q. WHAT ARE THE KEY POINTS OF YOUR CROSS REBUTTAL?**

A. My key points are presented below. For convenience they are grouped to correspond to the sections of my detailed testimony.

**COSS Development**

- Generation-related costs should be allocated on the basis of demand and energy.

- The Peak and Average allocator should weight the average component based on APS' investment in generating plant, not the system load factor.

**Revenue Spread**

- In developing their recommendations, the Intervenors rely inappropriately on COSS developed using the 4CP allocator.
- The recommendations of Staff and the Intervenors lack Bonbright's practical attributes of understandability and public acceptability.

**Other Changes**

- Elimination of rates E-10 and EC-1 is both unnecessary and contrary to the principle of rate stability.
- Staff's proposal to add a new charge and to increase existing charges by up to 100 percent is inconsistent with rate stability, and fails to spread burdens equitably.

**Q. WHAT ARE YOUR RECOMMENDATIONS?**

A. In addition to the seven recommendations presented in my direct testimony, I recommend that the Commission reject APS' use of the 4CP method in favor of the Peak and Average method recommended by Staff. However, Staff's weighting of the average component should be modified as described in my testimony.

## 2. COSS DEVELOPMENT

**Q. WHAT ISSUES CONCERNING COSS DEVELOPMENT WILL YOU ADDRESS?**

A. I will address two issues: choice of an allocation method for generation-related costs, and the weighting used in constructing the Average and Peak allocator.

**Q. HOW SHOULD GENERATION-RELATED COSTS BE ALLOCATED?**

A. Generation-related costs should be allocated on the basis of both peak demand and energy.

**Q. WHY IS THIS THE APPROPRIATE APPROACH?**

A. As I and Staff explain in our direct testimony, allocation of generation-related costs needs to reflect both the **amount** and the **type** of generating plant that APS has constructed. APS has a substantial amount of coal and nuclear in its plant mix. Investments in coal and nuclear plants are made to reduce energy costs and meet peak load, not solely to meet peak. Failure to allocate the cost of such investments on the basis of energy and demand is inconsistent with cost causation.

**Q. PLEASE DISCUSS THE INTERVENOR'S RECOMMENDATIONS CONCERNING ALLOCATION.**

A. Messrs. Baron, Goins, and Higgins all support the allocation of generation-related costs on the basis of demand alone, using APS' 4CP allocation method. Their

testimony does not address, and indeed does not even mention, the fact—supported by the APS' own witnesses, Mr. Bhatti and Mr. Wheeler—that plant was built to both meet peak and lower energy costs. Staff, on the other hand, recognizes and discusses this point. Staff recommends, as I do, that the 4CP allocation method be rejected and instead that generation-related costs be allocated on the basis of energy and demand.

**Q. PLEASE DISCUSS STAFF'S PROPOSED ALLOCATOR FOR GENERATION-RELATED COSTS.**

A. Staff proposes the use of the Peak and Average allocation method. I support the use of this method, and have recommended its use by APS in the past. However, I differ with Staff's construction of the Peak and Average allocator. Staff recommends that the average (i.e., energy) component of the allocator be given a weight equal to the coincident load factor. Instead, I would recommend applying the Equivalent Peaker method. That method divides the cost of the Company's generating plant into the cost of an equivalent amount of peaking capacity, classified as demand-related, and a residual cost classified as energy-related. The peak and average components are weighted in the same proportion as the demand and energy components of the plant cost.

**Q. IS THIS WEIGHTING CONSISTENT WITH STAFF'S ARGUMENTS FOR THE ADOPTION OF THE PEAK AND AVERAGE METHOD?**

A. Yes. The NARUC Manual describes the Equivalent Peaker method as follows:

> Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. (NARUC Manual, page 52, emphasis in original)

Use of the Equivalent Peaker method ensures that the weighting in the Peak and Average allocator will correctly reflect the amount and type of plant APS has built. The importance of both the amount and type of plant constructed is what Staff emphasized in its argument for the use of the Peak and Average allocation method.

**Q. WOULD YOUR WEIGHTING SIGNIFICANTLY AFFECT THE CONSTRUCTION OF THE PEAK AND AVERAGE ALLOCATOR?**

A. Yes, likely it would. Use of the load factor gives the average component a weight of 56 percent. The analysis discussed in my 1991 testimony in an APS retail rate case (Docket No. U-1345-90-007) showed that the Equivalent Peaker produces a weighting of 80 percent or more for the average component.

## 3. REVENUE SPREAD

**Q. WHAT IS REVENUE SPREAD?**

A. Revenue spread refers to the pattern of increases or decreases in revenue requirements that the Commission might approve. Staff and the Intervenors have all made proposals concerning revenue spread. Schedule JS-14 provides a brief summary of these proposals for APS' two major customer classes, Residential and General Service.

**Q. DO YOU HAVE ANY COMMENTS ON THE DEVELOPMENT OF THE STAFF AND INTERVENORS REVENUE SPREAD PROPOSALS?**

A. Yes, I do. All of the Intervenors base their proposals, in part, on COSS results developed using the 4CP allocator. As I explained in my direct testimony and in the preceding section, use of this allocator is inappropriate. The Intervenors also characterize revenue requirements that produce class rates of return less than the Company average, resulting in a subsidy. Correctly used, the term "subsidy" refers to pricing below marginal not embedded cost as the interveners appear to assume. Rather than completely removing "subsidies," as the Intervenors' analyses suggest, a reasonable goal for COSS is to gradually move class rates of return toward unity.

Staff's revenue spread is based on a more appropriate COSS than that relied upon by the Interveners. However, as I explained in the preceding section, there are still problems with the construction of Staff's Peak and Average allocator. Further, as I

noted in my direct testimony, there is the anomalous effect of APS' treatment of transmission on COSS results to consider. Taking all of this into account, in my view none of the COSS results currently available provide a reasonable basis for a departure from across-the-board increases or decreases.

**Q. PLEASE DISCUSS THE ROLE OF JUDGMENT IN STAFF AND INTERVENORS REVENUE SPREAD PROPOSALS.**

A. While all of the proposals rely on COSS for support, all are based substantially on judgment. With this in mind, I would ask the Commissioners to look carefully at the numbers in Schedule JS-14 and ask themselves the following questions:

- The vast majority of APS customers are residential. Is it reasonable to give these customers 36 to 50 percent more than the average increase, or less than half of the average decrease?
- Are such disproportionate allocations likely to satisfy the practical requirements of understanding and public acceptance contained in Bonbright's well-known *Criteria of a Sound Rate Structure* (Bonbright's criteria are reproduced in my Schedule JS-8).

In my view, the answer to both of these questions is "no."

**Q. DO YOU HAVE ANY COMMENTS ON STAFF'S REVENUE SPREAD PROPOSAL?**

A. Yes, I do. Staff has proposed unspecified differences in the decreases for individual rates. For the reasons discussed in my direct testimony, such differences are

1 inappropriate. I recommend that any decrease (or increase) be applied across-the-

2 board to all residential rates.

3

## 4. OTHER CHANGES

**Q. WHAT ISSUES WILL YOU ADDRESS IN THIS SECTION?**

A. I will address two issues raised in Staff's testimony: eliminating rates E-10 and EC-1 and changing service charges substantially.

**Q. DO YOU SUPPORT THE PROPOSED ELIMINATION OF E-10 AND EC-1?**

A. No. There is a strong presumption in electric utility ratemaking in favor of existing rates. Bonbright expresses this presumption, in his *Criteria of a Sound Rate Structure*, through the maxim "The best tax is an old tax." Eliminating rates E-10 and EC-1 would affect about 120,000 of APS' customers. Staff has identified no specific need to eliminate these rates now. Nor has it identified any benefit of immediate elimination. As Staff noted, when these two rates were closed 67 percent of residential customers were on them. Now the figure is about 15. Keeping things as they are will allow the rates to be eliminated by the gradual departure, rather than by an abrupt, disruptive change.

**Q. PLEASE DISCUSS STAFF'S PROPOSAL TO CHANGE SERVICE CHARGES.**

A. In conjunction with a recommended decrease of 8.1 percent, Staff has recommended the addition of a new service charge as well as increases in existing charges ranging up to 100 percent. From the response to Q.1.9 from RUCO to Staff, it appears that Staff's recommendations are meant to track increases in costs. Cost tracking does not

1 give weight to the avoidance of unanticipated adverse impacts, as called for in
2 Bonbright's Criterion of Rate Stability. Further, the addition of a new charge and
3 increases of up to 100 percent fail to address the concern for equitable treatment of all
4 customers that Staff displayed in developing its recommended revenue spread.
5
6 **Q. ARE YOU OPPOSED TO ANY INCREASE IN SERVICE CHARGES?**
7 A. No. The increase in costs does need to be conveyed via a price signal. However, in
8 the face of a recommended decrease, the 15 percent cap on increases in existing
9 charges and rejection of a new charge, is appropriate.
10
11 **Q. DOES THIS CONCLUDE YOUR CROSS REBUTTAL?**
12 A. Yes, it does.

## RECOMMENDED REVENUE SPREADS
## (Percent of Average Change)

| Witness | Residential | | General Service | |
|---|---|---|---|---|
| | Increase | Decrease | Increase | Decrease |
| Propper | 100 | NA | 100 | NA |
| Andreasen | NA | 49 | NA | 162 |
| Baron | 136 | NA | 61 | NA |
| Goins | 150 | NA | 49 | NA |
| Higgins | 138 | NA | 60 | 125 |
| Stutz | 100 | 100 | 100 | 100 |

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

DOCKET NO. E-01345A-03-0437

# DIRECT TESTIMONY

of

# STEPHEN AHEARN

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

September 27, 2004

EXHIBIT

RUCO-9

Admitted

INTRODUCTION.....2

PUBLIC INTEREST.....4

COMPETITIVE ISSUES .....6

ENERGY EFFICIENCY AND RENEWABLES.....7

## INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Stephen Ahearn. My business address is 1110 West Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. I have been employed by the state of Arizona as the Director of the Residential Utility Consumer Office ("RUCO") since January 2003. From 1998 through 1999, I was employed at the Arizona Corporation Commission in the capacity of Executive Consultant. From 1990 to 1998, I was actively involved with utility regulation at the Commission and utility policy-making at the Legislature in my role as the Manager of Planning and Policy at the Department of Commerce Energy Office. Additionally, I have had training in utility ratemaking and telecommunications policy conducted by NARUC and New Mexico State University, respectively. Finally, I have an MBA in Finance from UCLA

Q. What is the purpose of your testimony?

A. My testimony is offered in support of the Settlement arrived at by virtually all intervenors in this case, including RUCO. In particular, the focus of my testimony will be on the following areas: public policy, treatment of the PWEC assets and associated competitive issues, energy efficiency and renewable energy. My colleague Marylee Diaz Cortez will offer testimony

addressing the revenue requirement, rate design and adjustor mechanism elements in the Settlement.

Q. Please summarize your testimony.

A. The Settlement is a balanced resolution of competing issues and interests. All parties were able to fully audit the APS application; as a consequence, all parties were in a position to negotiate from a standing of relative strength and openness. The process was facilitated well, participants engaged meaningfully, and enough time was permitted to yield an unhurried result. The resulting Settlement has been embraced by the vast majority of participants.

Q. What are the main provisions of the Settlement?

A. From RUCO's perspective, the principal elements include:

- A total revenue requirement increase of approximately $75 million for a percentage increase of 4.21%. This increase is composed of a 3.77% base rate increase plus a temporary .44% increase for the Competition Rules Compliance Charge ("CRCC");
- Incorporation of the PWEC generation assets into the APS rate base at a significant discount to book value;
- A Power Supply Adjustor ("PSA") mechanism that at once limits annual per kWh price volatility and provides an incentive to the Company to minimize power supply costs;

- A meaningful commitment to energy efficiency demand-side management programs, designed to total $48 million in the years 2005-07, with provisions for recovery partially through base rates and partially through an adjustor;
- A commitment to renewable energy via establishment of an adjustment mechanism to fully recover costs incurred as a result of any future order of the Commission to increase the Environmental Portfolio Standard, as well as a commitment by the Company to solicit at least 100 MW and 250,000 MWh annually for delivery beginning in 2006; and
- Competitive procurement of power from wholesale markets, but with an allowance for the Company to self-build generation under certain circumstances.

**PUBLIC INTEREST**

Q. How is the public interest satisfied by this Settlement Agreement?

A. At the most fundamental level, the Settlement satisfies the public interest because rate increases have been minimized and will be just and reasonable; the issue of PWEC generation asset treatment has been resolved, providing the Company and other participants with regulatory certainty; the Company is provided an opportunity to earn a sufficient return to satisfy its capital, reliability, service and other needs without

being unduly enriched; and the multiple parties representing competing interests have reached consensus on the terms of the Agreement.

Q. Why is a negotiated settlement process an appropriate way to resolve this matter?

A. RUCO believes this case is different from previous APS rate cases, insomuch as this particular case benefited from a full audit by both RUCO and ACC Staff of APS' cost-of-service. More than half a year passed after the filing of the application before intervenors filed their direct testimony, permitting sufficient time for a thorough review of the application. Settlement negotiations began only after all parties had an opportunity to fully review the Company's application and the filed cases of the other intervenors. Further, the binding agreement of the signatories to the Settlement precludes their initiating potentially protracted litigation in the event of an order antithetical to their interests. The Settlement results in clarity and regulatory certainty, without the risk and delays associated with the appeal process. Finally, parties to the Settlement are not asking the Commission to abandon its review and oversight of this case; Commissioners are of course not precluded from questioning the parties to assure themselves that the Settlement is truly balanced and is what it purports to be.

**COMPETITIVE ISSUES**

Q. Please describe how the PWEC assets were dealt with in the Settlement.

A. The disposition of the PWEC assets was resolved in the Settlement. The Company had requested a rate-basing of all Arizona-based PWEC assets at their book value of approximately $882 million as of June 30, 2004. Many parties objected to the transfer to rate base of the assets for a variety of reasons, including: the perceived lack of an immediate need by the Company for additional generation or power contracts; the desire for greater plant valuation transparency, given that other recent purchases of generation facilities have been at a discount to book value; merchant competitors wanted to assure that rate basing wouldn't permanently extinguish the opportunity for the development of a healthy wholesale market.

The timing question was resolved by the Settlement by the agreement to ratebase the PWEC assets all at once. The Settlement addressed the financial concerns of other parties by setting the transfer price at $700 million, a $182 million discount to the June 30, 2004 book value ($148 million compared to December 31, 2004 book value). Competitive concerns were in large measure addressed by the development of a fairly large, 1000 MW solicitation that will be open only to non-PWEC, non-APS market participants for delivery in 2007 and beyond.

Q. What other competition-related issues were resolved by the Settlement?

A. Also of concern to merchant competitors was the Company's continued ability to self-build generation as needed. The Settlement's self-build restriction provides a lengthy window of time for merchants to develop a wholesale electricity market while shielded from competitive pressures that could potentially be brought by the Company building additional generation itself. Importantly, if the wholesale market does not develop as expected, and the Company is able to demonstrate to the Commission that merchant generators cannot cost-effectively meet its needs, the Company could be exempted from this provision.

**ENERGY EFFICIENCY AND RENEWABLES**

Q. Please describe the energy efficiency demand-side management provisions of the Settlement.

A. APS agrees to spend $48 million on energy efficiency programs in the years 2005-07. $10 million annually will be collected through base rates; the balance will be collected through an adjustor mechanism in the year following actual expenditures. Importantly, a formal collaborative energy efficiency working group with many participants is also established to assist with development and monitoring of energy efficiency programs. All programs recommended by this collaborative working group will require approval by the Commission prior to implementation.

Q. What benefits does RUCO see in these energy efficiency elements of the Settlement?

A. Effective energy efficiency programs can accomplish any and all of the following: customers are made more aware of their ability to control their own energy consumption and therefore, their bills; monies saved on utility bills can be devoted to other productive economic uses; more pervasive use of efficient equipment and appliances reduces the strain and demand on the existing electricity system and reduces the rate at which the future need for generation and accompanying infrastructure increases; environmental benefits to air quality and water quality *and quantity* from reduced consumption of primary fuels to generate electricity.

Q. Please describe the renewable energy-related provisions of the Settlement.

A. The Settlement provides for a mechanism to fully fund an increased EPS, in the event that a finding is made by the Commission in the future that a funding increase is warranted to satisfy the EPS requirements. Additionally, the Company has agreed to issue an RFP in 2005 for not less than 100 MW of renewable energy to be delivered beginning in 2006, with a goal of acquiring not less than ten percent of annual system incremental peak capacity from renewable resources, subject to a cost premium not to exceed 25% over conventional resources. This 100 MW is in addition to any energy and capacity contracts renewable energy

providers may win in the 1,000 MW solicitation set aside for competitive supply in an RFP to be let in 2005 for delivery in 2007 and beyond.

Q. What benefits does RUCO see in these renewable energy elements of the Settlement?

A. RUCO agrees with the Commission that increased utilization of indigenous renewable energy resources is beneficial for fuel diversity, risk minimization, sustainable local economic development and for environmental reasons. The Settlement advances responsibly the development of renewables by: establishing a mechanism to sufficiently fund the EPS; reserving a 100 MW capacity opportunity for renewables; establishing a goal of meeting ten percent of future capacity additions from renewables; and providing an opportunity for renewable technologies to compete head-to-head with conventionally-fueled generators in the larger 1,000 MW RFP next year. RUCO recognizes that in the case of some renewable technologies, procurement of renewable resources may be at a premium to the market price of conventional technologies. However, for all the reasons cited above, as well as the cost-capping provisions built into the Settlement, RUCO believes the worthy public policy objective of increased use of renewable energy is well served by this Settlement.

Q. Does this conclude your testimony?

A. Yes.

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

DOCKET NO. E-01345A-03-0437

# DIRECT TESTIMONY

of

# MARYLEE DIAZ CORTEZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

September 27, 2004

EXHIBIT

Number RUCO-10

Admitted

INTRODUCTION ..... 2
REVENUE REQUIREMENT ..... 2
RATE ADJUSTORS ..... 5
RATE DESIGN ..... 6
CONCLUSION ..... 7

## INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez.

Q. Have you previously testimony in this docket?

A. Yes. I filed direct testimony in this docket on February 3, 2004. My testimony addressed RUCO's recommended revenue requirement.

Q. What is the purpose of your additional testimony?

A. The purpose of this additional testimony is to support a settlement that the majority of the parties to this docket have recently negotiated and to recommend that the Commission adopt the settlement. Specifically, my testimony will address the settlement as it pertains to the agreed upon revenue requirement, rate adjustor mechanisms, and rate design. Mr. Stephen Ahearn will address the policy issues, including Demand Side Management, the PWEC assets, and competitive issues.

## REVENUE REQUIREMENT

Q. What revenue requirement is included in the settlement agreement?

A. The parties have agreed on a revenue requirement of $1,867,084,000, which represents a 3.77% increase over the 2002 test year adjusted revenue.

Q. How does this compare with the revenue requirement requested in APS's application?

A. APS's application proposed a revenue requirement of $1,966,674,000, which represents a 9.77% increase over 2002 test year adjusted revenue.

Q. How does the settlement revenue requirement compare with the revenue requirement recommended by RUCO in its direct testimony?

A. RUCO recommended a revenue requirement of $1,831,515,000 (including Miscellaneous revenues). This represented a 2.84% decrease from 2002 test year adjusted revenues.

Q. How is it that RUCO is willing to settle on a 3.77% *increase* when it originally recommended a 2.84% *decrease*?

A. RUCO's original revenue requirement recommendation was comprised of two phases. Phase I of the proceeding was to resolve all rate case issues excepting the PWEC assets and expenses. The 2.84% decrease was applicable to Phase I and did not contemplate any additional energy and capacity costs. RUCO recommended a Phase II portion of the docket, which was to take place after a least cost process was conducted on APS's energy and capacity requirements. During Phase II any additional revenue requirement applicable to energy and capacity would be included in rates. Thus, the 2.84% decrease was applicable only to Phase I, which did not contemplate any additional capacity. RUCO always anticipated

that the Phase II energy and capacity determination would create additional revenue requirement. Thus, the settlement revenue requirement, which resolves all issues, is not comparable to RUCO's proposed decrease, which does not include the revenue requirement associated with additional capacity and energy.

Q. Does RUCO believe the settlement agreement revenue requirement is fair and reasonable?

A. Yes.

Q. What is the basis of RUCO's conclusion that the 3.77% rate increase is fair and reasonable?

A. RUCO's analysis of a fair and reasonable settlement revenue requirement began with our original recommended revenue requirement. We then assessed and estimated what the Phase II energy and capacity analysis might have yielded and factored in our perception of litigation risk. The revenue requirement ultimately included in the settlement agreement is consistent with our estimates.

Q. Did the parties reach agreement on each and every ratemaking element that comprises the agreed upon 3.77%?

A. No, nor was it even intended that we would reach resolution at that level. RUCO determined the 3.77% increase using its own analysis and

assumptions, as did each the parties. Thus, while all signatories support the agreed upon revenue requirement, each signatory will have a somewhat different view of the make-up of the 3.77% increase. In large part this approach was one of the reasons the parties, despite very divergent points of view, were able to agree upon a revenue requirement.

**RATE ADJUSTORS**

Q. Do the terms of the settlement agreement include any rate adjustor mechanisms or surcharges?

A. Yes. The settlement agreement includes the continuation of the existing EPS surcharge and a new Competitive Rules Compliance Charge (CRCC) designed to recover competitive transition costs over a five year period, at which time the surcharge will cease. Three rate adjustors are included in the settlement agreement; a Power Supply Adjustor (PSA), a Transmission Cost adjustor, and a DSM adjustor.

Q. In direct testimony did RUCO support these adjustor mechanisms?

A. No. RUCO's direct position did not include rate basing of the PWEC assets. Without the PWEC assets, APS's fuel mix was more heavily weighted with coal and nuclear, the cost of which is not currently volatile or widely fluctuating. Thus, under those circumstances, RUCO did not believe the proposed PSA would fit certain criteria for rate adjustment mechanisms, nor did RUCO find that it was even necessary. However,

with the inclusion of the PWEC assets, a significant portion of APS's fuel mix is natural gas, which does meet the volatility test in my direct testimony.

RUCO's direct position supported the inclusion of additional DSM funding in base rates. As a compromise in the settlement agreement RUCO has agreed to partial base rate funding and partial adjustor funding for DSM. Likewise, RUCO's agreement for a Transmission adjustor represents a trade-off made in the interest of a comprehensive settlement agreement.

**RATE DESIGN**

Q. Please describe the settlement agreement's allocation of the of the 3.77% rate increase.

A. Under the terms of the settlement agreement, the 3.77% rate increase will be allocated among the customer classes as follows:

| | | |
|---|---|---|
| * | Residential | 3.94% |
| * | General Service | 3.50% |
| * | Irrigation | 5.00% |
| * | Lighting | 5.00% |

Q. Does this rate allocation represent a compromise on RUCO's part?

A. Yes. In direct testimony RUCO advocated an even across-the-board allocation of the revenue requirement, whereby each customer class

would be allocated the same percentage increase or decrease as was ultimately adopted. The settlement agreement allocation represents a compromise on RUCO's part, made to facilitate a settlement that RUCO believes to be fair on an overall basis. Further, in return for this compromise allocation of the rate increase RUCO was able to achieve some of its other rate design goals. This included the preservation of Schedule E-10 and EC-1 rates (which APS was proposing to eliminate). The elimination of these rates would have had disproportional impacts on the residential customers on these rate schedules. The settlement rate design also accomplishes an even allocation of the increase over the individual residential rate schedules, as well as preserves time-of-use peak and off peak periods.

**CONCLUSION**

Q. What are your concluding remarks regarding the settlement agreement?

A. The settlement agreement reaches a fair and reasonable result for all parties. This was no small accomplishment in light of the numerous issues in this case and diverse interests of the parties. The settlement agreement also resolves issues that reach far beyond revenue requirements and rate design, and provides a platform for APS to move forward under a new regulatory format that embraces wholesale competition and at the same time leaves intact the safeguards of regulation.

Q. Does this conclude your testimony in support of the settlement agreement?

A. Yes.

APS SETTLEMENT AGREEMENT
EFFECTS OF SETTLEMENT RATES ON AVERAGE & MEDIAN E-12 CUSTOMERS
COMMISSIONER MAYES HOMEWORK
SUBMITTED BY RUCO

| LINE NO. | DESCRIPTION | AVERAGE USAGE | MEDIAN USAGE |
|---|---|---|---|
| | **CURRENT:** | | |
| 1 | JUNE 2004 USAGE | 738 | 460 |
| 2 | JUNE BILL @ CURRENT RATES | $72.10 (a) | 43.52 (a) |
| | **SETTLEMENT:** | | |
| 3 | SETTLEMENT BILL (BASE INC. ONLY) | 73.55 | 44.20 |
| 4 | SETTLEMENT BILL WITH CRCC | 73.80 | 44.36 |
| 5 | SETTLEMENT BILL WITH PSA | 76.75 | 46.20 |
| 6 | SETTLEMENT BILL WITH TCA | 76.93 | 46.31 |
| 7 | SETTLEMENT BILL WITH EPS | 77.28 | 46.66 |
| 8 | SETTLEMENT BILL WITH DSM | 77.43 | 46.76 |
| 9 | PERCENT INCREASE | 7.39% | 7.43% |

(a) INCLUDES CURRENT EPS SURCHARGE

| **DATA INPUTS:** | CURRENT RATES | SETTLEMENT RATES | |
|---|---|---|---|
| MONTHLY SERVICE CHARGE | 7.5 | 7.59 | |
| SUMMER - 1ST 400 | 0.07376 | 0.0757 | |
| 2ND 400 | 0.10281 | 0.10556 | |
| OVER 800 | 0.11991 | 0.12314 | |
| WINTER - ALL USAGE | 0.07394 | 0.07361 | |
| CRCC SURCHANGE | | 0.000338 | PER KWH |
| PSA SURCHARGE @ MAX | | 0.004 | PER KWH |
| TCA SURCHARGE @ TRIGGER | | 0.000238 | PER KWH |
| EPS SURCHARGE @CURRENT | | 0.35 | AT CAP (400 KWH) |
| DSM SURCHARGE | | 0.000212 | PER KWH |
| TOTAL 2004 KWH | | 28,288 | MWH |

EXHIBIT
Admitted
RUCO-11

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**ACC JURISDICTIONAL REVENUE REQUIREMENTS (000'S)**

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**SCHEDULE MDC-1**
**PAGE 1 OF 3**

SENARIO 1 - RUCO DIRECT POSITION PLUS
RATE BASING OF W. PHX & SAGUARO

| LINE NO. | DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,437,380 | $ 5,690,552 | $ 4,563,966 |
| 2 | ADJUSTED OPERATING INCOME | 258,604 | 258,604 | 258,604 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 7.52% | 4.54% | 5.67% |
| 4 | REQUIRED RATE OF RETURN | 7.43% | 4.49% | 5.59% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 255,232 | 255,232 | 255,232 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | (3,372) | (3,372) | (3,372) |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ (5,578) | $ (5,578) | $ (5,578) |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,929,993 | $ 1,929,993 | $ 1,929,993 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 1,924,416 | $ 1,924,416 | $ 1,924,416 |
| 11 | PERCENTAGE AVERAGE INCREASE | -0.29% | -0.29% | -0.29% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7



EXHIBIT
tabbies
RUCO-12
Admitted

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**ACC JURISDICTIONAL REVENUE REQUIREMENTS (000'S)**

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| LINE NO. | SENARIO 2 - RUCO DIRECT POSITION PLUS RATE BASING OF W. PHX & SAGUARO PLUS 25 BASIS POINTS<br>DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,437,380 | $ 5,690,552 | $ 4,563,966 |
| 2 | ADJUSTED OPERATING INCOME | 258,604 | 258,604 | 258,604 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 7.52% | 4.54% | 5.67% |
| 4 | REQUIRED RATE OF RETURN | 7.54% | 4.55% | 5.68% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 259,111 | 259,111 | 259,111 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 507 | 507 | 507 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 837 | $ 837 | $ 837 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,929,993 | $ 1,929,993 | $ 1,929,993 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 1,930,831 | $ 1,930,831 | $ 1,930,831 |
| 11 | PERCENTAGE AVERAGE INCREASE | 0.04% | 0.04% | 0.04% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
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**PAGE 1 OF 3**

| LINE NO. | SENARIO 3 - RUCO DIRECT POSITION PLUS RATE BASING OF W. PHX & SAGUARO PLUS 50 BASIS POINTS<br>DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,437,380 | $ 5,690,552 | $ 4,563,966 |
| 2 | ADJUSTED OPERATING INCOME | 258,604 | 258,604 | 258,604 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 7.52% | 4.54% | 5.67% |
| 4 | REQUIRED RATE OF RETURN | 7.65% | 4.62% | 5.76% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 262,990 | 262,990 | 262,990 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 4,386 | 4,386 | 4,386 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 7,252 | $ 7,252 | $ 7,252 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,929,993 | $ 1,929,993 | $ 1,929,993 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 1,937,246 | $ 1,937,246 | $ 1,937,246 |
| 11 | PERCENTAGE AVERAGE INCREASE | 0.38% | 0.38% | 0.38% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
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| LINE NO. | SENARIO 4 - RUCO DIRECT POSITION PLUS RATE BASING OF W. PHX & SAGUARO PLUS 75 BASIS POINTS<br>DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,437,380 | $ 5,690,552 | $ 4,563,966 |
| 2 | ADJUSTED OPERATING INCOME | 258,604 | 258,604 | 258,604 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 7.52% | 4.54% | 5.67% |
| 4 | REQUIRED RATE OF RETURN | 7.76% | 4.69% | 5.85% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 266,869 | 266,869 | 266,869 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 8,265 | 8,265 | 8,265 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 13,667 | $ 13,667 | $ 13,667 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,929,993 | $ 1,929,993 | $ 1,929,993 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 1,943,661 | $ 1,943,661 | $ 1,943,661 |
| 11 | PERCENTAGE AVERAGE INCREASE | 0.71% | 0.71% | 0.71% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**ACC JURISDICTIONAL REVENUE REQUIREMENTS (000'S)**

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| LINE NO. | SENARIO ~~2~~ 5 RUCO DIRECT POSITION PLUS RATE BASING ALL PWEC (STEP 2) PLUS 50 BASIS POINTS NO INCREMENTAL DSM<br>DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,928,283 | $ 6,451,042 | $ 5,189,663 |
| 2 | ADJUSTED OPERATING INCOME | 271,549 | 271,549 | 271,549 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 6.91% | 4.21% | 5.23% |
| 4 | REQUIRED RATE OF RETURN | 7.65% | 4.66% | 5.79% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 300,549 | 300,549 | 300,549 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 29,000 | 29,000 | 29,000 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 47,957 | $ 47,957 | $ 47,957 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,940,807 | $ 1,940,807 | $ 1,940,807 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 1,988,764 | $ 1,988,764 | $ 1,988,764 |
| 11 | PERCENTAGE AVERAGE INCREASE | 2.47% | 2.47% | 2.47% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
**ACC JURISDICTIONAL REVENUE REQUIREMENTS (000'S)**

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**PAGE 1 OF 3**

| LINE NO. | SENARIO 1 - RUCO DIRECT POSITION PLUS RATE BASING ALL PWEC (STEP 2) NO DSM<br>DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,929,178 | $ 6,451,944 | $ 5,190,561 |
| 2 | ADJUSTED OPERATING INCOME | 254,763 | 254,763 | 254,763 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 6.48% | 3.95% | 4.91% |
| 4 | REQUIRED RATE OF RETURN | 7.43% | 4.52% | 5.62% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 291,749 | 291,749 | 291,749 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 36,986 | 36,986 | 36,986 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 61,164 | $ 61,164 | $ 61,164 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,940,807 | $ 1,940,807 | $ 1,940,807 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 2,001,971 | $ 2,001,971 | $ 2,001,971 |
| 11 | PERCENTAGE AVERAGE INCREASE | 3.15% | 3.15% | 3.15% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
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**SCHEDULE MDC-1**
**PAGE 1 OF 3**

| LINE NO. | SENARIO 4 - RUCO DIRECT POSITION PLUS RATE BASING ALL PWEC (STEP 2) PLUS 50 BASIS POINTS 20 MIL INCREMENTAL DSM<br>DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,928,900 | $ 6,451,664 | $ 5,190,282 |
| 2 | ADJUSTED OPERATING INCOME | 259,973 | 259,973 | 259,973 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 6.62% | 4.03% | 5.01% |
| 4 | REQUIRED RATE OF RETURN | 7.65% | 4.66% | 5.79% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 300,596 | 300,596 | 300,596 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 40,623 | 40,623 | 40,623 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 67,179 | $ 67,179 | $ 67,179 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,940,807 | $ 1,940,807 | $ 1,940,807 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 2,007,987 | $ 2,007,987 | $ 2,007,987 |
| 11 | PERCENTAGE AVERAGE INCREASE | 3.46% | 3.46% | 3.46% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
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**SCHEDULE MDC-1**
**PAGE 1 OF 3**

| LINE NO. | SENARIO 7 - RUCO DIRECT POSITION PLUS RATE BASING ALL PWEC (STEP 2) PLUS 25 BASIS POINTS<br>DESCRIPTION | (D)<br>RUCO ORIGINAL COST | (E)<br>RUCO RCND | (F)<br>RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,929,178 | $ 6,451,944 | $ 5,190,561 |
| 2 | ADJUSTED OPERATING INCOME | 254,763 | 254,763 | 254,763 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 6.48% | 3.95% | 4.91% |
| 4 | REQUIRED RATE OF RETURN | 7.54% | 4.59% | 5.71% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 296,183 | 296,183 | 296,183 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 41,420 | 41,420 | 41,420 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 68,497 | $ 68,497 | $ 68,497 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,940,807 | $ 1,940,807 | $ 1,940,807 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 2,009,304 | $ 2,009,304 | $ 2,009,304 |
| 11 | PERCENTAGE AVERAGE INCREASE | 3.53% | 3.53% | 3.53% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
**TEST YEAR ENDED DECEMBER 31, 2002**
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**SCHEDULE MDC-1**
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SENARIO ~~4~~ 3 - RUCO DIRECT POSITION PLUS
RATE BASING ALL PWEC (STEP 2) PLUS
~~25~~ 50 BASIS POINTS

| LINE NO. | DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,929,178 | $ 6,451,944 | $ 5,190,561 |
| 2 | ADJUSTED OPERATING INCOME | 254,763 | 254,763 | 254,763 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 6.48% | 3.95% | 4.91% |
| 4 | REQUIRED RATE OF RETURN | 7.65% | 4.66% | 5.79% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 300,617 | 300,617 | 300,617 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 45,854 | 45,854 | 45,854 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 75,829 | $ 75,829 | $ 75,829 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,940,807 | $ 1,940,807 | $ 1,940,807 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 2,016,637 | $ 2,016,637 | $ 2,016,637 |
| 11 | PERCENTAGE AVERAGE INCREASE | 3.91% | 3.91% | 3.91% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

**ARIZONA PUBLIC SERVICE COMPANY**
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**ACC JURISDICTIONAL REVENUE REQUIREMENTS (000'S)**

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**SCHEDULE MDC-1**
**PAGE 1 OF 3**

| LINE NO. | SENARIO 4 - RUCO DIRECT POSITION PLUS RATE BASING ALL PWEC (STEP 2) PLUS 75 BASIS POINTS<br>DESCRIPTION | (D) RUCO ORIGINAL COST | (E) RUCO RCND | (F) RUCO FAIR VALUE |
|---|---|---|---|---|
| 1 | ADJUSTED RATE BASE | $ 3,929,178 | $ 6,451,944 | $ 5,190,561 |
| 2 | ADJUSTED OPERATING INCOME | 254,763 | 254,763 | 254,763 |
| 3 | CURRENT RATE OF RETURN (L2 / L1) | 6.48% | 3.95% | 4.91% |
| 4 | REQUIRED RATE OF RETURN | 7.76% | 4.73% | 5.88% |
| 5 | REQUIRED OPERATING INCOME (L4 * L1) | 305,051 | 305,051 | 305,051 |
| 6 | OPERATING INCOME DE(SUF)FICIENCY (L5 - L2) | 50,288 | 50,288 | 50,288 |
| 7 | GROSS REVENUE CONVERSION FACTOR | 1.65375 | 1.65375 | 1.65375 |
| 8 | GROSS REVENUE INCREASE | $ 83,162 | $ 83,162 | $ 83,162 |
| 9 | CURRENT REVENUES T/Y ADJUSTED | $ 1,940,807 | $ 1,940,807 | $ 1,940,807 |
| 10 | PROPOSED ANNUAL REVENUE (L8 + L9) | $ 2,023,970 | $ 2,023,970 | $ 2,023,970 |
| 11 | PERCENTAGE AVERAGE INCREASE | 4.28% | 4.28% | 4.28% |

REFERENCES:
COLUMNS (A) THRU (C): COMPANY SCHEDULE A-1
COLUMNS (D) THRU (F): SCHEDULES MDC-2, MDC-4, AND MDC-7

Table 1: The Economic Costs and Benefits of Ratebasing the PWEC Units

| | All Units Annual Savings/(Costs) Current Year $ ($000) | All Units Cumulative Savings/(Costs) Current Year $ ($000) | All Units Annual Savings/Costs PV @ 8.25% ($000) | All Units Cumulative Savings/(Costs) PV @8.25% ($000) | All Units Annual Savings/Costs PV @ 7.07% ($000) | All Units Cumulative Savings/(Costs) PV @7.07% ($000) |
|---|---|---|---|---|---|---|
| 2005 | (76,934) | (76,934) | (71,070) | (71,070) | (71,854) | (71,854) |
| 2006 | 21,100 | (55,834) | 18,006 | (53,064) | 18,405 | (53,448) |
| 2007 | 20,851 | (34,983) | 16,438 | (36,626) | 16,987 | (36,461) |
| 2008 | 13,546 | (21,437) | 9,865 | (26,761) | 10,307 | (26,154) |
| 2009 | 15,030 | (6,406) | 10,112 | (16,649) | 10,681 | (15,472) |
| 2010 | 23,756 | 17,350 | 14,764 | (1,885) | 15,768 | 295 |
| 2011 | 39,106 | 56,456 | 22,452 | 20,567 | 24,242 | 24,538 |
| 2012 | 52,549 | 109,005 | 27,870 | 48,437 | 30,424 | 54,962 |
| 2013 | 38,246 | 147,251 | 18,738 | 67,175 | 20,681 | 75,643 |
| 2014 | 61,101 | 208,352 | 27,655 | 94,830 | 30,858 | 106,501 |
| 2015 | 53,270 | 261,621 | 22,273 | 117,102 | 25,127 | 131,628 |
| 2016 | 55,423 | 317,044 | 21,407 | 138,509 | 24,416 | 156,044 |
| 2017 | 39,191 | 356,235 | 13,984 | 152,493 | 16,125 | 172,169 |
| 2018 | 83,057 | 439,292 | 27,377 | 179,870 | 31,917 | 204,086 |
| 2019 | 108,427 | 547,719 | 33,016 | 212,886 | 38,915 | 243,002 |
| 2020 | 134,350 | 682,069 | 37,791 | 250,677 | 45,035 | 288,037 |
| 2021 | 171,190 | 853,259 | 44,484 | 295,161 | 53,595 | 341,632 |
| 2022 | 154,951 | 1,008,210 | 37,196 | 332,357 | 45,308 | 386,940 |

EXHIBIT
RUCO-13
Admitted

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

DOCKET NO. E-01345A-03-0437

# SETTLEMENT TESTIMONY SUMMARY

OF

STEPHEN AHEARN

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 4, 2004

EXHIBIT

RUCO-14

Admitted

ARIZONA PUBLIC SERVICE
DOCKET NO. E-01345A-03-0437
SUMMARY OF SETTLEMENT TESTIMONY OF STEPHEN AHEARN

---

The settlement testimony of Stephen Ahearn addresses the following aspects of the case:

1. The Public Interest /Public Policy;
2. Competitive Issues; and,
3. Renewable Energy and Energy Efficiency

The following summary seeks to reconcile the settlement's disposition of these issues with RUCO's original filed case.

Public Interest

As distinct from previous APS rate cases, this case provided the opportunity for RUCO and the Commission Staff sufficient time to conduct a full audit of the Company's cost-of-service study and to develop litigation positions and supporting testimony without hurry. It was only after the respective parties' cases were filed that settlement negotiations began.

One measure of the process having met a public interest threshold for appropriateness is the completely inclusive nature of the negotiations themselves. An additional measure of success in meeting public policy objectives is the very substantial, nearly universal consensus ultimately reached on the final settlement agreement itself. That so many parties with conflicting interests could embrace a single result bespeaks a successful process and final product.

The ultimate expression of the agreement having met the Public Interest is the degree to which rate increases have been minimized without jeopardizing the financial integrity of the applicant.

Competitive Issues

Summary of Positions:

The settlement provides for the ratebasing of the PWEC generation assets at the end of this year, keeps alive the possibility of developing successful wholesale and retail electricity markets and provides competitive generators the opportunity to compete for much of the Company's future capacity needs . RUCO's original recommendations contemplated a multi-year phase-in of additional capacity and a termination of retail competition in the state.

Reconciliation of Positions:

RUCO originally suggested a multi-year approach to resolving the PWEC-related issues in this case. Essentially, RUCO argued that the Company's need for the PWEC capacity was not immediate, that all non-ratebase elements of the instant case could be resolved

in this docket, that the PWEC asset-related issues could be put off to another day and that, in any event, the question of the value of the PWEC assets should be subject to a market mechanism such as an auction. The Company made a fair showing through its rebuttal testimony and throughout the settlement negotiations of a need to secure additional capacity sooner rather than later, and the settlement accomplished the asset valuation concern by requiring a heavily discounted transfer price. RUCO's concern about competitive retail markets was heightened by the perception of a transmission-related power grab by the FERC wherever retail markets exist. That and other retail market-related issues raised by RUCO are addressed in the settlement by referring them to the Electric Competition Advisory Group for further evaluation. The settlement tempers a potential over-reliance on wholesale markets with the Company's continued ability to self-build generation under conditions of market failure. In short, the settlement adequately balances the Company's needs with those of its competitors, and minimizes the risks to consumers of exposure to the volatility of pure markets.

Efficiency and Renewables

Summary of Positions:

The settlement funds efficiency demand-side management programs at an average of $16 MM over each of the next three years, funded both through base rates and a one-year lagged surcharge mechanism. Funding for renewables and the EPS remains at current levels, with a provision to adjust upward if the Commission acts to increase the standard and funding needed to meet its goals successfully. RUCO's litigation position sought to fund the EPS entirely through the surcharge, re-assign the existing EPS funding to DSM, to fund DSM entirely through base rates and to increase overall DSM spending to approximately $35 MM annually.

Reconciliation of Positions:

The settlement's final funding level for efficiency DSM of $48 MM over three years is thought by RUCO to be both a reasonable negotiated result of the different parties' beginning litigation positions and a sufficient funding level to adequately underwrite a range of programs that will deliver consequential benefits for all consumers. Finding a way to fund this greatly increased level of efficiency DSM expenditures through a combination of base rates and a lagged surcharge is a creative means to achieve the desirable end. As for the renewables/EPS elements of the settlement, a mechanism to increase funding levels is made available should the Commission determine that additional monies are needed to meet EPS program goals.

Summary

RUCO believes the settlement agreement is a result of informed give-and-take, effective facilitation of a difficult multi-party forum and the recognition of the parties of a fair outcome. As a result, RUCO urges its acceptance.

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

DOCKET NO. E-01345A-03-0437

# SETTLEMENT TESTIMONY SUMMARY

OF

MARYLEE DIAZ CORTEZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 4, 2004

EXHIBIT

RUCO-15

Admitted

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-03-0437
SUMMARY OF THE SETTLEMENT TESTIMONY OF MARYLEE DIAZ CORTEZ

---

The settlement testimony of Ms. Diaz Cortez addresses the following issues:

1) Revenue Requirement
2) Rate Adjustor Mechanisms
3) Rate Design

In the following, Ms. Diaz Cortez summarizes the settlement's position on these issues and reconciles the settlement with RUCO's original litigation positions on these issues.

Revenue Requirements

Summary of Positions:

The settlement agreement provides for a $1,867,084,000 revenue requirement which represents a 3.77% increase over 2002 test year adjusted revenues. This compares with a 9.77% increase as originally requested by APS and a 2.84% decrease originally recommended by RUCO.

Reconciliation of Positions:

While RUCO originally recommended a rate decrease for APS, it must be remembered that RUCO had recommended a two phase process for determining APS's revenue requirement: Phase I addressed all rate case elements except the PWEC asset and Phase II would address the PWEC assets. RUCO's 2.84% decrease recommendation was applicable to Phase I, and thus by definition did not consider the PWEC assets. Had Phase II ever happened, RUCO fully anticipated its Phase I recommendation would incrementally increase proportionate to the amount of PWEC to be included in rate base. Thus, the 2.84% decrease was applicable merely to Phase I and was not representative of RUCO's final recommendation as it would relate to both the Phase I and Phase II issues. RUCO believes the settlement revenue requirement is a reasonable approximation of a revenue requirement that might have come out of a Phase II litigation of the PWEC issue.

Rate Adjustment Mechanisms

Summary of Positions:

The settlement agreement includes two surcharges; a continuation of the existing EPS surcharge and a new Competitive Rules Compliance Charge (CRCC) designed to recover competitive transition costs over a five-year period. The agreement includes the implementation of three new rate adjustor mechanisms: a Power Supply Adjustor (PSA), a Transmission Cost adjustor, and a DSM adjustor. APS's original application requested the two surcharges included in the settlement as well as the PSA and Transmission Adjustors.

APS did not originally request a DSM adjustor. RUCO originally supported the two surcharge charges and opposed the PSA and Transmission Adjustors. While RUCO's original position recommended an increased level of DSM spending, it recommended funding of DSM through base rates, rather than an adjustor.

Reconciliation of Positions:

RUCO did not support the PSA in its original Phase I position because absent the PWEC generation plants, APS's fuel mix was more heavily comprised of coal and nuclear, the cost of which is not currently volatile or widely fluctuating. Under RUCO's Phase I recommendation the proposed PSA did not fit the criteria for a rate adjustor. However, with the settlement's inclusion of the PWEC assets in rate base, the fuel mix becomes more heavily weighted with gas, which would meet the volatility test for a rate adjustor mechanism.

Rate Design

Summary of Positions:

Under the terms of the settlement agreement, the 3.77% rate increase will be allocated among the customer classes as follows:

| | | |
|---|---|---|
| * | Residential | 3.94% |
| * | General Service | 3.50% |
| * | Irrigation | 5.00% |
| * | Lighting | 5.00% |

RUCO's original testimony recommended an even allocation of the required increase (or decrease) across all customer classes. APS also originally proposed an even allocation of the rate increase across all customer classes.

Reconciliation of Positions:

While the settlement rate design does not result in an even allocation of the increase across all customer classes, RUCO was ultimately able to accept the settlement rate design allocation for four reasons:

1) The disparity among the increase allocated to the various rate classes is not material;

2) In return for RUCO's compromise on the rate increase allocation position, it gained acceptance of some of its other rate design goals. This included the preservation of Schedule E-10 and EC-1 residential rates (which APS proposed to eliminate). The elimination of these rates would have had disproportional impacts on the residential customers on these rate schedules.

3) Preservation of time-of-use on-peak and off-peak periods, as well as preservation the existing ratio between on-peak vs. off-peak rates. APS's proposed rates would have modified peak times and materially altered the ratio between on and off-peak rates. This would have dampened any existing incentive to shift on-peak load to off-peak periods.

4) It was very unlikely that a near global settlement would be reached without this rate design compromise. RUCO believed this to be a small concession relative to the beneficial results achieved on the other issues in this case through settlement.

Summary

RUCO believes the settlement reaches a fair and reasonable result for all parties and urges its acceptance.

Southwestern Power

Admitted
EXHIBIT
Southwestern Power 1

Summary of Testimony

of

Tom Wray

on Behalf of

Southwestern Power Group II, L.L.C.

and

Bowie Power Station, L.L.C.

Q.1 Please summarize the proposed testimony that Southwestern Power Group II, L.L. C. and Bowie Power Station, L.L.C. (collectively SWPG/ Bowie) have filed in this proceeding.

A.1 On October 22, 2004 SWPG/ Bowie filed testimony in support of the proposed Settlement Agreement which is currently pending before the Commission in this case. In that testimony, SWPG/ Bowie indicate they support the proposed Settlement Agreement, as it relates to their interests, because (i) it provides a measure of clarity and predictability with regard to Arizona Public Service Company's ("APS") future (or post –2005) procurements of power that was not present after the Commission's Track A and Track B decisions; and (ii) the provisions governing APS' ability to "self-build" generation for the next 10 years restore a measure of that opportunity for growth of the competitive wholesale electric market in Arizona which had existed prior to the Commission's issuance of its Track A and Track B decisions.

Q.2 Please respond to Commissioner Maye's October 29, 2004 letter requesting that all parties to the Settlement Agreement include in the summaries of their testimony (i) a comparison between their original position and their settlement position on significant issues, (ii) an explanation of why their change in position is believed to be in the public interest, and (iii) why they changed their position(s) on the issue(s) in question.

A.2 I will try to be responsive, consistent with the recognition that the negotiations resulting in the proposed Settlement Agreement were conducted in confidentiality under the Arizona Rules of Civil Procedure, and with the understanding that the specific content of the discussions would not be admitted into evidence in any subsequent litigation, which in our view included hearings in this case.

SWPG/ Bowie did not file any testimony prior to October 22, 2004. Thus, their "original position" was reflected in the direct testimony submitted by the Arizona Competitive Power Alliance ("Alliance") on February 3, 2004. The Alliance's witness, Greg Patterson, will be responding to Commissioner Mayes' request on behalf of the Alliance.

SWPG/ Bowie's individual intervention in this case, as well as their participation through the Alliance, was occasioned by their desire to preserve as much as possible that opportunity for the development and growth of a competitive wholesale electric market in Arizona which had been envisioned by AAC R14-2-1606(B) and AAC R14-2-1615(A). The Commission's Track A and Track B decisions had had the effect of reducing the potential size of that competitive market from what it otherwise would have been under the Commission's Electric Competition Rules. In our opinion, Commission acceptance of APS's proposed acquisition and rate basing of Pinnacle West Energy Corporation's ("PWEC") electric generation assets in Arizona would have further reduced the size of that market. Thus, we actively supported the arguments against APS' proposal set forth in the direct and surrebuttal testimony filed by the Alliance.

As any party who has been a litigant is aware, no advocacy position is without the risk of loss, regardless of how strongly one may believe in the merits of its position. That is because the ultimate decision on the merits as to a given issue is made by an independent third party. In this case, that third party is the Commission. Being aware of this fact, and with the underlying goal of trying to preserve as much of the opportunity for a competitive wholesale market in APS' service area as might be possible, SWPG/ Bowie entered the settlement negotiations with a willingness to explore alternatives to their original advocacy position.

As the settlement negotiations progressed, and various parties began to shift from their respective original advocacy positions, SWPG/ Bowie came to the conclusion that there was not a broad base of support for their original position on the PWEC generation asset issue. Thus, they began to explore the feasibility of alternative means by which their goal of preserving a meaningful opportunity for a competitive wholesale market for the foreseeable future might be achieved. This was particularly important for the Bowie Project, because the first power block will not come on line before late 2007 or early 2008.

It ultimately became apparent that a combination of the provisions governing APS' post-2005 power procurements, and the conditions governing APS' ability to "self-build" generation during the next 10 years, represented an alternative means by which SWPG/ Bowie could achieve their strategic objective through negotiation. Thus, they actively supported that approach both individually and as members of the Alliance. Fortunately, other parties to the settlement negotiations were acceptive to that approach as well.

The determination of what is in the "public interest" is appropriately a decision for the Commission to reach. However, SWPG/ Bowie believe that the proposed Settlement Agreement produces a result on the PWEC generation asset issue which is in the "public interest" because it facilitates the preservation of a meaningful opportunity for wholesale electric competition within APS' service area while simultaneously addressing certain concerns that APS and the Commission's Staff had expressed. In our view, that would not be the situation if APS was allowed to acquire and rate base the PWEC generation assets without the power procurement and "self-build" provisions of Sections IX of the proposed Settlement Agreement.

Q.3 Does this complete the summary of your previously filed testimony, and your response to Commissioner Mayes' request?

A.3 Yes, it does.

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Admitted

EXHIBIT

Southwestern Power 2

# TESTIMONY OF TOM WRAY

# ON BEHALF OF

# SOUTHWESTERN POWER GROUP II, LLC

# AND

# BOWIE POWER STATION, LLC

**DOCKET NO. E-01345A-04-0437**

Q.1 Please state your name and business address.

A.1 My name is Tom Wray. My business address is: 4350 E. Camelback Rd., Phoenix, Arizona.

Q.2 On whose behalf are you appearing in this proceeding?

A.2 I am appearing on behalf of Southwestern Power Group II, LLC ("SWPG") and Bowie Power Station, L.L.C. ("Bowie"). I am General Manager of SWPG. SWPG and Bowie have participated throughout the proceeding, both as members of the Arizona Competitive Power Alliance ("Alliance"), and as an individual intervenor.

Q.3 Did SWPG/ Bowie participate in the settlement negotiations which have resulted in the proposed Settlement Agreement which is currently pending before the Commission?

A.3 Yes. We were actively involved throughout those negotiations.

Q.4 Do SWPG/ Bowie support Commission approval and adoption of the provisions of the Settlement Agreement, and the various regulatory actions by the Commission which the Settlement Agreement contemplates?

A.4 Yes, we do.

Q.5 What are the reasons for your support?

A.5 Greg Patterson's testimony on behalf of the Alliance provides a general discussion of the reasons why SWPG/ Bowie believe that the proposed Settlement Agreement is both in the public interest, and in the interest of Arizona's independent power producer or merchant generator community.

SWPG/ Bowie have been authorized to site and construct a 1,000 MW natural gas-fired, combined cycle electric generating station near Bowie, Arizona. Our current plans are to place the first power block into commercial operation in late 2007 or early 2008. A particular benefit for SWPG/ Bowie is the clarity and predictability that the Settlement Agreement provides with regard to future procurements of power by Arizona Public Service Company ("APS"), commencing with the RFP for 1,000 MW of power beginning in 2005. While that RFP may or may not offer SWPG/Bowie a possible market opportunity for some of the output from the Bowie plant, we believe that the proposed Settlement Agreement provisions governing APS' future (or post-2005) procurements of power provide a clarity and predictability that was not readily apparent following the Commission's issuance of its Track B decision, and its conduct of the initial Track B solicitation.

In addition, the conditions and procedure set forth in the proposed Settlement Agreement which would govern any "self-build" activities by APS until 2015 are also very important to independent power producers, such as SWPG/Bowie, who were attracted to the prospective competitive wholesale electric market in Arizona before the Commission's issuance of its Track A and Track B decisions. Those decisions arguably had the effect of reducing or freezing the size of that competitive market which otherwise might have existed under R14-2-1606(B) and R14-2-1615(A) prior to the issuance of the Track A and Track B decisions. The "self-build" provisions of the proposed Settlement Agreement, in our opinion, restore a measure of that opportunity for growth of the competitive wholesale market that had previously existed, with a resulting atmosphere of stability for the merchant generator community in Arizona and the competition it seeks to provide. At the same time, the proposed "self-build" conditions and procedure reserve to the Commission the discretion to expressly authorize APS to self-build prior to 2015 as to a particular demonstrated need, when the competitive market has not been responsive to its needs, with a view towards providing for that end result which is in the best interest of APS' ratepayers.

Q.6 Do SWPG/ Bowie believe that the proposed Settlement Agreement is beneficial from the perspective of the other parties to this proceeding?

A.6 Obviously that is a conclusion for those parties to reach as to their respective interests, or the interests of those for whom they speak, and to express themselves accordingly. However, it is worth noting that of the approximately 30 parties who participated in the settlement negotiations, 25 have signed the proposed Settlement Agreement, 4 have expressed no opposition, and only 1 is opposed.

Q.7 Does that complete your testimony?

A.7 Yes, it does.

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# Staff

EXHIBIT
S-1
Submitted

**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THERON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | ) | DOCKET NO. E-01345A-03-0437 |

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DIRECT

TESTIMONY

OF

LINDA A. JARESS

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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**EXECUTIVE SUMMARY**
**ARIZONA PUBLIC SERVICE COMPANY**
**DOCKET NO. E-01345A-03-0437**

Staff recommends a **decrease** in APS' revenue requirement of $142.7 million or 8.0 percent compared to APS' request for an increase of $175.1 million or 9.8 percent. The single largest disputed issue in this case is the treatment of the Pinnacle West Energy Corporation ("PWEC") assets which have a revenue impact exceeding $100.0 million per year. Staff is recommending against ratebasing the PWEC assets in large part because APS has not demonstrated that these assets represent the best economic choice for its customers. Further, inclusion of the PWEC assets in rate base may negate over $200.0 million in expected savings (over a three-year period) associated with the Commission's competitive bidding process carried out under Track B.

Staff's recommended decrease was derived using an original cost rate base of $3.1 billion, a rate of return on original cost rate base of 7.26 percent and a cost of equity of 9.0 percent. APS' request for an increase was derived from a rate base of $4.21 billion, an 8.67 percent rate of return and an 11.5 percent cost of equity. Staff's lower recommended rate of return better recognizes interest rates that have declined significantly in the past twenty years to levels comparable to the 1950 and '60's.

Staff also recommends that APS should not recover the $234.0 million that APS wrote-off as a result of the order approving the 1999 Settlement Agreement and now proposes to recover over a fifteen year period. Staff's testimony shows that recovery of the $234.0 million does not meet standard rate-making criteria and that the going-forward revenue requirements have not been reduced by the write-off.

Staff is opposed to a fuel or purchased power adjustor that does not prevent unintended benefits to APS' shareholders and harm to customers under high load growth conditions.

Regarding the preliminary inquiry ordered by the Commission in Decision No. 65796 and moved to this case, Staff believes that APS' actions during the transition to competition violated the spirit, if not the letter, of the Retail Electric Competition Rules, the Code of Conduct and the order approving the 1999 Settlement Agreement. Also, the public statements made by APS, PWEC and Pinnacle West Capital Corporation representatives are conflicting regarding the purpose for which certain PWEC generating plants were built.

## INTRODUCTION

**Q. Please state your name, occupation, and business address.**

A. My name is Linda A. Jaress. I am an Executive Consultant III in the Utilities Division of the Arizona Corporation Commission ("ACC" or "Commission"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

**Q. Please state your educational background and professional experience.**

A. I received a Bachelor of Arts Degree from Michigan State University and a Master of Business Administration Degree from the University of Hawaii. I was employed as a Research Analyst for the Hawaii Trucking Association from 1977 through 1978 and as a Financial Analyst for the State of Hawaii, Division of Consumer Advocacy from 1980 through 1985. In 1985, I was employed by the Arizona Corporation Commission ("Commission") as a Senior Rate Analyst and received a promotion to Manager, Financial Analysis in 1991. I also served as the Acting Chief of the Accounting and Rates Section for a total of 12 months during 1997 and 2000. On January 1, 2001, I was promoted to the position of Executive Consultant III.

**Q. Please list your duties and responsibilities as Executive Consultant III.**

A. I complete special projects for the Director and Assistant Directors. Among those projects are report writing and oversight of the RFP process for most of the RFPs issued by the Utilities Division. I also write testimony and Staff Reports and serve as the Director's Office liaison with consultants.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to summarize Staff's testimony and recommendations regarding Arizona Public Service Company's ("APS") request for an increase in rates. I

will address some of the broader assertions of APS witnesses that ratepayers are obligated to reimburse APS for a $234 million write-off it made as a result of the order approving the 1999 Settlement Agreement and that the Commission is obligated to rate base the generation assets of Pinnacle West Energy Corporation ("PWEC"). I will also address APS' request for Commission approval of the APS/PWEC power contract. Finally, my testimony will provide the results of the preliminary inquiry ordered by Decision No. 65796.

## SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

**Q. Please discuss the most significant issues in the rate case and summarize Staff's position or recommendation on each issue.**

A. APS proposed a $175.1 million, or 9.8 percent increase in revenues. Staff recommends a $142.7 million, or 8.0 percent **decrease** in APS revenues. The single largest disputed issue in this case is the treatment of the assets of APS' affiliate, Pinnacle West Energy Corporation ("PWEC"). Exclusion of these assets from APS' rate base reduces APS' annual revenue requirement by over $100.0 million.

Staff is recommending against ratebasing the PWEC assets in large part because APS has not demonstrated that these assets represent the best economic choice for its customers. Further, inclusion of the PWEC assets in rate base may negate over $200.0 million in expected savings (over a three-year period) associated with the Commission's competitive bidding process carried out under Track B.

APS' requested increase was derived from an original cost rate base of $4.21 billion, an 8.67 percent rate of return and an 11.5 percent cost of equity capital. Staff's decrease was derived from an original cost rate base of $3.1 billion, a rate of return on original cost rate

base of 7.26 percent and a cost of equity of 9.0 percent. Staff's lower cost of capital better recognizes interest rates that have declined significantly in the past twenty years to levels comparable to the 1950 and '60's.

APS also requested the recovery of $234 million ($183 million after tax) that it wrote off after the 1999 Settlement Agreement. Staff testimony shows that recovery of the $234 million does not meet standard rate-making criteria that rates should reflect test-year or ongoing costs and that the going-forward revenue requirements have not been reduced by the previous write-off. Staff does not believe that the $234 million represents stranded costs, but if interpreted as stranded costs, the amount should not be collected because the Company will have collected its stranded costs through other provisions of the order approving the 1999 Settlement Agreement.

APS requested an increase in fuel and purchased power expenses of $121 million over those recorded during the 2002 test year. Most of the increase is attributable to the increased costs of gas. Staff is recommending that rates include an increase of $114.6 million for fuel and purchased power.

Staff's review of APS' cost estimate for decommissioning the units at the Palo Verde Nuclear Generating Station ("Palo Verde"), concludes that, for the most part, APS' cost estimates conform to the methodology employed in the industry and are consistent with the minimum requirements of the Nuclear Regulatory Commission. However, Staff reduced the annual contribution of APS customers for decommissioning to reflect a higher residual value of some of the structures, systems and infrastructure of Palo Verde. Also, Staff adjusted the Unit 2 decommissioning funding schedule so it matches the licensed life of the unit.

Staff opposes a fuel and/or purchased power adjustor unless APS is able to resolve a critical imbalance that would occur under certain conditions. An imbalance to the detriment of customers would occur between the recovery of fixed production costs through base rates and the recovery of fuel and purchased power expenses through the adjustor mechanism during periods of high load growth.

Staff recommends spreading the rate decrease over all customer classes, although at different percentages. A cost of service study was used by Staff as a guide to determine those percentages, but the overriding factor in our rate design guidelines was ensuring that all customers benefited from the rate decrease.

Staff recommends that APS recover its costs for pre-approved demand-side management (DSM) programs through a DSM adjustment mechanism. Staff recommends that the caps per service on the EPS-1 surcharge tariff be increased to help APS meet its Environmental Portfolio Standard requirements. This will result in an increase in spending for renewables of $4.4 million. Staff does not oppose APS' requested Returning Customer Direct Assignment Charge with conditions. Finally, Staff recommends some changes to the selected charges and wording on APS' proposed service schedules.

**Q. Provide the names of Staff's witnesses and the subject matter of their testimony.**

A. The chart shown below lists each Staff witness and the subject matter of their testimony.

| Witness | Consultant or Utilities Division Staff | Topical Areas |
|---|---|---|
| Linda Jaress | Staff | Summary of Staff's Case, Response to Certain APS Assertions and Results of Preliminary Inquiry |
| Barbara Keene | Staff | System Benefits, Env. Port. Std. DSM, RCDAC and Service Schedules |
| Joel Reiker | Staff | Capital Structure, Cost of Debt, Return on Equity and Overall Cost of Capital |
| Erinn Andreasen | Staff | Rate Design |
| Lee Smith | LaCapra Associates | Cost Allocation, Competition Rules Compliance Charge Treatment of Transmission Costs and Adjustor, $234 M Write-Off. |
| Harvey Salgo | LaCapra Associates | Regulatory Treatment of PWEC Assets and Track B Purchased Power Contracts |
| Doug Smith | LaCapra Associates | Purchased Power and Fuel Costs and Off-system Sales. |
| Michael J. Majoros, | Snavely King Majoros O'Connor & Lee | Depreciation |
| Steven Carver | Utilitech, Inc. | Rate Base and Income Statement Adjustments – Cash Working Capital, Severance Costs |
| James Dittmer | Utilitech, Inc. | Rate Base and Income Statement Adjustments – Property Taxes, Econ. Development/ Advertising |
| Harold Judd | Accion Group | Nuclear Decommissioning Planning and Funding |

**Q. Provide a brief reconciliation of APS' revenue requirement request with Staff's recommendations.**

A. Below is a chart that reconciles the major differences between APS' and Staff's revenue requirement recommendations. The chart begins with APS' requested increase, then

illustrates the most significant individual reductions recommended by Staff and ends with the resulting Staff recommendation for a decrease in revenue requirements.

| **APS' Recommended Overall Rate Increase ($000)** | **$175,090** |
|---|---|
| **Less:** | |
| Rate Base and Operating Income Impacts of Removal of PWEC Assets from Rate Base | (105,539) |
| Difference in Cost of Capital | (74,644) |
| Difference in Proposed Depreciation Rates (other than PWEC Assets) | (40,703) |
| APS' Proposal to Reverse 1999 Settlement Write Down -- Rate Base & Expense Amortization | (29,674) |
| APS' Proposed Inclusion of Non-Cash Expenses in Lead Lag Study & Other Corrections | (10,291) |
| Difference in Property Tax Expense | (9,196) |
| Disallowance of Discretionary Economic Development, Advertising & Charitable Contributions Expense | (6,872) |
| Eliminate APS' Proposed Amortization of Severance Costs | (6,189) |
| Difference in Fuel & Purchased Power Costs with PWEC Excluded from Rate Base | (6,020) |
| Difference in Recommendations for Nuclear Decommissioning Provision | (5,697) |
| Difference in Methods of Jurisdictional Allocations | (5,076) |
| All Other Miscellaneous Rate Base & Operating Expense, and CRCC Differences | (22,279) |
| Environmental Portfolio Standard Revenues | 4,400 |
| **Staff's Proposed Overall Rate (Decrease)** | **($142,690)** |

**REBUTTAL OF MR. WHEELER AND DR. HIERONYMUS**

**Q. Please address the "equitable considerations" that Mr. Wheeler's direct testimony requests the Commission address in its Decision.**

A. Mr. Wheeler requested that the Commission rate base certain of the PWEC assets as reparation or "equitable consideration" for halting divestiture of APS' generating plants. He testified that "APS and its affiliates made concessions of considerable value and have relied in good faith to their ultimate detriment on the restructuring requirements of the

Electric Competition Rules and the promises of the 1999 Settlement." Also, Mr. Wheeler testified that "Along with reversal of the 1999 Settlement $234 million write-off, rate basing the PWEC assets will significantly mitigate the unaddressed impacts resulting from that Order."

Staff disagrees with Mr. Wheeler's assumption that the Commission must rate base the PWEC assets and allow APS to reverse the $234 million write-off in order to appropriately address the impacts of the Track A order. First, Staff Witness Lee Smith discusses in detail why it is not necessary for the Commission to allow APS to reverse the $234.0 million write-off related to the 1999 Settlement Agreement and how APS has not shown that the write-off was detrimental.

Second, the Commission has taken extraordinary actions to prevent "detriments" to the financial health of APS and its affiliates from the change in the course of divestiture. Decision No. 65434, dated December 3, 2002 approved APS' emergency request for a waiver of the Affiliated Interests Rules to loan PWCC $125.0 million when PWCC lost its ability to renew a bank facility. The speed with which the Commission responded is a further indication of the Commission's willingness to address the impacts of the Track A order. The application was filed on November 8th and the Decision was issued less than one month later.

Decision No. 65796, issued April 4, 2003, approved a $500.0 million loan or guarantee from APS to PWEC. The Decision recognized that, with conditions, the financing was in the public interest even though acknowledging on page 39 that "the transaction poses some risks to the Company and to its ratepayers..."

Finally, within this case, Staff is making two recommendations that, if adopted, will also help ensure that APS and its affiliates do not suffer "detriments". First, as will be discussed below, Staff is recommending the Commission approve the costs related to the APS/PWEC purchased power contract entered as a result of the Track B solicitation. Ordinarily, utilities do not request, Staff does not recommend, nor does the Commission approve, future purchased power contract costs. Second, Staff is recommending approval of the Competition Rules Compliance Charge ("CRCC") that recovers the reasonable costs incurred by APS during its compliance with the Retail Competition Rules. Staff's recommendation includes the extra thirty-three percent of the costs of divestiture that, according to the Addendum to the 1999 Settlement Agreement, APS' shareholders were to bear. Thus, both Staff and the Commission have taken actions to address the impacts of the Track A order.

**Q. Please address Dr. Hieronymus' assertions in his testimony that the Commission should determine the prudence of the Redhawk, West Phoenix and Saguaro generation units when constructed by PWEC and that it is <u>not</u> appropriate to analyze the contemporary economics of the PWEC generation when determining their rate base treatment.**

A. Staff strongly disagrees with Dr. Hieronymus' testimony on this issue. The prudence of the construction and cost of construction of assets owned by a non-utility enterprise (PWEC) is irrelevant to the determination of APS' rate base. Certainly, the potential transfer price along with APS' need for assets from a non-utility would be of interest to the Commission. However, if APS were purchasing assets from another, non-affiliated generating company and requested rate base treatment of those assets, the prudence, or for that matter the purpose, of the assets when originally built would have no relevance to the Commission's decision to rate-base or not rate-base the assets.

Finally, it would be neither logical nor fair to APS' ratepayers for the Commission to allow rate base treatment of assets constructed by a non-utility based on circumstances when the assets were built and ignore whether or not they are prudent additions to APS' generation portfolio today.

**REQUESTED APPROVAL OF THE APS/PWEC CONTRACT**

**Q. Mr. Wheeler also requested that the Commission approve and "assure cost recovery" of the recently executed Track B power contract between APS and PWEC. Why does APS believe Commission approval is necessary?**

A. Section 3.4 of the APS Master Power Purchase and Sale Agreement that applies to the APS/PWEC contract includes the following language:

> "APS will file with the ACC an application for approval and full cost recovery by APS for such Transactions within sixty (60) days after acceptance of the Transaction ("the Request for Approval"). If the ACC has not issued a final order expressly approving full recovery of all costs incurred by APS in such Transactions within twelve (12) months of the submission of the Request for Approval either party may, at its option, terminate the Transaction as to any and all deliveries on or after January 1, 2006 without further liability."

Also, Mr. Wheeler's testimony stated that "APS cannot afford to jeopardize its rights under the contract" and that APS is making the filing in this case, "to protect its rights under the PWEC contract, which is critical to meeting the needs of APS customers..." These statements imply that if the Commission does not approve the APS/PWEC contract, PWEC or APS might exert their rights to terminate the contract after January 1, 2006 leaving APS open to the market for a large amount of power.

**Q. What is Staff's recommendation regarding the approval of the APS/PWEC contract?**

A. The Commission generally has not approved the purchased power contracts of investor-owned utilities. The Commission determines the reasonableness of the expenses incurred under purchased power contracts after the contracts are in effect. However, Staff believes that the APS/PWEC power contract is extraordinarily favorable to customers. Thus, Staff recommends that the Commission take the highly unusual step of approving the costs incurred under the APS/PWEC contract as requested.

**Q. Should the Commission continue to pre-approve the costs incurred under APS' purchased power contracts?**

A. It is the utility's responsibility to enter prudent contracts whether for power, fuel or office supplies, and the risk of recovery of the costs incurred under those contracts should remain with the utility. If not for the special circumstances of this case, Staff would recommend that the Commission dismiss the application for pre-approval of "full recovery of all costs" incurred in this purchased power contract. In fact, the Commission should put APS on notice that it is APS' responsibility to write and manage its power contracts in a prudent manner. If APS writes a clause into a contract that relies upon an action of the Commission, the risk that the Commission may not take that action should be born by APS.

## PRELIMINARY INQUIRY INTRODUCTION

**Q. How is your testimony on the preliminary inquiry organized?**

A. First, I will provide the background of the Commission's Decision to direct Staff to conduct a preliminary inquiry. Then, I will address specific concerns about Arizona Public Service Company's ("APS") actions listed in that Commission's decision.

**Q. What conclusions have you drawn from the inquiry?**

A. I conclude that APS' actions during the transition to competition violated the spirit, if not the letter of the Retail Electric Competition Rules ("the Rules"), the Code of Conduct and the order approving the 1999 Settlement Agreement ("Settlement Agreement".) APS took actions that increased its natural competitive advantage to the detriment of others who intended to participate in electric competition. Although these actions should also be judged independent of their consequences, ratepayers appear to have been unharmed by the actions at issue.

## ORIGIN OF THE INQUIRY

**Q. Provide the background of this preliminary inquiry.**

A. The preliminary inquiry was ordered by the Commission on April 4, 2003, in Decision No. 65796 which approved, with conditions, the application of APS to issue up to $500.0 million of debt and loan the proceeds to PWEC ("the Financing case"). The purpose of the debt was to enable PWEC to refinance shorter-term bridge loans incurred for the construction of generation assets in Arizona and Nevada.

**Q. Provide the portions of Decision No. 65796 that supported and required the preliminary inquiry.**

A. In Note 18, on pages 33 and 34, the Decision said:

> "During that two-year period [January 1, 2001 to January 1, 2003,] APS' parent formed competitive affiliates, including PWEC, and PWCC/PWEC built 4 new generating units and obtained a contingent investment grade rating for PWEC…APS' position in this application that these assets were "dedicated" to APS customers raises the issue of possible intended noncompliance with the Commission's electric competition rules and/or possible anti-competitive activity."

On Page 34, lines 16 through 21, the Decision said,

> "Further, we believe that a preliminary inquiry into APS, PWCC, and PWEC's actions related to the transition to electric competition, particularly compliance with our electric competition rules and with Decision No. 61973 and APS' activities with its affiliates should be undertaken by Staff. Of concern to us is testimony and evidence elicited during this hearing of the PWCC enterprise's possible use of APS (both its generation assets and captive ratepayers) to gain advantage in the developing competitive environment."

And, on Page 44:

> "That Staff shall commence a preliminary inquiry into Arizona Public Service Company and its affiliate's compliance with the Electric Competition Rules, Decision No 61973, its Code of Conduct, and applicable law."

**Q. How was the inquiry conducted?**

A. I reviewed the record in the financing case that resulted in Decision No. 65796, ("the Financing Decision"), including the testimony, hearing transcripts, and Open Meeting transcripts. Data requests and responses from the financing case were reviewed and additional data requests were sent. I also reviewed relevant data responses in this rate case. The Rules, the APS Code of Conduct, Decision No. 61973, the Settlement Agreement, APS and PWCC 10Ks and 10Qs filed with the Securities Exchange Commission and annual reports were also reviewed. I also reviewed recordings of the 2000 presentation to rating agencies made by PWCC and APS officers.

**Q. Please summarize the five issues raised by the Decision that you are going to address in your testimony.**

A. A significant portion of the Financing Decision was devoted to concerns over how PWEC was able to obtain an investment grade rating from bond rating agencies in early 2001

when it was seeking to acquire long-term financing to construct generating plants. The Decision discussed possible contractual relationships among APS, PWEC and parent, Pinnacle West Capital Corporation ("PWCC") that resulted in an APS commitment to purchase either directly or indirectly, the full output of the PWEC plants for four years ending December 31, 2004. The four-year period would have extended into the time when APS was required to be purchasing its power directly from the market through competitive bids and arms-length transactions. The issue of whether the presentation of the contracts to the bond rating agencies gave the PWCC entities an unfair competitive advantage will be addressed as Issue #1.

Issue #2 raised by the Decision is the existence of a contract between APS and an affiliate that may have been anti-competitive. PWEC's construction of generating plants with the explicit intention of serving APS is Issue #3.

Another concern expressed in the Decision, Issue #4, is related to APS' assertion that it could not build plants during the period between the approval of the Settlement Agreement and divestiture. Issue #5 is the fairness of APS' application for an air quality permit on behalf of PWEC. Finally, Issue #6 addresses the transfer of land from APS to PWEC for the purposes of the construction of the generating plants by PWEC.

**ISSUE #1 – PWEC'S REPRESENTATIONS TO THE BOND RATING AGENCIES**

**Q. What information was provided to the bond rating agencies in early 2001 that may have increased the bond rating of PWEC and given it an unfair advantage in the nascent Arizona retail electric competition market?**

A. At least one of the bond rating agencies was provided with draft contracts that, if consummated, would have resulted in APS' purchase, directly or indirectly, of all of the output of PWEC until December 31, 2004.

**Q. Why are contracts for the output of generating plants important to bond rating agencies?**

A. Bond ratings generally reflect the level of risk in an investment. An investment in a merchant generating plant that is either planned or under construction is safer if a contract has been entered for the sale of all of the plant's output compared to an investment in a plant with no assured purchaser of its output. A safer investment receives a higher bond rating. Bonds with higher ratings have lower interest rates. All else held constant, the ultimate cost of the power from a merchant plant with a higher bond rating will be lower than the cost of power from a plant with a lower bond rating.

**Q. Why would it have been unfair for PWEC to represent to the bond rating agencies that it had a firm purchaser for all of its power for four years?**

A. It would have been unfair because it would indicate to the rating agencies that few or none of the other merchant plants would be selling much or any power to APS, the largest electric utility in Arizona. This would put the other plants at a disadvantage in obtaining a favorable bond rating, attracting financing or generating revenue because their potential market would shrink considerably.

**Q. How do you know that the bond rating agencies were supplied with draft contracts?**

A. One of APS' supplemental responses to Panda data request 1.42 in the Financing case, shows that the bond rating agencies were supplied with the draft contracts.

**Q. During the hearing in the Financing case, what did APS say was the purpose of the contracts?**

A. Ms. Barbara Gomez (Treasurer of APS, PWCC, PWEC, and APS Energy Services) testified that the contracts were used as modeling assumptions and "stress tests" during PWEC's negotiations with the bond rating agencies. One line of questions from both Panda and the Administrative Law Judge to Ms. Gomez was related to the aforementioned contracts. Here is one exchange between Ms. Gomez and Mr. Engleman who represented Panda:

> Q. Isn't it correct that APS – or excuse me – that Pinnacle West Energy Corp. told the credit rating agencies that they had a contract to sell all of their output and that it would continue for four years?
> A. Basically, what it is is that we made the assumption that there would be a purchased power agreement occurring…So the assumption was made that for the first two years, '01 and '02, that there would be 100 percent of PWEC's assets would be sold back to APS. And from '03 on, it was assumed that it would go through the competitive bid process. But it was assumed that there would be the four years of a PPA. And then that PWEC, the way the rating agencies like to look at it, is they assume that it's 100 percent merchant thereafter because we had no signed contracts to be able to show them.
> Q. When you say 100 percent merchant thereafter, after 2004 or after January 1, 2002?
> A. After 2004. (January 8, 2003 Transcripts pages 143 and 144)

**Q. Did the bond rating agencies realize that the contracts supplied to them were draft contracts?**

A. Apparently Standard and Poor's believed they were valid contracts. In Exhibit Panda-5 placed in evidence in the Financing hearing, Standard and Poor's supported its April 18,

2001 triple "B" corporate credit rating of PWEC as reflecting "A four year purchased power agreement (PPA) with APS that provides a secure off-taker for 100% of PWEC's capacity through 2002, though less than 50% for 2003 and 2004."

In another APS response to Staff 11-64, APS provided an article by Moody's Investors Service dated April 18, 2001 that said, "Although APS will be moving its generating assets into PWEC, Moody's expects the relationship between PWEC, PWCC and APS to function as a vertically integrated utility servicing the needs of Phoenix, especially during the next four years." And Moody's also commented that "The signing of the all-requirements contracts coupled with PWEC's plans to add significant electric capacity in Arizona demonstrate a commitment to that strategy." Thus, whatever information APS had given to Moody's, the analyst writing the article clearly believed the contracts were signed and resulted in relationships among the PWCC affiliates that would result in operations substantially the same as before divestiture.

**Q. Have the bond rating agencies indicated the extent to which their bond ratings for PWEC were influenced by the existence of the draft contracts?**

A. No, they have not. Staff sent APS data requests (LAJ 5.41) asking APS to ask the bond rating agencies to supply that information. APS responded that it had directed the questions to the appropriate individuals at Standard and Poors and Fitch. As of the date of the filing of this testimony, Staff has not received any further responses.

**ISSUE #2 – APS' DIRECT OR INDIRECT CONTRACT WITH ITS GENERATION AFFILIATE**

**Q. How did the Rules limit APS' purchases from PWCC and PWEC?**

A. A.A.C. R14-2-1615 (A) required divestiture of APS' competitive assets including generation by January 1, 2001. This date was extended to January 1, 2003, by the Settlement Agreement. The language in the Rules limiting APS' power purchases after January 1, 2003, reads as follows:

> A.A.C. R14-2-1606.B. After January 1, 2001, *[January 1, 2003 for APS]* power purchased by an investor owned Utility Distribution Company for Standard Offer Service shall be acquired from the competitive market through prudent, arm's length transactions, and with at least 50% through a competitive bid process."

Thus, APS would need to have divested its generation, become a distribution company and be purchasing all of its power to sell to Standard Offer Customers from the market by the same date of January 1, 2003.

**Q. Did the Settlement Agreement allow APS to purchase power from PWEC, the affiliate to which APS was transferring its generation assets?**

A. Yes, it did. The Addendum to the Settlement Agreement filed in compliance with the Decision approving the Settlement Agreement provided that:

> "An affiliated generation company formed pursuant to this Section 4.1 may competitively bid for APS' Standard Offer load, but enjoys no automatic privilege outside of the market bid on account of its affiliation with APS."

**Q. Was there any prohibition against PWCC selling power to APS?**

A. No. But such sales, according to the Rules, would have to be either through competitive bid or through an arm's length transaction.

**Q. From the two excerpts from the Rules and the Addendum shown above, what do you believe the Commission intended?**

A. The Commission expected a competitive bid process where (if it desired to sell power to APS) PWEC, the "affiliated generation company" would bid to supply APS power for its Standard Offer Customers on an equal basis with other generating companies and that APS would enter power contracts in arms-length transactions.

**Q. Please describe the contracts supplied in response to Panda data request 1.42.**

A. One contract was a Power Sale Agreement between PWEC and PWCC, by and through its marketing and trading division and pursuant to PWEC's market rate tariff and service agreement. Under this contract, PWEC would sell all of its output to PWCC. The other contract was between PWCC and APS whereby PWCC would supply all of APS' power.

These contracts appear to be fully developed, detailed purchased power agreements containing the term of the contract (beginning when the APS generation fossil assets transferred to PWEC through December 31, 2004), the date of the contract (January 1, 2001), and exhibits. In the contract between PWEC and PWCC, the exact amounts of fixed payments to be made by PWCC are delineated in an appendix, shown separately for each month for certain identified units. Formulae are given to determine after-the-fact adjustments for actual vs. projected gas burns and for variable payments for certain units. Names and titles are printed under the signature blocks, but the copies provided were not signed. The agreement between PWCC and APS is similarly written, but not identical.

According to a response to Staff data request LAJ 6.4, the primary author/drafter of both of the contracts was an attorney with Pinnacle West Capital Corporation.

**Q. What is the significance of the December 31, 2004 ending date of the contracts?**

A. December 31, 2004 is two years after the date when APS was required to be purchasing power "from the competitive market through prudent, arm's length transactions, and with at least 50 percent through a competitive bid process."

**Q. In conducting this inquiry, have you become aware of any competitive bid process that APS conducted that resulted in the draft contract with PWCC?**

A. No, I am not.

**Q. Do you believe the draft contracts were negotiated as arms length transactions?**

A. No, I do not.

First, in response to LCA 3-68, APS revealed that from 1997 until the Track A Order, resource planning and generation were part of the same business unit and that this unit was "to encompass both APS generation for as long as that generation remained at APS, and any new generation affiliate required by the ACC." This implies that at least until the Track A order in September, 2002, APS and PWEC planning and generation activities were joint.

Second, according to APS witness Dr. Hieronymus, on page five of his direct testimony, "planning functions sometimes were wholly in APS and sometimes were split between APS, PWEC and Pinnacle West corporate." This statement indicates that there were no clear lines of demarcation regarding which entity was planning for which entity. Under

such relationships, arms-length transactions among the affiliates would be difficult, if not impossible.

Finally, APS itself acknowledges in its response to STF11-66 that it may be impossible for affiliates to enter arms-length transactions between and among themselves. When asked to explain how the draft contracts fulfilled the arms-length transaction requirement of Rule 1606 (B), APS replied that "...with those caveats [Rule 1606(B) wasn't in effect yet] APS has interpreted the term 'arms-length' in terms of *result* rather than in terms of *process*. (emphasis added) This is necessarily so since affiliates cannot, as a practical matter, negotiate as if they were not affiliates."

**Q. How did APS reach the conclusion that it did not need to purchase power through arms-length transactions or competitive bid as required by the Rule and the order approving the 1999 Settlement Agreement?**

A. In response to data request LAJ-6.27, a question about the potential impact of the APS/PWCC and the PWEC/PWCC draft contracts, APS indicated that it believed the Rule did not forbid bi-lateral contracts. The relevant portion of APS' response is as follows:

> "Also, at the time the PPA arrangements were developed, there was no guidance from the Commission as to how either the 50% 'competitive bid' provision of Rule 1606(B) would work in practice even after it became effective in 2003...Likewise, the portion of APS needs post-2002 that Rule 1606(B) clearly allowed to be obtained through bilateral contracts of the type contemplated in the then-anticipated PPA was only limited by the need for it to come from 'the wholesale market' and be 'arms length.' The 'wholesale market' was precisely where PWCC was to obtain power for APS needs (PWEC is as much a part of the 'wholesale market' as any non-affiliated generator), and there was no reason for APS or PWCC to believe that the Commission would conclude that a market-based PPA for the remaining 50 percent of APS' requirements, (even if supplied, at least in part, from the assets that APS was required to divest), would not comply with that requirement of Rule

1606(B), or that the Commission would reject an alternative cost-based arrangement when later proposed for its approval."

**Q. If the contracts between APS and PWCC and PWCC and PWEC had been consummated, what could have been the effects on APS' Standard Offer Customers?**

A. In the short run, there would have been no effect. Pursuant to the Settlement Agreement, APS' rates decreased every July 1st through 2003 regardless of the cost of power to APS. Even if PWCC was selling PWEC's power directly to APS at higher than market prices, APS would have had to absorb that cost and would not have had the opportunity to pass on the costs to ratepayers until July 2004 when its purchased power mechanism was scheduled to go into effect. In the long run, (in the absence of the Track A and B Decisions) if the contracts diminished competition and, in the extreme, drove PWEC's competition out of business, APS' Standard Offer Customers could have paid "monopoly prices" under retail competition.

**Q. Continuing this scenario, couldn't APS' Standard Offer Customers have become direct access customers of other electric service providers if APS prices became high?**

A. Yes. However, if the contract arrangement allowed PWEC to sell all of its power to APS for four years, it likely would have reduced the incentive for potential competitors to build plants to serve Arizona and customers ability to choose an alternative generation provider could have been severely limited or even non-existent.

**Q. Is the draft contract between APS and PWCC that was provided to the bond rating agencies in early 2001 the same contract for which APS requested a variance from the Rules on October 18, 2001?**

A. No. They are different contracts.

**ISSUE #3 – PWEC'S CONSTRUCTION OF GENERATING PLANTS TO SERVE APS**

**Q. Why is the reason that PWEC built certain generating plants important in determining intended non-compliance with the Rules?**

A. If PWEC built the plants only to serve APS, it either must have been supremely confident that it would win the competitive bid required by R14-2-1606(B) and the Addendum to the 1999 Settlement Agreement or believed it could somehow circumvent that requirement. Also, APS is asserting that because certain of the PWEC plants were built to serve APS, they should be included in APS' rate base.

**Q. How has Mr. Jack Davis testified regarding the purpose of the PWEC plants?**

A. In the recent hearings on the financing case, under questioning by APS' attorney, Mr. Mumaw, Mr. Davis (member of the Board of Directors and President of PWCC and member of the Board of Directors and President and Chief Executive Officer of APS) testified as follows:

> Q. Mr. Davis, just to wrap that issue up, it has been your position and your testimony that certain plants were built to serve APS' load and were needed to serve APS load?
>
> A. Absolutely. The plants we called the reliability plants, which are Redhawk 1 and 2, West Phoenix 4 and 5, and Saguaro 3.

**Q. Are there any statements made by other PWCC Officers that contradict any of Mr. Davis' testimony?**

A. Yes. In 1999, at the generator siting hearing for Redhawk, Mr. Ed Fox, Vice President for Communications, Environment and Safety for PWCC, testified that "These facilities will be merchant plants. They truly will be in the competitive market." I interpret that statement to mean that the Redhawk Units were built to compete in the developing competitive market, not dedicated to serve APS.

Also in an undated document admitted in the Financing hearing as Exhibit P-12, entitled "Generation business Plan 2000" on an unnumbered page, Mr. Bill Stewart addressed the Redhawk Project. He said that "Redhawk is a larger merchant plant consisting of four 530-megawatt units…"

Mr. Stewart also addressed PWEC's business plan that would include a diverse portfolio of generation assets that PWEC would acquire through construction and purchase of existing power plants. He then pointed out the "robust" demand growth in the "western United States, especially in Nevada and in the Arizona-New Mexico-California subregions." He commented that "PWE's [PWEC's] plan is geared to capture part of this growth potential and to put our competitors on notice that we intend to gain a substantial market share in our region." This statement can be easily interpreted to mean that PWEC was positioning itself as a "competitor" in the electricity market and did not envision that the construction and purchase of plants was just to serve APS.

**Q. Were other statements made that indicate that the PWEC units were built for both the market and APS?**

A. Yes. For example, as early as April 23, 1999, in a press release announcing a short-lived PWCC partnership with Calpine Corporation for generation at West Phoenix, Mr. Bill Post (member of the Board of Directors and President of PWCC and member of the Board of Directors and Chief Executive Officer of APS), at that time representing PWCC, announced: "We are committed to meeting the growing needs of our customers as well as pursuing new opportunities in competitive generation markets."

In Pinnacle West Capital Corporation's SEC Form 10 – K dated March 1999, for the period ending December 31, 1998, under the heading "Competitive Strategies," APS seems to have been contemplating building for both itself and the market as seen in the following quotation from Page 5 (underlining added):

> "APS is pursuing strategies to maintain and enhance its competitive position. These strategies include (i) cost management, with an emphasis on the reduction of variable costs (fuel, operations, and maintenance expenses) and on increased productivity through technological efficiencies; (ii) a focus on APS' core business through customer service, distribution system reliability, business segmentation, and the anticipation of market opportunities; (iii) an emphasis on good regulatory relationships; (iv) asset maximization (e.g., higher capacity factors and lower forced outage rates); (v) *expanding APS' generation asset base to support growth in the competitive power marketing arena* (emphasis added); (vi) strengthening APS' capital structure and financial condition; (vii) leveraging core competencies into related areas, such as energy management products and services; and (viii) establishing a trading floor and implementing a risk management program to provide for more stability of prices and the ability to retain or grow incremental margin through more competitive pricing and risk management. Underpinning APS' competitive strategies are the strong growth characteristics of APS' service territory. As competition in the electric utility industry continues to evolve, APS will continue to evaluate strategies and alternatives that will position us to compete effectively in a more competitive, restructured industry."

Also, at an analyst conference held by PWCC on October 26, 2000, Mr. Post set forth some of the underlying principles of PWCC's strategic plan that implied that APS' strategy was to maintain flexibility in the use of the PWEC assets in the changing electricity market. He said, "We have the flexibility to deal with both regulatory and market challenges." He also said,

> "We have sized our generation expansion plan, when you combine that with our existing generation, to what we think the native load will be, gives us the ability to deal with changes in regulation, the re-regulation of this market. It positions us to be able to get the maximum value out of

> those generating assets." And, "We think that natural hedge, our ability to be able to look at the market from a competitive standpoint and move aggressively from a market point of view, is certainly our preference but as we think about the reaction that's going to come about as a result of the California issues this summer as well as the unwillingness of public power to break the vertical integration that they can uniquely maintain, its going to be difficult to achieve a fully liquid and transparent market in here in the west. That's our first goal."

**Q. Why were the contracts (had they been signed) in the best interest of APS, PWEC, and PWCC?**

A. With divestiture occurring on or before January 1, 2003, and a purchased power adjustor resulting from the 1999 Settlement Agreement expected to go into place on July 1, 2004, APS knew that it would be exposed to market prices for 18 months without the benefit of the purchased power adjustor. Without a better arrangement, PWEC would have had to sell in the market. Agreements such as those in the draft contracts would have benefited PWEC by having a firm purchaser of all of its power and would benefit APS by sheltering it somewhat from the market.

**ISSUE #4 – WAS APS FORBIDDEN TO BUILD ITS OWN PLANTS?**

**Q. Did Mr. Davis also address the alternative of APS building the plants and then transferring the plants to PWEC?**

A. Yes, in the same Financing hearing he said,

> "My testimony is clear to me, in the context of a code of conduct, that Arizona Public Service was prohibited from building new generation within Arizona Public Service, because it wasn't allowed to participate in what was defined in the code of conduct as interim competitive activities. And that needs to be interpreted also in the light of just a whole general policy of the Commission dating back since prior to 1996, they did not want the incumbent vertically integrated utility to own or operate generating facilities....And we think it was in the spirit of the rules and in

the letter of the code of conduct that Arizona Public Service should not build." Page 520, January 10, 2003 lines 4 through 12 and Page 521 lines 2 through 4.

**Q. Provide the Code of Conduct and other language that APS believes prohibited building generators within APS.**

A. According to APS' Code of Conduct, Section X, "APS shall not provide Interim Competitive Activities." The Code of Conduct defines Interim Competitive Activities as meaning "Any Competitive Services, exclusive of those set forth in A.A.C. R14-2-1615(B), that APS may lawfully provide until December 31, 2002." Competitive Services are defined as: "all aspects of retail electric services described in A.A.C. R14-2-1601(7). The rule referred to defines Competitive Services as "all aspects of retail electric service except those services specifically defined as "Noncompetitive Services" pursuant to R14-2-1601(29) or noncompetitive services as defined by the Federal Energy Regulatory Commission. Non-competitive services were further defined in A.A.C. R14-2-1601 (30) as including "Distribution Service, Standard Offer Service, transmission and any ancillary services deemed to be non-competitive by the Federal Energy Regulatory Commission, [and] Must-Run Generating Units services."

**Q. How do you interpret the excerpts from the Code of Conduct and the Rules as they relate to APS' ability to build generating plants?**

A. I interpret them as prohibiting APS from providing certain kinds of retail services but not from engaging in construction activities.

**Q. Do you believe that the Code of Conduct foreclosed APS from building generating plants during the period between the implementation of the Rules and January 1, 2003?**

A. No, I do not. Even if APS' Code of Conduct were interpreted to prohibit the construction of generation by APS, Section XIV of the Code of Conduct provides a procedure to modify the Code of Conduct by APS filing an application with the Commission setting forth the proposed modifications and the reasons supporting them.

**ISSUE #5 --APS' APPLICATION FOR AN AIR QUALITY PERMIT ON BEHALF OF PWEC**

**Q. The Financing Decision also expressed concern that PWEC may have received an unfair competitive advantage when APS applied for an air quality permit on behalf of PWEC. Please describe the circumstances under which APS applied for the permit.**

A. On September 14, 1999, APS filed a Significant Permit Revision Application for the West Phoenix Power Plant. On the date of the application, PWEC did not exist. However, on September 27, 1999, PWEC filed its articles of incorporation and became a legal entity.

To determine the level of competitive advantage that APS' action may have resulted in, Staff asked APS to supply the cost of the application processes and to which PWCC entity's books it was charged. APS responded that the costs related to the air quality permit revisions for West Phoenix CC4, West Phoenix CC5 and Saguaro CT3 totaled $522,705 plus some minor administration costs and that the permit costs were all charged to PWEC and capitalized (LAJ-5.15). Regardless of the ownership or purpose of the plants, ultimately PWEC paid for the permits. Thus, it is doubtful that PWEC benefited significantly from this action on the part of APS.

**ISSUE #6 -- APS TRANSFER OF LAND TO PWEC**

**Q. Who was the previous owner of the land upon which PWEC built the West Phoenix and Saguaro plants?**

A. The land was owned by APS. According to APS' response to LCA-3.81, the transfer of its land to PWEC was completed by inter-company journal entries and at book value.

**Q. Has PWEC already acknowledged that land ownership might give it a competitive advantage?**

A. Yes. A paragraph on page 7 of "Pinnacle West Energy: Business Plan 2001" dated March 15, 2001 and marked as Exhibit P-13 in the Financing case addresses this issue. The paragraph mentions 32,550 megawatts of generation capacity proposed for the Southwest and points out that only a portion of that generation would be built "due to limited availability of transmission and natural gas pipeline capacity and land and water resources." It then goes on to say that "PWEnergy has a competitive advantage because it has acquired the necessary land and water rights and was among the first to break ground in Arizona."

**Q. How could this action by APS have inhibited electric competition?**

A. If other generation companies that intended to build plants to serve Arizona purchased land at negotiated prices and at full market value while PWEC built on land purchased at a non-negotiated price below market value, the ultimate cost of electricity from those companies, all else held equal, would be higher than the cost of electricity from the PWEC plants.

## CONCLUSIONS

Q. **What have you concluded about the actions of PWEC/PWCC/APS as they related to electric competition?**

A. I believe that in PWCC's efforts to maximize and stabilize earnings, PWCC and its affiliates acted in ways, that absent the Track A and B Decisions, would likely have negatively impacted electric competition in Arizona. Those actions included the presentation of draft contracts among APS, PWEC and PWCC to the bond rating agencies thereby increasing PWEC's bond rating and that the contracts were neither the result of competitive bidding nor arms-length transactions. The draft contracts could have assured the purchase of every kilowatt-hour generated by PWEC and significantly limited APS' participation in the electricity market thereby reducing the demand for "independent" power in Arizona. I also believe that the transfer of land from APS to PWEC gave PWEC an unfair advantage, although slight, in the electricity market. Public statements made by officers of PWEC/APS/PWCC are conflicting as to the purpose for which certain PWEC generation plants were built. Finally, the apparently cooperative generation planning and building activities between and among APS, PWEC and PWCC would also have given PWEC an unfair advantage in the competitive markets.

**Q. Were customers harmed by APS' actions?**

A. No. From 1999 through 2004, the customers have been protected by a prohibition on rate increases adopted as part of the 1999 Settlement Agreement. Therefore, any actions by APS that may have given PWEC a competitive advantage did not affect APS customers.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

EXHIBIT
S-2
Admitted

ADDENDUM TO

DIRECT

TESTIMONY

OF

LINDA A. JARESS

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY FOR
A HEARING TO DETERMINE THE FAIR VALUE
OF THE UTILITY PROPERTY OF THE COMPANY
FOR RATEMAKING PURPOSES, TO FIX A JUST
AND REASONABLE RATE OF RETURN
THEREON, TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP SUCH RETURN, AND
FOR APPROVAL OF PURCHASED POWER
CONTRACT

FEBRUARY 23, 2004

**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | ) | DOCKET NO. E-01345A-03-0437 |

ADDENDUM TO THE DIRECT

TESTIMONY

OF

LINDA A. JARESS

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2002

**Q. Please state your name, occupation, and business address.**

A. My name is Linda A. Jaress. I am an Executive Consultant III in the Utilities Division of the Arizona Corporation Commission ("Commission"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

**Q. Did you file direct testimony in this docket on February 3, 2004?**

A. Yes, I did.

**Q. What is the purpose of this addendum to your testimony?**

A. The purpose of this addendum to my testimony is to provide Staff's response to the questions raised by Commissioner Gleason in his letter to the parties to this case, as filed on September 8, 2003.

**Q. What are Commissioner Gleason's first two questions?**

A. The first is, "How should the Commission calculate the market value of a power plant?" and the second, "If the Commission should look at the plant's current market value instead of the original cost to build the plant, how can the Commission determine the market value?" These questions are closely related in that both address the determination of market value of power plants. Thus, I will respond to both simultaneously.

Establishing power plant values, or the value (price) of any asset, typically requires application of one of two methods. One method is the discounted cash flow ("DCF") method. Under the DCF method, future cash flows associated with the projected revenues from the sale of power, less expenses, are discounted by applying a discount rate to create a present value, or price. In other words, the value of the plant today is equal to the present value of its future cash flows. The inputs to the estimates of the future cash flows

and the applied discount rate typically reflect a vast range of assumptions that can significantly affect the outcome of the analysis.

A second means of calculating the market value of a power plant is through a review of actual sales transactions involving similar generating assets. The sales prices of "comparable" plants sold in "comparable" markets establish primary reference points. Close attention must be paid to the particulars of the power plants, markets, financing, etc. to ensure comparability and, hence, a reasonable market valuation. This method is limited by the number and comparability of recent sales. In seeking to determine the market value of a power plant, a commission could rely on the results of a DCF analysis, a comparables analysis, or a combination of the two.

**Q. Has Staff made a recommendation in this case as to the market value of the PWEC assets?**

A. No.

**Q. Why hasn't Staff addressed the market value of the PWEC assets in its analysis of whether the PWEC assets should be rate based?**

A. Staff's focus has been on whether the Company has demonstrated that the PWEC assets would be an appropriate addition to APS' supply portfolio and ratebase at the value proposed. The Company has proposed to ratebase the PWEC assets at net book value rather than at market value.

**Q. What is Commissioner Gleason's third question?**

A. Commissioner Gleason's third question is, "What power plants are on the market that can serve Arizona consumers?"

**Q. Is Staff aware of power plants that can serve Arizona that are for sale?**

A. Staff is aware that there are power plants in Arizona that are financially distressed and may be for sale. On February 5, 2004, TECO Energy, Inc. announced its decision to exit from its ownership of its Gila River plant and announced a letter of intent with certain lenders to transfer ownership of the plant to them. Also, National Energy & Gas Transmission (previously, PG & E National Energy Group) has reached an agreement with lenders to transfer their Arizona plant, Harquahala Generating, to the lenders. However, a potential purchaser in the market for a power plant, such as APS, would have more generator-specific information regarding this market than Staff.

I note that, before the results of the December 2003 RFP are used as an indicator of the market value of other generating units that could serve the Arizona market, the Company should demonstrate that (1) its solicitation was properly-designed and implemented, and (2) the results of the December 2003 solicitation are in fact fully comparable and appropriate to the proposed application.

**Q. Regarding the Commissioner's fourth question, what actions has Staff taken to respond?**

A. Commissioner Gleason's letter also asks, "Has any other state commission faced a situation where a regulated energy utility applied to incorporate merchant assets into its rate base? What did that commission decide?" Staff contacted 41 state public utilities commissions and received responses from 38. Staff also spoke with a FERC representative regarding potential FERC matters relevant to this question.

According to Staff of the Washington Utilities and Transportation Commission, Avista Utilities acquired the Coyote Springs II generating plant from an affiliate and, through a settlement agreement approved by the Commission, was allowed to include the plant in

rate base. However, neither the settlement agreement nor the Decision that approved the settlement agreement discusses the matter of valuation.

NorthWestern Energy, the current owner of the distribution assets of the now defunct Montana Power Company, is currently before the Montana Commission requesting approval of a 10-year contract with an affiliate which owns the Montana First Megawatts generating plant under construction in Great Falls, Montana. According to a Montana Commission Staff member, discussions are also being held about rate-basing the plant.

In another case somewhat related to the Commissioner's question, is currently underway at the California Public Utilities Commission regarding an application by Southern California Edison for approval to acquire, develop, construct, own and operate Mountainview Power Project as a wholly-owned subsidiary and to enter a power purchase agreement with the subsidiary for the purchase of electricity. One of the proposals under consideration is for the utility to directly own the plant and include it in rate base rather than enter a purchased power contract with the subsidiary which would own the plant.

Also, in a similar case, Duquesne Light Company filed an application with the Pennsylvania Public Utilities Commission in December 2003, for approval of a "Plan for Provider of Last Resort." The Plan includes a power contract with a direct subsidiary which has recently entered into an agreement to purchase the Sunbury Station generating plant in Shamokin Dam, Pennsylvania. The application is currently under review.

**Q. The fifth question is, "How will competitive solicitation of wholesale power as envisioned in the Commission's Track B Order be affected by the inclusion of PWEC assets into APS?" Please respond.**

A. Under the power contract between APS and PWEC that was part of the outcome of the competitive solicitation process, APS is purchasing 1,700 MW of capacity in the summer months from PWEC. APS has asserted that, if the PWEC assets are ratebased, the contract will be ended. The most apparent impact, of ratebasing the PWEC assets would be felt in September 2006, when the contract's term would have ordinarily expired. At that point, at least 1,700 MW of capacity will not need to be competitively bid. Thus, the Arizona market available to other suppliers will be diminished, which could affect them economically and could affect the long term viability of some.

Also, and most importantly, ratebasing the PWEC assets anytime before the expiration of the APS/PWEC contract would cause APS customers to lose some of the $200 million of the benefits of the Track B solicitation already undertaken.

**Q. Does this conclude the addendum to your testimony?**

A. Yes, it does.

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN MAYES
Commissioner

| | |
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| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | DOCKET NO. E-01345A-03-0437 |

DIRECT

TESTIMONY

OF

JOEL M. REIKER

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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## EXECUTIVE SUMMARY

The direct testimony of Staff witness Joel M. Reiker addresses the following issues:

Capital Structure – Staff recommends the Commission adopt APS' actual capital structure consisting of approximately 55 percent debt and 45 percent equity.

Cost of Debt – Staff recommends the Commission adopt a 5.82 percent cost of long-term debt.

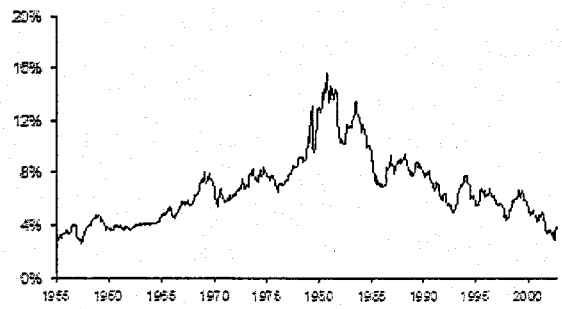
Cost of Equity – Staff recommends the Commission adopt a 9.0 percent return on equity ("ROE"). Staff bases its ROE recommendation on its discounted cash flow ("DCF") and capital asset pricing model ("CAPM") analyses. Staff's recommendation is based on cost of equity estimates ranging from 7.7 percent to 10.6 percent.

Overall Rate of Return - Staff recommends the Commission adopt an overall rate of return ("ROR") of 7.3 percent. Staff's ROR recommendation results in a pre-tax interest coverage ratio of 3.1. This represents a fair and reasonable rate of return on APS' rate base and will allow the Company to maintain its financial integrity.

Comment on the Direct Testimony of Company Witness Charles E. Olson - The Commission should reject Dr. Olson's proposed ROE range of 11.25 percent to 11.75 percent for the following reasons:

> Dr. Olson's assumption that the Company's two alternative capital structures do not affect the cost of equity is incorrect. As a firm increases leverage, the cost of equity goes up. Relying on a 50/50 debt-to-equity capital structure rather than a 55/45 debt-to-equity capital structure lowers APS' cost of equity approximately 30 basis points.
>
> Dr. Olson's 11.25 to 11.75 percent ROE recommendation exceeds a reasonable cost of equity estimate for an average-risk security (based on actual returns). The average compound and arithmetic annual returns on U.S. equities have been 8.3 percent and 9.7 percent, respectively, using 199 years of data from 1802 to 2001. Intermediate-term Treasury securities are currently at levels comparable to the 1950's and '60's, suggesting that capital costs, including the cost of equity, are lower then they have been in decades:

Chart 2: History of 5- and 10-Year Treasury Yields




> Dr. Olson's DCF estimates should be rejected for the following reasons:

1. Dr. Olson's sample group is riskier than APS, as evidenced by an average debt ratio of .60 compared to APS' debt ratio of .55.

2. Dr. Olson's use of an average dividend yield in the constant growth DCF model is inappropriate. There is no point in "smoothing" stock prices for use in a model that assumes perfect markets.

3. Dr. Olson's expected dividend yield for IDACORP is overstated by 338 basis points according to data of October 9, 2003.

4. Dr. Olson's exclusive reliance on analysts' forecasts of earnings growth in the constant growth DCF model is inappropriate because it assumes that investors do not look at other information such as past growth, and analysts' forecasts of earnings growth are known to be overly optimistic. To the extent investors are aware of the bias in analysts' projections of future earnings, they will make appropriate adjustments. Further, *First Call*, which Dr. Olson relies on exclusively in his constant growth DCF analysis, has revised its earnings growth estimates downward since Dr. Olson completed his analysis.

5. After correcting the errors contained in his analysis, Staff's restatement of Dr. Olson's constant growth DCF estimate averages 9.0 percent.

Dr. Olson's risk premium study should be rejected for the following reasons:

1. The yield to maturity on a corporate bond cannot be meaningfully compared to the cost of equity because a corporate bond contains some default risk which is diversifiable. Therefore, the investor's expected return is lower than the bond's yield to maturity.

2. Dr. Olson misapplies the historical differential between S&P 500 returns and *high grade* corporate bond yields to the current yield on *medium grade* bonds. To the extent there is any validity to such a risk premium study, Dr. Olson's cost of equity estimate is inflated by 114 basis points.

3. Dr. Olson's risk premium study in no way assesses the risk of an electric utility. Dr. Olson's risk premium study is inappropriate because it fails to distinguish the risk of an electric utility with the risk of the S&P 500, which includes a wide range of companies such as aerospace/defense, computers, etc.

4. Dr. Olson's risk premium study is based on a general rule of thumb. The Commission should primarily rely on cost of equity models developed in the corporate finance literature, such as the DCF and CAPM, rather than on rules of thumb. The DCF method is the most widely used model for estimating the cost of equity in public utility

rate cases and the CAPM is the most popular method of estimating the cost of equity among firms.

Dr. Olson's financing cost adjustment should be rejected for the following reasons:

1. Dr. Olson fails to consider in his testimony stock expenses that would reduce his adjustment. Stock purchase fees, otherwise known as brokers' fees, result in an investor paying more than the price quoted on the market, and would reduce the required dividend yield in the DCF, offsetting the issuance cost adjustment.

2. Dr. Olson fails to consider stock that Pinnacle West and other companies issue under employee stock ownership plans ("ESOP") and dividend reinvestment plans ("DRIP"), which save the underwriting costs of a regular share issue.

3. Dr. Olson's method of increasing the authorized ROE applies to retained earnings – equity that is never issued.

Dr. Olson's suggestion that "market pressure" associated with stock offerings should be compensated for in the ROE should be rejected for the following reasons:

1. The market pressure component is inconsistent with the concept of efficient markets, the theory inherent in the DCF and CAPM.

2. The alternative explanation for a decline in stock price after the announcement of a public offering has nothing to do with the increased supply but simply with the information that the issue provides. Most financial economists agree with this alternative explanation.

## INTRODUCTION

**Q. Please state your name, occupation, and business address.**

A. My name is Joel M. Reiker. I am a Senior Regulatory Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

**Q. Briefly describe your responsibilities as a Senior Regulatory Analyst.**

A. In my capacity as a Senior Regulatory Analyst, I perform studies to estimate the cost of capital for utilities that are seeking rate relief. I also provide recommendations to the Commission on mergers, acquisitions, financings, and sales of assets, and I have occasionally acted as arbitrator in disputes brought before the Utilities Division.

**Q. Please describe your educational background and professional experience.**

A. In 1998, I graduated cum laude from Arizona State University, receiving a Bachelor of Science degree in Global Business with a specialization in finance. My course of studies included classes in corporate and international finance, investments, accounting, statistics, and economics. I began employment as a Staff rate analyst in 1999. Since that time, I have attended various seminars and classes on general regulatory and business issues, including the cost of capital and the use of energy derivatives. I have participated in over fifty regulatory proceedings.

**Q. What is the scope of your testimony in this case?**

A. I provide Staff's recommended rate of return in this case. I address the appropriate capital structure, as well as the appropriate costs of debt and equity for establishing the revenue requirement for Arizona Public Service Company ("APS" or "Company").

## SUMMARY OF TESTIMONY AND RECOMMENDATIONS

**Q. Briefly summarize how Staff's cost of capital testimony is organized.**

A. Staff's cost of capital testimony is organized into six sections. Section I discusses the Company's capital structure. Section II discusses APS' cost of debt. Section III discusses risk and presents the findings of Staff's cost of equity capital analysis that uses the discounted cash flow ("DCF") model and the capital asset pricing model ("CAPM"). Section IV presents Staff's recommended return on equity ("ROE") for APS. Section V presents Staff's overall rate of return ("ROR") recommendation. Finally, Staff's comments on the Company's proposed ROE are presented in section VI.

**Q. Have you prepared any exhibits to your testimony?**

A. Yes. I prepared eleven schedules (JMR-1 to JMR-11) and two exhibits (JMR-1 and JMR-2) that support Staff's cost of capital analysis.

**Q. Please summarize Staff's ROR recommendations.**

A. Staff's ROR recommendation is summarized in the following table:

**Table 1**

| | Weight | Cost | Weighted Cost |
|---|---|---|---|
| Long-term Debt | 54.8% | 5.82% | 3.19% |
| Common Equity | 45.2% | 9.0% | 4.07% |
| **Cost of Capital/ROR** | | | **7.3%** |

## I. APS' CAPITAL STRUCTURE

**Q. What capital structure did Staff rely on to calculate its recommended rate of return?**

A. Staff relied on APS' actual capital structure consisting of approximately 55 percent debt and 45 percent equity. According to the Company's response to Staff data requests STF 2.8 and STF 2.9 (Exhibit JMR-1), APS' capital structure on June 30, 2003 consisted of approximately 55 percent debt and 45 percent equity. Additionally, according to Schedule D-1 of the Company's application, APS' capital structure is expected to be approximately 55 percent debt and 45 percent equity on December 31, 2003.

**Q. What capital structure does APS propose?**

A. The Company proposes two alternative capital structures depending on whether the Pinnacle West Energy Corporation ("PWEC") generating assets[1] are included in rate base.

If the Commission allows APS to include the PWEC generating assets in rate base, the Company proposes its actual capital structure consisting of approximately 55 percent debt and 45 percent equity. If the PWEC generating assets are not included in rate base, the Company proposes its December 31, 2002 historical capital structure, which consisted of approximately 50 percent debt and 50 percent equity. The former recognizes an additional $500 million in long-term debt issued by APS in May, 2003.[2]

---

[1] West Phoenix combined cycle generating units 4 & 5, Saguaro combustion turbine Unit No. 3 and Redhawk Units 1 & 2.

[2] On April 4, 2003, the Commission issued Decision No. 65796, authorizing APS to issue up to $500 million in long term debt. On May 7, 2003, APS issued $500 million in unsecured notes and subsequently loaned the funds to its affiliate, Pinnacle West Energy Corporation ("PWEC"). The funds loaned to PWEC are intended to pay off an equivalent amount of Pinnacle West Capital Corporation ("PWCC") (APS' parent) debt previously incurred to finance construction of PWEC generating assets.

**Q. Does APS' capital structure and cost of capital depend on whether the PWEC generating assets are included in rate base?**

A. No. The $500 million issuance of May, 2003 is debt of the Company regardless of what is included in rate base. Investors do not ignore debt, nor do they color-code it. Therefore, the Company's actual capital structure (approximately 55 percent debt and 45 percent equity) is required to estimate APS' *current* cost of capital in this proceeding.

## II. THE COST OF DEBT

**Q. What is Staff's recommended cost of debt?**

A. Staff recommends a 5.82 percent cost of long-term debt. Staff calculated its recommended cost of debt using APS' December 31, 2003, projected balances.[3] Staff's calculation is shown in Schedule JMR-2.

**Q. What is the Company's proposed cost of debt?**

A. The Company's proposed cost of debt depends upon which capital structure is adopted. If a capital structure consisting of approximately 50 percent debt and 50 percent equity is adopted, APS proposes a 5.81 percent cost of debt. If a capital structure consisting of 55 percent debt and 45 percent equity is adopted, APS proposes a 5.76 percent cost of debt.

Staff calculated its recommended cost of debt using the internal rate of return ("IRR") methodology and it is slightly higher than APS' proposed cost of debt under the 55 percent debt/45 percent equity scenario.

[3] Per APS' response to STF 3-10 attached as Exhibit JMR-2.

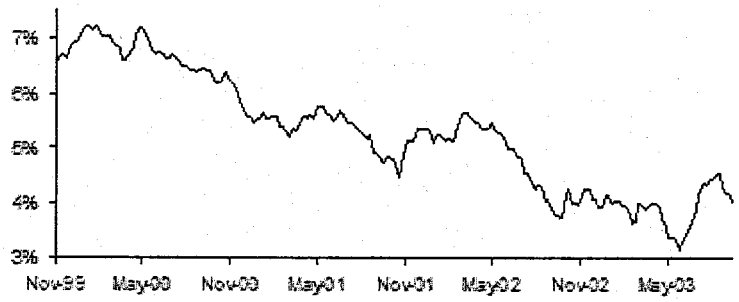
## III. THE COST OF EQUITY

### Comment on Capital Costs in General

**Q. What has been the general trend of capital costs in recent years?**

A. Interest rates have declined in recent years. Chart 1 graphs intermediate-term U.S. Treasury rates from November 1999 to October 2003:

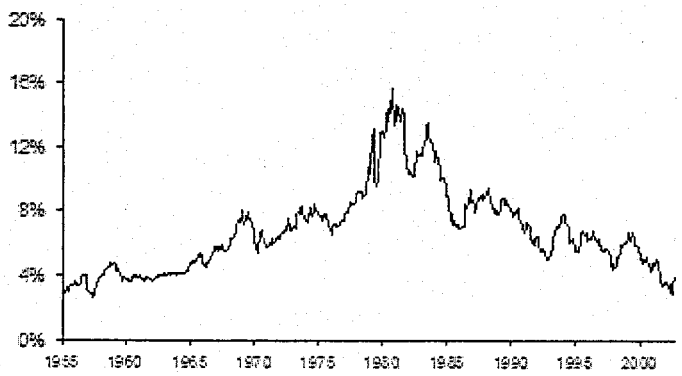
Chart 1: Average Yield on 5-, 7-, & 10-Year Treasuries




Source: Federal Reserve

The following graph puts interest rates and capital costs in general, into historical perspective. Interest rates have declined significantly in the past twenty years and are currently at levels comparable to the 1950's and '60's.

Chart 2: History of 5- and 10-Year Treasury Yields




Source: Federal Reserve

According to the capital asset pricing model, the cost of equity moves in the same direction as interest rates. Chart 2 suggests that capital costs, including the cost of equity, are lower than they have been in decades.

**Q. What have historical returns been for average risk securities?**

A. Wharton School finance professor Jeremy Siegel published his findings that the average compound and arithmetic annual returns on U.S. equities have been 8.3 percent and 9.7 percent, respectively, using 199 years of data from 1802 through 2001.[4]

One should keep in mind that the above returns are actual returns, not expected returns. However, any request for an allowed ROE at or above 10.0 percent exceeds the compound and arithmetic average historical return on U.S. equities for the period mentioned above. The risk of a regulated electric utility, as measured by the capital asset pricing model beta, is significantly below the theoretical average beta for all stocks of 1.0. I discuss the average beta (.67) of the electric utility industry later. Therefore, the required return on an investment in the electric utility industry is significantly below the average required return on the market.

**Capital Structure and Risk**

**Q. How is risk defined?**

A. Modern portfolio theory ("MPT") separates risk into two categories; market risk and unique risk. Market risk is defined as the sensitivity of an investment's returns to market returns. Market risk, also known as systematic risk, is the risk related to economy-wide perils that threaten all businesses such as changes in interest rates, inflation, and general

[4] Siegel, Jeremy J. *Stocks for the Long Run*, third edition. McGraw-Hill, New York. 2002. p.13.

business cycles. Market risk is the only type of risk that affects the cost of equity. The most prevalent measure of market risk is "beta." Beta is the measurement of an investment's market risk, and it reflects both the business risk and financial risk of a firm.

Unique risk, or microeconomic risk, is risk that can be eliminated by portfolio diversification, i.e. buying securities in portfolios. Unique risk is not measured by beta nor does it factor into the cost of equity because it can be eliminated through simple shareholder diversification. Unique risks are peculiar to an individual company or investment project. Investors who hold diversified portfolios do not worry about unique risk; therefore, it does not affect the cost of capital. Additionally, investors who choose to be less than fully diversified will not expect to be compensated for unique risk.

**Q. Please distinguish between business risk and financial risk.**

A. Business risk is the risk associated with the fluctuation in earnings due to the basic nature of a firm's business. Financial risk is the risk to shareholders caused by a firm's reliance on debt financing. Both business risk and financial risk affect the cost of capital.

**Q. What is the relationship between the capital structure and financial risk?**

A. A greater percentage of debt in a capital structure results in a higher level of financial risk.

**Q. How does APS' capital structure compare to capital structures of publicly traded electric utilities?**

A. APS' current capital structure has approximately the same percentages of debt and equity as the average capital structure of publicly traded electric utilities; therefore, APS has approximately the same level of financial risk. Schedule JMR-1 shows the average capital structure of thirty-three publicly traded electric utilities ("sample electric utilities") as of 2003, as well as APS' capital structure. As of June 2003, the sample electric utilities were capitalized with approximately 56 percent debt while APS' capital structure consists of approximately 55 percent debt. The sample electric utilities and their selected financial data are listed in Schedule JMR-3.

**Fair and Reasonable Return on Equity**

**Q. Define the term "cost of equity."**

A. A firm's cost of equity is that rate of return that investors expect to earn on their equity investment given the risk of the firm. An investor's expected return is equally defined as the return on equity that he expects on other investments of similar risk.

**Q. What models did Staff use to estimate APS' cost of equity?**

A. Staff used two market-based models: the discounted cash flow ("DCF") model and the capital asset pricing model ("CAPM"). Staff applied these two models to publicly traded stocks to estimate APS' cost of equity.

**Q. Did Staff apply the DCF model and the CAPM to APS directly?**

A. No, Staff did not apply the models directly to APS because APS does not have publicly

traded stock and Staff therefore lacks the information necessary to apply the market-based models. Staff used a sample of publicly traded electric utilities as a proxy.

**Q. What companies did Staff select as proxies or comparables for APS?**

A. Staff selected the thirty-three publicly traded electric utilities shown in Schedule JMR-3. These companies represent all of the electric utilities currently followed by *The Value Line Investment Survey* ("*Value Line*") who have at least 65 percent of their revenues derived from regulated operations, pay dividends, and are not currently in bankruptcy or expected to be in bankruptcy.

**Discounted Cash Flow Model Analysis**

**Q. Please provide a brief summary of the theory upon which the DCF method of estimating the cost of equity is based.**

A. The DCF method of estimating the cost of equity is based upon the theory that the market price of a stock is equal to the present value of all expected future dividends. Through a mathematical restatement, the discount rate, or cost of capital, can be derived from the expected dividend, the stock price, and a dividend growth rate. The formula is generally applied to a sample of companies that exhibit similar risk to the company in question and the resulting estimates for the discount rates (or costs of equity) are then averaged.

Use of the DCF method for estimating the cost of equity capital to a public utility was pioneered by Professor Myron Gordon in the 1960's, and it has become the most widely used model. In 1998, Professor Gordon said the following about the simplicity of his model when he gave the keynote Address at the 30th Financial Forum of the Society of Utility and Regulatory Financial Analysts:

> On its simplicity, the model made it extremely difficult, if not impossible, for a banker from Goldman Sachs or some other Wall Street firm, or for a finance professor from a prestige university to use the authority of his/her position to make extravagant claims before a regulatory agency. An independent expert or a member of a commission staff with far less impressive credentials could politely, firmly and effectively deflate any bombast in their testimony.[5]

**Q. How did Staff apply the DCF Model?**

A. Staff applied the DCF model using two different approaches. Staff's first approach used the constant-growth DCF model. Staff's second approach was to use a non-constant growth, or multi-stage DCF. The advantage of the multi-stage DCF is that it does not assume that dividends grow at a constant rate over time.

*The Constant-Growth DCF*

**Q. What is the constant-growth DCF formula used in Staff's analysis?**

A. The constant-growth DCF formula used in Staff's analysis is:

Equation 1:

$$K = \frac{D_1}{P_0} + g$$

where:

| | | |
|---|---|---|
| $K$ | = | the cost of equity |
| $D_1$ | = | the expected annual dividend |
| $P_0$ | = | the current stock price |
| $g$ | = | the expected infinite annual growth rate of dividends |

[5] Gordon, M. J. Keynote Address at the 30th Financial Forum of the Society of Utility and Regulatory Financial Analysts. May 8, 1998. Transparency 2.

The constant-growth DCF model shown in Equation 1 assumes that a company has a constant payout ratio and that its earnings are expected to grow at a constant rate. Thus, if a stock has a market price of $5 per share, an expected annual dividend of $.25 per share, and if its dividends were expected to grow 3 percent per year, then the cost of equity for the company would be 8.0 percent (the 5 percent dividend yield plus the growth rate of 3 percent per year).

**Q. How did Staff calculate the dividend yield component ($D_1/P_0$) of the constant-growth DCF formula?**

A. Staff calculated the yield component of the DCF formula by dividing the expected annual dividend by the spot stock price after the close of the market on October 9, 2003, as reported by *Yahoo Finance.*

Staff used the spot stock price because it reflects all publicly available information. According to the efficient markets hypothesis, the current stock price includes investors' expectations of future returns and is the best indicator of these expectations.

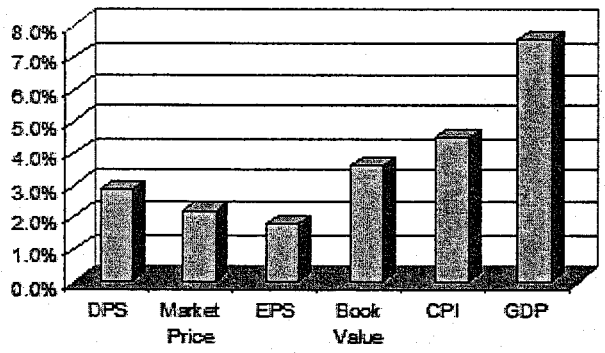
*Electric Utility Growth in General*

**Q. How fast have electric utilities grown compared to inflation and the economy in general?**

A. Growth rates for electric utilities lag not only the growth rate of the economy, but they lag the rate of inflation as well. From 1960 to 2000, dividends per share ("DPS") for electric utilities grew at a rate of 2.9 percent per year. Earnings per share ("EPS") grew at a rate

of 1.8 percent. Market price grew at a rate of 2.2 percent, and book value grew at a rate of 3.6 percent.[6] Over the same period gross domestic product ("GDP") and the consumer price index ("CPI") grew at rates of 7.6 percent and 4.5 percent, respectively.[7] The following chart provides historical perspective:

**Chart 3: Electric Utility Growth Rates Versus Consumer Price Index & GDP 1960 - 2000**




The above data represent past growth. To the extent investors rely on such past data to form expectations of future growth, electric utilities can be expected to grow at a rate that lags not only the growth rate of the economy, but inflation as well. Future long-term dividend growth for electric utilities in the range of 5 to 6 percent would be unusual, relative to the data presented above.

**Q. How did Staff estimate the dividend growth (g) component of the DCF model?**

A. Because the DCF model is predicated on dividend growth, Staff examined a combination of historical DPS growth and projections of future DPS growth provided by *Value Line*. Staff also examined historical and projected growth in EPS as well as intrinsic growth.

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[6] *Mergent Public Utility & Transportation Manual 2003*

[7] U.S. Department of Commerce Bureau of Economic Analysis and U.S. Department of Labor Bureau of Labor Statistics.

**Q. How did Staff estimate DPS growth?**

A. Staff estimated DPS growth by calculating the average rate of growth in dividends per share of the sample electric companies from 1997 to projected 2007. The results of the analysis are shown in Schedule JMR-4. Staff's analysis indicates an average DPS growth rate of 0.2 percent for the sample electric utilities.

**Q. Why did Staff examine EPS growth to estimate the dividend growth component of the constant-growth DCF model?**

A. Staff examined EPS growth because dividend growth does not occur independently of earnings. It would be virtually impossible for dividend growth to exceed earnings growth over the long run, as it would ultimately lead to payout ratios in excess of 100 percent, which are not sustainable. Therefore, Staff considered historical and projected growth in EPS in estimating expected dividend growth.

**Q. What is Staff's EPS growth rate?**

A. Schedule JMR-4 shows Staff's average rate of growth in EPS for the sample electric utilities. Staff's average EPS growth rate is 3.4 percent using data from 1997 to projected 2007 for the sample electric utilities.

One should note that analysts' projections of future earnings are generally high,[8] and vary widely depending on the source.

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[8] See Seigel, Jeremy J. Stocks for the Long Run. 2002. McGraw-Hill. New York. p. 100. Malkiel, Burton G. A Random Walk Down Wall Street. 1999. W.W. Norton & Co. New York. p. 169. Dreman, David. Contrarian Investment Strategies: The Next Generation. 1998. Simon & Schuster. New York. pp. 97-98. Testimony of Professors Myron J. Gordon and Lawrence I. Gould, consultant to the Trial Staff (Common Carrier Bureau), FCC Docket 79-63, p. 95.

**Q. What is retention growth?**

A. Retention growth is simply the product of the percentage of earnings retained by the company ("retention ratio") and the book/accounting return on equity. This concept is based upon the theory that dividend growth can only be achieved if a company retains and reinvests a portion of its earnings in itself to earn a return.

**Q. What is the formula for the retention growth rate?**

A. The retention growth rate formula is:

Equation 2:

$$g = br$$

where: $g$ = retention growth
$b$ = the retention ratio (1 – dividend payout ratio)
$r$ = the accounting/book return on common equity

**Q. What retention (br) growth rate did Staff calculate for the sample electric utilities?**

A. Staff calculated an average retention (br) growth rate of 4.5 percent for the sample electric utilities, as shown on Schedule JMR-5. Staff calculated the rate by averaging the retention growth rate for the years 1998 to 2002, and *Value Line*'s projected br growth rate for the period 2006 - 2008.

**Q. Under what circumstances is the br growth rate method a reasonable estimate of future dividend growth?**

A. The br growth rate is a reasonable estimate of future dividend growth if the retention ratio is fairly constant and if the market price to book value ("market-to-book") ratio is

expected to equal 1.0. The average retention ratio of the sample electric utilities has ranged from 10 percent to 40 percent since 1997. The average market-to-book ratio of the sample electric utilities is 1.5. (See Schedule JMR-3.) Staff assumes that investors expect the market-to-book ratio to remain above 1.0.

**Q. What is the financial implication of a market-to-book ratio greater than 1.0?**

A. The implication is that investors expect the sample electric utilities to earn book/accounting returns on equity greater than the companies' costs of equity.

**Q. How has Staff accounted for the assumption that investors expect the average market-to-book ratio of the sample electric utilities to remain above 1.0?**

A. Staff accounted for the assumption that investors expect the average market-to-book ratio of the sample electric utilities to remain above 1.0 by adding a second growth term to its br growth rate to arrive at the intrinsic growth rate.

**Q. What is the second growth term Staff used to account for the assumption that investors expect the average market-to-book ratio of the sample electric utilities to remain above 1.0?**

A. The second growth term, derived by Myron Gordon in his book, *The Cost of Capital to a Public Utility*[9], is found by multiplying a variable, v, by another variable, s. Staff will refer to the product of v and s as the vs, or stock financing growth term. The vs growth term represents the company's dividend growth through the sale of stock.

**Q. What does the variable v represent and how is it calculated?**

[9] Gordon, Myron J. *The Cost of Capital to a Public Utility*. MSU Public Utilities Studies, Michigan, 1974. pp 31-35.

A. The variable v represents the fraction of the funds raised from common stock sales that accrues to existing shareholders. It is calculated as follows:

Equation 3:

$$v = 1 - \left( \frac{book\ value}{market\ value} \right)$$

For example, if a share of stock with a $10 book value is selling for $13, the v term would equal .23 (calculated as 1-[$10/$13]). Staff has calculated v for the sample electric utilities to be .30.

**Q. What does the variable s represent and how is it calculated?**

A. The variable s represents the expected rate of increase in common equity from stock sales. For example, if a company has $100 in equity and it sells $10 of stock then s would equal 10 percent ($10/$100). Staff used historical accounting data to calculate an average s value for the sample electric utilities of 4.6 percent.

**Q. How does the vs term work?**

A. When a utility is expected to earn a book/accounting return equal to its cost of equity, then its market price will equal its book value and v will be equal to 0.0 (calculated as 1-($10/$10)). If a utility is expected to earn more than its cost of equity, then its market-to-book ratio will be greater than 1.0. If the market-to-book ratio is greater than 1.0 and v is positive when new shares are sold, then the book value per share of outstanding stock is less than the per share contributions of new shareholders. The per-share contribution in excess of book value per share accrues to the old shareholders in the form of a higher book value. The resulting higher book value leads to higher expected earnings and dividends. Thus, the growth term in the basic DCF model should include the vs growth term when

the market-to-book ratio is not expected to equal 1.0. Staff's vs growth term is 1.4 percent.

**Q. Shouldn't utilities' market-to-book ratios fall to 1.0 if their authorized ROEs are set equal to their costs of equity?**

A. Yes. Utilities' market-to-book ratios should fall to 1.0, in theory, making the vs term unnecessary. Setting the authorized return on equity for a utility equal to its cost of equity should eventually force the utility's market price to equal its book value. In principle, then, the vs term is unnecessary in the long run. In reality, rate orders do not force market-to-book ratios to 1.0 for a variety of reasons. For example, regulatory commissions do not issue orders simultaneously for multijurisdictional utilities, and a company may have earnings that are unregulated. Therefore, Staff included the vs growth term in its DCF analysis, even though the resulting growth rate estimate might be too high. Staff's resulting estimates are too high to the extent that investors expect the sample's average market-to-book ratio to fall to 1.0 because of falling authorized ROEs.

**Q. What is Staff's intrinsic growth rate and how was it calculated?**

A. Staff's intrinsic growth rate is 5.9 percent for the sample electric companies. It was calculated by adding Staff's br and vs growth rates and is shown in Schedule JMR-5.

**Q. What is Staff's expected infinite annual growth rate in dividends?**

A. Schedule JMR-6 shows Staff's calculation of expected dividend growth. Staff's expected annual dividend growth rate is also shown in the following table:

**Table 2**

| Growth Rate | g |
|---|---|
| Dividends Per Share (DPS) | 0.2% |
| Earnings Per Share (EPS) | 3.4% |
| Intrinsic Growth | 5.9% |
| **Average** | **3.2%** |

**Q. What is the result of Staff's constant-growth DCF analysis?**

A. Schedule JMR-7 shows the result of Staff's constant-growth DCF analysis. Staff's constant-growth DCF cost of equity estimate is also shown below:

**Table 3**

| $D_1/P_0$ | + | g | = | k |
|---|---|---|---|---|
| 4.5% | + | 3.2% | = | **7.7%** |

*The Multi-Stage DCF*

**Q. What is the multi-stage DCF formula?**

A. The multi-stage DCF formula is shown in the following equation:

Equation 4:

$$P_0 = \sum_{t=1}^{n} \frac{D_t}{(1+K)^t} + \frac{D_n(1+g_n)}{K-g_n}\left[\frac{1}{(1+K)}\right]^n$$

Where: $P_0$ = current stock price
$D_t$ = dividends expected during stage 1
$K$ = cost of equity
$n$ = years of non – constant growth
$D_n$ = dividend expected in year n
$g_n$ = constant rate of growth expected after year n

The multi-stage DCF model shown above incorporates at least two growth rates. It assumes that investors expect a certain rate of non-constant dividend growth in the near term known as "stage-1 growth", as well as a longer-term constant rate of growth known as "stage-2 growth."

**Q. How did Staff implement the multi-stage DCF model?**

A. Staff forecasted a stream of dividends and found the cost of equity that equates the present value of the stream to the current stock price for each of the sample electric utilities, consistent with Equation 4.

**Q. How did Staff calculate stage-1 growth?**

A. Staff forecasted dividends four years out for each of the sample electric utilities using *Value Line*'s estimate of the projected dividend for the next twelve months and *Value Line*'s projected DPS growth rate.

**Q. How did Staff estimate stage-2 growth?**

A. For stage-2 growth, or constant growth, Staff used the rate of growth in gross domestic product ("GDP") from 1929 to 2002, which is 6.5 percent. Historical growth in GDP is appropriate because it ultimately assumes that the electric utility industry will neither grow faster, nor slower, than the overall economy.

**Q. What is the result of Staff's multi-stage DCF analysis?**

A. Staff's multi-stage DCF estimate of the cost of equity to the sample electric utilities is 10.6 percent.

**Capital Asset Pricing Model**

**Q. Please describe the capital asset pricing model.**

A. The CAPM is the best-known model of risk and return. The CAPM is the work of Nobel prize-winning economists and provides a method to estimate the risk and expected return on a risky asset. The model concludes that the expected return on a risky asset is equal to the sum of the prevailing risk-free interest rate and the market risk premium adjusted for the riskiness of the investment relative to the market. The critical assumptions of the CAPM can be summed up in the following quote from the book, *The Stock Market: Theories and Evidence*:[10]

> The [CAPM] model presents a simple and intuitively appealing picture of financial markets. All investors hold efficient portfolios and all such portfolios move in perfect lockstep with the market. Portfolios differ only in their sensitivity to the market. Prices of all risky assets adjust so that their returns are appropriate, in terms of the model, to their riskiness. This riskiness is measured by a simple statistic, beta, which indicates the sensitivity of the asset to market movements.

According to a 2001 study published in the *Journal of Financial Economics*, among CFOs the CAPM is by far the most popular method of estimating the cost of equity.[11]

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[10] Lorie, James, Mary T. Hamilton. *The Stock Market: Theories and Evidence*. Richard D. Irwin, Inc. Homewood, Illinois. 1973. p. 202.

[11] Graham, John R., Campbel R. Harvey. "The Theory and Practice of Corporate Finance: Evidence from the Field." *Journal of Financial Economics*. 60 (2001) pp. 187-243.

**Q. What is the CAPM formula?**

A. The CAPM formula is shown in the following equation:

Equation 5:

$$K = R_f + \beta (R_m - R_f)$$

where:

| | | |
|---|---|---|
| $R_f$ | = | risk free rate |
| $R_m$ | = | return on market |
| $\beta$ | = | beta |
| $R_m - R_f$ | = | market risk premium |
| $K$ | = | expected return |

**Q. How was the CAPM implemented to estimate APS' cost of equity?**

A. Staff implemented the CAPM on the same sample electric utilities to which it applied the DCF model.

**Q. What risk-free rate of interest did Staff estimate?**

A. Staff estimated the risk-free rate to be 3.7 percent. The estimate is based upon an average of intermediate-term U.S. Treasury securities' spot rates published in *The Wall Street Journal*. Published rates, as determined by the capital markets, are objective, verifiable, and readily available, as opposed to rates published by a forecasting service which are not necessarily objective, and are certainly not necessarily verifiable or readily available. Staff averaged the yields-to-maturity of three intermediate-term[12] (five-, seven-, and ten-

[12] The use of intermediate-term securities is based on the theoretical specification that the time to maturity approximates the investor's holding period, and assumes that most investors consider the intermediate time frame (5-

year) U.S. Treasury securities quoted in the October 10, 2003, edition of *The Wall Street Journal*. Intermediate-term rates averaged 3.7 percent.[13]

**Q. What beta (β) did Staff use?**

A. Staff used the average of the *Value Line* betas for the thirty-three sample electric utilities in its analysis as a proxy for APS' beta. Column 'F' of Schedule JMR-3 shows that the average *Value Line* beta is .67 for the sample electric companies.

**Q. Please describe the expected market risk premium ($R_m - R_f$).**

A. The expected market risk premium is the amount of additional return that investors expect from investing in the market (or an average-risk security) over the risk-free asset.

**Q. What is Staff's estimate of the expected market risk premium?**

A. Staff's estimate for the market risk premium is 7.4 percent.

**Q. How did Staff calculate the expected market risk premium?**

A. Two approaches were used. The first approach is an estimate of the historical market risk premium. The second approach is an estimate of the current market risk premium.

**Q. Please describe Staff's first approach to estimating the market risk premium: estimating the historical market risk premium.**

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10 years) a more appropriate investment horizon. See Reilly, Frank K., and Keith C. Brown. Investment Analysis and Portfolio Management. 2003. South-Western. Mason, OH. p. 439.

[13] Average yield on 5-, 7-, and 10-year Treasury notes according to the October 10, 2003, edition of *The Wall Street Journal*: 3.18%, 3.72%, and 4.30%, respectively.

A. For the first approach, Staff assumed that the average historical market risk premium is a reasonable estimate of the expected market risk premium. If one consistently uses the long-run average market risk premium to estimate the expected market risk premium, one should, on average, be correct.

Staff used the historical intermediate-term market risk premium published in Ibbotson Associates' *Stocks, Bonds, Bills and Inflation 2003 Yearbook* for the 77-year period from 1926 to 2002. Ibbotson Associates' calculation is the arithmetic average difference between S&P 500 returns and intermediate-term government bond income returns. The 77-year period is used to eliminate shorter-term biases while at the same time including unexpected past events including business cycles. Staff's market risk premium estimate using this approach is 7.4 percent.

**Q. Please describe the second approach to estimating the market risk premium: estimating the current market risk premium.**

A. Staff's second approach essentially boils down to inserting a DCF-derived ROE into the CAPM equation, along with a beta and long-term risk-free rate, and solving the CAPM equation for the implied market risk premium. *Value Line* projects the expected dividend yield (next 12 months) and growth for all dividend-paying stocks under its review. According to the October 3, 2003, edition of *Value Line*, the expected dividend yield is 1.9 percent and the expected annual growth in share price is 10.67 percent.[14] Therefore, the constant-growth DCF estimate of the cost of equity to all dividend-paying stocks followed

[14] 3 to 5 year price appreciation potential is 50%. $1.50^{1/4} - 1 = 10.67\%$

by *Value Line* is 12.6 percent. Using a beta of 1.00 and the current long-term risk-free rate of 5.22 percent, the implied current market risk premium is also 7.4 percent.[15]

**Q. What are the results of Staff's CAPM analysis?**

A. Schedule JMR-7 shows the results of Staff's CAPM analysis. Staff's CAPM cost of equity estimate is 8.7 percent.

## IV. FINAL COST OF EQUITY ESTIMATES FOR APS

**Q. Please summarize the results of Staff's cost of equity analysis.**

A. The following table shows the results of Staff's cost of equity analysis:

**Table 4**

| Method | Estimate |
|---|---|
| Average DCF Estimate | 9.1% |
| Average CAPM Estimate | 8.7% |
| **Overall Average** | **8.9%** |

Staff's average estimate of the cost of equity to the electric utility industry is 8.9 percent.

**Q. What is Staff's ROE recommendation for APS?**

A. Staff's ROE recommendation for APS is 9.0 percent.

[15] 12.6% = 5.22% + 1.00 x (current market risk premium); 7.4% = current market risk premium.
A long-term rate is used here because the constant-growth DCF model does not assume a holding period other than infinity. Therefore, a long-term risk-free rate is used for consistency.

**Commission Decision No. 66567 - Adjustment Clause**

**Q. Please provide a brief background of decision No. 66567.**

A. Decision No. 66567, dated November 18, 2003, approved the concept of a purchased power adjuster ("adjuster") for APS, the details of which are to be decided in this proceeding. In approving the concept of an adjuster, the Commission adopted several conditions proposed by Staff, including condition number 10, which states that a "reduction of risk should be considered in the cost of equity in APS' next rate case."[16]

**Q. Did Staff adjust its ROE recommendation to reflect reduced risk resulting from an adjuster?**

A. Staff found through its research that while support may exist for reducing the ROE for a utility that institutes an automatic adjustment clause, such reduction might very well be small and difficult to quantify. Further, Staff did not formulate a method to estimate the reduction because many of the companies in Staff's sample of electric utilities already have adjusters. To the extent such reduced risk is related to market risk, it is reflected in Staff's market-based analysis.

## V. RATE OF RETURN RECOMMENDATION

**Q. What is Staff's rate of return recommendation for APS?**

A. Staff recommends a ROR of 7.3 percent for APS, as shown in Schedule JMR-8 and the following table:

[16] Decision No. 66567, dated November 18, 2003. p. 8 at 16. Finding of Fact No. 17. p. 23 at 10 – 11.

**Table 8**

| | Weight | Cost | Weighted Cost |
|---|---|---|---|
| Long-term Debt | 54.8% | 5.82% | 3.19% |
| Common Equity | 45.2% | 9.0% | 4.07% |
| **Cost of Capital/ROR** | | | **7.3%** |

**Financial Integrity**

**Q. Will Staff's recommendation allow APS to maintain its financial integrity?**

A. Yes. Staff's ROR recommendation results in a pre-tax interest coverage ratio of 3.1 calculated in column F of Schedule JMR-8. Interest coverage is one of the determinants of a company's bond rating – other things equal, a higher ratio of earnings to interest results in a higher bond rating. According to Standard & Poor's ("S&P") 2003 Corporate Ratings Criteria, the median interest coverage ratio for an 'A' rated utility is 3.0.[17]

## VI. COMMENT ON THE DIRECT TESTIMONY OF COMPANY WITNESS CHARLES E. OLSON

**Q. What topics will Staff address in this portion of its testimony?**

A. Staff will address Company witness Dr. Olson's testimony regarding the Company's proposed capital structure alternatives, and his recommended ROE, including his proposed financing cost adjustment.

**Capital Structure**

**Q. On page 9 of his direct testimony Dr. Olson suggests that the Company's two alternative capital structures do not affect the cost of equity. (See direct testimony of Charles E. Olson. P. 9 at 20 – 24.) Is he correct?**

[17] Standard & Poors 2003 Corporate Ratings Criteria. P. 50.

A. No. As a firm increases its leverage, the cost of equity goes up lockstep with beta. Therefore, a lower percentage of debt results in a lower level of financial risk and a lower cost of equity.

**Q. How does relying on a 50/50 debt-to-equity capital structure rather than a 55/45 debt-to-equity capital structure affect APS' cost of equity?**

A. Relying on a 50/50 debt-to-equity capital structure rather than a 55/45 debt-to-equity capital structure lowers APS' cost of equity by approximately 30 basis points. This 30 basis point discount represents the required financial risk adjustment resulting from a capital structure that is less leveraged than the average capital structure of the sample electric utilities. Staff calculated this financial risk adjustment using the methodology developed by Professor Robert Hamada of the University of Chicago, which incorporates capital structure theory with the CAPM. The Hamada equation is generally used to estimate the effect leverage has on a stock's beta. The negative 30 basis point cost of equity adjustment required if the Commission adopts a 50/50 debt-to-equity capital structure is shown in Schedules JMR-9 through JMR-11.

**Return on Equity**

**Q. What return on equity does Dr. Olson recommend for APS?**

A. Dr. Olson recommends a ROE range of 11.25 to 11.75 percent.

**Q. What reasonableness test can Staff apply to his recommendation before discussing his methods?**

A. One reasonableness test is to compare Dr. Olson's 11.25 to 11.75 percent recommendation to the historical overall market returns that Staff discussed earlier. Dr. Olson's 11.25 to

11.75 percent recommendation exceeds a reasonable cost of equity estimate for an average-risk security (based on actual returns). As previously shown in Chart 1 and Chart 2, interest rates have declined in recent years, suggesting that capital costs, including the cost of equity, are lower than they have been in recent decades.

Also, Earlier Staff testified that the average beta for the electric utility industry is .67. An 11.25 to 11.75 percent cost of equity for an average electric utility implies an 11 to 12 percent market risk premium ([11.25% to 11.75% - 3.7%]/.67). This exceeds Staff's estimate of both the current and historical market risk premiums, and is contrary to suggestions by academics that the current equity risk premium is lower than the historical equity risk premium in general.[18]

**Dr. Olson's DCF Estimates**

*Sample Selection*

**Q. On page 20 of his direct testimony, Dr. Olson suggests that his sample group is less risky than APS. (See direct testimony of Charles E. Olson. P. 20 at 4 – 5.) Is he correct?**

A. No. According to Attachment CEO-3 of Dr. Olson's direct testimony, the companies in his comparable group are comprised of approximately 60 percent debt and 40 percent equity. As stated previously, a higher debt ratio equates to greater financial risk and results in a higher cost of equity. This is evidenced by the average beta of the companies in Dr. Olson's comparable group, which is .75. (See Table 5)

[18] Siegel. pp. 16 – 18, 121 – 122.

**Table 5**

| | Dr. Olson's Comparable Group | Staff's Sample Electric Utilities | APS |
|---|---|---|---|
| Beta | .75 | .67 | N/A |
| Debt Ratio | 60% | 56% | 55% |

According to the Hamada methodology mentioned above, the cost of equity to the companies in Dr. Olson's comparable group is 50 to 70 basis points *higher* than the cost of equity to APS, depending on which capital structure is employed.

*Miscalculated Dividend Yield*

**Q. Explain how Dr. Olson's use of a six-month average dividend yield in his DCF analysis is inappropriate.**

A. Dr. Olson's DCF estimates based on six-month average dividend yields are inappropriate because there is no point in "smoothing" stock prices for use in a model that assumes perfect markets. The expected dividend yield requires the most recent spot stock price in the denominator of the calculation ($D_1/P_0$). Professor Myron Gordon, the father of modern DCF analysis, advises:

> The term for dividend yield in Eq. [1] expression for a share's yield is the forecast dividend for the coming period, $D_1$, divided by the current price, $P_0$. The value assigned to $P_0$ should be the price of the share at the time the share yield is being estimated. The rationale for using the current price is that at each point in time it reflects all the information available to a company's investors regarding future dividends.[19]

[19] Testimony of professors Myron J. Gordon and Lawrence I. Gould, consultants to the Trial Staff (Common Carrier Bureau), FCC Docket 79-63. p. 63.

The spot stock price is the only appropriate price to use in the denominator of the DCF equation in order to maintain consistency with the efficient markets hypothesis, a crux of modern corporate finance theory.

**Q. Can Staff cite any further support for the use of a spot yield rather than a historical average?**

A. Yes. The tendency of some analysts to overlook financial principles and use a historical average dividend yield was the focus of a 1996 article in *Public Utilities Fortnightly* by Steven Kihm:

> To the extent that prior yields form a reference point for expectations of future yields, the information content of historic yields is already included in the current spot yield. Thus, to average the historic yield with the spot yield simply double counts any relevant historic information and leads us away from rather than toward the actual future yield.
>
> Note also that by averaging historical data we introduce more distant data into the analysis. This forces us to put less weight on the current spot yield, so that we can consider yields estimated in a period where market participants knew less about next year than they do today. This simply does not make sense.

In the above referenced article, Mr. Kihm reported the results of his empirical analysis of utility bond yields and electric utility dividend yields from 1954 to 1993. The results of his study of historical average and spot dividend yields were qualitatively identical to his results for bond yields:

> By all accuracy measures, the spot forecast outperforms the forecasts based on historic averages. The spot forecast is also dominant in terms of

volatility reduction. And we see clearly the longer the averaging period, the worse the forecasting method by any measure.[20]

**Q. Has the Commission ruled on the use of spot market data in estimating the cost of capital?**

A. Yes. In Decision No. 64727, dated April 17, 2002, the Commission agreed with Staff's use of spot market data in estimating the cost of debt and equity.[21]

**Q. Are there additional problems with Dr. Olson's calculation of the expected dividend yield?**

A. Yes. Dr. Olson's expected dividend yield for IDACORP is biased severely upward.

**Q. Please explain how Dr. Olson's dividend yield for IDACORP is biased upward.**

A. According to Attachment CEO-6 of Dr. Olson's direct testimony, he calculates an average dividend yield for IDACORP of 7.67 percent, which is the highest of all of the companies in his sample. Dr. Olson ultimately adjusts this yield upward by multiplying it by one-half his expected dividend growth rate of 5.0 to 5.5 percent, resulting in an expected dividend yield for the coming period ($D_1/P_0$) for IDACORP of 7.87 percent.[22] Dr. Olson essentially assumes that IDACORP will pay dividends totaling $1.91 over the next year.[23] However, on September 18, 2003, IDACORP announced that it will reduce its annual dividend from $1.86 to $1.20. Therefore, investors logically expect IDACORP to pay a dividend of $1.20 in the next twelve months, not $1.91. Thus, the appropriate annual dividend rate to use in the expected dividend yield ($D_1/P_0$) component of the DCF formula is $1.20, not

[20] Kihm, Steven G. "The Superiority of Spot Yields in Estimating Cost of Captial." *Public Utilities Fortnightly*. February 1, 1996. pp. 42 – 45.
[21] Application of Black Mountain Gas Company. Docket No. G-03703A-01-0263.
[22] See direct testimony of Charles E. Olson, p. 22 at 1 – 23: [7.67%{1+.5(5.25%)}] = 7.87%
[23] Dividend rate of $1.86 (per Attachment CEO-6) x [1+{.5(5.25%)}] = $1.91

$1.91. As of October 9, 2003, Dr. Olson's expected dividend yield for the coming period ($D_1/P_0$) for IDACORP is overstated by 338 basis points.[24]

*Expected Growth Calculation Problem*

**Q. Explain how Dr. Olson's exclusive reliance on analysts' forecasts of earnings growth is inappropriate to forecast dividend growth and results in inflated cost of equity estimates.**

A. Dr. Olson's exclusive reliance on analysts' forecasts of earnings growth in his DCF analysis is inappropriate because it assumes that investors do not look at other information such as past and forecasted growth DPS and intrinsic growth.

**Q. Is there a problem with relying exclusively on analysts' forecasts of earnings growth in a DCF analysis?**

A. Yes. Analysts' forecasts of earnings are known to be overly optimistic.

**Q. How do you respond to Dr. Olson's statement that, "financial analysts who make earnings forecasts are aware of historical growth rates. This means the historical information is reflected in these forecasts to the extent deemed relevant. Therefore, it is not necessary to use it again..." (See direct testimony of Charles E. Olson. P. 21 at 19 – 23.)**

A. While Staff agrees that professional analysts may have considered past growth in their forecasts, the appropriate dividend growth rate to use in the DCF formula is the dividend growth rate expected by investors, not reported by analysts. Therefore, the reasonable

[24] IDACORP's stock price on October 9th, 2003: $26.7. [7.87% - ($1.20 ÷ $26.70) = 3.38%]

assumption that investors rely, to some extent, on past growth in addition to analysts' forecasts, warrants consideration of both.

**Q. How does Dr. Olson's exclusive reliance on analysts' forecasts of earnings growth result in inflated cost of equity estimates?**

A. Dr. Olson's exclusive reliance on analysts' forecasts of earnings growth results in inflated cost of equity estimates because analysts' earnings forecasts are known to be overly optimistic. To the extent that investors are aware of the bias in analysts' projections of future earnings, they will make appropriate adjustments.

**Q. Can Staff provide evidence to support its testimony that analysts' forecasts of future earnings are high?**

A. Yes. Many experts in the financial community have commented on bias/over-optimism in analysts' forecasts of future earnings.[25] A study cited by David Dreman in his book *Contrarian Investment Strategies: The Next Generation* found that *Value Line* analysts were optimistic in their forecasts by 9 percent annually, on average for the 1987 – 1989 period. Another study conducted by David Dreman found that between 1982 and 1997, analysts overestimated the growth of earnings of companies in the S&P 500 by 188 percent.

Burton Malkiel of Princeton University studied the one-year and five-year earnings forecasts made by some of the most respected names in the investment business. The

[25] See Seigel, Jeremy J. *Stocks for the Long Run*. 2002. McGraw-Hill. New York. p. 100 Malkiel, Burton G. *A Random Walk Down Wall Street*. 1999. W. W. Norton & Co. New York. p. 169. Dreman, David. *Contrarian Investment Strategies: The Next Generation*. 1998. Simon & Schuster. New York. pp. 97 – 98. Testimony of Professors Myron J. Gordon and Lawrence I Gould, consultants to the Trial Staff (Common Carrier Bureau). FCC Docket 79-63. p. 95. Claymen, Michelle R., Robin A. Schwartz. "Falling in Love Again – Analysts' Estimates and Reality." *Financial Analysts Journal*. Sep/Oct 1994. 66 – 68.

results showed that, when compared with actual earnings growth rates, the five-year estimates of professional analysts were worse than the predictions from several naïve forecasting models, such as the long-run rate of growth in national income. Professor Malkiel discusses the results of his study in the following quote from his book *A Random Walk Down Wall Street*:

> When confronted with the poor record of their five-year growth estimates, *the security analysts honestly, if sheepishly, admitted that five years ahead is really too far in advance to make reliable projections*. They protested that although long-term projections are admittedly important, they really ought to be judged on their ability to project earnings changes one year ahead.
>
> Believe it or not, it turned out that their one-year forecasts were even worse than their five-year projections. It was actually harder for them to forecast one year ahead than to estimate long-run changes.
>
> The analysts fought back gamely. They complained that it was unfair to judge their performance on a wide cross section of industries, because earnings for electronics firms and various "cyclical" companies are notoriously hard to forecast. *"Try us on utilities," one analyst confidently asserted. So we tried it and they didn't like it. Even the forecasts for the stable utilities were far off the mark. Those the analysts confidently touted as high growers turned out to perform much the same as the utilities for which only low or moderate growth was predicted.*[26] (emphasis added)

**Q. Are investors aware of the problems associated with analysts' forecasts?**

A. Yes. In addition to books, numerous articles appearing in *The Wall Street Journal* and other publications have cast a negative light on research analysts and their forecasts.[27]

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[26] Malkiel. pp. 168 – 169.

[27] See Brown, Ken. "Analysts: Still Coming Up Rosy." *The Wall Street Journal*. January 27, 2003. p. C1. Karmin, Craig. "Profit Forecasts Become Anybody's Guess." *The Wall Street Journal*. January 21, 2003. p. C1. Gasparino, Charles. "Merrill Lynch Investigation Widens." *The Wall Street* Journal. April 11, 2002. p. C4. Elstein, Aaron. "Earnings Estimates Are All Over the Map." *The Wall Street Journal*. August 2, 2001. p. C1. Dreman, David. "Don't Count on those Earnings Forecasts." *Forbes*. January 26, 1998. p. 110.

One such article, entitled "Analysts: Still Coming Up Rosy" appeared in the January 27th, 2003, edition of *The Wall Street Journal*. According to the article, "stock analysts are unshaken in their optimistic, if delusional, belief that most of the companies they cover will have above average, double-digit growth rates during the next several years. That is, of course, highly unlikely." As stated previously, to the extent investors are aware of the bias in analysts' projections of future earnings, they will make appropriate adjustments.

**Q. Can Staff identify any other problems with relying exclusively on analysts' forecasts?**

A. Yes. Another problem with relying exclusively on analysts' forecasts and ignoring past growth is that the results are entirely dependant on the source of the particular forecast. For example, Dr. Olson relies on the average earnings growth forecast for the companies in his comparable group provided by *First Call*, which is 5.2 percent. (See direct testimony of Charles E. Olson. Attachment CEO-7.) However, *Zacks Investment Research* projects an average near-term earnings growth rate of 4.4 percent for the companies in Dr. Olson's comparable group. It should also be noted that *First Call* has revised its estimates, and now projects a near-term earnings growth rate of only 4.6 percent for the companies in Dr. Olson's comparable group.

*Restatement of Dr. Olson's DCF Estimate*

**Q. Has Staff restated Dr. Olson's DCF cost of equity estimate to reflect the above information regarding his DCF analysis?**

A. Yes. Below, Staff restates Dr. Olson's DCF cost of equity estimate to reflect (1) APS having less financial risk than the companies in Dr. Olson's sample, as evidenced by its

capital structure, (2) spot market data as of October 9th, 2003, and (3) revision of the average projected near-term earnings growth rate provided by *First Call*.

**Table 6**

| $D_1/P_0$ | + | $g$ | = | Cost of Equity to Sample Co.'s | Financial Risk Adjustment | = | **Cost of Equity to APS** |
|---|---|---|---|---|---|---|---|
| 5.0% | + | 4.6% | = | 9.6% | -50 to -70 basis points | = | **8.9% to 9.1%** |

Staff's restatement *does not* incorporate the reasonable assumption that investors would examine other factors as indicators of expected dividend growth that would lower their estimate, such as past DPS, EPS, and intrinsic growth in addition to analysts' projections of future earnings growth, which are considered to be high.

**Dr. Olson's Risk Premium Study**

**Q. What is Dr. Olson's "risk premium" study?**

A. Dr. Olson examines the historical difference between returns on the S&P 500 and the Salomon Brothers Long-Term High-Grade Corporate Bond Index as reported by Ibbotson Associates' in *Stocks, Bonds, Bills and Inflation*. The period he used was 1926 to 2002. His risk premium estimate is 6.0 percent. He adds this estimate to the average yield on Moody's medium grade (Baa rated) corporate bonds for April and May 2003, of 6.6 percent to arrive at a cost of equity estimate of 12.6 percent. (See direct testimony of Charles E. Olson. p. 23 at 10 – 25.)

**Q. Is Dr. Olson's risk premium study valid to estimate APS' cost of equity?**

A. No. First, Staff has concerns about the use of a corporate bond rate to imply meaningful equity risk premiums. Because a corporate bond contains some default risk which is diversifiable, the investor's expected rate of return is lower than the bond's yield to maturity. Therefore, the yield to maturity on a corporate bond cannot be compared to the cost of equity. Professor Laurence Booth of the Rotman School of Management at the University of Toronto states the following:

> As for the premium over long term A bond yields, it has to be pointed out here that corporate bonds are default risky. The maximum return you can get from a corporate bond held to maturity is the yield to maturity. Since corporate bonds are default risky, the investor's expected rate of return is significantly lower than the yield to maturity. As a result, *the yield to maturity on a corporate bond is not an estimate of the investor's required rate of return, and cannot be meaningfully compared to the [cost of equity]*. Only the yield to maturity on a default free government bond is an estimate of a required rate of return, similar to the [cost of equity]. This is why *all risk comparisons should be to government default free bonds, otherwise you mix apples and oranges*.[28] (emphasis added)

Second, Dr. Olson's risk premium study is not appropriate because he misapplies the historical differential between S&P 500 returns and *high grade* corporate bond yields to the current yield on *medium grade* bonds. According to Attachment CEO-1, page 4 of Dr. Olson's direct testimony, Baa rated (medium grade) corporate bond rates were, on average, 114 basis points *higher* than Aaa rated (high grade) corporate bond rates in April and May 2003. To the extent there is any validity to such a risk premium study, Dr. Olson's cost of equity estimate is inflated by 114 basis points due to the yield spread between Aaa rated and Baa rated corporate bonds.

[28] Booth, Laurence. "The Importance of Market-to-Book Ratios in Regulation." *NRRI Quarterly Bulletin*. Winter 1997. pp. 415 – 425.

Third, Dr. Olson's risk premium study is quickly dismissed because it in no way assesses the risk of an electric utility. Electric utilities are significantly less risky than the average risk security, as evidenced by CAPM betas. Dr. Olson's risk premium study measures APS' cost of equity as if it currently had the risk of an average-risk security. Dr. Olson's risk premium study is inappropriate because it fails to distinguish the risk of an electric utility company from the risk of the S&P 500. The S&P 500 includes a wide range of companies from a wide range of industries, including aerospace/defense, computers (software), leisure time products, etc. This Commission should not estimate APS' cost of equity based on stock market returns in these other industries with patently differing risks from the risks of providing electric power.

Finally, while the risk premium approach is based on a general rule of thumb that common stocks are riskier than bonds, the Commission should primarily rely on cost of equity models developed in the corporate finance literature rather than on rules of thumb. Staff recommends that the Commission rely on the DCF method and CAPM rather than Dr. Olson's risk premium study. The DCF method is the most widely used model for estimating the cost of equity in public utility rate cases. The CAPM was developed by Nobel Prize winning economists and is the most popular method for estimating the cost of equity among CFOs.[29]

**Dr. Olson's Financing Cost Adjustment**

**Q. What is Dr. Olson's financing cost adjustment and how did he calculate it?**

A. Dr. Olson recommends adding 17 to 18 basis points to his cost of equity estimates to account for the costs associated with issuing new common shares, as well as "market

[29] Graham, John R., Campbel R. Harvey. Pp. 187 – 243.

pressure" associated with new stock offerings. (See direct testimony of Charles E. Olson. P. 24 at 12 – 22 & P. 26 at 8 – 16.) His cost of equity estimates range from 11.07 percent to 11.58 percent. He adjusts these estimates upward to 11.25 percent to 11.75 percent to account for financing costs. (See direct testimony of Charles E. Olson. P. 26 at 10 – 16.) In support of his adjustment Dr. Olson provides information regarding the average percent commission paid by electric utilities in 2002 and 2003, which was 3.15 percent. Dr. Olson claims that 3.15 percent "is not sufficient, however, to provide Pinnacle West with a reasonable probability of issuing common shares at a price above book value because of capital market fluctuations." (See direct testimony of Charles E. Olson. P. 25 at 1 – 3.)

**Q. Should the Commission adopt Dr. Olson's recommendation to boost the allowed ROE to account for financing costs and market pressure associated with issuing new equity?**

A. No. As Staff explains below, the recovery of equity issuance expenses by increasing the allowed ROE is inappropriate.

**Q. Does Dr. Olson consider all stock expenses in his testimony, such as fees that would *reduce* his adjustment?**

A. No, he fails to consider stock purchase fees, otherwise known as brokers' fees, as opposed to the stock issuance fees he does consider. Brokers' fees result in an investor paying more than the price quoted on the stock exchange, and would reduce the required dividend yield in the DCF, offsetting the issuance cost adjustment.[30]

[30] The effect of brokers' fees is analyzed in David Habr's article, "Commission Staff Report: A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," *NRRI Quarterly Bulletin*. 9, no. 1, January 1988. pp. 95 – 104.

**Q. Does Dr. Olson consider equity that was issued at little or no cost to the Company?**

A. No. Dr. Olson failed to consider stock that Pinnacle West and other companies issue under employee stock ownership plans ("ESOP") and dividend reinvestment plans ("DRIP"), which save the underwriting costs of a regular share issue.

**Q. Does Dr. Olson consider equity that is never issued, such as retained earnings?**

A. No. Dr. Olson's method of increasing the authorized ROE also applies to retained earnings – equity that is never issued.

**Q. On page 26 of his direct testimony Dr. Olson states that there is "market pressure" associated with stock offerings that should be compensated for in the ROE. (See direct testimony of Charles E. Olson. P. 26 at 13 – 15.) What is "market pressure?"**

A. Market pressure is the presumed tendency for a company's stock price to decline after the announcement of a public offering, due to an increase in shares outstanding.

**Q. Is the market pressure component consistent with the concept of efficient markets, the theory inherent in the DCF and CAPM?**

A. No, the market pressure component is inconsistent with the efficient markets hypothesis as articulated by Brealey and Myers in their text *Principles of Corporate Finance*:

> Because stock issues usually throw a large additional supply of shares onto the market, it is widely believed that they must temporarily depress the stock price...This belief in price pressure implies that after the decline in price the company's shares can be bought for less than their true value. It is therefore inconsistent with market efficiency. The alternative view stresses that investors buy stocks because they offer a fair reward for their risk. If the stock price fell solely because of increased supply, then that stock

> would offer a reward which was *more* than commensurate with the risk, and investors would be attracted to it as donkeys to a thistle.[31]

The alternative explanation for a decline in stock price after the announcement of a public offering has nothing to do with the increased supply but simply with the information that the issue provides, such as management's view of the company's prospects for future growth. Brealey and Myers explain that most financial economists now interpret the stock price drop in equity issue announcements as an information effect and not a result of the additional supply.[32]

**Q. On page 24 of his direct testimony Dr. Olson testifies that "if a return on common equity exactly equal to the investors' requirement is authorized and earned," when new shares are issued, net proceeds will be less than book value and existing shareholder investment will be diluted. Therefore, the authorized rate of return must be increased. (See direct testimony of Charles E. Olson. P. 24 at 13 – 22.) Is this approach consistent with the guidelines set forth by the Supreme Court in *Bluefield* and *Hope*?**

A. No. As correctly noted by Dr. Olson on page 6 of his direct testimony (lines 6 – 14) the relevant rate of return contemplated by *Bluefield* and *Hope* is that return required by the investor (i.e. the cost of capital). Therefore, allowing a rate of return that is higher than the cost of capital, as Dr. Olson suggests, is inconsistent with *Bluefield* and *Hope*. Dr. Olson agrees with this concept when he states on page 5 (lines 13 – 18) of his direct testimony that "the purpose of pubic utility regulation with respect to rate of return is to permit the regulated company to earn its cost of capital … earnings levels above the cost

[31] Brealey, Richard A. Stewart C. Myers. *Principles of Corporate Finance.* McGraw-Hill, New York. 1991. p. 349.
[32] Brealey, Richard A. Stewart C. Myers. 2000. p. 423.

of capital in the long-run imply excessive profits ..." Dr. Olson's testimony is internally inconsistent.

**Q. How is Dr. Olson's proposal inconsistent with Commission treatment of stock issuance cost ROE adjustments?**

A. To Staff's knowledge, the Commission has never added a stock issuance cost adjustment to the authorized ROE. Staff does not recommend that it do so in this case.

**Q. Should a utility recover the cost of issuing new stock in rates?**

A. Yes, the cost of issuing stock is a necessary cost of business. However, Staff recommends that stock issuance expenses should be treated as adjustments to revenue requirement based on actual expenses in the test year or some other reasonable and direct method, rather than boosting the allowed ROE. The expense method for recovering stock issuance costs directly estimates expected stock issuance costs and includes them in revenue requirement as expenses.

## VII. CONCLUSION

**Q. Please summarize your recommendations.**

A. Staff recommends the Commission adopt a 9.0 percent ROE, a 5.82 percent cost of debt, and a 7.3 percent ROR. Staff recommends the Commission give little weight to the testimony of the Company's witness Dr. Charles Olson. Staff disagrees with his methods and his estimates are not representative of current costs of equity.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

Arizona Public Service Company
Average Capital Structure of Sample Electric Utilities

| Line No. | [A] Company | [B] Long-Term Debt | [C] Common Equity |
|---|---|---|---|
| 1 | | | |
| 2 | Sample Electric Utilities | 55.9% | 44.1% |
| 3 | | | |
| 4 | Arizona Public Service Company | 54.8% | 45.2% |
| 5 | | | |
| 6 | | | |
| 7 | | | |
| 8 | | | |
| 9 | | | |
| 10 | | | |
| 11 | Source: Value Line | | |
| 12 | Schedules D1 & D2 of the Company's application and the Company's response to STF 3.10, does not include vehicle lease obligation | | |

Schedule JMR-1

Arizona Public Service Company
Cost of Long-Term Debt
31-Dec-03

| Line No. | [A] Interest Rate | [B] Description | [C] Issue Date | [D] Maturity Date | [E] Original Life | [F] Principal Amount: Original Issue | [G] Principal Amount: Currently Outstanding | [H] Net to Company: Total Dollar Amount | [I] Net to Company: Per $100 Principal Amount | [J] Cost of Money to Company (Bond Table Basis) | [K] Annual Debt Service Cost | [L] B. P. Difference | [M] Coupon Cost of Debt |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 5.500% | First mortgage bonds - fixed rat | 09/02/93 | 08/15/28 | 35 | $25,000 | $25,000 | $24,906 | 99.624% | 5.524% | $1,381 | 2.44 | $1,375 |
| 2 | 5.880% | First mortgage bonds - fixed rat | 09/02/93 | 08/15/28 | 35 | $141,150 | $141,150 | $140,625 | 99.628% | 5.905% | $8,335 | 2.52 | $8,300 |
| 3 | 5.880% | First mortgage bonds - fixed rat | 09/02/93 | 08/15/28 | 35 | $12,850 | $12,850 | $12,802 | 99.626% | 5.905% | $759 | 2.54 | $756 |
| 4 | 6.630% | First mortgage bonds - fixed rat | 03/02/94 | 03/01/04 | 10 | $100,000 | $80,000 | $98,731 | 98.731% | 6.807% | $5,446 | 17.7 | $5,304 |
| 5 | 1.690% | Pollution control bonds - variabl | 09/14/94 | 09/01/24 | 30 | $65,750 | $65,750 | $65,020 | 98.890% | 1.738% | $1,143 | 4.76 | $1,111 |
| 6 | 1.700% | Pollution control bonds - variabl | 05/25/94 | 05/01/29 | 35 | $57,000 | $57,000 | $56,501 | 99.125% | 1.733% | $988 | 3.34 | $969 |
| 7 | 1.750% | Pollution control bonds - variabl | 05/25/94 | 05/01/29 | 35 | $35,000 | $35,000 | $34,694 | 99.126% | 1.784% | $624 | 3.36 | $613 |
| 8 | 1.750% | Pollution control bonds - variabl | 05/25/94 | 05/01/29 | 35 | $35,000 | $35,000 | $34,694 | 99.126% | 1.784% | $624 | 3.36 | $613 |
| 9 | 1.750% | Pollution control bonds - variabl | 05/25/94 | 05/01/29 | 35 | $36,980 | $36,980 | $36,656 | 99.124% | 1.784% | $660 | 3.38 | $647 |
| 10 | 1.690% | Pollution control bonds - variabl | 05/25/94 | 05/01/24 | 30 | $49,400 | $49,400 | $48,803 | 98.791% | 1.742% | $861 | 5.18 | $835 |
| 11 | 1.690% | Pollution control bonds - variabl | 09/14/94 | 09/01/24 | 30 | $31,500 | $31,500 | $30,975 | 98.333% | 1.762% | $555 | 7.18 | $532 |
| 12 | 1.690% | Pollution control bonds - variabl | 10/12/94 | 10/01/29 | 35 | $32,650 | $32,650 | $31,981 | 97.951% | 1.769% | $578 | 7.88 | $552 |
| 13 | 1.690% | Pollution control bonds - variabl | 12/12/96 | 12/01/31 | 35 | $6,710 | $6,710 | $6,449 | 96.110% | 1.841% | $124 | 15.12 | $113 |
| 14 | 1.690% | Pollution control bonds - variabl | 11/16/98 | 11/01/33 | 35 | $16,870 | $16,870 | $16,661 | 98.761% | 1.737% | $293 | 4.74 | $285 |
| 15 | 1.690% | Pollution control bonds - variabl | 04/07/99 | 04/01/34 | 35 | $20,000 | $20,000 | $19,783 | 98.915% | 1.731% | $346 | 4.14 | $338 |
| 16 | | PCB Bank commitment fees | | | 0 | | | | | | $3,348 | 0 | $0 |
| 17 | 7.480% | Capitalized Lease | 02/01/01 | 10/01/03 | 3 | $650 | $169 | $650 | 100.000% | 7.480% | $13 | 0 | $13 |
| 18 | 5.450% | Capitalized Lease | 11/01/01 | 11/01/06 | 5 | $926 | $678 | $926 | 100.000% | 5.450% | $37 | 0 | $37 |
| 19 | 6.750% | Other Long-term Debt | 11/22/96 | 11/15/06 | 10 | $100,000 | $83,695 | $82,958 | 82.958% | 9.418% | $7,882 | 266.8 | $5,649 |
| 20 | 5.050% | Other Long-term Debt | 11/01/02 | 05/01/29 | 27 | $90,000 | $90,000 | $89,213 | 99.126% | 5.110% | $4,599 | 6 | $4,545 |
| 21 | 6.250% | Other Long-term Debt | 01/13/98 | 01/15/05 | 7 | $100,000 | $100,000 | $99,301 | 99.301% | 6.375% | $6,375 | 12.54 | $6,250 |
| 22 | 5.875% | Other Long-term Debt | 02/24/99 | 02/15/04 | 5 | $125,000 | $125,000 | $124,100 | 99.280% | 6.044% | $7,555 | 16.9 | $7,344 |
| 23 | 7.625% | Other Long-term Debt | 08/07/00 | 08/01/05 | 5 | $300,000 | $300,000 | $297,999 | 99.333% | 7.789% | $23,367 | 16.36 | $22,875 |
| 24 | 6.375% | Other Long-term Debt | 10/05/01 | 10/15/11 | 10 | $400,000 | $400,000 | $397,295 | 99.324% | 6.468% | $25,872 | 9.28 | $25,500 |
| 25 | 6.500% | Other Long-term Debt | 03/01/02 | 03/01/12 | 10 | $375,000 | $375,000 | $372,453 | 99.321% | 6.594% | $24,728 | 9.38 | $24,375 |
| 26 | 4.650% | Other Long-term Debt | 05/15/03 | 05/15/15 | 12 | $300,000 | $300,000 | $295,346 | 98.449% | 4.822% | $14,466 | 17.18 | $13,950 |
| 27 | 5.625% | Other Long-term Debt | 05/15/03 | 05/15/33 | 30 | $200,000 | $200,000 | $195,731 | 97.866% | 5.776% | $11,552 | 15.06 | $11,250 |
| 28 | | | | | | | | | | | | | |
| 29 | Sum: | | | | | $2,657,436 | $2,620,402 | $2,615,253 | | | $152,509 | | $144,130 |
| 30 | | | | | | | | | | | | | |
| 31 | | | | | | | | | | | | | |
| 32 | Cost of Debt: | 5.82% | | | | | | | | | | | 5.50% |
| 33 | | | | | | | | | | | | | |
| 34 | | | | | | | | | | | | | |
| 35 | | | | | | | | | | | | | |

36 Source: APS' response to STF 3-10, does not include $17,448 in vehicle lease obligation.

Schedule JMR-2

Arizona Public Service Company
Selected Financial Data of Sample Electric Utilities

| Line No. | [A] Company | [B] Symbol | [C] Spot Price 10/9/03 | [D] Book Value 10/9/03 | [E] Mkt To Book | [F] *Value Line* Beta $\beta$ | [G] Raw Beta $\beta_{raw}$ |
|---|---|---|---|---|---|---|---|
| 1 | Alliant Energy | LNT | 23.08 | 20.09 | 1.1 | 0.70 | 0.52 |
| 2 | Ameren | AEE | 43.50 | 26.03 | 1.7 | 0.65 | 0.45 |
| 3 | Avista | AVA | 16.12 | 15.08 | 1.1 | 0.75 | 0.60 |
| 4 | Cent. Vermont P.S. | CV | 23.65 | 17.04 | 1.4 | 0.45 | 0.15 |
| 5 | CH Energy Group | CHG | 44.90 | 29.53 | 1.5 | 0.70 | 0.52 |
| 6 | Cleco Corporation | CNL | 16.81 | 10.71 | 1.6 | 0.90 | 0.82 |
| 7 | Con. Edison | ED | 40.73 | 28.62 | 1.4 | 0.55 | 0.30 |
| 8 | DPL Inc. | DPL | 18.35 | 6.74 | 2.7 | 0.80 | 0.67 |
| 9 | DTE Energy Co. | DTE | 36.25 | 28.10 | 1.3 | 0.60 | 0.37 |
| 10 | Empire District | EDE | 22.30 | 14.87 | 1.5 | 0.60 | 0.37 |
| 11 | Energy East Corp. | EAS | 23.44 | 17.53 | 1.3 | 0.70 | 0.52 |
| 12 | Entergy Corp. | ETR | 54.08 | 37.57 | 1.4 | 0.65 | 0.45 |
| 13 | FirstEnergy | FE | 32.58 | 24.60 | 1.3 | 0.70 | 0.52 |
| 14 | FPL Group, Inc. | FPL | 64.48 | 37.50 | 1.7 | 0.60 | 0.37 |
| 15 | Green Mtn. Power | GMP | 22.35 | 19.39 | 1.2 | 0.60 | 0.37 |
| 16 | Hawaiian Electric | HE | 44.13 | 29.41 | 1.5 | 0.55 | 0.30 |
| 17 | IDACORP, Inc. | IDA | 26.70 | 22.69 | 1.2 | 0.75 | 0.60 |
| 18 | MGE Energy Inc. | MGEE | 31.33 | 14.84 | 2.1 | 0.55 | 0.30 |
| 19 | NiSource Inc. | NI | 21.34 | 17.76 | 1.2 | 0.65 | 0.45 |
| 20 | Northeast Utilities | NU | 18.86 | 17.58 | 1.1 | 0.65 | 0.45 |
| 21 | NSTAR | NST | 46.90 | 25.50 | 1.8 | 0.65 | 0.45 |
| 22 | P.S. Enterprise Gp. | PEG | 40.74 | 19.09 | 2.1 | 0.75 | 0.60 |
| 23 | Pinnacle West | PNW | 35.64 | 30.18 | 1.2 | 0.70 | 0.52 |
| 24 | PNM Resources | PNM | 28.71 | 25.71 | 1.1 | 0.70 | 0.52 |
| 25 | Progress Energy | PGN | 44.49 | 30.10 | 1.5 | 0.[illegible]5 | 0.75 |
| 26 | Puget Energy, Inc. | PSD | 22.90 | 16.60 | 1.4 | 0.65 | 0.45 |
| 27 | SCANA Corp. | SCG | 35.25 | 20.77 | 1.7 | 0.60 | 0.37 |
| 28 | Sempra Energy | SRE | 28.80 | 15.07 | 1.9 | 0.80 | 0.67 |
| 29 | Southern Co. | SO | 29.60 | 12.73 | 2.3 | 0.65 | 0.45 |
| 30 | TECO Energy,Inc. | TE | 14.71 | 13.27 | 1.1 | 0.75 | 0.60 |
| 31 | Westar Energy | WR | 18.98 | 14.39 | 1.3 | 0.60 | 0.37 |
| 32 | Wisconsin Energy | WEC | 31.28 | 19.76 | 1.6 | 0.60 | 0.37 |
| 33 | WPS Resources | WPS | 41.82 | 26.77 | 1.6 | 0.70 | 0.52 |
| 34 | | | | | | | |
| 35 | Average | | | | 1.5 | 0.67 | 0.48 |
| 36 | | | | | | | |
| 37 | Source: Yahoo Finance, Value Line | | | | | | |

Schedule JMR-3

Arizona Public Service Company
Growth in Earnings and Dividends
Sample Electric Utilities

| Line No. | [A] | [B] Dividends Per Share 1997 to 2007 DPS | [C] Earnings Per Share 1997 to 2007 EPS |
|---|---|---|---|
| 1 | | | |
| 2 | Sample Electric Utilities | 0.2% | 3.4% |
| 3 | | | |
| 4 | | | |
| 5 | | | |
| 6 | | | |
| 7 | Source: Value Line | | |

Schedule JMR-4

Arizona Public Service Company
Intrinsic Growth
Sample Electric Utilities

| Line No. | [A] Company | [B] Retention Growth 1998 to 2007 br | [C] Stock Financing Growth vs | [D] Intrinsic Growth 1998 to 2007 br + vs |
|---|---|---|---|---|
| 1 | | | | |
| 2 | Sample Electric Utilities | 4.5% | 1.4% | 5.9% |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | Source: Value Line, MSN Money | | | |

Schedule JMR-5

Arizona Public Service Company
Calculation of Expected Infinite Annual Growth in Dividends
Sample Electric Utilities

| Line No. | [A] | [B] |
|---|---|---|
| | | g |
| 1 | DPS Growth | 0.2% |
| 2 | EPS Growth | 3.4% |
| 3 | Intrinsic Growth | 5.9% |
| 7 | | |
| 8 | Average | 3.2% |
| 9 | | |
| 10 | | |
| 11 | | |
| 12 | Supporting Schedules: Schedule JMR-4 and Schedule JMR-5 | |

Schedule JMR-6

Arizona Public Service Company
Final Cost of Equity Estimates
Sample Electric Utilities

| Line No. | [A] | [B] | | [C] | | [D] | | [E] |
|---|---|---|---|---|---|---|---|---|
| | **Constant Growth DCF** | | | $D_1/P_0$ | + | g | = | k |
| 1 | Constant Growth DCF Estimate | | | 4.5% | + | 3.2% | = | 7.7% |
| 2 | Multi-Stage DCF Estimate | | | | | | = | 10.6% |
| 3 | **Average of DCF Estimates** | | | | | | | **9.1%** |
| 4 | | | | | | | | |
| 5 | **CAPM Method** | **Rf** | + | $\beta$ | x | (Rp) | = | k |
| 6 | Historical Market Risk Premium | 3.7% | + | 0.67 | x | 7.4% | = | 8.7% |
| 7 | Current Market Risk Premium | 3.7% | + | 0.67 | x | 7.4% | = | 8.7% |
| 8 | **Average of CAPM Estimates** | | | | | | | **8.7%** |
| 9 | | | | | | | | |
| 10 | | | | | | | | |
| 11 | | | | | | **Average** | | **8.9%** |
| 12 | | | | | | | | |
| 13 | Source: The Wall Street Journal, Value Line, Yahoo Finance, Ibbotson Associates SBBI 2003 Yearbook | | | | | | | |
| 14 | Supporting Schedules: Schedule JMR-6 | | | | | | | |

Schedule JMR-7

Arizona Public Service Company
Capital Structure
And Weighted Cost of Capital

| Line No. | [A] | [B] Weight (%) | [C] Cost | [D] Weighted Cost | [E] Gross Rev. Conv. Factor | [F] Grossed-Up Cost |
|---|---|---|---|---|---|---|
| 1 | Long-term Debt | 54.8% | 5.82% | 3.19% | 1.00 | 3.19% |
| 2 | Common Equity | 45.2% | 9.0% | 4.07% | 1.63 | 6.64% |
| 3 | Weighted Average Cost of Capital/ROR | | | 7.3% | | 9.8% |
| 4 | | | | | | |
| 5 | | | | Pre-Tax Interest Coverage [3 ÷ 1] | | 3.1 |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | Supporting Schedules: Schedule JMR-1, Schedule JMR-2, Schedule JMR-7 | | | | | |

Schedule JMR-8

Arizona Public Service Company
Calculation of Unlevered Beta
Sample Electric Utilities

$$\beta_{UL} = \frac{\beta_L}{1 + BD + EC\ (1 - t)}$$

Where :

$\beta_{UL}$ = unlevered beta
$\beta_L$ = levered beta
$BD$ = book debt
$EC$ = equity capital
$t$ = tax rate

| Line No. | [A] | [B] Value Line Levered Raw Beta $\beta_L$ | [C] Tax Rate t | [D] Book Debt BD | [E] Equity Cap EC | [F] Unlevered Raw Beta $\beta_{UL} = \frac{\beta_L}{1+\frac{BD}{EC}(1-t)}$ |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | Sample Electric Utilities | 0.48 | 33% | 0.56 | 0.44 | 0.26 |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | Source: Value Line | | | | | |
| 9 | Supporting Schedules. Schedule JMR-1, Schedule JMR-3 | | | | | |

Schedule JMR-9

Arizona Public Service Company
Calculation of Relevered Beta
Using 50/50 Debt-to-Equity Capital Structure

$$\beta_{RL} = \beta_{UL}\ (1 + (1 - t)BD + EC)$$

Where :

$\beta_{RL}$ = relevered beta
$\beta_{UL}$ = unlevered beta
$t$ = tax rate
$BD$ = book debt
$EC$ = equity capital

| Line No. | [A] | [B] Unlevered Raw Beta $\beta_{UL}$ | [C] Book Debt BD | [D] Equity Cap EC | [E] Tax Rate t | [F] Relevered Raw Beta $b_{RL}=\beta_{UL}(1+(1-t)BD/EC))$ $\beta_{RL}$ | [G] Adjusted Relevered Beta .35 + .67(Raw Beta) $\beta_{RL}$ |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | Arizona Public Service Company | 0.26 | 0.50 | 0.50 | 39.5% | 0.41 | 0.63 |
| 3 | | | | | | | |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | Source: Schedule C3 of the Company's application, direct testimony of Charles E. Olson, p. 8 at 17 - p. 10 at 9 | | | | | | |
| 10 | Supporting Schedules: Schedule JMR-9 | | | | | | |

Schedule JMR-10

Arizona Public Service Company
Required Capital Structure Adjustment
For Using 50/50 Debt-to-Equity Capital Structure

| Line No. | [A] | [B] | | [C] | | [D] | | [E] |
|---|---|---|---|---|---|---|---|---|
| | **CAPM Method** | **Rf** | **+** | **$\beta$** | **x** | **(Rp)** | **=** | **k** |
| 1 | Historical Market Risk Premium | 3.7% | + | 0.67 | x | 7.4% | = | 8.7% |
| 2 | Current Market Risk Premium | 3.7% | + | 0.67 | x | 7.4% | = | 8.7% |
| 3 | **Average of CAPM Estimates** | | | | | | | **8.7%** |
| 4 | | | | | | | | |
| 5 | **Relevered Beta** | **Rf** | | **$\beta$** | | **(Rp)** | | **k** |
| 6 | Historical Market Risk Premium | 3.7% | + | 0.63 | x | 7.4% | = | 8.4% |
| 7 | Current Market Risk Premium | 3.7% | + | 0.63 | x | 7.4% | = | 8.4% |
| 8 | **Average of CAPM Estimates** | | | | | | | **8.4%** |
| 9 | | | | | | | | |
| 10 | Capital Structure Adjustment (8 - 3) | | | | | | | -0.3% |
| 11 | | | | | | | | |
| 12 | | | | | | | | |
| 13 | | | | | | | | |
| 14 | | | | | | | | |
| 15 | Supporting Schedules: Schedule JMR-7, Schedule JMR-10 | | | | | | | |

Schedule JMR-11

**ARIZONA PUBLIC SERVICE COMPANY**
**RESPONSE TO STF 2-8**
**Balance of Long-term debt**
**as of June 30, 2003**
**(dollars in thousands)**

| (a) Description of loan or bond issuance | (b) Interest Rate | (c) Issue Date | (d) Maturity Date | (e) Original Issue | (f) Principal Outstanding | (g) Principal due within one year | (h)** Unamortized Debt Expense | (h)** Unamortized Debt Discount |
|---|---|---|---|---|---|---|---|---|
| First mortgage bonds - fixed rate | 8% | 2/9/1993 | 2/1/2025 | 150,000 | - | - | 284 *** | 324 *** |
| First mortgage bonds - fixed rate | 7.25% | 8/10/1993 | 8/1/2023 | 100,000 | 54,150 | | 574 | 930 |
| First mortgage bonds - fixed rate | 5.5% | 9/2/1993 | 8/15/2028 | 25,000 | 25,000 | | 678 | 67 |
| First mortgage bonds - fixed rate | 5.875% | 9/2/1993 | 8/15/2028 | 141,150 | 141,150 | | 1,098 | 377 |
| First mortgage bonds - fixed rate | 5.875% | 9/2/1993 | 8/15/2028 | 12,850 | 12,850 | | 151 | 34 |
| First mortgage bonds - fixed rate | 6.625% | 3/2/1994 | 3/1/2004 | 100,000 | 80,000 | 80,000 | 76 | 27 |
| First mortgage bonds - fixed rate | 6.75% | 11/22/1996 | 11/15/2006 | 100,000 | 83,695 | | 316 | 122 |
| Senior notes - fixed rate | 5.05% | 11/1/2002 | 5/1/2029 | 90,000 | 90,000 | | 638 | |
| Pollution control bonds with senior notes - fixed rate | 1.730% | 5/25/1994 | 5/1/2029 | 57,000 | 57,000 | | 265 | |
| Pollution control bonds with senior notes - variable 1 year mode | 1.75% | 5/25/1994 | 5/1/2029 | 35,000 | 35,000 | | 161 | |
| Pollution control bonds with senior notes - variable 1 year mode | 1.75% | 5/25/1994 | 5/1/2029 | 35,000 | 35,000 | | 163 | |
| Pollution control bonds with senior notes - variable 1 year mode | 1.75% | 5/25/1994 | 5/1/2029 | 36,980 | 36,980 | | 172 | |
| Pollution control bonds with senior notes - variable 1 year mode | 0.9% | 5/25/1994 | 5/1/2024 | 49,400 | 49,400 | | 428 | |
| Pollution control bonds - variable daily rate | 0.9% | 9/14/1994 | 9/1/2024 | 65,750 | 65,750 | | 526 | |
| Pollution control bonds - variable daily rate | 0.9% | 9/14/1994 | 9/1/2024 | 31,500 | 31,500 | | 387 | |
| Pollution control bonds - variable daily rate | 1.05% | 10/12/1994 | 10/1/2029 | 32,650 | 32,650 | | 509 | |
| Pollution control bonds - variable weekly rate | 1.43% | 12/12/1996 | 12/1/2031 | 6,710 | 6,710 | | 213 | |
| Pollution control bonds - variable daily rate | 1.05% | 11/16/1998 | 11/1/2033 | 16,870 | 16,870 | | 268 | |
| Pollution control bonds - variable daily rate | 1.43% | 4/7/1999 | 4/1/2034 | 20,000 | 20,000 | | 231 | |
| Pollution control bonds - variable daily rate | 6.25% | 1/13/1998 | 1/15/2005 | 100,000 | 100,000 | | 151 | |
| Unsecured notes - fixed rate | 5.875% | 2/24/1999 | 2/15/2004 | 125,000 | 125,000 | 125,000 | 115 | 8 |
| Unsecured notes - fixed rate | 7.625% | 8/7/2000 | 8/1/2005 | 300,000 | 300,000 | | 890 | 621 |
| Unsecured notes - fixed rate | 6.375% | 10/5/2001 | 10/15/2011 | 400,000 | 400,000 | | 2,263 | 1,107 |
| Unsecured notes - fixed rate | 6.5% | 3/1/2002 | 3/1/2012 | 375,000 | 375,000 | | 2,237 | 2,294 |
| Unsecured notes - fixed rate | 5.625% | 5/7/2003 | 5/15/2033 | 200,000 | 200,000 | | 1,975 | 2,202 |
| Unsecured notes - fixed rate | 4.65% | 5/7/2003 | 5/15/2015 | 300,000 | 300,000 | | 2,430 | 2,196 |
| Unsecured notes - fixed rate | 5.78% * | 9/1/1999 | 9/1/2012 | 20,664 | 20,086 | 3,148 | | |
| Capitalized lease obligations - Vehicles | 5.45% | 10/24/2001 | 11/1/2006 | 926 | 629 | 252 | | |
| Capitalized lease obligations - Tape Library | 7.75% | 2/1/2001 | 9/1/2003 | 650 | 13 | 13 | | |
| Capitalized lease obligations - EMC disk | | | | | 2,694,433 | 208,413 | 17,199 | 10,389 |

* Weighted average interest rate of all vehicle leases.
** Calculation assumes that these amounts are equal to "issuance costs (not expensed)".
*** The remaining outstanding debt balance of $33,075,000 for the 8% Series Due 2/1/2025 was redeemed on 4/7/2003.
The related unamortized debt expense and unamortized debt discount was reclassifed to loss on reacquired debt in 3rd quarter 2003.

(i)
During the 18 month period 1/1/2002 to 6/30/2003, Arizona Public Service did not have any redemption expense related to debt that was redeemed/reacquired.

Exhibit JMR-1
Page 1 of 2

Exhibit JMR-1
Page 2 of 2

ARIZONA CORPORATION COMMISSION STAFF SECOND SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437

STF 2-9 Please provide the June 30, 2003, dollar amount of common stockholders equity for Arizona Public Service Company.

Response:

The common stockholders equity amount at June 30, 2003 is $2,155,473,000.

Witness: Chris N. Froggatt

Exhibit JMR-2
Page 1 of 3

ARIZONA CORPORATION COMMISSION STAFF THIRD SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437

STF 3-10 Refer to Schedule D-2, page 1, column "End of Projected Year 12/31/2003" of the Company's application. Please provide a schedule giving a description of the particular loans or bond issuances that are included in each class of debt, the amount expected to be outstanding on 12/31/2003, and provide calculations supporting the annual interest for each loan or bond issuance.

RESPONSE:

Attached are the supporting schedules for Schedule D-2 for the "End of Projected Year 12/31/2003" that provide a description of the bonds, the issue date, the due date, the amount expected to be outstanding on 12/31/03, the original principal amount, and the net proceeds from the original issue. The annual interest is calculated using the "Yield to Maturity" formula. (RC01563)

Witness: Chris Froggatt

Exhibit JMR-2
Page 2 of 3

ARIZONA PUBLIC SERVICE COMPANY
Projected Cost of Long-Term Debt
First Mortgage Bonds Outstanding
December 31, 2003
(Thousands of Dollars)

Schedule D-2

Backup page 1

| Line No. | Series | Offering Date | Due Date | Prin Amt of Issue | Prin Amt Outstdng | Net Proceeds From Prin Amt of Issue | Cost of Money | Annualized Interest | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.0550 | 09/02/93 | 08/15/28 | 25,000 | 25,000 | 24,906 | 5.52% | 1,381 | 1 |
| 2 | 0.0588 | 09/02/93 | 08/15/28 | 141,150 | 141,150 | 140,625 | 5.90% | 8,328 | 2 |
| 3 | 0.0588 | 09/02/93 | 08/15/28 | 12,850 | 12,850 | 12,802 | 5.90% | 758 | 3 |
| 4 | 0.0663 | 03/02/94 | 03/01/04 | 100,000 | 80,000 | 98,731 | 6.80% | 5,443 | 4 |
| 5 | | | | | | | | | 5 |
| 6 | Total | | | | $ 259,000 | | 6.14% | $ 15,910 | 6 |

Exhibit JMR-2
Page 3 of 3

ARIZONA PUBLIC SERVICE COMPANY
Projected Cost of Long-Term Debt
Other Long-Term Debt Outstanding
December 31, 2003
(Thousands of Dollars)

Schedule D-2

Backup page 2

| Line No. | Series | Offering Date | Due Date | Prin Amt of Issue | Prin Amt Outstdng | Net Proceeds From Prin Amt of Issue | Cost of Money | Annualized Interest | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| | Pollution Control Indebtedness* | | | | | | | | |
| 1 | 1.69% | 09/14/94 | 09/01/24 | 65,750 | $65,750 | $65,020 | 1.74% | $1,143 | 1 |
| 2 | 1.70% | 05/25/94 | 05/01/29 | 57,000 | 57,000 | 56,501 | 1.73% | 988 | 2 |
| 3 | 1.75% | 05/25/94 | 05/01/29 | 35,000 | 35,000 | 34,694 | 1.78% | 624 | 3 |
| 4 | 1.75% | 05/25/94 | 05/01/29 | 35,000 | 35,000 | 34,694 | 1.78% | 624 | 4 |
| 5 | 1.75% | 05/25/94 | 05/01/29 | 36,980 | 36,980 | 36,656 | 1.78% | 660 | 5 |
| 6 | 1.69% | 05/25/94 | 05/01/24 | 49,400 | 49,400 | 48,803 | 1.74% | 861 | 6 |
| 7 | 1.69% | 09/14/94 | 09/01/24 | 31,500 | 31,500 | 30,975 | 1.76% | 555 | 7 |
| 8 | 1.69% | 10/12/94 | 10/01/29 | 32,650 | 32,650 | 31,981 | 1.77% | 578 | 8 |
| 9 | 1.69% | 12/12/96 | 12/01/31 | 6,710 | 6,710 | 6,449 | 1.84% | 124 | 9 |
| 10 | 1.69% | 11/16/98 | 11/01/33 | 16,870 | 16,870 | 16,661 | 1.74% | 293 | 10 |
| 11 | 1.69% | 04/07/99 | 04/01/34 | 20,000 | 20,000 | 19,763 | 1.73% | 346 | 11 |
| 12 | | | | | | | | | 12 |
| 13 | Bank Commitment Fees | | | | | | | 3,348 | 13 |
| 14 | Total PC Indebtedness | | | | $ 386,860 | | 2.62% | $ 10,144 | 14 |
| 15 | | | | | | | | | 15 |
| 16 | * All Rates are Adjusted Daily | | | | | | | | 16 |
| 17 | | | | | | | | | 17 |
| 18 | Capitalized Lease Obligation | | | | | | | | 18 |
| 19 | 7.48% | 2/01/01 | 10/01/03 | $650 | 169 | $650 | 7.75% | $13 | 19 |
| 20 | 5.45% | 11/01/01 | 11/01/06 | $926 | 678 | $926 | 5.45% | $37 | 20 |
| 21 | | | | $19,554 | 17,446 | $19,554 | 5.78% | $1,008 | 21 |
| 22 | Total Capitalized Lease Obligation | | | | 18,293 | | 5.79% | $1,058 | 22 |
| 23 | | | | | | | | | 23 |
| 24 | 6.75% | 11/22/96 | 11/15/06 | 100,000 | 83,695 a | 82,958 | 6.82% | $5,707 | 24 |
| 25 | 5.05% | 11/01/02 | 05/01/29 | 90,000 | 90,000 a | 89,213 | 5.11% | $4,598 | 25 |
| 26 | 6.25% | 01/13/98 | 01/15/05 | 100,000 | 100,000 | 99,301 | 6.38% | $6,377 | 26 |
| 27 | 5.875% | 02/24/99 | 02/15/04 | 125,000 | 125,000 | 124,100 | 6.05% | $7,564 | 27 |
| 28 | 7.6250% | 08/07/00 | 08/01/05 | 300,000 | 300,000 | 297,999 | 7.80% | $23,386 | 28 |
| 29 | 6.3750% | 10/05/01 | 10/15/11 | 400,000 | 400,000 | 397,295 | 6.54% | $26,170 | 29 |
| 30 | 6.5000% | 3/01/02 | 3/1/12 | 375,000 | 375,000 | 372,453 | 6.66% | $24,989 | 30 |
| 31 | 4.6500% | 05/15/03 | 05/15/15 | 300,000 | 300,000 | 295,346 | 4.82% | $14,469 | 31 |
| 32 | 5.6250% | 05/15/04 | 05/15/33 | 200,000 | 200,000 | 195,731 | 5.78% | $11,563 | 32 |
| 33 | Total Other Long-Term Debt | | | $ 2,011,130 | $ 1,991,988 | | 6.32% | $ 125,881 | 33 |

a. Other Long-Term Debt Senior Notes

EXHIBIT
S-4
Admitted

**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | DOCKET NO. E-01345A-03-0437 |

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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## APPENDIX

Resume of Barbara Keene

# EXECUTIVE SUMMARY
# ARIZONA PUBLIC SERVICE COMPANY
# DOCKET NO. E-01345A-03-0437

Ms. Keene's testimony recommends that APS recover its costs for pre-approved demand-side management (DSM) programs through a DSM adjustment mechanism. Staff recommends that the total of System Benefits should be $33,115,801. Staff recommends that the caps per service on EPS-1 be increased to help APS meet its Environmental Portfolio Standard requirements. Staff does not oppose the Returning Customer Direct Assignment Charge with conditions. Staff recommends that some of the charges on the service schedules be set at amounts lower than APS proposes. Staff also opposes some of the proposed wording changes on the service schedules.

## INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

**Q. By whom are you employed and in what capacity?**

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of electric utility special contracts, review of utility tariff filings, assessment of utility demand-side management programs, and analysis of electric utility production costs and marginal costs. A copy of my résumé is provided in the Appendix.

**Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01345A-03-0437?**

A. Yes.

**Q. What is the purpose of your testimony?**

A. My testimony is concerned with demand-side management ("DSM") for Arizona Public Service ("APS"), System Benefits, the Environmental Portfolio Standard, the Returning Customer Direct Assignment Charge, and APS' service schedules.

## DEMAND-SIDE MANAGEMENT

### Benefits of DSM

**Q. What is DSM?**

A. DSM is the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner. DSM programs are also known as conservation or energy efficiency programs.

**Q. Does APS and the rest of society benefit from having DSM programs?**

A. Cost-effective DSM programs can meet the demand for electric energy services at a lower cost than purchasing or generating power. Reduced peak demand can delay the need for construction of new generation and transmission facilities. In addition, reducing energy (kWh) needs reduces the operating costs of current generating facilities. Reduced energy production may also lead to reduced air emissions from power plants, reduced consumption of water by generating unit cooling towers, and reduced degradation of land at mining sites.

**Q. Why should APS and Staff consider the benefits and costs of DSM to society rather than just to APS?**

A. We are seeking the least cost means of meeting the demand for electric energy services. A program that is not least cost wastes society's resources. Because customer costs and new generation costs may not be part of APS' costs, we need to look beyond APS' costs and benefits. The Commission adopted the use of the societal cost test in its resource planning decision (Decision No. 57589).

**Q. What are the societal benefits of a DSM program?**

A. From a societal perspective, relevant benefits come from avoiding new generating, transmission, and distribution capacity and avoiding burning of fuel and other variable costs. Because existing power plants have already been built and the associated societal costs have already been incurred, the fixed costs of existing power plants are sunk costs which cannot be avoided by a reduction in the demand for kW and kWh. Therefore, the only costs to society that can be avoided by DSM are those associated with the construction of new capacity and the variable costs associated with the generation of additional electricity.

**Q. How can the societal costs of a DSM program be calculated?**

A. The costs to society to implement a DSM program are the incremental costs of any equipment, including installation and operating costs, and program administrative costs. Incentives offered to customers to participate are not societal costs, but are transfer payments (transfers of income from one person or organization to another without supplying goods or services for these payments).

**APS' Current DSM Programs**

**Q. Does APS currently have any DSM program?**

A. Yes. According to semi-annual reports filed with the Commission, APS currently has one DSM program: Energy-Wise Assistance Program. According to APS' response to STF 5-13, APS has other DSM programs that I describe later in my testimony.

**Q. Please describe the Energy-Wise Assistance Program.**

A. The Energy-Wise Assistance Program was pre-approved by Staff on December 21, 1998. As presented to Staff in 1998, the program is designed to provide low-income customers with weatherization and energy education and consists of the following components: Weatherization, Repair/Replacement Program, Energy Education, ACAA Administration, and Communications.

**Q. Please describe the Weatherization component.**

A. The Weatherization component is comprehensive and includes health and safety measures. Where possible, the program is coordinated with the federal Weatherization Assistance Program ("WAP") to achieve maximum cost efficiency and expand the scope of measures performed on each house. The maximum APS contribution is capped at $1,500 per house, excluding administrative costs. Customers must have incomes less than 150 percent of the poverty level, using a 90-day test proof of income, to be eligible for services. Customers must also show proof of home ownership or tenant waivers from

their landlords. Eligible measures include adjusting space heaters and evaporative coolers, repairing ductwork, installing weather stripping and insulation, and general repairs to roofs, windows, doors, ceilings, and floors.

**Q. Please describe the Repair/Replacement Program component.**

A. This component repairs or replaces HVAC (heating, ventilation, and air conditioning) systems, evaporative coolers, and electric water heaters. Replacement is limited to when repair costs exceed replacement costs or when the appliance is found to be inoperable with repairs. Customers must have incomes less than 150 percent of the poverty level, using a 30-day test proof of income, to be eligible for services. Customers must show proof of ownership of the appliance and social security cards for all members of the household.

**Q. Please describe the Energy Education component.**

A. Energy Education consists of training community action agency staff to deliver energy education, both in-office and in-home. In addition, APS will provide $25 to a community action agency to help cover the costs of an in-home visit for bill assistance recipients to receive energy education.

**Q. Please describe the ACAA Administration component.**

A. The Arizona Community Action Association ("ACAA") administers the Energy-Wise Assistance Program. ACAA coordinates the program between APS and nine local community action agencies (located in Phoenix, Tucson, Flagstaff, Yuma, Coolidge, Globe, and Safford); serves as the central point for invoicing, tracking, validating, and reporting activities to APS; identifies technical assistance needs and provides training; and develops the energy education program. In response to requests from ACAA, the Arizona Energy Office ("AEO") calculates present value analyses of how much measures are worth, comparing costs to install a measure with savings to the customer.

**Q. Please describe the Communications component.**

A. This component includes the design and development of brochures, posters, stickers, survey forms, and evaluation forms.

**Q. How much has APS agreed to spend on the Energy-Wise Assistance Program?**

A. As part of the 1999 Settlement, APS agreed to continue this program in an annual amount of at least $500,000 through July 1, 2004.

**Q. How much has APS been spending on the Energy-Wise Assistance Program?**

A. APS has reported the following program expenditures: $434,763 in 1999; $462,990 in 2000; $399,365 in 2001, and $394,354 in 2002. Therefore, APS did not spend the promised $500,000 in any year. In addition, those amounts include expenditures for bill assistance. Bill assistance is not DSM, although it is a System Benefit which will be discussed later in this testimony.

**Q. What other DSM programs does APS currently have?**

A. In 1997, Staff pre-approved two programs for APS. They were the Residential New Construction Market Transformation Program and the Residential HVAC Retrofit Market Transformation Program. Beginning in 2001, APS stopped reporting on these programs in its semi-annual DSM reports. A statement in the report for the second half of 2000 after the section on Market Transformation was, "This is the last time this will be reported as a DSM activity." Staff understood this to mean that the programs were no longer being conducted. At that time, Decision No. 63364 that approved the Environmental Portfolio Standard said that utilities should shift DSM spending to renewables. However, APS' response to STF 5-13 indicates that these programs are still in effect. APS has indicated that it will revise its semi-annual DSM reports to include these programs.

**Q. Please describe the Residential New Construction Market Transformation Program.**

A. As presented to Staff in 1997, the objective of the program was to encourage the market adoption of energy-efficient new home construction techniques and more energy-efficient HVAC systems. The program promotes the Environmental Protection Agency's Energy Star Home Program, which is a voluntary labeling program for energy-efficient products, including houses. APS provides training for home builders on selling energy efficiency and the Energy Star Home Program. For HVAC contractors, APS provides training, qualification, and advertising costs. APS provides consumers with information and referrals to qualified contractors. Per APS' response to STF 5-14, APS spent $168,159 on this program in 2002.

**Q. Please describe the Residential HVAC Retrofit Market Transformation Program.**

A. As presented to Staff in 1997, this program sought to educate contractors and residential customers about energy-efficient HVAC on existing houses. Per APS' response to STF 5-14, APS spent $106,357 on this program in 2002. APS also spent $372,877 on joint education and promotional costs for both residential market transformation programs.

**Q. Are there any other DSM programs?**

A. According to APS' response to STF 5-13, APS also has programs for Residential Time of Use (educational materials); Commercial Energy Information, Analysis and Training; and Commercial and Industrial Power Partners Program. These programs have not been pre-approved by Staff. In 2002, APS spent $10,335; $47,595; and $13,383 on these programs, respectively.

**Q. What DSM programs should APS pursue?**

A. APS should evaluate possible DSM programs, considering the costs and kW and kWh savings associated with each program. APS should then select the most beneficial and cost-effective projects to pursue.

Ideally, APS should engage in DSM programs as long as the incremental societal benefits (deferred capacity, avoided fuel costs, and avoided environmental impacts) are greater than the incremental cost of those programs to society.

## Cost Recovery of DSM Programs

**Q. How does APS currently recover its costs related to its DSM activities?**

A. In Decision No. 59601 (APS' Rate Reduction Agreement, April 24, 1996), the Commission allowed $7 million to be included in base rates for DSM and renewables. Of the $7 million total, APS was required to undertake at least $3 million of DSM per year on average, and at least $3 million on renewable projects per year on average. The Decision provides that if APS spends less than the $7 million included in base rates on DSM and renewables per year on average, the Commission, at the next rate case, shall review these expenditures and may order appropriate refunds to ratepayers.

**Q. How much did APS spend each year?**

A. According to semi-annual DSM and Renewables reports filed by APS, APS spent an annual average of $6,992,000 from 1996 through 2002. That number is close enough to $7,000,000 to not require a refund to ratepayers.

**Q. What cost recovery mechanisms could be used to recover APS' DSM costs in the future?**

A. Possible mechanisms include using a deferral account with amortization into base rates, simply putting a level of costs in base rates, recovery through any fuel and purchased power adjustor approved for APS, or setting up a separate DSM adjustment mechanism.

**Q. Should APS recover its DSM costs through a deferral account with base rate amortization?**

A. No. When a deferral account is used, pre-approved DSM costs are placed in the deferral account and earn interest until the utility's next rate case, when the costs are considered for base rate cost recovery. If there are significant DSM activities taking place, the deferral account balance grows quickly, including the attendant interest, and can become a major cost which has to be dealt with in the utility's next rate case. In addition, a deferral account may not allow for the timely recovery of DSM costs to the same extent as some other cost recovery mechanisms.

**Q. Should APS recover its DSM costs directly through base rates with no deferral accounting?**

A. No. While recovery of DSM costs through base rates provides for current cost recovery, placing DSM costs in base rates does not provide the Commission and APS with flexibility to increase or decrease DSM spending, as circumstances dictate. Additionally, a utility could choose to end its DSM activities, and there would be no way to remove the DSM funding from base rates until the next rate case.

**Q. Should APS recover its DSM costs through a fuel and purchased power adjustor (if approved for APS)?**

A. No. While recovery of DSM costs through a fuel and purchased power adjustor would provide timely and more flexible cost recovery, it would complicate the administration of the fuel and purchased power adjustor. One disadvantage of this type of recovery mechanism is that customers who choose to obtain power in the competitive market would not continue to pay for DSM which is a public benefit.

**Q. How should APS recover its costs for DSM programs?**

A. Staff recommends that APS be allowed to recover its costs for pre-approved DSM programs through a separate DSM adjustment mechanism. Recovery of pre-approved DSM costs through a DSM adjustment mechanism would provide the flexibility to adjust the level of DSM spending as needed in the future, while also providing timely recovery of pre-approved DSM costs. It would also provide a separate and specific accounting for pre-approved DSM costs.

A DSM adjustment mechanism would allow the costs associated with pre-approved programs to be recovered as the level of expenses associated with those programs changes. In addition, separating these expenses from other expenses included in base rates provides an incentive to initiate programs at any time rather than in the context of a rate case.

**Q. How would customers be billed?**

A. The DSM adjustment mechanism, as a charge per kWh, would be included on all customer bills as a separate line item. It would be a nonbypassable charge, meaning that customers who obtain power in the competitive market would continue to pay the charge.

**Q. How would the proposed DSM adjustment mechanism work?**

A. The proposed DSM adjustment mechanism would consist of an account where the costs for pre-approved DSM programs would be recorded for each program by APS as the costs were incurred. By January 31 of each year, APS would file with Staff to set the per kWh DSM adjustment mechanism charge. APS would document the costs placed in each DSM program subaccount during the previous year and the revenue received from ratepayers through the per kWh charge during the previous year. Staff would analyze this information. Then the per kWh charge for the next year would be calculated by

dividing the account balance by the number of kWh used by customers in the previous year.

**Q. Should annual DSM program expenditures be capped?**

A. Yes. After reviewing past expenditures, Staff has determined that an appropriate amount for an annual cap would be $4 million.

**Q. What kinds of costs should APS be able to recover?**

A. Staff recommends that APS recover the program costs associated with pre-approved DSM projects. Program costs include administrative expenses, monitoring expenses, any incentives such as rebates, promotional expenses, educational program expenses, and the costs of demonstration facilities. The total costs to be recovered could not exceed $4 million per year.

**Q. Because Staff is recommending an adjustment mechanism to recover DSM costs, is an adjustment to operating expenses required?**

A. Yes. Staff witness Dittmer describes in his testimony the adjustment ($1,051,381) necessary to remove DSM costs from operating expenses.

**Q. What programs should APS include in the DSM adjustment mechanism?**

A. The costs of the Energy-Wise Assistance Program should be included in the DSM adjustment mechanism after the conclusion of this rate case.

**Q. What about including the other current DSM programs?**

A. None of the costs of the other programs should be included in the DSM adjustment mechanism at this time. For the two residential market transformation programs, APS should provide updated information on features of the programs as well as the evaluation information that APS had indicated at the time of pre-approval that it would provide at

regular intervals. After Staff has reviewed the information and determines that the programs are cost-effective, APS could begin to recover the costs of those programs through the adjustment mechanism. For the programs that have never been submitted to Staff for pre-approval, APS would need to submit those programs through the procedures described below.

**Implementation of DSM Programs**

**Q. How should APS implement DSM programs?**

A. APS should submit proposed programs to Staff for pre-approval. (Decision No. 59601 delegated the authority to pre-approve DSM programs to Staff.) APS should also file a copy of DSM program plans with Docket Control, and interested parties would have 20 days to comment on the proposed DSM program. After a program is pre-approved, APS may begin entering the costs for that program as they are incurred into a new DSM adjustment mechanism subaccount.

**Q. What should APS include in a DSM program proposal?**

A. The proposal should include the purpose of the program, a description of the project, the expected level of participation, the expected kW and kWh savings, the expected societal costs, an implementation plan and schedule, a monitoring and evaluation plan, a description of incentives (if any), and a marketing plan.

Staff would consider whether the benefits of the measures to society exceed the costs to society. In addition, Staff would consider the reasonableness of any customer incentives proposed by APS. New programs could be added or existing programs terminated anytime during the year subject to Staff approval.

**Q. Why should each program proposal include a monitoring and evaluation plan?**

A. Monitoring can establish the impacts of each program on kWh and kW of consumption. Estimation of these impacts is necessary to determine whether a measure is actually cost-effective and to determine the amount of kW and kWh savings. Accurate estimates of savings are necessary in demand forecasting and long-range planning.

Monitoring DSM programs also enables the utility to refine its marketing and incentive efforts for each program. APS would need information on whether an incentive it offers is adequate, whether any participants are getting a free lunch, whether customers are receiving conservation information and using it properly, and so on.

**Q. Could engineering estimates be used to determine kW and kWh savings at lower cost than a monitoring program?**

A. No. Engineering data can provide some guidance on savings, but data on actual experience, taking into account customer behavior and field performance of the measure, is essential. An example of customer behavior influencing kW and kWh savings is when the customer lowers a thermostat because the new air conditioner is more efficient and costs less to operate. Actual experience may be far different than engineering data would suggest. It is difficult to know whether a program is cost-effective without knowing actual savings.

**Q. What are Staff's recommendations regarding monitoring?**

A. APS should include a monitoring plan in each program proposal. If the monitoring activity reveals that the program is not working as well as expected, APS should modify or terminate the program. APS should notify Staff about any plans to terminate a program before such termination occurs. APS should provide Staff with its plans for notification to potential participants. If a program is terminated, APS would be expected to give proper notice to potential participants as well as honor existing commitments.

For programs with large numbers of participants, a sample of customers should be observed to obtain usage data, customer characteristics, and building characteristics so that a statistical analysis of the measures can be conducted. Weather should be taken into account as appropriate. For measures installed in only a few locations, APS may have to monitor all of the sites to determine the impacts of the program. APS may monitor all of the customer's electricity usage or may submeter end uses, depending on whether end-use metering is the only way to measure the program impacts. It may be necessary to monitor customers before and after installation of measures, or a comparison group may be monitored.

Monitoring a particular type of measure may be discontinued after one or two years of experience, but APS should plan to monitor some customers over a longer period to determine whether the customers have stopped using the conservation measure after several years or have altered the measure's characteristics.

Customer surveys, focus groups, and other market evaluation techniques may be used to determine the effectiveness of the marketing and incentives for each measure.

**Q. How can Staff monitor APS' efforts?**

A. Staff recommends that APS submit mid-year and end-year reports in Docket Control containing the following information separately for each program: a brief description of the program; program modifications; programs terminated; the level of participation; a description of monitoring activities and results; kW and kWh savings; problems encountered and proposed solutions; costs incurred during the reporting period disaggregated by type of cost (such as administrative costs, rebates, and monitoring costs); findings from all research projects; and other significant information. Each report would be due 60 days after the conclusion of the reporting period. In addition, the

Commission may review program costs and performance in future rate cases. As part of its semi-annual DSM reports, APS would present the status of each subaccount balance.

**SYSTEM BENEFITS**

**Q. What are System Benefits?**

A. A.A.C. R14-2-1601(41) defines System Benefits as Commission-approved utility low income, demand-side management, consumer education, environmental, renewables, long-term public benefit research and development, nuclear fuel disposal and nuclear power plant decommissioning programs, and other programs that may be approved by the Commission from time to time.

**Q. What is the System Benefit Charge?**

A. A.A.C. R14-2-1608 requires each utility distribution company to file for Commission review nonbypassable rates or related mechanisms to recover the applicable pro-rata costs of System Benefits from all consumers located in the utility distribution company's service area. Utility distribution companies are to file for review of the System Benefit Charge ("SBC") at least every three years.

**Q. How did the SBC first become established for APS?**

A. The 1999 Settlement Agreement had Direct Access tariffs attached to it that contained an amount for the SBC ($0.00115/kWh for all Direct Access customers). Neither the Settlement Agreement nor the Decision that approved it contain any discussion about how the SBC was derived for APS.

**Q. What programs does APS currently include in its SBC?**

A. Per APS' response to WRA 1-8, the proposed SBC includes $9,844,557 for renewables, DSM, and low income programs; $18,929,620 for Palo Verde decommissioning;

$2,839,027 for on-going independent spent fuel storage (ISFS); and $8,130,791 for amortization of ISFS. The total SBC, as proposed by APS, is $39,743,995.

**Q. Please discuss each component of the SBC.**

A. Staff witness Harry Judd will discuss the Palo Verde decommissioning and ISFS components of the SBC. Since Staff is recommending a separate mechanism to recover costs for DSM described in the above section of this testimony, DSM costs should be removed from the SBC. Costs for renewables ($6,000,000) are used to help meet the Environmental Portfolio Standard requirements discussed in the next section of this testimony. Low income programs consist of the bill assistance ($61,679) mentioned in the above testimony about the Energy-Wise Assistance Program and rate discounts associated with E-3 and E-4 assistance rates ($2,844,557).

**Q. Please describe the E-3 and E-4 assistance rates.**

A. Rate Schedules E-3 (Energy Support Program) and E-4 (Medical Care Equipment) provide discounted rates to low-income residential customers. The amount of discount depends on monthly usage. According to APS' annual report on E-3 and E-4, 24,196 customers received discounts totaling $2,844,557 in 2002. Administrative expenses were $64,939.

**Q. What does Staff recommend to be included in the SBC?**

A. Staff recommends that the SBC include $8,906,236 for renewables and low income programs (including $6,000,000 for renewables, $61,679 for bill assistance, and $2,844,557 for E-3 and E-4 rate discounts), $13,411,212 for Palo Verde Decommissioning, $2,839,027 for ISFS, and $7,959,326 for amortization of ISFS. The total SBC should be $33,115,801. The difference between APS' proposed total SBC and Staff's proposed total SBC is due to Staff's removal of DSM costs from the SBC and the

adjustments proposed by Harry Judd in the amounts for Palo Verde decommissioning and ISFS amortization.

## ENVIRONMENTAL PORTFOLIO STANDARD

**Q. What is the Environmental Portfolio Standard?**

A. The Environmental Portfolio Standard ("EPS"), embodied in A.A.C. R14-2-1618, was approved by the Commission in 2001. The EPS requires utility distribution companies to derive a portion of the retail energy they sell from solar resources or environmentally friendly renewable electricity technologies. The portfolio percentage increases annually and was 0.4 percent in 2002, with at least 50 percent from solar resources.

**Q. Did APS meet its EPS requirement in 2002?**

A. No. APS only met 60 percent of its 2002 requirement.

**Q. What did APS do in regard to renewables in 2002?**

A. During 2002, APS installed new solar generation capacity, maintained existing solar plants, provided off-grid solar services, continued its Solar Partners "green pricing" program, explored non-solar renewables, tested new technologies, and purchased EPS credits from other providers.

**Q. How is the EPS funded?**

A. The costs of the EPS are to be recovered through current System Benefits Charges and through an Environmental Portfolio Surcharge, approved by Decision No. 63354 on February 8, 2001. The surcharge is currently set at $0.000875 per kWh with monthly caps per service of $0.35 for residential customers, $13.00 for non-residential customers, and $39.00 for non-residential customers with demands of 3,000 kW or more.

**Q. How much funding did APS have for renewables in 2002?**

A. In 2002, APS received $6,571,745 from the Environmental Portfolio Surcharge, $6,000,000 in System Benefits, and $259,000 from its Solar Partners program.

**Q. How much additional funding would APS have needed to meet its 2002 EPS requirement?**

A. Per APS' response to STF 9-59, APS would have needed an additional $50.2 million to meet its EPS requirement by continuing to install photovoltaic (PV) systems itself to meet the solar portion of the requirement.

**Q. What does Staff recommend regarding funding of the EPS for APS?**

A. An increase of $50.2 million would be an extraordinary increase. However, Staff does recommend that funding for renewables be increased by a smaller amount to help APS meet its EPS requirements. The increase should occur in the Environmental Portfolio Surcharge (Rate Schedule EPS-1). Staff recommends that the rate on EPS-1 remain at $0.000875 per kWh, but that the monthly caps per service be increased to $0.99 for residential customers, $25.00 for non-residential customers, and $100.00 for non-residential customers with demands of 3,000 kW or more. It should be emphasized that not all customers would pay the amounts of the caps every month. The caps are a maximum. This should result in an increase in revenues from the surcharge of about $4.4 million.

In addition, Decision No. 63354 had approved EPS-1 on an interim basis, pending true-up in a rate review proceeding in which fair value findings are determined by the Commission. Since the current proceeding would constitute such a rate review proceeding, Staff recommends that the EPS-1 be made permanent with Staff's proposed revisions.

**Q. What else does Staff recommend regarding the EPS for APS?**

A. Currently, APS meets the solar portion of its portfolio requirement mostly by installing photovoltaic ("PV") systems themselves. Staff recommends that APS take the following actions to make the available dollars go further:

- APS should expand its existing buydown program, where customers pay for part of the cost of projects.
- APS should pursue more large-scale solar thermal electric projects.
- APS should enter into contracts to buy electricity or EPS credits from private developers of solar projects (PV or thermal).

## RETURNING CUSTOMER DIRECT ASSIGNMENT CHARGE

**Q. What is the Returning Customer Direct Assignment Charge?**

A. The Returning Customer Direct Assignment Charge ("RCDAC") is intended to recover from Direct Access customers the additional costs, both one-time and recurring, that these customers would otherwise impose on other Standard Offer customers if and when the former return to Standard Offer service from their competitive suppliers. Decision No. 66567 approved the RCDAC for APS with conditions as proposed by Staff.

**Q. What were those conditions?**

A. Staff recommended the following conditions:

1. The RCDAC tariff should specify that the charge will be applicable only to individual customers or aggregated groups of customers of 3 MW or greater.
2. The RCDAC tariff should indicate that a customer will not be subject to the RCDAC if the customer provides APS with one year's advance notice of intent to take Standard Offer service.
3. APS should break down the individual components of the potential charge on the RCDAC tariff, define them, and provide a general framework that describes the way in which the RCDAC will be calculated.

4. APS should file a revised Schedule AP-2 for Staff review prior to its implementation.

5. The RCDAC and Schedule AP-2 should not be effective until the conclusion of APS' rate case.

**Q. What is Staff's position on the RCDAC at this time?**

A. Staff continues to not oppose the RCDAC with the above conditions.

## SERVICE SCHEDULES

**Schedule 1 - Terms and Conditions for Standard Offer and Direct Access Services**

**Q. What does Staff recommend in regard to Schedule 1?**

A. APS has proposed many changes to Schedule 1, including some of the charges. Although most of the proposed wording changes are acceptable, Staff recommends that the charges primarily be cost-based, rounded up to the nearest $0.50. APS provided cost information in DJR_WP1.

**Q. Which charges does either APS or Staff propose to change?**

A. The charges and proposed changes are summarized in the following table:

| Description (Schedule 1 Section) | Current Charge | APS Proposed Charge | Staff Proposed Charge |
|---|---|---|---|
| trip charge (2.2.1) | none | $17.50 | $16.00 |
| after-hour service establishment (2.2.2) | $50 | $75.00 | $75.00 |
| after-hour other services (2.2.3) | none | hourly rate | $75.00 |
| overhead reconnection (4.5.1) | $87.50 | $100.00 | $96.50 |
| underground reconnection (4.5.1) | $125.00 | $125.00 | $115.00 |
| on-site energy evaluation (4.6) | $50.00 | $90.00 | $82.00 |
| joint site meeting (6.2.3) | $30.00 metro<br>$75.00 outside<br>$30/hr after 30 minutes | $70.00 all areas<br>hourly rate after 30 minutes | $62.00 all areas<br>$53/hr after 30 minutes |
| reread charge (6.4.4 and 6.4.5) | $10.00 | $20.00 | $16.50 |
| meter test (6.5) | $25.00 | $30.00 meter shop<br>$100.00 field | $30.00 meter shop<br>$50.00 field |

**Q. Please discuss your recommendation regarding the trip charge.**

A. The proposed trip charge would occur when a company representative travels to a customer site to establish, reconnect, or re-establish service but is unable to complete the requested service due to lack of access to the meter panel. APS proposes that the charge be $17.50. Because DJR_WP1 shows costs for a trip to be $15.56, Staff recommends that the trip charge be set at $16.00.

**Q. Please discuss your recommendation regarding the after-hour establishment charge.**

A. An after-hour charge occurs when a customer requests that service be established, reconnected, or re-established outside of regular working hours or on the same day of request. The current charge is $50.00. APS proposes to increase the charge to $75.00. Although DJR_WP1 show costs to be $91.13, Staff recommends that the after-hour charge be set at $75.00 because an increase in a charge should not be too large.

**Q. Please discuss your recommendation regarding the after-hour charge for other services.**

A. This is a new charge for service establishment work that is generally more complicated and time consuming than basic service activities. APS has proposed that the charge be billed at hourly rates to be determined by the company. Staff recommends that the charge be set at a fixed rate so that the customer knows in advance what the charge will be. Staff recommends that the charge be set at $75.00 to be consistent with the after-hour establishment charge discussed above.

**Q. Please discuss your recommendation regarding the overhead and underground reconnection charges.**

A. When a customer is reconnected after being terminated for delinquent payments, the customer is charged a reconnection charge. If the termination was at the pole (overhead), then the reconnection charge is currently $87.50. If the termination was in underground

equipment, the reconnection charge is currently $125.00. APS has proposed to increase the overhead reconnection charge to $100.00 and leave the underground reconnection charge at $125.00. Because the costs of reconnection are $96.03 for overhead and $114.54 for underground, Staff recommends that the overhead reconnection charge be set at $96.50 and the underground reconnection charge be reduced to $115.00.

**Q. Please discuss your recommendation regarding the on-site energy evaluation charge.**

A. An on-site evaluation charge occurs when a company field investigator performs an on-site visit to evaluate how a customer may reduce energy usage. APS proposes to increase this charge from $50.00 to $90.00. Since DJR_WP1 shows costs to be $81.98, Staff recommends that the on-site evaluation charge be set at $82.00.

**Q. Please discuss your recommendation regarding the joint site meeting charge.**

A. A joint site meeting charge occurs when an Electric Service Provider ("ESP") or a customer requests a joint meeting for removal of the company's metering equipment or lock ring. Currently, there is a $30.00 charge for meetings in the Phoenix metropolitan area and $75.00 for all other areas. There is an additional charge of $30.00 per hour if the meeting exceeds 30 minutes. APS proposes to charge $70.00 for all areas plus an hourly rate to be determined by the company for meetings that exceed 30 minutes. Actual costs are $30.72 for meetings in the Phoenix area, $92.68 for meetings elsewhere, and $52.96 for meetings that exceed 30 minutes. Since the average cost is $61.71, Staff recommends that the joint site meeting charge be set at $62.00 for all areas plus $53.00 per hour for meetings that exceed 30 minutes. Although this would be a large increase for meetings in Phoenix, no one was charged a joint site meeting charge from January 2001 through September 2003.

**Q. Please discuss your recommendation regarding the reread charge.**

A. A reread charge occurs when the company is asked to reread a customer's meter, and the original reading was not in error. A reread charge also occurs when a Meter Reading Service Provider fails to provide meter read data to the company, and the company obtains the data. The current charge is $10.00, and APS proposes to increase the charge to $20.00. Because actual costs are $16.50, Staff recommends that the reread charge be set at $16.50.

**Q. Please discuss your recommendation regarding the meter test charge.**

A. APS will test a meter upon request. If the meter is found to be within acceptable limits, there is a meter read charge, currently set at $25.00. APS proposes to increase the charge to $30.00 if the test is performed in the meter shop and $100.00 if the test is performed in the field. Actual costs vary by phase and type of meter. Staff recommends that the meter test charge be set at $30.00 if performed in the meter shop and, to avoid too large of an increase, $50.00 if performed in the field.

**Q. What else does Staff recommend for Schedule 1?**

A. APS has suggested revised wording to Section 2.5.1.2 regarding criteria for not requiring a security deposit. APS would replace language accepting a letter from another electric utility with language about an acceptable credit rating. Staff opposes this change because it would not be consistent with A.A.C. R14-2-203.B.b.

APS has proposed rewording Section 5.4 regarding company access to customer sites. Staff accepts the changes but recommends that the following sentence be added to the end of the paragraph: "Written termination notice is required prior to disconnecting service under this schedule."

APS has proposed a new provision (Section 5.5.2) regarding customers creating hazards or obstructions of easements. Staff recommends the new provision be adopted but that the following sentence be added: "Company will notify the customer in writing of the violations."

In Section 6.2, all references to "Load Serving ESP" should be replaced with "Meter Service Provider" or "MSP."

In Section 6.4, "Load Serving ESP" should be replaced with "Meter Reading Service Provider."

**Schedule 3 - Conditions Governing Extensions of Electric Distribution Lines and Services**

**Q. Please explain the current construction allowance policy.**

A. Currently, when a residential customer requests a line extension, there is no cost to the customer for 1,000 feet. The customer would pay the cost for any additional feet up to 2,000 feet or up to $25,000. That payment would be made in the form of an advance which is refundable as additional customers are served off of the line extension. If the advance has not been totally refunded within five years, the advance is no longer refundable.

**Q. What has APS proposed in regard to this policy?**

A. APS has proposed replacing the 1,000-foot construction allowance with a cost allowance of $3,500. For costs between $3,500 and $25,000, the customer would pay a non-refundable contribution in aid of construction.

**Q. What does the proposed change in the construction allowance mean to customers?**

A. Per the testimony of APS witness Mr. David Rumolo (p. 9, lines 5-9), the proposed $3,500 allowance equates to the cost of a typical underground extension of 500 feet,

while the cost of an overhead extension of 1,000 feet is approximately $10,000. In response to STF 7-49, APS states that the $3,500 allowance equates to approximately 200 feet of an overhead extension. Therefore, under APS' proposed $3,500 allowance, customers would receive 1/5 to 1/2 of the footage that is currently allowed. Staff opposes replacing the 1,000-foot allowance with a $3,500 allowance.

**Q. What does Staff recommend in regard to customer advances of costs?**

A. Staff recommends that the current refundable advances be retained in Schedule 3. This would be consistent with the provisions of A.A.C. R14-2-207.C.1.

**Schedule 7 - Electric Meter Testing and Maintenance Plan**

**Q. Please describe APS' proposed changes to Schedule 7.**

A. APS has proposed editorial changes to reflect current American National Standards Institute ("ANSI") standards and the addition of language for performance of solid-state meters.

**Q. What is Staff's recommendation regarding Schedule 7?**

A. Staff recommends that the changes reflecting current ANSI standards not be made at this time. Currently, A.A.C. R14-2-209.E.1 requires the use of "the 1995 edition (and no future editions) of ANSI C12.1 (American National Standard Code for Electricity Metering)." Staff also opposes replacing the words "meter maintenance and testing program" with "performance monitoring plan." A.A.C. R14-2-209.E.2 uses "meter maintenance and testing program." To use "performance monitoring plan" may be misleading regarding the intent of the rule.

**Schedule 10 - Terms and Conditions for Direct Access**

**Q. What does Staff recommend for Schedule 10?**

A. In Section 3.6.1, the last word should be "less" instead of "more."

Section 4.2.1 provides for an Electric Service Provider to obtain customer usage data from APS and that APS may charge for the data. Staff recommends that the phrase "at rates approved by the ACC" not be removed from the paragraph.

In Section 5.1.7, the words "Meter Reading Service Providers ("MRSP")" should not be replaced with "a Load Serving ESP or its MRSP when providing meter reading services." Only an MRSP, not a Load-Serving ESP, can provide meter reading services.

Section 8.12.2 must be made consistent with A.A.C. R14-2-1612.L.10 and 11 in regard to the ownership of Current Transformers and Potential Transformers.

In the last sentence of Section 8.15, "MSRP" should be "MRSP."

In Section 8.16.1.3, the words "with the" should be deleted.

**SUMMARY OF STAFF RECOMMENDATIONS**

**Q. Please summarize Staff's recommendations.**

A. 1. Staff recommends that APS be allowed to recover its costs for pre-approved demand-side management ("DSM") programs through a DSM adjustment mechanism.

2. Staff recommends that the total of System Benefits should be $33,115,801.

3. Staff recommends that the caps per service on EPS-1 be increased to help APS meet its Environmental Portfolio Standard requirements and that the tariff be made permanent. Staff also recommends that APS take steps to make the dollars go further.

4. Staff does not oppose the Returning Customer Direct Assignment Charge with conditions.

5. Staff recommends that the trip charge be set at $16.00.

6. Staff recommends that the after-hour establishment charge be set at $75.00.
7. Staff recommends that the after-hour charge for other services be set at $75.00.
8. Staff recommends that the overhead reconnection charge be set at $96.50.
9. Staff recommends that the underground reconnection charge be reduced to $115.00.
10. Staff recommends that the on-site evaluation charge be set at $82.00.
11. Staff recommends that the joint site meeting charge be set at $62.00 for all areas plus $53.00 per hour for meetings that exceed 30 minutes.
12. Staff recommends that the reread charge be set at $16.50.
13. Staff recommends that the meter test be set at $30.00 if performed in the meter shop and $50.00 if performed in the field.
14. Staff opposes revised wording in Section 2.5.1.2 of Schedule 1 regarding criteria for not requiring a security deposit.
15. Staff recommends that a sentence about written termination notice be added to Section 5.4 of Schedule 1.
16. Staff recommends that a sentence about written notification of violations be added to Section 5.5.2 of Schedule 1.
17. Staff recommends that all references to "Load Serving ESP" be replaced with "Meter Service Provider" or "MSP" in Section 6.2 of Schedule 1.
18. Staff recommends that all references to "Load Serving ESP" be replaced with "Meter Reading Service Provider" in Section 6.4 of Schedule 1.
19. Staff opposes replacing the 1,000-foot allowance with a $3,500 allowance in Schedule 3.
20. Staff recommends that the current refundable advances be retained in Schedule 3.
21. Staff recommends that APS' proposed changes in Schedule 7 reflecting current ANSI standards not be made at this time.
22. Staff opposes replacing the words "meter maintenance and testing program" with "performance monitoring plan" in Schedule 7.

23. Staff recommends that the word "more" be replaced with "less" in Section 3.6.1 of Schedule 10.

24. Staff recommends that the phrase "at rates approved by the ACC" should not be removed from Section 4.2.1 of Schedule 10.

25. Staff recommends that the words "Meter Reading Service Providers ("MRSP")" should not be replaced with "a Load Serving ESP or its MRSP when providing meter reading services" in Section 5.1.7 of Schedule 10.

26. Staff recommends that Section 8.12.2 of Schedule 10 be made consistent with A.A.C. R14-2-1612.L10 and 11 in regard to the ownership of Current Transformers and Potential Transformers.

27. Staff recommends correcting typos in Sections 8.15 and 8.16.1.3 of Schedule 10.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

# RESUME

## BARBARA KEENE

### Education

| | |
|---|---|
| B.S. | Political Science, Arizona State University (1976) |
| M.P.A. | Public Administration, Arizona State University (1982) |
| A.A. | Economics, Glendale Community College (1993) |

### Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

### Employment History

**Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989).** Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

**Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984).** Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

### Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003; Staff Report on Code of Conduct.

## Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

*Annual Planning Information* - editions from 1984 to 1989
*Hispanics in Transition* - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

## Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

*Customer Repayment of Utility DSM Costs*, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | ) | DOCKET NO. E-01345A-03-0437 |

DIRECT

TESTIMONY

OF

ERINN ANDREASEN

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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**EXECUTIVE SUMMARY**
**ARIZONA PUBLIC SERVICE COMPANY**
**DOCKET NO. E-01345A-03-0437**

Ms Andreasen's testimony is recommending the following:

1. In order for all customer classes to benefit from the recommended overall rate decrease, Staff is recommending that no customer class or subclass be assigned a revenue increase or an increase to rates.
2. Staff recommends that the residential class receive a 4.04 percent revenue decrease, the general service class receive a 13.4 percent revenue decrease, the irrigation class receive a 2.19 percent decrease, and the street lighting and dusk to dawn customer classes receive a 1.1 percent decrease.
3. Within the residential rate class, Staff recommends that ET-1 and ECT-1R should receive average decreases. E-10 and EC-1 should receive less than the average decrease and E-12 should receive an above average decrease.
4. Staff recommends that the categories within the general service rate class should receive decreases to varying degrees. Staff recommends that the medium and extra large general service classes should receive average decreases, the small general service rate class should receive a greater than average decrease, and the large general service class should receive less than half of the average decrease.
5. If revenue requirements result in a rate increase, Staff would recommend that the revenues be allocated across the main customer classes in a more even distribution. However, Staff would recommend that the Commission adopt the proportion identified in this testimony for the intraclass allocation.
6. Staff recommends that APS' proposal to eliminate E-10 and EC-1 be adopted, but EC-1 would be phased out over a one-year timeframe consistent with the phasing out of E-10. In addition, Staff recommends that APS present customers on E-10 and EC-1 with written notice of its intent to cancel these rates and institute a customer education plan to inform customers of alternative rate options.

7. Staff recommends approval and believes that offering additional time-of-use options to APS' customers will provide customers with a greater range of time-of-use benefits and provide benefit to APS by reducing its peak load. In addition, Staff recommends that APS be required to file a report after three years from a decision in this proceeding that evaluates the outcomes of adopting the optional-time periods. The filing should make a recommendation regarding the continuation of the experimental time periods.
8. Staff recommends that APS establish an on and off-peak rate for the winter-billing period on its seasonally differentiated residential and general service time-of-use rates. However, Staff recommends that the winter on and off-peak hours be modified to reflect the hours of actual system peak.
9. Staff recommends that the residential basic services charges remain at current levels or are decreased to reflect cost tracking. In addition, if the revenue requirements adopted provide for a rate increase, APS should not increase any one residential customer service charge by more than 5 percent.
10. Staff recommends that the general service basic services charges remain at current levels. However, if the revenue requirements adopted provide for a significant rate increase, APS should increase its general service basic service charges to bring them closer to cost.
11. Staff recommends that APS establish an on and off-peak energy component for the winter billing period on E-32 TOU. In addition, Staff recommends that the winter on and off-peak hours be modified to reflect the hours of actual system peak.
12. Staff recommends that APS' proposal to remove franchise fees from base rates be adopted and that such fees should be listed as a separate line item on customers' bills.

## INTRODUCTION

**Q. Please state your name, occupation, and business address.**

A. My name is Erinn Andreasen. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

**Q. Please describe your educational background and professional experience.**

A. In 1999, I graduated summa cum laude from Arizona State University, receiving a Bachelor of Science degree in Agribusiness with a specialization in international business. In 2003, I received a Masters Degree in Business Administration from the University of Phoenix with a specialization in global business. I have worked at the Commission for over three years as an Economist and a Public Utilities Analyst. My current duties include the review and evaluation of applications for electric Certificates of Convenience and Necessity, electric utility special contracts, demand-side management programs, utility tariff filings, and rate design.

**Q. What is the scope of your testimony in this proceeding?**

A. My testimony will address revenue allocations and rate design proposals based on Staff's revenue requirement and cost of service recommendations. In addition, I will also address general issues related to Arizona Public Service Company's ("APS") rate schedules.

**Q. Does your testimony recommend that a specific set of rates be adopted?**

A. No. My testimony will identify specific guidelines for the company to follow in structuring its rates. The rates to ultimately be adopted by the Administrative Law Judge and Commission will be influenced by adoption of various considerations to be put forth by Staff, APS, and the intervenors in this proceeding.

**REVENUE ALLOCATIONS AND RATE DESIGN**

**Q. Please identify the change in revenues that Staff is recommending.**

A. Based on Staff adjustments to the Test Year, Staff is recommending an overall revenue decrease of $154.5 million in base revenues. Staff's recommended decrease is approximately an 8.62 percent reduction to revenues from base rates.

**Q. Did you rely on the cost of service study as referred to by Staff witness Smith in the development of Staff's recommended revenue allocations?**

A. Yes, as a guide. The cost of service study illustrates the degree to which the class rate of return deviates from the system average rate of return. The closer a class rate of return is to the system average the more accurately the class is contributing to its full embedded cost and return on rate base.

**Q. Please identify each of the customer classes across which rates are to be spread?**

A. APS' cost of service study breaks down its customer classes into five main categories. They are: residential, general service, irrigation, street lighting, and dusk to dawn. Within the residential class, there are categories for each of the five residential rate schedules. Within the general service category, there are subcategories of small (0<=kW<100), medium (100<=kW<1000), large (1000<=kW<3000), and extra large (kW>3000). Certain rate schedules in the general service class such as E-32 may correspond to more than one subclass. For instance, customers in the small, medium, and large general service categories may take service on one rate schedule.

**Q. Generally, what did Staff's cost of service study identify about APS' customer classes?**

A. The cost of service study demonstrated that to varying degrees the residential, street lighting, and dusk to dawn classes are contributing less than their cost, and the general service class is contributing more than its cost and return on rate base.

The study also identified the differences in the intraclass returns for the general service and residential subclasses. The differentials between the residential subclasses are moderate while the differentials between the general service subclasses are greater.

**Q. In addition to the cost of service study, what other considerations should be taken into account regarding revenue allocations?**

A. Some of the key considerations in revenue allocations include: the effect of rate design proposals, the availability of alternative energy options to customer groups, the magnitude of the overall rate change, and customer equity.

For instance, APS is proposing to eliminate a certain residential rate schedule over time. In order to create an incentive for customer migration, the revenue change to this schedule should establish a price signal that encourages customer migration. In addition, certain types of customers have alternative options to receiving service from APS. These customers can be price sensitive because they have alternatives, which could allow them to adopt alternative energy sources such as natural gas, to self generate, bypass the distribution system, or relocate their operations.

The magnitude of the overall revenue change and customer equity are also important considerations in the rate allocation process.

**Q. In addition to the information provided by the cost of service study, what non-cost criteria should also be considered in translating revenues into rates?**

A. There are a variety of generally accepted non-cost criteria that are considered in the rate design process. These considerations include the effectiveness in yielding the total revenue requirements, revenue stability for the company, rate continuity for the customer, simplicity and public acceptability, fairness of the rates in apportionment of total cost of service among different rate classes, avoidance of undue discrimination in rate relationships, and efficiency in discouraging the wasteful use of the service.

**Q. What approach did Staff take toward applying the decrease to APS customer classes?**

A. In order for all customer classes to benefit from the recommended overall rate decrease, Staff is recommending that no customer class or subclass be allocated a revenue increase or given an increase to rates.

**Q. Did Staff consider other approaches regarding its rate design proposal?**

A. Yes. Staff considered a rate design that reflected each customer class' required contribution to system average rate of return based on Staff's cost of service study. However, designing rates based strictly on cost of service would have led to some customer classes getting rate increases. Staff also explored a rate design that gave an equal percentage decrease across all customer classes. However, this approach ignored the results of the cost of service study. Staff felt that it was important to give each customer class, and each subclass, a rate decrease, yet balance the percentage decreases for each class and subclass with the results of the cost of service study. Therefore, those customer classes who were paying a larger rate of return than the system average will

receive a larger rate decrease. Staff's proposed rate design balances cost-based principles with non-cost principles so that all customers benefit from the recommended decrease.

**Q. How do you recommend that Staff's recommended decrease be distributed among APS' customer classes?**

A. A summary of Staff's proposed revenue allocations is shown in schedule EAA-1. Staff recommends that the residential class receive a 4.04 percent revenue decrease, the general service class receive a 13.4 percent revenue decrease, the irrigation class receive a 2.19 percent decrease, and the street lighting and dusk to dawn customer classes receive a 1.1 percent decrease.

**Q. The cost of service study illustrates that the street lighting and dusk to dawn customer classes are contributing a negative rate of return. Why would Staff recommend that these classes receive a revenue decrease?**

A. Although Staff is recommending a decrease for these classes, the revenue decrease that Staff is supporting is much less than the average decrease. Staff believes that this minimal decrease is equitable in these circumstances. As stated above, Staff is recommending that no customer class or subclass be assigned an increase in rates. Instead of rigidly applying the results of the cost of service study, Staff has used it as a guide, and has also balanced cost-based principles with non-cost principles in determining how to spread the revenue decrease among customer classes.

**Q. Please explain Staff's recommended intraclass revenue allocations for the residential class.**

A. Within the residential rate class, ET-1 and ECT-1R should receive average decreases. E-10 and EC-1 should receive less than the average decrease and E-12 should receive an

above average decrease. APS has proposed phasing out E-10 over a one-year timeframe and Staff is proposing a similar phase out period for EC-1, which will be addressed later in this testimony. Providing a less than average decreases to EC-1 and E-10 would create an incentive for customers on E-10 and EC-1 to explore other applicable rate options.

**Q. Please explain Staff's recommended intraclass revenue allocations for the general service class.**

A. Staff recommends that the categories within the general service rate class should receive decreases to varying degrees. Staff recommends that the medium and extra large general service classes should receive an average decreases, the small general service rate class should receive a greater than average decrease, and the large general service class should receive less than half of the average decrease.

**Q. If the revenue requirement were to change significantly, would your recommended class allocation approach change?**

A. While significant changes may call for an alternative approach to the apportionment across the main customer classes, the proportions identified in this testimony for the intraclass revenues would continue to apply.

For instance, if revenue requirements resulted in a rate increase, Staff would recommend that the revenues be allocated across the main customer classes in a more even distribution. However, Staff would recommend that the Commission adopt the proportions identified in this testimony for the intraclass allocation. For instance, for the general service class, the medium and extra large general service classes would receive average increases, the small general service rate class would receive a less than average

increase, and the large general service class would receive greater than half of the average increase.

**Residential Rate Design**

**Q. Please summarize APS' residential rate design proposals.**

A. APS is proposing to eliminate frozen rate schedule E-10 after a one-year phase out period, eliminate frozen rate schedule EC-1, eliminate the winter time-of use periods on ET-1 and ECT-1R, introduce two optional on-peak time-of-use periods on ET-1 and ECT-1R, remove an existing summer energy block from E-12, and unbundle each residential rate. APS is not proposing any changes to its low income and medical equipment rates E-3 and E-4.

**Q. Please summarize APS' proposal to eliminate frozen rate schedules E-10 and EC-1.**

A. APS is proposing to eliminate frozen rate schedules E-10 and EC-1 and place the existing customers onto alternative rate options. Customers on E-10 would be placed on schedule E-12 after a one-year phase out period while customers on EC-1 would be transferred to ECT-1R immediately.

**Q. Does Staff agree with this proposal?**

A. Yes, in part. Staff believes that the intention in freezing these rates schedules was to eventually phase them out over time. Customer counts have decreased since these rates were frozen in 1991. At the time E-10 was frozen, approximately 50 percent of residential customers took service on the rate schedule. Since that time, the number of residential customers on E-10 has declined to 11 percent. At the time EC-1 was frozen, approximately 17 percent of residential customers took service on that rate schedule. Since that time, the number of customers on EC-1 has declined to 3 percent.

Although Staff agrees that E-10 and EC-1 should be eliminated, Staff believes that customers on EC-1 should also be given a one-year phase out period so that customers on both rate schedules have a similar timeframe to evaluate and choose alternative rate options. In addition, Staff recommends that APS present customers on E-10 and EC-1 with written notice of its intent to cancel these rates and institute a customer education plan to inform customers of alternative rate options.

**Q. Please describe APS' proposed changes to its residential time-of-use tariffs.**

A. Schedule ET-1 is a time-of-use tariff that features seasonal billing periods, a basic service charge, and an energy rate. Schedule ECT-1R is a time-of-use tariff that features seasonal billing periods, a basic service charge, and an energy and demand component. On both rate schedules, APS is proposing to eliminate the on-peak and off-peak hours during the winter billing period and replace them with a single energy rate. In addition, APS has introduced two optional summer on-peak time-of use periods on ET-1 and ECT-1R that would be limited to participation by a maximum of 10,000 customers combined for both rate schedules. The experimental on-peak periods proposed would be 7 am to 7 pm and 8 am to 8 pm Monday through Friday. APS is not requesting a change to its regular residential on-peak period from 9 am to 9 pm.

**Q. Does Staff recommend approval of the experimental time-of-use periods proposed by APS on ET-1 and ECT-1R?**

A. Yes, with one modification. Staff recommends approval and believes that offering additional time-of-use options to APS' customers will provide customers with a greater range of time-of-use benefits and provide benefit to APS by reducing its peak load. In addition, Staff recommends that APS be required to file a report after three years from a decision in this proceeding that evaluates the outcomes of adopting the optional-time

periods. The filing should make a recommendation regarding the continuation of the experimental time periods.

**Q. Does Staff agree that the on-peak and off-peak periods during the winter billing period for APS' residential time-of-use schedules should be eliminated?**

A. No. Staff believes sending on and off-peak price signals to customers to reduce their load during times of system peak is important to encourage conservation. However, Staff is concerned that the current on-peak winter time period does not directly correspond to APS' hourly on-peak system periods. See attachment EAA-2. APS' load data suggest that the system winter peak occurs between 7 am and 9 am and 7 pm to 10 pm. These types of winter peak periods are similar in other service territories as well. APS' current winter on-peak time period is from 9 am to 9 pm, and is identical to the time period for the summer on-peak period.

**Q. What does Staff recommend regarding APS' winter on and off-peak time periods?**

A. Staff recommends that APS maintain an on and off-peak rate for its winter billing period on its residential time-of use rates. However, Staff recommends that the on and off-peak hours be modified to reflect the hours of actual system peak.

**Q. Please comment on APS' proposed changes to its residential basic service charges?**

A. A summary of the present and proposed basic service charge is presented in schedule EAA-3. APS is proposing to move from a monthly basic service charge to a daily basic service charge and make various changes to the residential basic service charges. APS is proposing to increase its basic service charges on E-10 and E-12, reduce the basic service charge on ET-1 slightly, and make no change to the basic service charge on ECT-1R. The greatest increase is $5.00 per month or a 66 percent increase on E-12. Under APS'

proposal, customers who migrate from E-10 to E-12 and from EC-1 to ECT-1R will also experience a $5.00 per month increase. Staff does not believe that such a significant increase to the residential basic service charge is reasonable. However, based on Staff's cost of service study, APS is currently charging less than its cost on E-10, E-12, and EC-1, and slightly more than cost on ET-1 and ECT-1R. Therefore, if a rate increase were adopted, Staff would support a somewhat smaller increase on E-10 and E-12.

**Q. What does Staff recommend regarding the residential basic service charges?**

A. Staff is opposed to an increase in the residential basic service charges at this time. Staff recommends that the residential basic services charges remain at current levels or are decreased to reflect cost tracking. In addition, if the revenue requirements adopted provide for a rate increase, APS should not increase E-10 or E-12 or any customer service charge by more than 5 percent.

**General Service Rate Schedules**

**Q. Please summarize APS' General Service rate design proposals.**

A. APS is proposing to eliminate experimental time-of-use rates E-21, E-22, E-23, and E-24 and transfer these customers onto a new time-of-use rate, E-32 TOU. APS also proposes to add the month of May to the summer billing period on applicable rate schedules, add the hours of 9:00 am and 10:00 am to the on-peak time period on applicable rate schedules, unbundle rate E-30, unbundle and redesign rate E-32, introduce a new rate E-32 TOU, modify E-32R to be consistent with E-32, unbundle rates E-34 and E-35 and redesign them to provide a discount for customers who take service at transmission voltage levels. APS is not proposing any changes to rate E-53, and E-54, which are used in conjunction with other applicable rate schedules.

**Q. Please discuss the current rate structure of Schedule E-32.**

A. The rate is seasonal and consists of a monthly minimum, a demand charge, and an energy charge. The calculation of the rate is complex because there are discrete charges set for various combinations of demand and energy usage. The rate is structured in such a manner that a customer with a higher load factor pays a lower energy charge than a customer using the same amount of energy at a lower load factor. This rate structure provides customers with an incentive to evenly spread out electricity use during times of APS' system peak.

**Q. Please describe APS' proposed changes to E-32.**

A. APS is proposing to unbundle the rate based on customer metering and voltage requirements. In addition, APS has broken down the rate into two usage categories: monthly maximum demands of 20 kW or less and monthly maximum demands of greater than 20 kW. APS has simplified the rate structure for customers with monthly maximum demands of less than 20 kW by removing the demand component. In addition, for customers with monthly maximum demands of 20 kW or greater, the number of blocks has been reduced, a demand block has been set at 500 kW, and an energy block has been set at the first 200 kWh per kW. APS has also proposed providing discounts for customers taking service at Primary or Transmission voltage levels.

**Q. Please comment on the changes to E-32.**

A. Generally, Staff is supportive of the redesign of the rate because it has been simplified and is more easily understandable. Under the proposed rate structure and proposed rates, for customers with demands greater than 20 kW, the small general service and medium general service customers with higher load factors generally experience less of a rate increase than customers with lower load factors in the same cost of service categories. For

the large general service class, the customers with a load factor between approximately 25 and 45 percent would experience the greatest increase.

**Q. Please comment on the basic service charges for the general service schedules.**

A. APS has proposed increases to its general service basic service charges in varying degrees. A review of Staff's cost of service illustrates that the present rates are below cost for the small, medium, and large general service categories. However, Staff is opposed to an increase in the general basic service charges at this time.

**Q. What does Staff recommend regarding the basic service charges for the general service schedules.**

A. Staff recommends that the general service basic services charges remain at current levels. However, if the revenue requirements ultimately adopted by the Commission provide for a rate increase, APS should be able to increase its general service basic service charges to bring them closer to cost.

**Q. What does Staff recommend in regards to APS' proposed E-32 TOU?**

A. Staff recommends that APS establish an on and off-peak energy component for the winter billing period on E-32 TOU. In addition, Staff recommends that the winter on and off-peak hours be modified to reflect the hours of actual system peak.

**<u>Classified Rate Schedules</u>**

**Q. Please summarize APS' Classified rate design proposals.**

A. APS is proposing to eliminate rate E-38 and E-38-8T and transfer those customers to rates E-221 and E-221-8T respectively. Rate E-221 has been redesigned and simplified, and rates E-47 and E-58 have been reformatted to include a menu format of lighting options.

**Q. Does Staff have any recommendations regarding the classified rate schedules at this time?**

A. No.

**UNBUNDLED RATES**

**Q. Please describe the rationale for requiring unbundled rates.**

A. The Commission established the requirement for standard offer rates to be unbundled in the electric competition rules (R14-2-1606(C)(2)). In a retail market that is open to competition, unbundling the standard offer rates into their functional rate components is necessary in order to send customers the price signals they need in order to evaluate competitive service alternatives. Unbundled rates are also important to competitive providers, because they provide the information necessary to determine whether or not it would be profitable to offer their services within a specific territory.

**Q. Please identify the unbundled rate elements that APS has proposed.**

A. APS has broken down certain standard offer rates into the following elements: daily basic service charge, metering, meter reading, billing, system benefits, transmission, distribution, and generation.

Q. **Did APS adopt unbundled rate elements based on cost of service?**

A. No. Based on unbundled cost information provided by APS, certain rate elements deviate from the rates that were generated from an unbundled cost analysis. In an ideal scenario, these rate elements would directly reflect the embedded cost of providing these services. However, due to certain rate design goals, some rates would need to deviate from cost.

**Q. Please comment on the generation and the distribution unbundled rate elements proposed by APS and their relationship to cost.**

A. Based on APS unbundled analysis, generally the generation rates for residential rates are below embedded cost and the generation rates for the general service rates are above embedded cost. Generally, the distribution costs are greater than embedded cost for residential rates and below embedded cost for general service rates. For its residential rate schedules, APS has set the distribution rate equal for all residential service schedules.

**Q. What is the effect of adopting unbundled rate elements that do not reflect cost?**

A. Deviating from cost-based unbundled rate elements creates price signals that can lead to uneconomic distortions in the competitive market. If the Commission wishes to facilitate retail competition, an effort should be made to base unbundled rates on cost to the extent possibile. However, this can be difficult because the bundled rate from which the unbundled rates are derived may not reflect the full cost due to rate design considerations.

**Q. Does Staff have any concerns regarding the approach APS has taken to unbundling its rates?**

A. Not at this time. However, if the revenue requirements were to change significantly Staff's position may change.

**FRANCHISE FEES**

**Q. What is a franchise fee?**

A. A franchise fee is implemented as part of a service agreement between local governments and a utility to reimburse local governments such as municipalities or counties for use of public rights-of-way and other public services. APS is assessed these fees based on its gross revenues.

**Q. Please explain APS' proposal regarding the assessment of franchise fees.**

A. Currently, the franchise fee is calculated based on a statewide average of fees charged by municipalities to APS. This fee is currently collected through base rates, and all customers pay a uniform rate. In APS' proposal, the fees would be removed from base rates, displayed as a separate line item on a customer's bill, and reflect the actual amount of the fee charged to APS by the specific municipality in which a customer resides.

**Q. Does Staff agree with APS' proposal?**

A. Yes. Staff believes that this proposal is appropriate from a customer equity standpoint. When franchise fees are included in base rates, some customers may be over or underpaying their community's fees. In some instances, customers are paying fees when their community does not assess them. This proposal would allow APS to match franchise fee amounts to the specific communities that assess them to APS. Staff recommends that APS' proposal to remove franchise fees from base rates be adopted and that such fees should be listed as a separate line item on customers' bills.

**Q. Please summarize Staff's recommendations.**

A. 1. In order for all customer classes to benefit from the recommended overall rate decrease, Staff is recommending that no customer class or subclass be assigned a revenue increase or given an increase to rates.

2. Staff recommends that the residential class receive a 4.04 percent revenue decrease, the general service class receive a 13.4 percent revenue decrease, the irrigation class receive a 2.19 percent decrease, and the street lighting and dusk to dawn customer classes receive a 1.1 percent decrease.

3. Within the residential rate class, Staff recommends that ET-1 and ECT-1R should receive average decreases. E-10 and EC-1 should receive less than the average decrease and E-12 should receive an above average decrease.
4. Staff recommends that the categories within the general service rate class should receive decreases to varying degrees. Staff recommends that the medium and extra large general service classes should receive average decreases, the small general service rate class should receive a greater than average decrease, and the large general service class should receive less than half of the average decrease.
5. If revenue requirements result in a rate increase, Staff would recommend that the revenues be allocated across the main customer classes in a more even distribution. However, Staff would recommend that the Commission adopt the proportion identified in this testimony for the intraclass allocation.
6. Staff recommends that APS' proposal to eliminate E-10 and EC-1 be adopted, but EC-1 would be phased out over a one-year timeframe consistent with the phasing out of E-10. In addition, Staff recommends that APS present customers on E-10 and EC-1 with written notice of its intent to cancel these rates and institute a customer education plan to inform customers of alternative rate options.
7. Staff recommends approval and believes that offering additional time-of-use options to APS' customers will provide customers with a greater range of time-of-use benefits and provide benefit to APS by reducing its peak load. In addition, Staff recommends that APS be required to file a report after three years from a decision in this proceeding that evaluates the outcomes of adopting the optional-time periods. The filing should make a recommendation regarding the continuation of the experimental time periods.
8. Staff recommends that APS establish an on and off-peak rate for the winter-billing period on its seasonally differentiated residential and general service time-of-use rates. However,

Staff recommends that the winter on and off-peak hours be modified to reflect the hours of actual system peak.

9. Staff recommends that the residential basic services charges remain at current levels or are decreased to reflect cost tracking. In addition, if the revenue requirements adopted provide for a rate increase, APS should not increase any one residential customer service charge by more than 5 percent.
10. Staff recommends that the general service basic services charges remain at current levels. However, if the revenue requirements adopted provide for a significant rate increase, APS should increase its general service basic service charges to bring them closer to cost.
11. Staff recommends that APS establish an on and off-peak energy component for the winter billing period on E-32 TOU. In addition, Staff recommends that the winter on and off-peak hours be modified to reflect the hours of actual system peak.
12. Staff recommends that APS' proposal to remove franchise fees from base rates be adopted and that such fees should be listed as a separate line item on customers' bills.

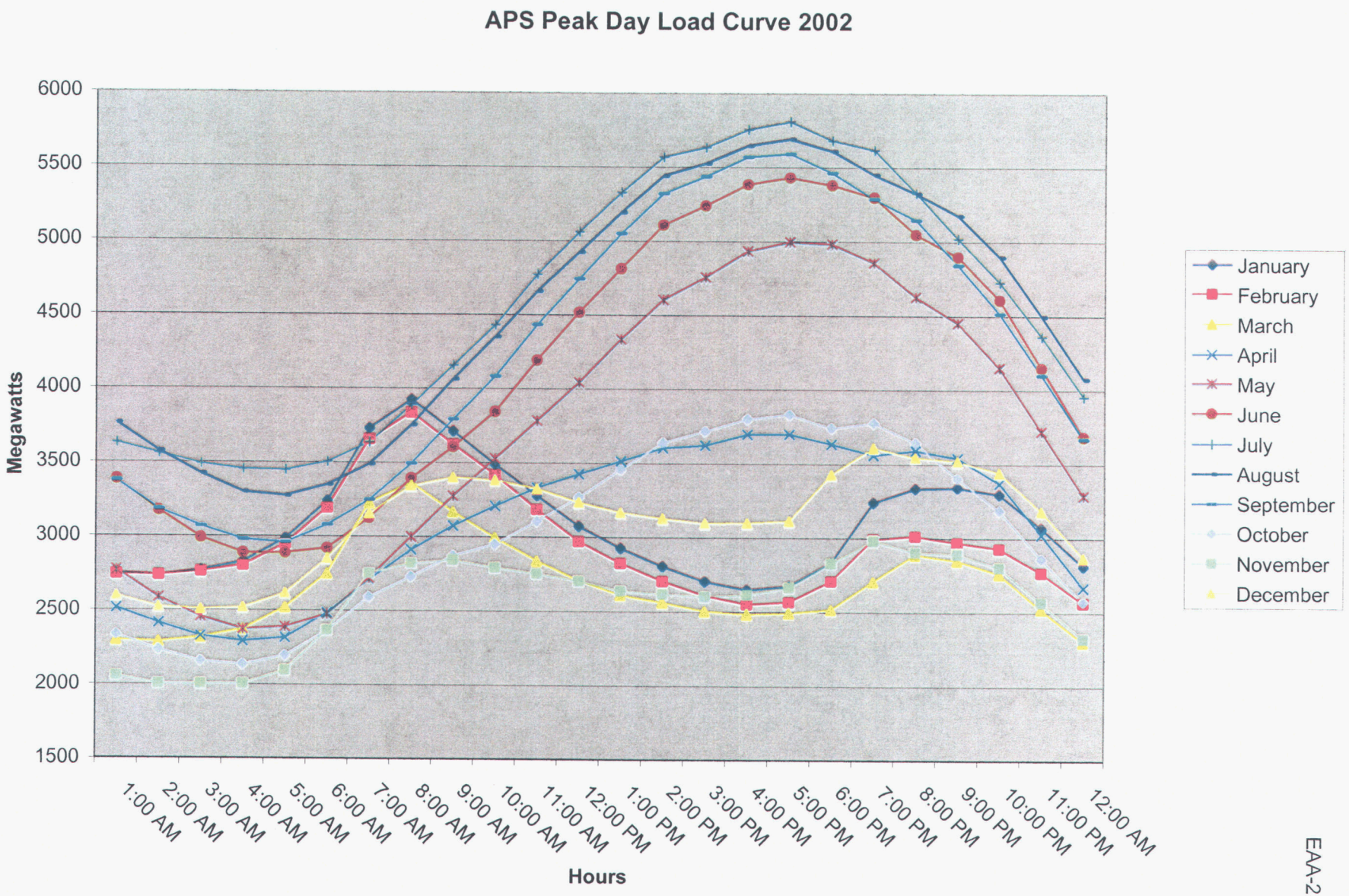
**Q. Does this conclude your direct testimony?**

A. Yes, it does.

Arizona Public Service
E-01345A-03-0437
Staff Recommended Revenue Allocations

EAA-1

| Customer Class | Percent Change |
|---|---|
| Residential | -4.04% |
| General Service | -13.4% |
| Irrigation | -2.19% |
| Street Lighting | -1.01% |
| Dusk to Dawn | -1.01% |
| Total Retail | -8.26% |


APS Peak Day Load Curve 2002
Megawatts
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1:00 AM
2:00 AM
3:00 AM
4:00 AM
5:00 AM
6:00 AM
7:00 AM
8:00 AM
9:00 AM
10:00 AM
11:00 AM
12:00 PM
1:00 PM
2:00 PM
3:00 PM
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM
10:00 PM
11:00 PM
12:00 AM
Hours
January
February
March
April
May
June
July
August
September
October
November
December

Arizona Public Service
E-01345A-03-0437
Residential Basic Service Charges

EAA-3

Residential Rate Schedules

| | Present Monthly Rate | Company Proposed Monthly Rate * | Dollar Change | Percent Change |
|---|---|---|---|---|
| E-10 Classic Rate | $7.50 | $8.24 | $0.74 | 9.87% |
| E-12 Standard Rate | $7.50 | $12.50 | $5.00 | 66.67% |
| ECT-1R Combined Advantage Plan | $15.00 | $15.00 | $0.00 | 0.00% |
| ET-1 Time Advantage Plan | $15.00 | $14.75 | -$0.25 | -1.67% |

Effects of Customer Migration from the Phase out of E-10 and EC-1

| | Present Monthly Rate | Company Proposed Monthly Rate * | Dollar Change | Percent Change |
|---|---|---|---|---|
| E-10 to E-12 | $7.50 | $12.50 | $5.00 | 66.67% |
| EC-1 (Residential Service with Demand) to ECT1-R | $10.00 | $15.00 | $5.00 | 50.00% |

* Monthly Rate = (proposed daily rate X 365 days)/12 months

EXHIBIT
S-6
Admitted

**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman

WILLIAM A. MUNDELL
Commissioner

JEFF HATCH-MILLER
Commissioner

MIKE GLEASON
Commissioner

KRISTIN K. MAYES
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | ) | DOCKET NO. E-01345A-03-0437 |

DIRECT

TESTIMONY

OF

HAROLD T. JUDD

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

February 3, 2004

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## EXECUTIVE SUMMARY
## ARIZONA PUBLIC SERVICE COMPANY
## DOCKET NO. E-01345A-02-0403

Mr. Judd testifies on ways to modify decommissioning funding by APS customers. His recommendations are designed to align decommissioning expense collection with the remaining operation life of the Palo Verde units. Mr. Judd also recommends correcting the decommissioning cost estimate by recognizing that some assets included in the cost estimate will have a useful life after the nuclear units are out of service. If his recommendations are adopted, the annual decommissioning obligation of APS customers will be reduced by $5.6 million to $13,611,000.

Q. Please state your name, business address, and position.

A. My name is Harold T. Judd. I am Vice President of Accion Group, Inc., consultants to the energy industry. Our main office is at 244 North Main Street, Concord, New Hampshire 03301-5041.

**Q. Please describe the clients of Accion Group.**

A. Accion Group provides strategic planning, operational evaluation and regulatory support services to utilities and to state regulatory agencies nationwide.

**Q. What is the purpose of your testimony?**

A. Accion Group was retained by the ACC Staff to review the nuclear decommissioning expense charges proposed to be included in the cost of service determination for APS. My testimony addresses that review and our recommendations concerning the amount of decommissioning costs of the Palo Verde units that should be included in APS's jurisdictional retail rates.

**Q. Please describe your prior work experience.**

A. I began my career in 1978 in New Hampshire as the Deputy Consumer Advocate for the Legislative Utilities Consumer Counsel. I left that office as

1 Acting Consumer Advocate in 1979 to become the Deputy General
2 Counsel and Energy Advisor to the Special Assistant to the President in
3 the White House Office of Consumer Affairs. In 1981, I was appointed an
4 Assistant Solicitor for the Department of Energy. From 1985 through 1987, I
5 served as the Economic Development Advisor to the Congress of the Federated
6 States of Micronesia, and as Special Counsel to the President of the FSM. From
7 September 1989 until January 1994, I served in the Office of the Attorney General
8 for the State of New Hampshire, first as an Assistant Attorney General and later
9 as a Senior Assistant Attorney General. In 1994, I entered the private practice of
10 law in Concord, New Hampshire where I provided general utility and corporate
11 representation with an emphasis on utility restructuring. In 1996, I became the
12 National Regulatory Manager for Southern Electric International, a wholly owned
13 subsidiary of the Southern Company. In 1997, I joined PG&E Energy Services, a
14 wholly owned subsidiary of PG&E Corporation, as Chief Counsel and Director of
15 Regulatory Policy. I am a founding director of Accion Group, Inc., which was
16 formed in 2001.
17
18 **Q. Please describe your education.**
19
20 A. I graduated from the University of Wisconsin at Madison in 1974 with a
21 B.A. Degree. In 1978, I received a law degree from the Franklin Pierce
22 Law Center. I have continued my education through professional
23 education courses.

**Q. What is your experience in the field of nuclear decommissioning?**

A. In 1979 I drafted what was to become the first nuclear decommissioning statute for the State of New Hampshire. In light of the controversy surrounding the Seabrook Station, the state opted to establish rigorous decommissioning standards that exceeded those imposed by the Nuclear Regulatory Commission (NRC) and established a committee of state officials, known as the Nuclear Decommissioning Fund Committee (NDFC), to oversee decommissioning funding. Since 1999 I have represented the NDFC as legal counsel, while my firm has also provided financial and engineering expertise to the committee. In 2000, on behalf of the NDFC and the New Hampshire Legislature, I authored a complete revision to the state's decommissioning statute in anticipation of the Seabrook Station sale to a merchant generator. New Hampshire now has the most comprehensive decommissioning statute in the nation, addressing all of the major decommissioning issues facing the industry.

**Q. Briefly describe your review of the decommissioning costs for the Palo Verde units.**

A. In addition to reviewing APS's pre-flied testimony and exhibits, we reviewed the study used by Palo Verde as a basis for projecting the cost of decommissioning all three Palo Verde units. As part of that review we considered the assumptions developed by APS for the storage and disposal of radioactive waste and spent

nuclear fuel, the activities included in the decommissioning estimate, and the period over which decommissioning, including the ultimate disposal of spent nuclear fuel, is projected to be completed. We reviewed the assumptions that APS used in developing the schedule of payments necessary to meet the decommissioning funding requirements that the study concluded were necessary. These included escalation, inflation, funding period and the impact of the uncertainties inherent in estimating the cost of disposing of decommissioning-generated low level radioactive waste. We also evaluated APS's proposal to recover its projected annual decommissioning contributions in retail rates from Arizona ratepayers.

**Q. Briefly describe how APS accounts for decommissioning costs for the Palo Verde units in the rate application.**

A. Simply stated, APS segregated decommissioning expenses into three discrete amounts. There is an amount for the funding of decommissioning each of the Palo Verde Units 1 through 3 and all facilities other than the Independent Spent Fuel Storage Installation (ISFSI). The ISFSI expense is accounted for in two pieces, with the post shutdown expense separated from the ISFSI amortization requirement. Each account is identified in Attachment DGR-6 that accompanies the pre-filed testimony of APS witness Donald G. Robinson.

**Q. In summary, what did you determine?**

A. Our review showed that the cost estimate prepared for the Palo Verde units, for the most part, conforms to the methodology employed in the industry and applies the same standards as applied by the vast majority of other nuclear stations in the U.S and are consistent with the minimum requirements of the NRC. The decommissioning study that was completed in 2001 was relied upon to project decommissioning costs and to establish the funding schedule presented by APS. The decommissioning study was conducted by TLG Services, using conservative estimates of disposal costs. The assumptions that APS used in their schedule of payments model such as escalation, inflation and the cost of Low Level Radiological Waste (LLRW) disposal were also reasonable and in line with current industry thinking.

**Q. Are there adjustments to APS' cost of service request that you recommend be made in this rate case?**

A. Yes, I have two. First, I recommend that the projected cost of decommissioning be reduced to reflect the probability that certain of the structures, systems and infrastructure of the site will have residual commercial and industrial value after, or even during, decommissioning. If done, the estimated cost of decommissioning Palo Verde would be reduced by approximately $89 million and the annual contribution by APS customers would be reduced by $800,000.

Second, I recommend that the Unit 2 decommissioning funding schedule be adjusted to match the licensed life of the unit. As discussed below, this would significantly reduce the required annual contribution to the Trust yet meet the desire to be fully funded when the plant is out of the rate base. This change would reduce the annual contribution by approximately $4.8 million. Together, these two adjustments would reduce the annual contribution by APS customers to $13,611,000.

**Q. Please summarize the options available to the ACC for setting the criteria for the proper scope of decommissioning.**

A. There are four that have been generally used. First, federal law (10 CFR 50.75) requires that all nuclear power plants meet the NRC Minimum funding requirements. This is a non-site specific formulaic approach. The starting point is a 1986 decommissioning estimate for the Trojan Nuclear Plant in Oregon that is then escalated to the present through labor, energy, and low level radioactive waste disposal cost adjustments prescribed in the regulations. Many states, however, require a site-specific estimate that significantly exceeds the NRC Minimum.

Second, there is the Licensing Termination Estimate that is a site-specific estimate that projects the cost of meeting the NRC's requirements (10 CFR 20) for removing radiological contamination and releasing the site for unrestricted use. This is generally 75% to 95% of a Full Site Restoration or "greenfields" estimate. A Full Site Restoration estimate assumes that essentially all site structures and systems are removed and the surface is restored to a condition close to its natural state. This is essentially the type of estimate presented in the 2001 TLG Study for Palo Verde.

Finally, there is the Commercial-Industrial Estimate. This is an approach to decommissioning in which certain of the buildings, structures, systems and physical features constructed for the operating station are deemed to have value for the site's post-nuclear commercial or industrial development and are, therefore, excluded from the scope of the estimate.

**Q. Does a Commercial-Industrial Estimate exclude all non-radiologically contaminated structures from the scope of decommissioning?**

**A.** No. Only those that are likely, or at least have reasonable potential, to be used for another commercial or industrial purpose once the nuclear reactor is removed are excluded from the decommissioning cost estimate. For example, power block buildings that will be heavily damaged through the decontamination process would be assumed to be completely dismantled and the costs included in the

estimate. A cooling tower, however, that could be used to support a re-powering of the site would have continuing value and would not be included in the decommissioning estimate.

**Q. What is the scope of the Palo Verde decommissioning study?**

A. The Palo Verde decommissioning cost study assumes that all site structures and systems except the switchyard and site drainage facilities will be removed by the end of the operation life of the nuclear reactors.

**Q. What are your views on APS' approach to developing it's cost estimates?**

A. The Palo Verde decommissioning cost study is consistent with traditional decommissioning studies in not recognizing that some on-site improvements will have continuing usefulness after the nuclear facilities are out of service. It is my opinion, however, that assets with remaining commercial value should be excluded from the cost estimate of decommissioning to avoid overstating the decommissioning cost and, in turn, overcharging customers.

**Q. What types of improvements are included in the Palo Verde decommissioning study that could be excluded from the decommissioning cost estimate?**

A. If there is a possibility that another power plant requiring cooling water will be located at the site, the Circulating Water Systems, the Water Reclamation facilities and pipelines, spray ponds, evaporation ponds, Cooling Towers and the Make-up Reservoir should be excluded from nuclear decommissioning. The Diesel Generators and their supporting systems could have value as power sources once freed from their emergency requirements. Non-contaminated support buildings could be used for power or non-power applications as warehouses, shops or office space. Roads, parking lots, potable water systems, sewage systems and other infrastructure would also have value for a wide range of potential future commercial or industrial ventures.

**Q. Have you determined how much the Palo Verde decommissioning cost estimate could be reduced if it took the Commercial-Industrial approach?**

A. Based on a review limited to the spreadsheets (Appendices C, H, I, J, K, and L) contained in the 2001 Palo Verde Decommissioning Cost Study, it appears that a Commercial-Industrial approach that excludes the dismantling activities discussed above would reduce the estimated cost by about $89 million. Attachment HTJ-1. This is a conservative estimate as it does not include the commensurate reduction in period dependent costs such as Utility Staff, energy, heavy equipment rental, and insurance that would result from the exclusion of these activities from the estimate. In Attachment HTJ-2 I have provided a summary of the NRC Minimum, Full Site Restoration, License Termination and Commercial/Industrial

Estimates to demonstrate the impact of recognizing the value of limiting decommissioning activities by not including the cost of removing improvements that have residual usefulness. The reduction in the overall estimate is small, about 5%, but no insignificant.

**Q. What would be the effect of removing those assets from the decommissioning cost estimate?**

A. The immediate and obvious effects would be to decrease the cost estimate and to reduce the annual contribution to the decommissioning fund. Other effects would be to encourage realistic planning for future use of the site, including its role in meeting future energy needs.

This estimate of effect is based on our review of the facilities included in the Palo Verde decommissioning plan. However, the precise effect of removing facilities from the decommissioning plan will only be known after there is a new comprehensive decommissioning study performed for the Palo Verde units, excluding all assets that have a useful life after the nuclear units are shut down. Each decommissioning study is a detailed work plan for dismantling a nuclear station, including the order in which things are removed. Typically, the decommissioning and demolition process takes ten years before a nuclear site is reduced to the ISFSI. In order to correctly account for the change in cost, it will be necessary to adjust the decommissioning plan, and the corresponding earnings

and withdrawals from the decommissioning trust fund, to reflect the timing of when the facilities remaining in the decommissioning plan will be removed.

**Q. Is this recognition of remaining commercial life used elsewhere?**

A. Yes. New Hampshire moved to this standard in 2000 in recognition of the fact that the Seabrook site would be used for other commercial purposes during and after decommissioning. This step was taken in response to the desires of local communities that were anxious to improve the likelihood that commercial and industrial facilities would continue to be located at the site to support their tax base and provide jobs. The joint owners of the Seabrook Station also recognized the value of this approach because it reduced decommissioning funding obligations and signaled a governmental recognition of the likelihood that generation facilities might be located at the site in the future.

**Q. If the projected cost of decommissioning is reduced by $89 million, what impact would that have on the annual contribution to the decommissioning trust?**

A. I estimate that the annual decommissioning cost would be reduced by approximately $800,000. As discussed above, it will be necessary to determine the timing of each decommissioning activity to have a more precise appreciation for the effect on the annual contribution. I believe it is appropriate in this rate

case to use my estimate for the purpose of establishing APS' retail rates. A more comprehensive analysis of the impact of using the Commercial/Industrial approach can then be provided by APS during a future rate case.

Q. **Have you reviewed the Schedule of Amounts to be Deposited in the Palo Verde Decommissioning Trusts included in APS' Cost of Service, Attachment DGR-6 and the assumptions that were used to develop that schedule?**

A. Yes I have. Attachment HTJ-3 is a summary of the assumptions and conclusions contained in the 2001 Pal Verde Decommissioning Cost Study. I previously discussed the appropriateness of the APS cost estimate. Next I will discuss the escalation rate employed to estimate the ultimate cost in nominal dollars of the decommissioning effort that will be required at the end of the projected license life of the three units, the expected rate of return on the funds contributed into the trusts, and the periods over which APS will be contributing to the decommissioning Trust.

**Q. Would you please explain the "escalation" factor?**

A. The cost estimate utilized to develop the funding schedule is an estimate of what it would cost to decommission the Palo Verde plant today if it were in the condition it is expected to be in at the time the plant's license terminates. The

estimate is based on today's labor, material, and waste disposal costs. In order to assure that enough funding is available to complete the necessary decommissioning tasks, the cost estimate has to be inflated to reflect anticipated increases in the costs of labor materials and waste disposal as well as increases in taxes and regulatory expenses. This rate of inflation applied to decommissioning activities is referred to as "escalation". As discussed in the testimony of APS witness Robinson, APS uses a 4% rate, which reflects the long-term historic general inflation of the overall economy in the past twenty years.

**Q. Do you believe that a 4% escalation rate is appropriate?**

A. Yes. This opinion is based on a recent review of the escalation rates of costs associated with decommissioning a nuclear power station that was completed by the New Hampshire Nuclear Decommissioning Financing Committee (NDFC) in December 2003. Seabrook Station proposed a decommissioning escalation rate calculated in accordance with the NRC standards set forth in 10 CFR 50.75. Their overall rate had four components: labor, material, energy and transportation, and low level radioactive waste (LLRW) disposal. Regional government-sanctioned indices were used to determine the projected rates of inflation over the funding period for labor, material and energy and transportation. The LLRW disposal component, usually the most volatile, was determined using the methodology of the NRC's set forth in NUREG 1307. An average of these four components, weighted in accordance with their percentage of the overall

estimated decommissioning cost, was then calculated to be 4.1%. The NDFC accepted the owners' escalation methodology, but added a contingency factor of 0.4% to reflect perceived risks not accounted for in the Seabrook cost estimate. While APS' escalation rate is lower, resulting in lower contribution requirements and ultimately in less funds being available to pay for the clean up of the Palo Verde plant, it appears to be reasonable at this time.

**Q. Is the escalation factor an assumption that should be periodically reviewed by this Commission?**

A. Yes. The Commission should require APS to propose an escalation rate each time that it submits a comprehensive decommissioning study. APS should include a detailed description of the methodology, the assumptions and the calculation for ACC review and approval. In light of the fact that the Palo Verde plant is expected to operate for an additional twenty years, any deviations in funding resulting from under or over estimation of the escalation rate can then be remedied through gradual adjustment of the annual contribution rate.

**Q. Have you reviewed the anticipated rates of return on funds invested in the Trusts?**

A. Yes. APS primarily contributes its decommissioning funding into tax advantaged Qualified Trusts. These Trusts pay taxes on earnings at a Federal rate of 20% as

compared to the higher corporate rates that would otherwise apply. Investments are made pursuant to established guidelines that permit investments in qualifying equities and fixed income securities as well as in other securities permitted by the guidelines. APS bases its earnings estimates on advice provided to it by the funds investment advisors. In the current case, APS has assumed that the Trusts will earn at a blended after-tax rate of 4.8%, compounded annually for the life of the trusts. This estimate appears to be within the range of earnings estimates for similar investments of which I am aware.

**Q. Is this estimate reasonable?**

A. Yes I believe it is.

**Q. Should the Commission review this assumption periodically?**

A. Yes it should. Annual rates of return on investments can be highly volatile and shortfalls or greater than expected annual performance can have significant impacts on required contribution levels. I would therefore recommend that APS be required to provide to the ACC detailed annual performance data on each of its Trusts, clearly describing actual earned rates of return and proposed changes in funding levels that may be required to mitigate the effect of any variance in earnings experienced. Annually, APS should also provide to the ACC its estimated rate of return on its investments in the Trusts for the remainder of the

Trusts life. As with the escalation factor, APS should be required to fully discuss the estimated rates of return on funds invested in the Decommissioning Trusts each time a new cost estimate is prepared and a comprehensive review of the adequacy of the Trusts is conducted.

**Q Has APS made an assumption regarding when it will complete funding of the Decommissioning Trusts?**

A Yes. APS has assumed that the funding period for Units 1 and 3 will be through 2026 and the funding period for unit 2 will be through 2015.

**Q. Please explain the significance of the decommissioning funding period.**

A Certainly. The period over which contributions are made dictates the annual contribution level. Typically, owners of nuclear facilities fund the Decommissioning Trusts over the plant's authorized license life. APS has chosen to do that for units 1 and 3. However, APS is funding and seeking recovery of annual contributions to the Unit 2 trusts that reflect its obligation to fully fund those trusts by 2015.

**Q. Why is APS funding decommissioning costs for Unit 2 over a period less than the unit's operating license life?**

A. The obligation to use a shorter period arose as a result of a financing transaction APS entered into with regard to Unit 2. In Decision 58644 in ACC Docket No. U1345-94-120, the Commission authorized APS to recover in rates the decommissioning contributions that reflect APS' obligation to fully fund the Unit 2 Trusts by 2015. However, in that decision the Commission noted that

> ...the Commission shall not be bound in any subsequent rate case to adopt the decommissioning funding levels or decommissioning factors adopted and approved herein.... (at p. 6).

**Q. Is APS asking to recover those accelerated contributions in rates to be established in this case?**

A. Yes they are. In addition, APS is seeking recovery of its Unit 2 spent nuclear fuel disposal costs (the expenses and amortization amount referred to by Mr. Robinson as the Independent Spent Fuel Storage Installation costs).

**Q. What is the effect of having customers fund the Unit 2 trust and ISFSI costs over a period shorter than the licensed life of the Unit.**

A. The accelerated funding has several effects on customers' rates, some beneficial and some adverse to current customers. Since the funding levels that are ultimately required to decommission the plant and the ISFSI are not affected by the timing of fund contributions, accelerating contributions and the recovery of

disposal costs will actually reduce total customer payments to fully fund the Trusts and dispose of the spent nuclear fuel. This is because fund earnings will be enhanced as a result of the higher fund balances that will be realized in earlier years. However, the acceleration of payments has the effect of shifting cost responsibility for decommissioning to present day customers and relieves customers who will receive benefits from the plant after 2015 of the responsibility for funding any part of the decommissioning expense. This intergenerational shift of responsibility is adverse to the interests of current customers. I believe that for rate making purposes such shifts of cost responsibility should generally be avoided.

**Q. If the funding included in rates for Unit 2 were levelized over its licensed life, what would be the annual contribution includable in rates?**

A. Mr. Robinson has calculated APS' 2005 decommissioning contributions to be approximately $19.2 million and it's ISFSI related expense to be approximately $1.5 million. Calculating a new payment schedule is a complex undertaking. Based on the information available to me, I would estimate that if the Commission were to allow recovery of decommissioning expenses and ISFSI costs on the basis of levelized recovery over the licensed life of each unit, the includable expense would decrease by between $4.8 million and $5.0 million annually. This estimate was developed using the computer model used by APS to determine Mr. Robinson's estimated contributions.

**Q. You have made two recommendations for action by the ACC in this rate case. Do you also have any recommendations for action by the ACC in future cases regarding APS's decommissioning contribution levels?**

A. I recommend that the ACC require APS, as part of its next comprehensive review of decommissioning costs at Palo Verde, to evaluate and report to the Commission on its planning for radioactive waste disposal.

**Q. How significant a component of the decommissioning cost estimate is the disposal of low-level radioactive waste (LLRW)?**

A. Burial and recycling of LLRW constitutes about 24% of the Palo Verde 2002 Decommissioning Cost Estimate. As importantly, the cost of the burial of LLRW is one of the components (along with labor, energy and transportation) of the decommissioning escalation rate used in the NRC's 10 CFR 50.75 methodology. It can, in fact, be the most volatile and significant of these components because of the political and regulatory uncertainties associated with LLRW burial.

**Q. What LLRW burial sites are available to the nuclear power industry?**

A. There are currently only three facilities licensed to accept LLRW from commercial nuclear power plants: a state-owned facility at Richland, Washington; a state-owned facility at Barnwell, South Carolina; and Envirocare, a private

facility in Utah. The facility at Richland, Washington is only available to states that belong to the Northwest Compact. This does not include Arizona. Since Envirocare is not licensed to accept the more highly contaminated waste (designated as Class B and Class C waste), these waste forms must be sent to Barnwell for burial. The State of South Carolina, however, passed legislation in 2000 that is gradually limiting access to Barnwell and will exclude all but Atlantic Compact members (South Carolina, Connecticut and New Jersey) by 2008.

**Q. What has the industry been doing to address this problem?**

A. The high cost of LLRW disposal is incenting the industry to find ways to minimize the LLRW produced through changes in operations and to use off-site processing to reduce the volume produced that must be buried. Off-site processing consists of volume reduction performed by private vendors using decontamination, compaction, dewatering, sorting and stabilizing technologies. The type of LLRW sent to Barnwell is particularly suited for this treatment.

**Q. How does this situation impact decommissioning estimates?**

A. Because of the uncertain availability of a place to bury the LLRW when the plants are decommissioned and the importance of these costs to properly funding decommissioning, assumptions on the future costs to bury LLRW should be

conservative. At the same time, it is appropriate for decommissioning cost studies possibly unavailable burial site.

**Q. Do you believe that the Palo Verde decommissioning cost study appropriately addresses the impact of LLRW disposal?**

A. I believe they are conservative, but reasonable. For example, the decommissioning-generated LLRW volumes at the three Palo Verde units that must be sent to a burial site exceed the volumes for Seabrook Station by 4, 18 and 18% on a per unit basis. The assumed overall burial costs per cubic foot at Palo Verde are also about 40% higher than at Seabrook Station. This probably stems from APS taking less credit for offsite processing of LLRW.

**Q. What recommendations do you make for future action with respect to LLRW disposal?**

A. I believe that APS handles projected decommissioning-generated LLRW disposal costs in a conservative manner. I recommend, however, that the ACC request APS to provide more detail on the basis of the assumptions related to projected costs at a future Southwest Compact facility, including a breakdown of the type and quantity that would be sent to Envirocare and this facility. Because of the tremendous impact that escalation can have on funding, I would also recommend that the ACC request that APS calculate escalation using the methodology

contained in 10 CFR 50.75. This includes consideration of regional labor, energy and transportation costs as well as using the methodology of NUREG 1307 in calculating the LLRW component of escalation. With this level of detail backing up the estimate, the ACC and its staff would be in a better position to review and make appropriate rulings regarding the treatment of the LLRW component of decommissioning.

**Q. Do you have any recommendations for future review?**

A. Yes. I believe the ACC should review the adequacy of the funding assurances provided by the out of state Palo Verde owners. Only 46.6% of Palo Verde is owned by Arizona utilities. In the event of a default by out of state owners, Arizona utilities could be at risk and the ability of the state to recover the decommissioning obligation of a defaulting owner or others may not be assured. It is appropriate for the ACC to consider whether the citizens of Arizona bear an excess risk for decommissioning costs, simply because Arizona agreed to be the host state for three nuclear reactors. At this time I am unaware of any reason to believe any owner of Palo Verde will default on its obligation, but I also believe it would be prudent for the ACC to take action before a problem exists. The NRC recognizes many forms of funding assurances that could be adopted without adverse impact on the owners, while at the same time providing financial protection for Arizona citizens.

**Q. In conclusion, what would be the impact of your recommended adjustments to APS' cost of service?**

A. I have recommended two adjustments. Adjusting the Unit 2 decommissioning funding to match license life of the unit would reduce the annual contribution by between $4.8 million and $5.0 million, and I recommend reducing the annual contribution by $4.8 million. Reducing the projected cost of decommissioning to reflect the future commercial use of the site would reduce the projected cost by approximately $89 million, which would, in turn, reduce the annual decommissioning contribution requirement by about $800,000. Combined, these recommendations would lower the annual decommissioning expense to be included in the APS cost of service to $ 13,611,000.

**Q. Does this conclude your testimony?**

A. Yes, it does.

# Decommissioning Costs Excluded from the APS Estimate Using a Commercial/Industrial Estimate (000,000)

| ACTIVITY, COMPONENT OR SYSTEM | DECON COSTS (2001 $) |
|---|---|
| | |
| **COOLING WATER** | |
| Circulating Water Systems | 507 |
| Plant Cooling Water | 265 |
| Essential Spray Ponds | 633 |
| Cooling Towers | 3,738 |
| Cooling Tower Electrical Building | 80 |
| Intake Structure and Canals | 168 |
| Nuclear Service Spray Ponds | 5,153 |
| Water Reclamation Facility | 8,025 |
| Water Reclamation Supply system Pipeline & Structures | 34,006 |
| Evaporation Ponds | 4,921 |
| Makeup Water Reservoir | 759 |
| **Subtotal** | **58,255** |
| | |
| **Buildings And Support Systems** | |
| Control Buildings | 2,259 |
| Turbine Buildings and Turbine Building Pedestal | 15,318 |
| Turbine Maintenance Facilities | 66 |
| Operations Support Building | 342 |
| Technical Support Center | 277 |
| Warehouse | 1,313 |
| Diesel Generator Building | 1,071 |
| Switchgear Building | 117 |
| Transformer Area | 243 |
| Chemical Storage Building | 318 |
| Corridor Building | 232 |
| Yard Tunnels | 843 |
| Administration Buildings (including Annex, Bldgs A and B) | 1,168 |
| Calibration Lab & Hot Instrument Calibration | 15 |

| | |
|---|---|
| Lab | |
| Vehicle Maintenance Facility | 77 |
| Energy Information Center | 73 |
| Fire Pumphouse | 32 |
| Guardhouse | 30 |
| LLRW Storage Facility | 147 |
| North Annex Building | 176 |
| Service Building | 189 |
| Decon & Laundry Facility | 273 |
| Miscellaneous Structures | 828 |
| **Subtotal** | **25,407** |
| | |
| **Infrastructure** | |
| Domestic Water | 415 |
| Fire Protection | 383 |
| Electrical (clean excluding RCA) | 2,334 |
| Sanitary Drains and Treatment | 217 |
| Retention Basin | 14 |
| **Subtotal** | **3,363** |
| | |
| **Surface Restoration** | |
| Grading and landscaping site | 174 |
| Site Fencing, Paving & Railroad | 1,497 |
| **Subtotal** | **1,671** |
| | |
| **Power** | |
| Diesel Generators and Support Systems | 252 |
| Station Blackout Gas Turbine Generator | 31 |
| **Subtotal** | **283** |
| | |
| **GRAND TOTAL** | **88,979** |

# Summary of the Palo Verde Nuclear Generating Station Decommissioning Estimates

(000,000)

| | PV 1 | PV 2 | PV 3 | ISFSI | Other Facilities | Combined | Comments |
|---|---|---|---|---|---|---|---|
| **NRC Minimum (2003$)** | | | | | | 1,095 | Based on 3x the NRC Minimum as calculated for Seabrook Station in 2003 |
| **Full Site Restoration (2001$)** | 511 | 543 | 578 | 267 | 73 | 1,972 | |
| **License Termination (2001$)** | 481 | 514 | 538 | 261 | 25 | 1,819 | |
| **Commercial/ Industrial (2001$)** | | | | | | 1,883 | |

# Palo Verde Decommissioning Assumptions
(000,000)

| | PV 1 | PV 2 | PV 3 | ISFSI | Other Facilities | Combined |
|---|---|---|---|---|---|---|
| **Full Site Restoration Estimate (2001 $M)** | 511 | 543 | 578 | 267 | 73 | 1972 |
| **Funding Period** | 2024 | 2025 | 2026 | 2024 | 2026 | |
| **Inflation of Contributions** | Levelized | | | | | |
| **Escalation of Decom Cost** | 4% | | | | | |
| **LLRW Disposal (Packaging, Shipping and Burial)** | | | | | | |
| **- Volume (1000cu. Ft.)** | 114 | 130 | 130 | 160 | | 390 |
| **- Cost (2001 $M)** | 147 | 160 | 164 | 9 | | 480 |
| **Yucca on line** | After 2010 | | | | | |
| **First Spent Fuel Shipped to Yucca** | After 2010 | | | | | |
| **Last Fuel Shipped to Yucca** | After 2037 | | | | | |
| **Earnings** | 4.8% | | | | | |

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**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF<br>ARIZONA PUBLIC SERVICE COMPANY FOR<br>A HEARING TO DETERMINE THE FAIR VALUE<br>OF THE UTILITY PROPERTY OF THE COMPANY<br>FOR RATEMAKING PURPOSES, TO FIX A JUST<br>AND REASONABLE RATE OF RETURN THEREON<br>TO APPROVE RATE SCHEDULES DESIGNED TO<br>DEVELOP SUCH RETURN, AND FOR APPROVAL<br>OF PURCHASED POWER CONTRACT | )<br>)<br>)<br>)<br>)<br>)<br>)<br>)<br>) | DOCKET NO. E-01345A-03-0437 |

DIRECT TESTIMONY

OF

LEE SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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## I. INTRODUCTION

**Q. What is your name and business address?**

A. My name is Lee Smith, and I work for La Capra Associates, 20Winthrop Square, Boston, Massachusetts.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Arizona Corporation Commission (Commission) Staff.

**Q. Please describe your background and experience.**

A. I am a Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 20 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resume is attached as Exhibit LS-1. I have testified previously regarding the 1999 Settlement that has given rise to some issues in this proceeding.

**Q. What is the purpose of your testimony?**

A. I am testifying on several topics. First, I present testimony on the appropriateness of the Company's request for a reversal of its 1999 writeoff of $183 million (after tax) subsequent to the Settlement of 1999. (The pretax value related to the $183 million is $234 million.) I also address the Company's proposed Competition Rules Compliance Charge ("CRCC"), and its request to collect 100% of its divestiture costs. I address some cost allocation issues which are necessary for Mr. Dittmer to complete Staff's overall revenue adjustments, including the cost of transmission. Finally, I comment on the Company's allocated cost of service study and present an allocated, unbundled cost study based on Staff's case.

**Q. What is the Company's request regarding the $234 million?**

A. The Company is requesting a "reversal" of a writeoff of regulatory assets that it took in 1999. To achieve this "reversal", it is proposing to increase rate base by $141.57 million, to be amortized over 15 years. The net impact on rates will be $7.8 million annually. (Robinson p. 40)

**Q. Please summarize your testimony.**

A. My testimony addresses the original writeoff and its relation to the rate reduction approved in the order that reviewed the settlement, the impact on the Company of the rate reduction itself, and whether the Company has suffered any significant harm as a result of the Commission's Track A Order, which halted its divestiture to PWEC. I also discuss stranded cost, both theoretically and in this context, since a stranded cost computation was the genesis of the original "writeoff" number. I recommend approval of the Company's proposed treatment of transmission costs, and recommend some modifications to the proposed Competition Rules Compliance Charge. I also support an unbundled allocated cost study which reflects Staff's recommendations on revenue requirements.

**Q. Please summarize what you have found with regard to the writeoff issue.**

A. I have found that:

- The proposed adjustment is not necessary to produce rates that will recover the Company's ongoing costs;
- The Company's going forward revenue requirements have not been reduced by the previous writeoff;
- While the Commission has modified the order that approved the 1999 Settlement, the Company has not suffered significant harm as a result of this modification;
- While APS did reduce rates as a result of the Settlement, some rate reductions would have occurred even without the Settlement;

- It is unreasonable to assume that APS' rates would have remained unchanged absent the settlement agreement;
- The Company will have collected more than the $350 million of "stranded costs" which the Settlement provided an opportunity for it to collect;
- The original stranded cost amount was based on an estimate of $533 million that was too high.

**Q. Is this case about stranded costs?**

A. No, it is not. In response to LCA 1-9, the company states that the "opportunity to recover $350 million was not affected by the failure of the Commission to permit the promised divestiture…"

**Q. Has the Company actually experienced any stranded costs?**

A. No, it has not. Since almost no customers have chosen alternative suppliers, the Company has not had excess generation which it had to sell at an amount less than its embedded cost.

**Q. Given the foregoing findings, what are your overall conclusions regarding the request to reverse the writeoff?**

A. The proposed adjustment does not meet the normal standard by which revenue requests are judged. While the Company appears to be proposing a different standard, I find that this standard also has not been met. My conclusion is that APS' proposal to reverse the writeoff is not justified, and should not be allowed.

## II. THE NORMAL RATEMAKING STANDARD

**Q. You indicated above that the adjustment does not meet the normal ratemaking standard. What is the normal ratemaking standard that you believe has not been met?**

A. The normal basis for a rate request is going-forward revenue requirements. That is, rates are normally designed to recover what is agreed to as the Company's cost of business. The Company's witness, Dr. Ken Gordon, also describes this standard: "the regulatory agency . . . sets rates that provide the utility a reasonable opportunity to recover its just and reasonable costs." (p.12) If the 1999 writeoff had resulted in a reduction to ratebase or some other change that jeopardized the Company's ability in this case to produce rates that would collect its ongoing costs, this request might have met this standard.

**Q. Has the Company said that the rates that it is filing in this proceeding will be lower because it took the writeoff?**

A. No. The Company's "...net generation plant...was not impacted by the 1999 Settlement Agreement." (LCA 1-11)

**Q. If the Company's request for reversal of the writeoff is granted, will the resulting rates recover more than the Company's ongoing costs?**

A. Yes. All else being equal, the proforma adjustment for the amortization of the writeoff will result in rates being set above the Company's current costs.

## III. COMPANY PROPOSAL REGARDING THIS ADJUSTMENT

**Q. If the request does not meet the normal ratemaking standard, how does the Company justify its request?**

A. The Company's position is that as part of the 1999 Settlement it agreed to a number of conditions, in particular to a series of rate reductions, and in return it expected to transfer APS generation assets to PWEC. Since the findings of Track A prevented it from transferring these assets, it apparently believes that it has not received a benefit that it expected, and, as a result, has suffered harm. Mr. Wheeler describes the modification of the order approving the Settlement

(elimination of divestiture) as being a case of "detrimental reliance." (Wheeler p.4)

The essence of the Company's claim seems to be that:

(i) APS was entitled to recover $533 million in stranded costs, but in the Settlement it agreed to the collection of $350 million (both in net present value terms);

(ii) APS had planned to establish PWEC and divest its generating facilities to it only because the Commission had previously required divestiture;

(iii) APS had been willing to accept a pretax $234 million write off related to stranded costs (resulting from the aforementioned net present value of $183 million after-tax, the difference between $533 million and $350 million) as the price for being allowed to implement its preferred form of divestiture;

(iv) But for the Commission-mandated divestiture, APS would not have agreed to the write-off as part of the 1999 Settlement;

(v) Given the Commission's reversal of position on divestiture, APS deserves to recover the $234 million write-off.

**Q. Has the Company testified that it has not had an opportunity to recover $350 million of stranded cost because the Commission did not permit divestiture?**

A. No. In response to LCA1-9, which asked the Company to "...explain whether and how APS' "reasonable opportunity to recovery $350 million...was affected by the non-sale", it says precisely the opposite. "The opportunity to recover $350 million was not affected by the Commission's decision to prevent divestiture of APS generation."

**Q. If the Company does not claim that the $234 million is related to an undercollection of stranded costs, what is it actually requesting in the adjustment for $234 million?**

A. The Company is essentially making a claim for a retroactive rate adjustment. The Company appears to be saying that 'our rates were lower in the past than we would like, so we would like higher rates in the future.' Although Mr. Wheeler testifies that it is not seeking to take back rate decreases, (Wheeler testimony p. 21), the Company is in fact asking to recover a portion of the rate decreases of the past four years.

The company has made no showing that such revenues are appropriate under normal ratemaking standards, nor has the Company demonstrated that it has been harmed. Furthermore, I describe in Section V how the stranded cost claim by the company that was a basis for the settlement is a dubious figure.

## IV. THE COMPANY HAS NOT SUFFERED SIGNIFICANT HARM

**Q. Please summarize your response to the Company's claims that it has been harmed.**

A. The Company has not established that it has actually suffered significant financial harm. The writeoff has no independent impact, as it did not result in the Company's revenues being reduced, and failure to reverse the writeoff will not result in the Company receiving less than its cost of service in this case. Some rate reductions would have occurred even without the Settlement, and it is unreasonable for APS to assume that its rates would have remained unchanged subsequent to the conclusion of its stranded cost proceeding. The change in policy regarding divestiture has not had a large ongoing impact on the Company's finances. On the other hand, since the Company has been denied the recovery of the one-third of costs associated with restructuring, and with the reversal of Commission policy, it may be appropriate to collect the one-third of costs associated with restructuring in a surcharge mechanism, even though they do not constitute a significant cost.

**Q. Did the Company suffer any harm as a result of agreeing to a stranded cost number of $350 million?**

A. No. Mr. Wheeler testifies that "the restoration of that write-off has nothing to do with the actual level of stranded costs either incurred by the Company or collected in rates from customers seeking Direct Access. (Testimony, p. 19)[1] I will address the stranded cost situation further in Section V.

**Q. Have the Company's revenues since the Settlement been less than they would have been because of the writeoff?**

A. No. While revenues have been less than they would have been if no rate reductions had occurred, the writeoff was not the cause of the rate reductions, but the result of the rate reductions. The writeoff, according to the Company, "...was intended to represent a disallowance, on a present value basis, of a portion of the Company's generation-related revenue requirement for the years 1999-2000." (Response to LCA 1-3)

**Q. Were the regulatory assets that were the subject of the writeoff included in the assets that formed the basis for the APS stranded cost claim that was addressed in the 1999 Settlement Agreement?**

A. No. The regulatory assets that were written down bore no relation to the generating assets that were the subject of the Company's stranded cost claim. LCA 1-5. The Company has indicated that the affected regulatory asset balances had been approved for recovery by the Commission in prior proceedings. (Response to LCA 1-3, Wheeler Direct Testimony at 19.)

**Q. What did APS agree to in the Settlement regarding rate decreases?**

A. The Settlement specified that APS would reduce rates 1.5% annually for customers of less than 3 MW from 1999 through 2003. Larger customers were

[1] Although as I will explain later, the relevant measure of stranded cost collection is not determined only by customers choosing Direct Access.

also to receive rate decreases. The Settlement also allowed APS to seek a change in rates prior to 2004 in the event of an emergency or of material changes in APS' cost of service resulting from legal or regulatory actions.

**Q. APS implies that there would have been no change in its rates if it had not signed this particular Settlement. Do you agree with this?**

A. No. The proceeding regarding stranded costs and restructuring that resulted in the Settlement addressed APS' operations and APS' rates. There was a wide divergence of opinions in this proceeding regarding APS' rate levels and its stranded costs, and some parties took positions that may have led to rate reductions. Thus, it is quite possible that if the restructuring case had been litigated rather than settled, APS' rates would have been reduced by Commission order. APS' position that its rates would have remained unchanged if it had not signed this particular Settlement is speculative.

**Q. In the absence of the Settlement and the absence of any stranded costs, would a rate decrease have been justified?**

A. Yes. Evidence suggests that a rate decrease would have been justified independent of a settlement and/or any stranded costs. Part of the Settlement's initial rate reduction would have been required as a result of the 1996 Rate Reduction Settlement. (See letter from Ms. Klemstine in response to LCA 7-216). Moreover, there is evidence that APS has earned considerably more than its last allowed return on equity for most of the time since the Settlement. Thus, even without the Settlement, APS' rates would have been reduced in 1999, albeit by a lower amount, and also there would have been grounds for reducing APS' rates in the succeeding years. Thus, there is an important question as to what revenues, if any, the Company actually gave up in the Settlement. The Settlement may merely have been the actual mechanism that prevented overearning, but other mechanisms might have also achieved this result.

had supported those resources and paid for the training of personnel should not benefit from the trading operations.

**Q. Regarding the writeoff, if it were appropriate to adjust actual earnings to determine what the Company would have earned without the writeoff, has the Company made the appropriate adjustments?**

A. No. To consider what the rate of return might have been without the writeoff also requires increasing actual Company earnings for the foregone revenue. This presents a truer picture of where APS would have been if its rates had remained unchanged, since according to APS the "writeoff" and the rate reductions were intimately linked. If its rates had not changed, APS would have had additional revenues from 1999 through 2002 of $175.7 million (Response to LCA1-7). Thus, to demonstrate where APS would have been if its rates had not changed, after increasing expenses by the adjustment suggested by APS, the increase in amortization expense, we also must increase income. Exhibit LS-2 "undoes" the Settlement by adjusting the amortization expense, as the Company would do, and also increases revenues by the after-tax impact of the rate reduction. This computation again shows that APS would have overearned but for the rate reductions. The rates of return in 2000, 2001, and 2002 would have been 15.0%, 13.2%, and 10.8%. The major data responses that have been used in this computation and referred to elsewhere are contained in Exhibit LS-3.

**Q. The Company has further claimed that it has been harmed because the Commission modified the order that approved the 1999 Settlement. Has the Company demonstrated that it has actually suffered significant financial harm because of this modification?**

A. No. The response to LCA1-10 states that the Company made numerous concessions, including agreeing to less than $530 million in stranded costs, the writeoff, the rate decreases, the disallowance of 1/3 of divestiture costs, and the

dismissal of litigation against the Commission. I will address each of these "concessions" below.

**Q. Does the Company claim that it has suffered any other costs as a result of the change in Commission policy?**

A. Yes. According to the response to LCA1-10, "It has also left part of the generation built to serve APS load effectively "stranded" at PWEC with the associated diseconomies and financial strain of having to maintain two separate organizations for the same essential utility function." (LCA 1-10)

**Q. Has the Company established the value of what it has been denied by the cessation of the transfer of generating assets to PWEC?**

A. No. There has been no demonstration of the actual cost of the diseconomies which are supposed to result from having two separate organizations. In fact, since PWCC basically transferred Mr. Bhatti and its generation planning functions from APS to PWEC, it is not evident that any costs have been duplicated. In response to LCA 19-458, the Company states that the cost of financing PWEC on a stand-alone basis was at least 264 basis points. However, PWEC's financing costs would have been higher than APS' financing costs even if APS generation assets had been transferred to PWEC, because PWEC is a competitive unregulated entity and thus is subject to more risk than the regulated utility.

**Q. If there have been diseconomies resulting from the existence of the two separate organizations, need they persist into the future?**

A. No. Any APS costs associated with generation will be included as part of APS' regulated revenue requirement. PWEC, a non-regulated entity, may or may not recover all of its costs through its competitive activities. PWEC may compete with other nonregulated generating entities that also presumably have higher financing costs than regulated entities.

from its customers. Actual annual sales to jurisdictional customers would be multiplied by the CTC, and also multiplied by the percentage of load eligible for Direct Access Service ("DAS") during each year. This methodology was consistent with how the Company computed stranded costs.

**Q. Could you explain why the CTC was multiplied by total load eligible for DAS, rather than only by load that chose DAS?**

A. Yes. Based on the concept of stranded costs, it is appropriate to multiply the CTC times the total load eligible for DAS because customers who continue to purchase generation from APS are contributing to the collection of APS' stranded costs. The standard offer generation price covers both stranded cost and the market cost of generation, so that customers who purchase generation from the Company are contributing to the collection of stranded costs through the standard offer price. Customers who choose Direct Access would contribute to stranded cost collection through an explicit CTC.

## V. THE ISSUE OF STRANDED COSTS

**Q. How are stranded costs defined?**

A. The concept of stranded costs arose out of concerns that a company might be unable to collect all of the dollars that it had expended on generating assets if its customers were given the ability to purchase generation from other suppliers – in other words, if retail access were offered with no charge to customers for leaving. This would be a concern to a company when the embedded costs of the generating assets still to be recovered are greater than the revenues that the Company would receive by selling either the generating units themselves or by selling energy that becomes excess when customers choose alternative suppliers.

Another way of looking at stranded cost is as the difference between the value of the assets on the utility's books, or their net book value, and the market value of the same assets. This reflects the utility's position if it sells the assets. It might be interested in selling assets if it expected its generation load to decrease. If the market price is less than the net book value, the utility will not recover its full costs by selling the units, and would be considered to have stranded costs.

The Company seems to recognize this concept, as Mr. Wheeler testifies that "Stranded cost referred to the difference between the regulated cost of service for competitive electric assets, in this case generation, and what was then believed to be their market value." (Wheeler testimony, p.19) Stranded costs refer to the generation costs that the Company may be unable to collect when customers can choose other suppliers. Typically, a rate is developed which will allow the Company to collect these stranded costs from all customers.

**Q. Has this definition and collection of stranded costs been used in other jurisdictions?**

A. Yes. To my knowledge, all jurisdictions that have allowed utilities to collect stranded costs have computed stranded costs in a manner consistent with this definition: that is, comparing the market value of the assets with their book value. In some states, vertically integrated utilities have been required to sell their assets to the highest bidder. The sale price clearly establishes what the market is willing to pay for the assets, and the stranded costs which the utilities have been allowed to collect are the difference between the sale price and the book value.

**Q. Does the $533 million figure that APS refers to as its stranded cost have any relevance to this case?**

A. Only in that it is the basis for the claim that APS gave up something when it agreed to collect $350 million in stranded costs, rather than $533 million. APS attempted to demonstrate previously that it would have experienced $533 million of stranded costs if customers had chosen retail access. This figure was cited in

the near-term. It also claims that over the lives of the units customers will pay less in total net present value if they pay embedded costs rather than market prices. This illustrates the point that a short-run view does not capture the full value of such long-lived assets. The computation of the market value of the generating assets compared to the book values and the computation of the life-of-unit net revenue streams received from selling at competitive prices as compared to selling at embedded rates would accurately show the full value of the assets over their useful lives. This is because the market value of assets will typically be based on the net revenues that could be recovered from the assets over time. One method of estimating the value of the generating assets is to accumulate the estimated net revenues that the assets will receive from the competitive market, and to compute the net current value of that stream of net income. This is usually described as the Discounted Cash Flow method and should predict what the current market sales price of the units would be.

**Q. Why does an accurate measurement of stranded cost require examining either asset sale prices or a rigorous analysis of generating units over their entire lives?**

A. Although currently there may be a gap between embedded costs and market revenues, this gap will shrink and will probably reverse itself over time. As a result, in the later years of a unit's life, it is likely to be profitable in the market – that is, it will receive greater revenues by selling into the competitive market than it would have by selling at embedded costs.[2] This turnaround typically occurs because over time market prices tend to rise, while the embedded costs of a generating portfolio are likely to be stable or even to decrease, because the rate base tends to decrease as the initial investment is depreciated (i.e. costs are front-loaded). As a result, even if current embedded costs exceed market prices, lines depicting the two values over time usually cross in the future. Thus, typically

[2] O&M costs will usually rise, which is the reason that embedded costs do not always decrease over time.

there are near-term years in which market revenues will be less than embedded cost revenues, and future years in which this relationship is reversed. The buyer of the asset will recognize the full value of the asset over time, so asset sales prices provide this correct valuation. [3] By focusing only on the next six years, APS' method for estimating stranded costs does not reflect the full value of the assets, and would overcompensate the Company for costs that are truly at risk of being stranded.

**Q. Did the Settlement require APS to sell its generating assets for their market value?**

A. No. In fact, the Settlement specified that the units should be transferred at then current book value to a competitive affiliate of APS.

**A. What would be the result of this transfer at book value?**

Q. It would mean that if the units at that time were worth less than book value, the competitive affiliate would lose money on the units. However, if the units were worth more than book value, the competitive affiliate (and therefore PWCC) would make profits from sales from these units.

**Q. Was there other criticism of the Company's computation of stranded costs?**

A. Yes. Staff criticized the Company's projection of market prices as being too low, based on information available at the time.

**Q. Did the Company present any evidence prior to the Settlement regarding the market value of the generating assets at the time they would have been transferred to the competitive affiliate?**

A. The Settlement proceeding did not contain any such analysis. However, Mr. Landon testified in the Settlement proceeding for the Company that the assets

[3] This is the reason that some jurisdictions have required divestiture before providing utilities with stranded costs; the sale of the units clearly represents what the market thinks the units are worth.

were being transferred at more than their market value, so the Company should not have anticipated that the APS assets would have created profits.

**Q. What does the Company say currently about the market value of the APS assets?**

A. The Company indicates that its estimate of the market value of the output of its (APS) units [redacted]

**Q. Was the Company's method of computing stranded costs allowed by the ACC, and if so, why?**

A. The Commission had provided for a methodology similar to that utilized by the Company, although neither the methodology nor the $350 million were discussed substantively in the Settlement order.

The decision in RE-0000C-94-0165 in Order 60977 allowed only two options for utilities to choose and to receive stranded cost recovery. These included either a divestiture of all generation assets, which would determine the amount of stranded costs, or the "Transition Revenues Methodology", which was intended to provide sufficient revenues to stay out of bankruptcy.

In Decision 61677, the Commission noted that this appeared to condition recovery of stranded costs upon forced divestiture, which it ruled was not in the public interest. The Commission at that time accordingly added another option for computing stranded cost. The additional option was labeled the "Net Revenues Lost Methodology". While this was described as a methodology similar to that set forth by APS, the Order did not provide detailed guidance as to the computation of stranded costs, and its discussion of the collection of stranded cost is different from that adopted in the Settlement. In the Settlement Order, the

methodology issue was not discussed, and the $350 million that was to be collected was a result of negotiation.

**Q. What bearing does the issue of stranded cost have on the current proceeding?**

A. If the PWEC assets are rate-based, the Company may claim additional stranded costs associated with them. According to APS' methodology of calculating price differences for only a few years, there will be stranded costs associated with these units if APS' retail generation load decreases.[4] This is because typical cost of service treatment front-loads recovery of the cost of assets, so in the short-run even efficient units do not look profitable. However, if stranded costs were computed according to the discounted cash flow method, market sales from these particular units will probably be almost sufficient to recover embedded costs over the lives of the units. In fact, the major reason they might not be completely sufficient is that market prices at the present time appear to be below the long-run equilibrium.

## VI. COMPETITION RULES COMPLIANCE CHARGE

**Q. What is the Company requesting recovery of in the proposed CRCC?**

A. The Company is requesting the approval of a Competition Rules Compliance Charge ("CRCC") which shall collect $49,334,000 plus interest over 5 years. This will result in an annual expense of $8,283,000.

**Q. What costs are included in the $49 million?**

A. According to Mr. Robinson, there are three parts: 1) costs associated with the implementation of Direct Access; 2) costs associated with divestiture; and 3) costs

[4] The existing rules would appear to prohibit stranded costs based on the PWEC assets, because of the date they were built.

associated with the implementation of Track B. These three categories of costs include the deferred balance as of December 31, 2002, plus costs the Company projects it will incur prior to July 1, 2004, plus the 1/3 of asset divestiture amounts that had not been included in the balance. Interest is included at the actual 2nd quarter 2003 interest rate. The total amount to be collected is reduced by the amount the Company projects will be overrecovered by December 31, 2004 through the CTC.

**Q. What gave rise to these deferrals?**

A. Provision 2.6 of the Settlement specified that "...the Commission shall, prior to December 31, 2002, approve an adjustment clause or clauses which will provide full and timely recovery beginning July 1, 2004, of the reasonable and prudent costs of... compliance with the Electric Competition Rules of Commission-ordered programs or directives related to the implementation of the Electric Competition Rules..."

**Q. If the Commission previously approved the Settlement and the Settlement addendum that gave rise to these deferrals, what must be decided in this case?**

A. I believe there are three issues. One is whether all of the costs being requested are collectible. This depends first, on whether the costs were all "reasonable and prudent" and second, on whether they were completely a result of the electric restructuring efforts. Another issue is whether the Company should be allowed recovery of the 1/3 of costs associated with divestiture which the Commission concluded should be borne by shareholders. The final issue is the period of time over which these costs should be recovered.

**Q. Please describe the costs included in the Direct Access category.**

A. Below I list the 13 categories listed by the Company. I also group related costs together into 6 categories for ease of discussion.

TABLE 1

| | |
|---|---|
| CIS/Billing | Direct Access Capability |
| DA Coordination | |
| ESP Management | |
| WestConnect | FERC Compliance |
| Desert Star | |
| Financial | Direct Access Support |
| Generic Proceedings | |
| Inform & Educate | |
| Itron | Metering |
| Metering | |
| Scheduling | Load information |
| Settlement/Load Profiling | |
| (Overhead) Return Plus Benefit Loads | Overhead |

**Q. Were all of these costs required by Direct Access efforts, and required only because of Direct Access efforts?**

A. It does not appear so. I believe that some of these costs would have been incurred without the efforts to develop Direct Access.

**Q. Please describe the Direct Access Capability costs.**

A. In order to comply with the Electric Competition Rule, the Company needed to enhance its customer data and its billing system. This would enable it to keep track of Direct Access, to bill different rates, and to communicate with potential alternative suppliers. According to the responses to RUCO 5.7 and to CNE/SE 1.8, this required additional personnel and mainframe capacity, which has resulted

in deferred and ongoing lease payments for this capacity. There have also been additional payroll expenses which have been deferred.

**Q. Are these unusual expenses or levels of expense?**

A. In my experience, providing retail access generally requires additional Customer Information System and Billing ("CIS/Billing") activities. Bills usually need to be reformatted, additional customer data must be collected, and additional communication with customers and with retail suppliers must be provided for. These typically create additional costs. While the amounts spent by APS have been large, in my experience they are not dramatically out of line with such expenditures by other utilities that have unbundled rates and offered direct access. However, some of the dollars spent on CIS/billing probably provide the Company with additional capabilities that may have value in addition to providing customers with Direct Access. Some of the expenses that have been deferred in this category may have been necessary in the future in the absence of the Competition Rules.

**Q. Do you recommend denial of some of these Direct Access Capability costs?**

A. I have not seen information that would be a basis for denial of any of these costs. Amortizing these costs over a number of years is an appropriate way to respond to any costs that may provide additional services over a number of years.

**Q. Please describe what you have categorized as the FERC Compliance costs.**

A. In Order 2000 and Order 888, FERC has been requiring utilities to separate their transmission systems from their other operations in order to create truly open access to the nation's transmission system. The most recent manifestation of this effort is the establishment of Independent System Operators or Regional Transmission Organizations. Utilities in the Southwest have put efforts into forming complying organizations, first through Desert Star and more recently through West Connect.

**Q. Do you recommend inclusion of these costs in the CRCC?**

A. No. In response to CNE/SE 1.8 a, the Company states that these are the Company's share of development costs of first Desert Star and then West Connect, and notes that "Consistent with the Competition Rules, APS is supporting the development of an RTO." While these efforts would have contributed to a system that allowed Retail Access, I believe that the expenditures on West Connect and Desert Star would have been required whether or not Arizona wrote the Competition Rules and opened up Direct Access. The efforts to create a workable Independent System Operator ("ISO") or even a Regional Transmission Organization ("RTO") were necessary to respond to FERC's orders. These costs should not have been deferred for collection in the CRCC.

**Q. What do you recommend with regards to costs in the Direct Access Support, Metering, and Load Information categories?**

A. While these costs may have some value outside of Direct Access, it also appears that they were necessary to prepare for Direct Access. I recommend allowing these costs in the CRCC.

**Q. What do you recommend with regard to Overhead costs?**

A. The Settlement Order specified that all costs associated with Direct Access should be allowed. However, the "return plus benefit loads" costs included in the Company's requests must be reduced. Benefits associated with personnel whose salaries are included in the FERC Compliance category should be eliminated. From 1997 through 2002, the return component was based on the cost of short-term debt. (Response to LCA 25-533). Thereafter, it was computed on the basis of what the Company describes as the FERC-prescribed formula, which reflects equity as well as debt cost. I do not see a problem with this methodology.

**Q. What are the issues associated with divestiture costs?**

A. Again, they entail whether the costs were prudent, and whether they were all necessary for the efforts toward divestiture, and the issue of whether the utility should be denied 1/3 of these costs.

**Q. What do the divestiture efforts consist of, given that APS did not divest?**

A. The Company in response to LCA 25-543 describes the efforts as consisting of extensive analyses and preparation of submittals and filings that prepared for the transfer of plants. Further, they provided a breakdown of the almost $10 million of costs by category.

**Q. Do you see any problems with the divestiture expenses?**

A. It would be more accurate to say that I still have some questions regarding the level of expense. In particular, there are $2.5 million of internal Payroll-Related expenses, excluding inhouse legal expenses. These expenses suggest that the equivalent of between 7 and 11 full-time APS personnel worked on divestiture issues in 2000 and 2001. This strikes me as high, and may also have contributed to portfolio planning that had previously been performed by APS, but was being performed by PWEC during this period. There is additional discovery pending on this issue. I recommend that this expense be removed unless the Company response provides adequate support for this level of expense.

**Q. What do you recommend with regard to the 1/3 of divestiture costs which the Commission concluded should be borne by shareholders?**

A. I recommend that the Company be allowed to collect these costs. The Company expended these costs in response to an expectation of divestiture. These expenses were incurred solely in expectation of divestiture, and the Commission reversal of position on divestiture is therefore grounds to allow recovery of these expenses.

**Q. What are the issues related to Track B costs?**

A. It is not clear to me that these costs are allowed within the CRCC, as necessary to comply with the Electric Competition Rules. Purchasing power has always been a function of the utility, and will remain so as long as the utility has a responsibility to acquire power for any of its customers. The Track B costs were incurred out of the test year, and may have been higher than would be expected on an ongoing basis, but I do not recommend that they be collected in the CRCC.

**Q. Have you computed a recommended number?**

A. I have estimated the reduced annual CRCC based on these recommendations, that is excluding FERC compliance costs and the Payroll-related expenses in the Divestiture category. This results in an annual expense of $7.4 million, This computation is summarized in Exhibit LS -4.

## VII. ALLOCATION ISSUES RELATIVE TO REVENUE REQUIREMENTS

**Q. Please summarize the cost allocation issues that are directly relevant to the Staff computation of the total ACC revenue requirement.**

A. The total revenue requirement supported by Staff is affected by the treatment of transmission costs that has been proposed by the Company and by the allocation of various costs between the retail and the wholesale jurisdiction.

**Q. Please describe how transmission costs can be treated to develop transmission rates.**

A. In a typical rate case, historic transmission costs are identified, and proforma adjustments may be made to reflect known and measurable changes. If the utility is "unbundling" its costs, it will allocate a portion of its administrative and general expenses to the transmission function, and will include in the revenue requirement

calculation a return and income taxes on transmission rate base. This is the standard treatment of the cost of service in a retail proceeding.

**Q. Have you been aware of any alternative approaches to setting transmission rates?**

A. Yes. In states with retail access, the transmission rate may be based directly on the utility's Open Access Transmission Tariff (OATT).

**Q. APS has made a number of adjustments to rate base and to expenses associated with the provision of transmission and ancillary services. Please describe them.**

A. APS has essentially removed the standard transmission costs from its revenue requirements and replaced them with transmission costs based on a different computation, that of the OATT expense associated with its load.

**Q. Why has the Company proposed this different treatment?**

A. FERC requires that utilities with unbundled rates bill Scheduling Coordinators under the provisions of their Open Access Transmission Tariffs. This should ensure that customers choosing alternative generation suppliers are charged for transmission service on the basis of the same FERC approved transmission rate as Standard Offer customers. The OATT contains rates for both transmission service and most ancillary services (excepting must-run service). The proposed revenue request reflects APS' OATT billings as expenses associated with transmission and ancillary services. If transmission rate base and allocated expenses were not removed from the cost of service used to determine rates, transmission related costs would be recovered twice. The capital costs of the portion of assets that support ancillary services have also been removed from rate base.

**Q. What are the assets that support ancillary services?**

A. For the most part they are generation assets that are run partly to provide such ancillary services as regulation and spinning reserves. The Company has estimated the amount of generation rate base that provides these services by analyzing which particular generating units have been used to provide these services, and removing the corresponding portion from rate base.

**Q. How is the OATT expense which substitutes for the standard cost of transmission service computed?**

A. The Company computes a proforma expense by applying the OATT tariff to its proformed billing determinants. This represents what its OATT bill would be for its proforma load, and is more consistent with the filed case than the actual test year OATT bill.

Q. **What is the dollar impact on customers if the proposed adjustment is accepted?**

A. This depends on the Commission's findings regarding various aspects of the proposed revenue request. If the Company's rate of return, depreciation expense, and any other adjustments that impact the transmission cost of service calculation are accepted, it appears that retail customers will pay approximately $14 million less under the Company's proposed approach than they would under the standard cost of service approach.

**Q. Can you explain how this difference arises?**

A. Not precisely. There are usually some differences between FERC rate filings and state retail filings, so that even if the Company filed a case at FERC to justify a new OATT at the same time that it made a state cost of service filing, the rates would not be identical. In particular, FERC typically approves a different return on equity, which is usually higher. This cost component alone suggests that retail customers might pay somewhat more under a FERC rate than under a retail cost computation, all else being equal. Other reasons for differences between FERC

and retail rates may be that the treatment of some costs are different in the two jurisdictions, and the allocation between jurisdictions are different between FERC and the state commission. However, I expect that the biggest cause of the differences is that the OATT rates were based on costs and sales in test year 1995 (response to LCA 2.49). Since that time, I expect that rate base, expenses, and billing determinants have all increased, and the retail return requested in this proceeding is probably not equal to the return allowed in the existing OATT rate.

**Q. What will the dollar impact on customers be if Staff's cost of service recommendations, rather than the Company's proposals, are adopted by the Commission and if the proposed transmission treatment is accepted?**

A. It appears that the differences between the two approaches are much smaller, but it is likely that customers will still pay less under the proposal to replace transmission cost of service with OATT expenses.

**Q. Will customers continue to pay less in the long run under the Company's proposal than they would have under the cost of service approach?**

A. This depends on whether the Commission accepts a transmission cost adjustor. If it does, the amount that customers will pay will change. The amount is likely to change only slightly because of changed billing determinants, but may change by a significant amount if APS refiles its OATT and FERC approves a different OATT. Any resulting increase or decrease would flow through to customers through the transmission adjustor ( called the TCCF). The Company should keep the Commission informed when it files new OATT tariffs at FERC.

**Q. If the Company's proposed approach may not save customers much, is there any reason to accept it?**

A. I believe that there is. Retail choice could be distorted if the transmission charges to standard offer customers are based on the cost of service calculation rather than on the OATT rates. As I understand FERC's policies and jurisdiction, any retail

choice customer should be charged on the basis of the OATT. A customer that considers retail choice should make the decision based on the cost of generation from the utility versus the cost of generation from an alternative supplier. If the RA customer pays the OATT rate, and the Standard Offer customer pays the retail cost of service rate, the decision to choose retail access will be partly determined by the difference between the transmission rates, rather than on competitive generation prices.

**Q. If the Commission accepts the treatment of transmission costs as proposed by the Company, does this require that it also approve the proposed transmission adjustor?**

A. Accepting the proposed treatment of transmission costs does not require acceptance of the transmission cost adjustor. The adjustor was designed by the Company "to track changes occurring in a specific cost, whose base amount is included in retail rates." (Propper testimony, p. 18) The adjustor is necessary to ensure that Direct Access customers pay the same for transmission as Standard Offer customers, since Scheduling Coordinators will be charged the full OATT charge. Thus, if the OATT has changed since the OATT that was the basis for retail rates, and if there is not an adjustor, the DA transmission bill will be different from the Standard Offer transmission bill. I note, however, that even with the Company's proposal, there may be small differences between what customers pay due, for instance, to the timing of the imposition of the adjustor, and the fact that the adjustor will not be differentiated by class.

**Q. The Company has proposed that specific details regarding a Transmission Cost Adjustor be developed subsequent to the acceptance of the TCA concept by the Commission. Is that an acceptable means of working out some of the implementation?**

A. I believe that implementation details can be worked out subsequent to approval of the TCA.

**Q. What are your recommendations with regard to the TCA?**

A. I recommend that when the Company files a change in any of its OATT rates with FERC, it should also file a notice of such a filing with the ACC in this docket. In addition, it should be required to file its FERC application with the Utility Division director. The one change I would recommend to the Company's proposal is that the TCA should not take effect until the shortfall reflected in the Balancing Account reaches a trigger level that indicates a significant change. I suggest that a trigger of 5% of the total retail transmission cost approved in this case. When this trigger amount was reached, the Company should file for Commission approval of a TCA rate. I recommend that the Commission order the Company to file an implementation plant within 120 days of a decision in this case, for Commission approval.

**Q. You also mentioned the allocation of costs between retail and wholesale. Are you making any recommendations that will have a significant impact on retail revenue requirements?**

A. Yes. I recommend in section VIII that generation production capacity costs be allocated through use of the peak and average allocator, rather than the 4 Coincident Peak allocator which the Company has used. I believe that this better reflects cost causation, and is more consistent with ACC allocation precedents. This affects the allocation of some costs between retail and wholesale.

## VIII. ALLOCATION AND UNBUNDLING OF COSTS

**Q. Has the Company presented a cost of service study ("COSS") which unbundles its costs into different functions and allocates those costs between rate classes?**

A. Yes, the Company has presented results of a fully unbundled and allocated cost of service study, sponsored by Mr. Propper. This type of study is an appropriate

vehicle to produce the information necessary to develop unbundled rates based on embedded costs.

**Q. Please describe the methodology used by the Company in its allocated Cost of Service Study.**

A. Costs are "classified" as demand, energy, or customer related, and are also "unbundled" into various functions. Distribution costs, for instance, are categorized as substation, primary, and secondary. This subcategorization allows for a more accurate allocation of costs, since different customers place different demands on these parts of the distribution system. Costs which serve many functions, such as administrative and general costs, are spread among the functions. The functionalized costs are then allocated to the various rate classes. The study calculates the rates of return earned by each class based on the Company's depiction of its total costs, and also calculates total costs by function at the requested rate of return. These results can provide the basis for charging customers separately for different services, such as generation capacity, energy, transmission, distribution, and customer services.

**Q. Has the Company proposed to base its unbundled rate components for each class on the results of its COSS?**

A. No. As discussed by Ms. Andreassen, it has utilized the COSS only indirectly to affect its proposed rate design.

**Q. Does the COSS identify directly the costs that the Company proposes to reflect in a Fuel and Purchased Power ("FPPAC") adjustor, so that it can be utilized directly to set a FPPAC?**

A. No, it does not. Although there is a function called Production Energy, this includes more than fuel and purchased power costs. For instance, it includes operating and maintenance costs other than fuel and purchased power that are

classified as energy related. This function also includes a share of administrative and general expense. Neither the other energy related costs nor the administrative and general expense would be tracked in a FPPAC.

**Q. What did the Company's allocated Cost of Service Study indicate about the rates of return earned by the various rate classes?**

A. The Company's COSS found that the ACC jurisdictional load was earning a considerably lower rate of return than the nonjurisdictional load. Within the ACC, all of the General Service classes except the Large General Service class earned more than the average Company test year rate of return. All other classes earned less than the average Company rate of return, with the streetlighting classes earning the lowest rates of return.

**Q. Does the Company compute all functional costs in the same manner?**

A. No. Transmission and ancillary service costs are measured in a different manner, as discussed in Section VII above. The cost of service study computes allocated transmission costs, but these costs are then removed and the OATT transmission expense is substituted to represent transmission costs.

**Q. How does the Company model allocate costs between ACC jurisdictional load and the small amount of nonjurisdictional load?**

A. Jurisdictional allocation is determined by the cost of service study using the same allocation basis that is used to allocate costs between rate classes. In other words, rather than a different allocator to identify the non jurisdictional portion of a cost, each functional cost line is allocated first to jurisdictions and then to classes using the same allocator. This treats nonjurisdictional customers consistently with how retail customers are treated, so that the FERC jurisdictional classes even receive an allocation of overhead costs.

**Q. Do you support the methodology of using the same allocator for apportioning costs between jurisdictions and between rate classes?**

A. Yes. If an allocator best reflects the reason that the Company incurred a particular cost, it should be used to allocate between jurisdictions as well as between classes.

**Q. How has the Company allocated costs between classes?**

A. Generation, distribution, and customer costs are allocated on the basis of different allocators which are supposed to reflect cost causation, or the basic reason that the costs are incurred.

Generation capacity costs, also referred to as production-related demand costs, are allocated on the basis of system peak load, as measured by the coincident peaks in the four summer months ("4CP"). Mr. Propper testifies that production related assets "are generally designed and built to enable the Company to meet its system peak load". (Propper, p. 5)

**Q. Have you found that Mr. Propper has allocated costs appropriately?**

A. For the most part I support the Company's choice of allocators. However, I believe that the allocation of generation capacity costs is incorrect. The allocation of generation capacity costs is important, because a very large proportion of the Company's total costs are categorized as generation capacity. Of the Company's requested total company revenue requirement of $1,944 million, $677 million is in the production capacity function. (AP WP-3 p.5)

**Q. Why do you believe the Company's choice of allocator for generation capacity is incorrect?**

A. The 4 CP allocation method for generation capacity does not reflect cost causation because it does not reflect how the utility makes decisions regarding generation investment. Using the 4CP method implies that all generation capacity costs can

be explained by the utility's need to meet its peak load. While it is true that the amount of capacity in MWs that a utility will build (or purchase) is determined by its need to meet its peak load, the types of generation capacity that the utility acquires, and thus the dollars that it spends on capacity, are affected by a number of other considerations, but primarily by the tradeoff between capacity and energy costs. The cost of generating facilities per MW varies significantly between different types of generating units, from low capacity cost peaking units (roughly $400/KW) to very high capacity cost nuclear units (which cost more than $4000/KW). Normally, utilities build peaking units to meet peak needs. They build more expensive baseload plants when they expect to utilize them for many hours, so that they result in lower energy costs than if they had built peaking units. Mr. Bhatti agrees that "..the Company has sometimes built baseload plant [rather] than intermediate or peaking plant because the energy cost savings that result from building baseload plant rather than intermediate or peaking plant are greater than the additional capacity cost of the baseload plant". (Response to LCA 16-370) Customers with a high load factor, who use a large amount of energy relative to their peak loads, benefit from baseload plants because energy costs are lower than they would be without these plants. If capacity costs are allocated only on peak load, the proportion of capacity costs that high load factor customers pay for will not reflect the impact of the capacity dollars spent to reduce their energy costs. The high load factor customers pay less for energy, but do not pay their fair share of capacity costs that gave rise to the low energy costs. Conversely, allocation on the basis of peak alone results in low load factor customers, such as residential and small general service customers, paying a high proportion of generating capacity costs even though they do not receive a high proportion of energy savings.

**Q. How do you recommend allocating generation capacity costs?**

A. There are a number of allocation methods that reflect the fact that much of generation capacity cost is incurred in order to reduce energy costs and benefit

high load factor customers. In this case I recommend the "peak and average" method, which allocates a portion of generation capacity costs based on peak use and the remaining amount on energy. This method is relatively simple, requires less data than more sophisticated methods, and reflects the basics of cost causation better than allocating on peak alone.

**Q. Have you estimated the cost of serving each class consistent with Staff recommendations on revenue requirements and with your recommendations on the allocation of generation capacity costs?**

A. Yes. The Company provided me with the proprietary models that it uses to develop expense and ratebase inputs, and with the model that allocates these costs, and also assisted me in the use of these models. (Supplemental response to LCA 2-26) I have modified the inputs to these models to estimate class unbundled revenue requirements based on Staff's recommendations regarding revenue requirements and allocation.

**Q. Please describe how you modified the cost of service model to reflect Staff's adjustments to revenue requirements.**

A. First, I changed the demand production allocator from the 4 CP allocator to a Peak and Average allocator. Next, the total Company costs were modified.

The Company's model allocates what the Company depicts as test year costs and also all of its proforma adjustments. For the major Staff adjustments made to eliminate ratebasing of the PWEC assets and the reversal of the writeoff, it was possible to utilize the Company's models directly. The results of this process I will refer to as the "adjusted model." All of the proposed proforma adjustments are represented in the model by discreet "switches"; by turning off the switch, the model removes all costs associated with the adjustment. I rejected the rate base and expense adjustments associated with ratebasing the PWEC units and with

reversing the writeoff. The model reduces the cost of service by the dollars reflected in these two adjustments.

**Q. Did reversing these proforma Company adjustments require anything other than reversing the steps the Company took to make these adjustments?**

A. Yes, in one instance. The Company proposes that the rate of return should be higher if the PWEC assets are not ratebased. The COSS model reflects this rate of return through a revenue component of the PWEC adjustment. That is, the cost of service model computes costs associated with an 8.6% ROR. The Company would reflect the reduction in return that would result from utilizing the total Company ROR of 8.3% in the allocated cost model by entering a revenue increase associated with ratebasing the PWEC units. Since Staff does not agree that it is appropriate to utilize a different capital structure and a higher ROR if PWEC is not ratebased, when I "turned off" the PWEC adjustment I did not make a revenue adjustment for a different rate of return. I did enter a reduction in revenues associated with off-system sales that would not be made without the PWEC units.

**Q. Did you also estimate the impact of the other adjustments recommended by Staff that were not simply a matter of reversing the Company's proforma adjustment?**

A. Yes. Staff is supporting a lower return on rate base than the Company has proposed. We have modified the Company's model to reflect this lower return. The adjustments proposed by Mr. Dittmer and Mr. Majoros are somewhat more complicated because they reflect changes to various items of rate base and expense that are either changes to test year amounts or are partial changes to the Company proforma adjustments. In order to reflect the impact of these adjustments on class revenue requirements, I made discreet "below the line" changes to the model-produced revenue requirements.

**Q. How did you allocate these adjustments between functions?**

A. This was a two step process. Rate base and expense adjustments were reconciled to Staff's case, and then were allocated across functions. Staff's additional jurisdictional rate base adjustments were either functionalized as production capacity (deferred Pacificorp gain), distribution (eliminate capital vehicle lease), or as miscellaneous rate base. The miscellaneous rate base adjustment reflected the remaining difference between the adjusted model rate base, the specific production capacity and distribution capacity adjustments, and the final Staff ACC rate base. These rate base adjustments were then allocated to the ACC functional revenue requirements on the basis of the direct functionalization produced by the adjusted model. For example, the additional proforma distribution rate base adjustment was allocated among the distribution and customer accounts functions by the same percentage that total rate base in these functions was spread by the adjusted model. The miscellaneous rate base adjustment was spread across all functions that contained rate base costs. Expenses were treated similarly, with the fuel and purchased power adjustment functionalized as production energy and all remaining adjustments allocated as expenses excluding energy expense.

**Q. Please describe the estimation of class unbundled revenue requirements.**

A. Again, the adjusted model did most of the work. The additional proforma functionalized adjustments were allocated to classes based on the allocation of each function by the adjusted model to the class. For instance, if the adjusted model allocated x% of distribution substation plant to the Small General Service class, I would also allocate x% of the total proforma adjustment that was functionalized as distribution substation plant. The adjusted class rate base by function was added to the model rate base, and the return and associated income taxes were computed. The adjusted class expenses were added to the adjusted model's expenses by function, and totaled to produce the revenue requirement for the class and the function. The adjusted revenue requirement results for the ACC jurisdiction class are presented in Exhibit LS-5.

**Q. Will your results be identical to those that would be derived from making each expense and rate base adjustment within the model?**

A. No, but the results will be close enough to judge what the percentage impacts on customer classes would be of setting revenue requirements at the cost of service. At the conclusion of the case, the Company should file a revised allocated cost of service study that reflects more exactly all adjustments approved by the Commission.

**Q. What are the impacts on class rates of return of changing the generation capacity allocator alone, while not changing the requested revenue requirement?**

A. The total Company return does not change, of course, nor does the general relationship between major retail class rates of return, that is, the residential rate of return is lower than the general service class as a whole. However, the differentials between the class rates of return are generally reduced. The streetlighting classes' deficiencies increase significantly as the production demand allocator is changed to peak and average.

**Q. Please describe the results of the revised allocation of the Company's revenue requirement.**

First, the nonjurisdictional ROR decreased to a negative return. The overrall residential class ROR became positive, and the General Service ROR, while still positive, decreased. The cost of service study showed that for each class to earn the allowed rate of return, only the irrigation, streetlighting, and Large General service, and the Residential E-10 would need rate increases. Rates to other classes need to be decreased to result in equal class rates of return. Exhibit LS-6 shows the computation of class earned rates of return based on Staff revenue requirements.

## IX. CONCLUSIONS

**Q. Do you agree that the Company is entitled to recovery of the $234 million?**

A. No. The request clearly does not meet standard ratemaking criteria. On a going-forward basis, there is no evidence that this reduction has any significant impact on rates that the Company is filing in this proceeding.

This issue is not about stranded cost, but about rate reductions which the Company agreed to 4 years ago as part of the Settlement. It is true that Commission policy has changed, and the movement toward divestiture that was envisioned 4 years ago has not occurred. However, to allow the Company now to increase rates to recover some of the rate reductions agreed to in 1999 is simply retroactive ratemaking. The Company cannot demonstrate that rates would not have been reduced in the absence of the Settlement. It has also not demonstrated that it has suffered significant financial harm as a result of not being able to divest its generating assets to PWEC. I do not think the Company has provided justification as to why the Commission should take the highly unusual step of increasing the Company's rates to replace revenue which the Company did not earn in previous years, particularly since such additional revenues would have created additional overearning in some of those years.

**Q. What are your recommendations regarding the transmission cost adjustment and the CRCC?**

A. I recommend that the Commission accept the proposed treatment of transmission and a transmission cost adjustment mechanism. Further, I recommend that the Commission approve a CRCC which will recover the requested Direct Access costs, (excluding what I have categorized as FERC-compliance costs, and associated benefits), and Track B costs. With regard to divestiture costs, I recommend that the Company be allowed to collect 100% of these costs excluding the Payroll-Related costs.

**Q. What are your recommendations with regard to the allocated cost of service study?**

A. I recommend that production capacity costs be allocated on the basis of the peak and average allocator. The functional revenue requirements that I have estimated reflect the results of Staff's revenue requirement recommendations. Further, final functionalized costs should be determined on the basis of the final adjustments accepted by the Commission.

**Q. Does this conclude your testimony?**

A. Yes, it does.

# LEE SMITH

*LA CAPRA ASSOCIATES*
Managing Consultant

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Ms. Lee Smith is a Managing Consultant and Senior Economist at La Capra Associates. Ms. Smith has twenty years experience in utility economics and regulation. Her work has encompassed all aspects of utility pricing, cost analysis, forecasting, and both demand-side and supply planning in electric, gas, and water utility cases. Ms. Smith has analyzed issues of electric rates, including Standard Offer rates, rate unbundling, and appropriateness of utility costs in 18 different states for a multitude of utilities and other entities. She participated in development of the New England ISO, and has advised a number of clients on RTO pricing and organization. As a consultant, her clients have included gas and electric utilities, regulatory commissions and other public bodies. Previous to La Capra Associates, Ms. Smith was employed as the Director of Rates and Research at the Department of Public Utilities.

## RELEVANT EXPERIENCE

- Testified on PBR filing by Keyspan Gas for Massachusetts Attorney General.
- Advised the Arkansas Public Utilities Commission Staff on various issues, including EAI's sale of baseload generation.
- Testified at FERC on mechanisms to recover revenues lost when through or out rates eliminated.
- Advised the Pennsylvania Office of the Public Advocate on Standard Market Design, and testified at FERC on transmission pricing.
- Estimated retail class generation rates under continued regulated and retail access Arkansas Public Utilities Commission Staff; analyzed proposed change to System Resource Agreement by Entergy.
- Testified on delivery service rates in New Hampshire, Illinois, and Texas.
- Advised, provided testimony and participated in settlement discussion on Provider of Last Resort rates for Pennsylvania Office of the Public Advocate.
- Assisted the Arizona Corporation Commission in unbundling rates for all Arizona utilities, and negotiating with utilities on stranded cost and rate design.
- Advised Pennsylvania Office of the Public Advocate staff in restructuring proceedings; presented testimony on rate unbundling in eight cases.
- Assisted Massachusetts Division of Energy Resources in drafting restructuring legislation and negotiating additional restructuring settlements with utilities.

- Represented the Massachusetts Department of Energy Resources at NEPOOL committees engaged in developing the New England Independent System Operator, and an Open Access Transmission Tariff for New England.

## EMPLOYMENT HISTORY

**La Capra Associates** — Boston, MA
*Managing Consultant* — *2000 - Present*

**Department of Public Utilities:** — Boston, MA
***Director of Rates and Research,*** — *1982 - 1984*

## EDUCATION

**Tufts University, Economics** — Medford, MA
*Ph.D., all but dissertation* — *1966 - 1969*
*Tufts University Economics Department Fellowship, 1967-68*

**Brown University,** — Providence, RI
*International Relations and Economics, B.A., Honors* — *1965*
*Prize in International Relations, 1965*

**Boston College** — Boston, MA
*Study of Statistics* — *1966*

**Radcliffe** — Cambridge, MA
*Bunting Institute Fellowship* — *1970- 1971*

Exhibit LS -2

# ADJ. RETURN ON AVG. COMMON EQUITY ($000)

## Impact of Settlement removed
## Rate reduction and writeoff removed

| | 2000 | 2001 | 2002 | 2003 | 2004 | Source |
|---|---|---|---|---|---|---|
| NET INCOME (A) | 306,600 | 265,487 | 199,343 | 170,340 | 278,941 | *RUCO1.9* |
| AMORT. OF $234M DISALLOWANCE (after-tax) | (25,400) | (26,100) | (26,500) | (25,700) | (12,850) | *RUCO1.9* |
| Reverse Rate Reduction (after-tax) | 20,678 | 41,697 | 61,012 | 81,943 | 47,212 | *Calculated* |
| ENERGY TRADING MARGIN (after-tax) | | - | - | - | - | |
| NET INCOME FOR REGULATORY PURPOSES(D) | 301,878 | 281,084 | 233,855 | 226,583 | 313,304 | *Calculated* |
| | | | | | | |
| ENDING COMMON EQUITY | | | 2,159,312 | 2,162,314 | 2,690,969 | *RUCO1.9* |
| AVERAGE COMMON EQUITY (B) | 2,017,000 | 2,133,416 | 2,175,049 | 2,160,813 | 2,426,641 | *RUCO1.9* |
| | | | | | | |
| **RETURN ON AVERAGE COMMON EQUITY (D/B)** | **15.0%** | **13.2%** | **10.8%** | **10.5%** | **12.9%** | *Calculated* |

## Calculation of after tax foregone additional revenue

| | | | | | | |
|---|---|---|---|---|---|---|
| Revenue | 28,846 | 58,167 | 85,112 | 114,310 | 65,861 | *LCA 1-7* |
| After tax earnings | 20,678 | 41,697 | 61,012 | 81,943 | 47,212 | *Calculated* |

**LACAPRA'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON; TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LCA 1-9 (a) Please explain whether and how APS' "reasonable opportunity to recover $350 million net present value through a competitive transition charge" (see Section 3.3 of the May 14 Settlement Agreement), was affected by the non-"sale" (see Wheeler Direct Testimony at 22, line 1).

RESPONSE:

The opportunity to recover $350 million was not affected by the failure of the Commission to permit the promised divestiture of APS generation. However, absent such a promise, the Company would have never agreed to the write-off and would have continued to recover the entire $533 million during the period through 2004.

Witness: Steve Wheeler

**LACAPRA'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LCA 1-3 In reference to Mr. Wheeler's Direct Testimony (at 19, line 5-8), please verify that the write off "related directly to costs already found just and reasonable" was applied to assets (e.g., regulatory assets) that were different from those encompassed by the company's stranded cost claim (i.e., the $533 million discussed in Section 3.3 of the 1999 Settlement Agreement).

RESPONSE:

As an accounting matter, the write-off was taken against the regulatory asset amount allowed under the terms of both the 1996 and 1999 Settlements. It was intended to represent a disallowance, on a present value basis, of a portion of the Company's generation-related revenue requirement for the years 1999-2004.

Witness: Steven Wheeler

**LACAPRA'S SEVENTH SET OF DATA REQUESTS**
**TO ARIZONA PUBLIC SERVICE COMPANY**
**IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LCA 7.216 LCA Please provide the annual filings that were made in response to the 1996 Rate Reduction Agreement, i.e. the filings that resulted in the rate reductions in the four years prior to the Settlement.

RESPONSE:

Please see attachments marked RC01336 through RC01339.

Witness – To Be Determined

RECEIVED
1999 MAY 21 P 2: 37
AZ CORP COMMISSION
DOCUMENT CONTROL

Barbara A. Klemstine
Manager
Regulatory Affairs

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Mail Station 9909
P.O. Box 53999
Phoenix, AZ 85072-3999

May 21, 1999

Mr. Ray Williamson
Acting Director, Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

Re: Docket No. E-01345-95-491 (U-1345-95-491)
Arizona Public Service Company
Reduction in Retail Rates Pursuant to Paragraph 15.B of the
Second Restated and Amended Rate Reduction Agreement

Dear Mr. Williamson:

Pursuant to Decision No. 59601 (April 18, 1996), Arizona Public Service Company ("APS") is filing the annual calculation to determine the reduction to base rates provided for under Paragraph 15.B of the Second Restated and Amended Rate Reduction Agreement ("1996 Agreement"). The 1996 Agreement provided for a $48.5 million decrease in APS' retail rates, effective July 1, 1996 and also established a moratorium period (through July 1, 1999) on rate increases, while providing consumers an opportunity to automatically receive future price reductions based on the Company's ability to continue to lower its average cost.

Future rate reductions through the term of the 1996 Agreement were to be based on a comparison of the Company's average price per kilowatt-hour and its average cost per kilowatt-hour resulting from operations for the proceeding calendar year as defined in Attachment 3 of the 1996 Agreement. Any reduction for the current year would become effective for usage on or after July 1, if approved by the Commission. Under this provision, APS has decreased retail rates on July 1, 1997 by $17.6, and by an additional $16.9 million effective July 1, 1998.

Based upon the Company's 1998 financial performance, as adjusted pursuant to Attachment 3 from the 1996 Agreement and calculated pursuant to Exhibit No. 1 attached to Decision No. 60225, APS is able to further reduce rates through the rate incentive mechanism established in the 1996 Agreement. More specifically, the Company proposes to reduce annual retail rates by approximately $10.8 million, or .68%, effective July 1, 1999.

**APS**

**Arizona Public Service Company**

COMPANY CORRESPONDENCE

Mr. Ray Williamson
May 19, 1999
Page 2

The Company is requesting that this reduction be considered by the Commission for approval in conjunction with the 1999 Settlement Agreement, dated May 17, 1999. The 1999 Settlement Agreement (Article II, Section 2.2) provides for a 1.5% rate reduction, effective July 1, 1999, which is inclusive of the .68% reduction. The reduction will be applied with a uniform percent to customer's demand and energy charges, except as provided for in Attachment 2 of the 1996 Agreement.

Attached are: (1) a calculation of the proposed reduction in retail rates, (2) a copy of Attachment 3 from the 1996 Agreement, (3) a copy of Exhibit #1, Decision 60225, (4) a worksheet of adjustments to comply with the definitions from Attachment 3, (5) a worksheet that applies the reduction to eligible customers, and (6) a comparison of present and proposed rates.

Please call me at (602)250-2031 if you or your Staff have any questions.

Sincerely,

Barbara A. Klemstine

Barbara A. Klemstine
Manager
Regulatory Affairs

BAK/pb

Enclosures

Cc: Lori Hoover (w/o enclosures)
All Parities of Record- Docket No. U-1345-95-491
Docket Control

**LACAPRA'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LAC 1-7. Please identify all amounts (by year) by which APS' retail revenues have been (and will be) reduced relative to what they would otherwise have been as a consequence of implementation of the CTCs described under Section 3.3 of the Settlement Agreement:

RESPONSE:

Below are the annual amounts of revenue foregone due to the rate decreases required by the 1999 Settlement which APS contends were made possible by the reduced CTC implemented by such Settlement.

| Year | $000 | |
|---|---|---|
| 1999 | 3,526 | |
| 2000 | 28,846 | |
| 2001 | 58,167 | |
| 2002 | 85,112 | |
| 2003 (Estimated) | 114,310 | |
| 2004 (Estimated) | 65,861 | (through June 30, 2004) |

Witness: Donald Robinson

**LACAPRA'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LCA 1-10 Stranded cost recovery aside, please indicate whether and how the fact that "sale that was never consummated" (see Wheeler Direct Testimony at 22, line 1) adversely affected or might affect APS. For example, has any APS asset suffered impairment as a consequence of the "non-sale"?

RESPONSE:

The failure of the Commission to allow divestiture as promised in the 1999 Settlement violated one of the basic premises of the Agreement in which APS made numerous concessions, not the least of which were the write-off, five rate decreases, the disallowance of one-third of divestiture costs that had previously been fully recoverable under a prior Commission order and the dismissal with prejudice of litigation against the Commission. It has also left part of the generation built to serve APS load effectively "stranded" at PWEC with the associated diseconomies and financial strain of having to maintain two separate organizations for the same essential utility function. Whether these latter factors will continue to affect APS depends largely on how the Commission responds to the Company's request to rate base the PWEC assets.

Witness: Steve Wheeler

**LACAPRA'S NINETEENTH SET OF DATA REQUESTS**
**TO ARIZONA PUBLIC SERVICE COMPANY**
**IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LCA 19-458 With regard to the inefficiencies and costs created by PWCC having two separate generation entities, please quantify the annual cost that has been caused by this circumstance from 1999. Please provide workpapers and specific explanation of which costs have been duplicated.

RESPONSE:

Prior to the Track A Order, APS generation and PWEC generation operated as a single Generation Business Unit, and thus the inefficiencies and additional costs of having two entities (aside from the costs incurred to achieve divestiture) were minimal excepting perhaps for the higher cost of financing needed plant expansion at PWEC rather than at APS. APS has not calculated those higher historical financing costs.

Since the Track A Order, the Commission has required increasingly greater separation of the PWEC and APS generation. Moreover, the Commission itself determined the ongoing cost of financing PWEC on a stand-alone basis was at least 264 basis points. See Decision No. 65434. It its claim letter to the State of Arizona of February 21, 2003, this cost was estimated at $81,417,000.

Witness – Steven M. Wheeler

**LACAPRA'S SIXTENTH SET OF DATA REQUESTS**
**TO ARIZONA PUBLIC SERVICE COMPANY**
**IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LCA 16-371 Does APS have a current estimate of the market value of its generating assets? If so, please provide.

RESPONSE:

Market value is not relevant under prior ACC precedent to the determination of fair value rate base. However, to your point, APS has not performed any study addressing market value of APS' existing generation. However, the GE MAPS model provides the data needed for market valuation based on discounted cash flows. Based on the same philosophy for valuing incremental generation such as the PWEC units, attached are the higher inferred market valves, for APS existing generation assets. Market values from August 2003 for the same 3 scenarios described in the response to LCA 8-237 and RC01932, which is being provided pursuant to a protective agreement on a yellow-labeled CR-ROM.

Witness-Ajit Bhatti

CONFIDENTIAL

| Case | Market Value Above (below) Book Value (Millions) |
| --- | --- |
| Base | |
| Fundamental | |
| No New Gen. | |

* Ranges vary depending on discount rate of from 7.07% to 8.25%

LACAPRA'S TWENTY-FIFTH SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437

LCA 25-533 Please provide an electronic worksheet, with formulae intact, that shows the derivation of the Return costs that are included in the Return which is included in the Return plus Benefit Loads value of $7,180,430 as shown on RC02100, "Project to Date."

RESPONSE:

See attached RC02467. As the attached file contains values to the penny, there is an insignificant difference of $99 from the value provided on RC02100. Also, please note that a schedule responsive to LCA 25-532 is contained in the "Summary" tab of the Excel file attached hereto.

Regarding the calculation of the return costs, each month there are system generated entries made by the accounting system that take the APS cost of capital rate, at that point in time, times the prior month's balance of all the various Direct Access accounts. The sum of all of these entries is the Direct Access return component.

From 1997 through 2002, the return cost was calculated as capitalized interest. During that timeframe, capitalized interest was calculated each month as a percentage of the prior month's ending Construction Work In Progress ("CWIP") balance. The percentage used was calculated in accordance with SFAS 34, with the FERC assumption that construction is financed first by short-term debt. The weighted average cost of short-term debt was multiplied by the ratio of average short-term debt divided by average CWIP ("S/W"). This percentage was then added to the weighted average cost of long-term debt multiplied by (1 - S/W).

Thereafter, and due to the Commission's change of direction in the Track A Order, the return cost has been calculated as Allowance for Funds Used During Construction ("AFUDC"). AFUDC has been calculated each month as a percentage of the prior month's ending CWIP balance. The percentage used is derived from the FERC-prescribed formula which assumes that construction is financed first by short-term debt, and then by a combination of long-term debt and equity. The weighted average cost of short-term debt is multiplied by S/W. This percentage is then added to the weighted average cost of capital (including long-term debt and equity) multiplied by (1-S/W).

Also, each month there are system generated entries made by the accounting system that take the APS benefit loads rates, at that point in time, times all direct payroll charge to all of the various Direct Access accounts. The sum of all of these entries is the Direct Access Benefits Load. The benefits included in the benefit load rate include payroll taxes and the expenses associated with pensions, OPEB, 401(k), etc.

Witness: Donald Robinson

LACAPRA'S TWENTY-FIFTH SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437

LCA 25-543 Divestiture

Please provide a description of the activities that gave rise to the gross cost at the end of 2002, detailing expenses by year and by activity and by vendor when applicable.

RESPONSE:

As a result of the settlement with the ACC in 1999, APS was required to divest all of its generation assets by December 31, 2002. In order to meet this requirement, APS identified and undertook the necessary tasks to prepare for the transfer of its generation assets to Pinnacle West Energy Company (PWEC), an APS affiliate engaged in the sale of electricity at wholesale in the western United States. Due to the complex nature of these tasks, APS not only relied on in-house expertise, but also used the services of various outside counsel and consultants. Pursuant to the terms of the settlement, APS was allowed to recover two-thirds of the costs associated with the divestiture of these assets. It is these activities that give rise to the gross divestiture costs at the end of 2002. They include, but are not limited to extensive analyses and, where required, preparation of submittals and filings to attend to the following issues, among others:

- Appropriate corporate structure.
- Compliance with Federal Energy Regulatory Commission (FERC) regulations.
- Compliance with Nuclear Regulatory Commission (NRC) regulations.
- Environmental permit transfers.
- Various contractual issues including warranty claims and assignment of contracts.
- Tax issues relating to IRS clearances (e.g., private letter rulings).
- Employment matters.
- Real property transfers.
- Mortgage, sale and leaseback and other financial issues.
- Participant relations at APS power plants.
- Licenses, permits and authorizations.

Additionally, amounts associated with setting up office space and for new computer hardware and software were included.

Attached as RC02468 is a schedule showing annual amounts by year (through September 2002) by activity with major vendors identified.

Witness: Donald Robinson

**Divestiture Costs Activity by Resource Category by Year - Major Vendors Identified**

| Major Vendor | Total | 2002 | 2001 | 2000 | 1999 |
|---|---|---|---|---|---|
| **Materials & Supplies** | **$462,282** | **$187,709** | **$274,534** | **$40** | **$0** |
| Detail: | | | | | |
| Cambell Fisher Design | $78,746 | | $78,746 | | |
| Cisco Systems | $85,449 | | $85,449 | | |
| US Business Interiors | $154,925 | $105,497 | $49,428 | | |
| **Payroll-Related (excluding Law Department)** | **$2,499,724** | **$314,739** | **$912,336** | **$759,188** | **$513,462** |
| **Transportaion & Travel** | **$37,216** | **$129** | **$19,369** | **$17,718** | **$0** |
| **Rating Agency Expenses** | **$260,000** | **$0** | **$235,000** | **$25,000** | **$0** |
| Detail: | | | | | |
| Moody's Investor Services | $235,000 | | $235,000 | | |
| **Utilites - TWX, Microwave, Phone** | **$92** | **$92** | **$0** | **$0** | **$0** |
| **Computer Hardware/Software Purchase** | **$208,437** | **$73** | **$200,450** | **$7,913** | **$0** |
| Detail: | | | | | |
| Cisco Systems | $153,324 | | $153,324 | | |
| **Memberships and Dues** | **$5** | **$5** | **$0** | **$0** | **$0** |
| **Land Rights - Applications, Processing Fees** | **$150** | **$0** | **($1,400)** | **$1,550** | **$0** |
| **Outside Services - Accounting, Audit** | **$75,000** | **$0** | **$0** | **$75,000** | **$0** |
| Detail: | | | | | |
| Deloitte & Touche | $75,000 | | | $75,000 | |
| **Outside Services - Computer Software** | **$197** | **$197** | **$0** | **$0** | **$0** |
| **Outside Services - Contractors/Construction** | **$777,325** | **$340,807** | **$436,297** | **$221** | **$0** |
| Detail: | | | | | |
| Stevens-Leinweber Construction | $689,170 | $291,787 | $397,383 | | |
| **Contract Maintenance** | **$2,056** | **$1,975** | **$81** | **$0** | **$0** |
| **Outside Services - Consulting** | **$392,696** | **$13,314** | **$127,813** | **$251,569** | **$0** |
| Detail: | | | | | |
| Arthur Andersen LLP | $302,762 | $0 | $51,193 | $251,569 | |
| **Outside Services - Engineering** | **$47,856** | **$36,953** | **$10,902** | **$0** | **$0** |
| **Outside Services - Environmental** | **$484,451** | **$0** | **$464,451** | **$20,000** | **$0** |
| Detail: | | | | | |
| S & W Consultants | $462,565 | $0 | $462,565 | $0 | |
| **Outside Services - Legal** | **$1,847,047** | **$252,672** | **$697,516** | **$896,858** | **$0** |
| **Legal Out-of-Pocket** | **$2,404** | $0 | **$1,096** | **$1,309** | **$0** |
| **Outside Services - Security** | **$61** | **$24** | **$36** | **$0** | **$0** |
| **Outside Services - Seminars & Workshops** | **$2** | **$2** | **$0** | **$0** | **$0** |
| **Outside Services - Contract Labor** | **$824** | ($412) | **$1,235** | **$0** | **$0** |
| **Outside Services - Contract Labor Overtime** | **$16** | **$0** | **$16** | **$0** | **$0** |
| **Non-Specific Contract Labor** | **$14,624** | **$1,907** | **$4,547** | **$8,169** | **$0** |
| **Outside Services - Other** | **$271,720** | **$17** | **$84,290** | **$187,414** | **$0** |
| Detail: | | | | | |
| PA Consulting Services | $155,589 | | | $155,589 | |
| Geotechnical & Environmental Consultants | $65,000 | | $65,000 | | |
| **Training Materials & Programs** | **$6** | **$6** | **$0** | **$0** | **$0** |
| **Other Expenses - General /1/** | **$2,030,157** | **$47,045** | **$579,543** | **$802,303** | **$601,266** |
| Detail: | | | | | |
| Bank of America | $97,165 | | $97,165 | | |
| Navajo Nation | $200,000 | | | $200,000 | |
| PA Consulting Services | $83,299 | | $83,299 | | |
| S & W Consultants | $523,050 | | | $523,050 | |
| Standard & Poors | $300,000 | | $300,000 | | |
| **Contruction Overhead Load** | **$252,124** | **$102,423** | **$149,701** | **$0** | **$0** |
| **TOTAL** | **$9,666,472** | **$1,299,680** | **$4,197,813** | **$3,054,251** | **$1,114,728** |

/1/ Includes $433,736 of in-house law department charges, both payroll and non-payroll.

**LACAPRA'S SECOND SET OF DATA REQUESTS**
**TO ARIZONA PUBLIC SERVICE COMPANY**
**IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LCA 2.49 How was the APS OATT developed?

RESPONSE:

The APS OATT was developed to be consistent with the requirements established by FERC in its FERC Order No. 888 as set forth in APS' filings in FERC Docket Nos. ER 96-153-000 and ER 96-2401-000. The pertinent rates for transmission services were developed based on a COSS TYE 1995

Witness-Alan Propper

**RUCO'S FIFTH SET OF DATA REQUESTS**
**TO ARIZONA PUBLIC SERVICE COMPANY**
**IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

5.7 Direct Access Costs Refer to DGR_w/p18, page 2, and provide the following information:

a) Provide a description of the cost item titled "Incremental Mainframe" and explain why it should be recovered on an annual basis; and

b) Provide a description of the amounts included on the line entitled "2002 Payroll" and explain why APS' payroll annualization does not already capture this same payroll.

RESPONSE:

a) To comply with the Electric Competition Rule several modifications were required to the APS Customer Information System. These modifications, such as Universal Meter Capture, Dual Billing, Standard Offer Unbundling, Meter Ownership, and Direct Access Customer Identification, required additional main frame capacity and therefore it became necessary to lease a larger processor. The incremental increase in expenses between the existing and the new larger processor was deferred, as allowed under the 1999 Settlement Agreement, Section 2.6(3).

In 2002, these incremental costs were deferred. Once the deferral ceases, these incremental expenses will have to be charged to on-going O&M.

b) The payroll included on the line entitled "2002 Payroll" is the incremental payroll that was deferred in 2002 and associated with the personnel increases necessary to comply with the Electric Competition Rules such as responding to customer inquiries regarding Direct Access and the Electric Competition Rules, and support for Direct Access systems such as DASR and MDMA. In 2002, these payroll expenses were being deferred and thus were not included in test period O&M expenses. The payroll annualization adjustment uses the 2002 test year relationship between O&M and total payroll to allocate the change in payroll expense due to changes in monthly employee head counts and wage rates. Because these expenses are not in the test year O&M, no associated amounts are being allocated in the payroll annualization adjustment.

Witness: Donald Robinson

**CONSTELLATION NEW ENERGY AND STRATEGIC ENERGY'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT E-01345A-03-0437**

CNE/SE 1.8 Re: page 10 of DGR_WP33: Twelve costs related to the implementation of Direct Access are identified. For each of the twelve costs identified, please describe:

a. the general or overall purpose of the expenditure;
b. the primary components of the expenditure, if not included in (a); and
c. the rationale for the allocation of cost components, or whatever other division of costs was used, between Incremental and Capital Assets

RESPONSE:

a. **CIS/Billing** – As specified by the Competition Rules, the Company implemented new billing requirements. The cost of developing and implementing the required changes to the CIS (Customer Information System) was charged to this category. Most charges to this category consist of incremental leases and licensing.

**DA Coordination** – Implementation costs and, as necessary, on-going costs associated with APS coordinating with ESPs (Energy Service Providers) in order to provide Direct Access to customers consistent with the Competition Rules. For example, APS must be able to accept and process DASRs (Direct Access Service Requests) and had to build specialized systems and hire incremental personnel. Most charges to this category are for payroll associated with new employees hired to perform this work.

**APS WestConnect** – The Company's share of development costs associated with the development of WestConnect, the future RTO (Regional Transmission Organization). Consistent with the Competition Rules, APS is supporting the development of an RTO. Most charges to this category consist of incremental outside legal fees.

**Desert Star IOU** – The development costs associated with the development of Desert Star, the predecessor to West Connect. Most charges to this category consist of incremental outside legal fees.

**Financial** – Costs associated with APS using EDI (Electronic Data Interchange) to handle ESP billings as required by the Competition Rules. Charges are mainly for incremental outside vendor services.

**Generic Proceedings** – Costs associated with Commission-initiated proceedings related to electric industry restructuring, particularly Track A and Track B. Most charges are related to incremental outside consulting services.

**Inform & Educate** – The Competition Rules require the Company to inform and educate customers on their options related to Direct Access. Activities related to these requirements, including incremental payroll, direct mailings and bill stuffers, printing, etc., are charged to this category.

**LACAPRA'S SIXTENTH SET OF DATA REQUESTS**
**TO ARIZONA PUBLIC SERVICE COMPANY**
**IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT**
**E-01345A-03-0437**

LCA 16-370 Does Mr. Bhatti agree that the Company has sometimes built baseload plant than intermediate or peaking plant because the energy cost savings that result from building baseload plant rather than intermediate or peaking plant are greater than the additional capacity cost of the baseload plant? If he does not agree, please explain why the Company or any utility would build plant with higher capacity costs than would be caused by intermediate or peaking plant.

RESPONSE:

Yes. The last APS built baseload plants added to APS system were the Cholla and Palo Verde Power plants, which were initially planned in the 1970's and completed in the 1980's. The planning of these plants was based on the prevalent issues at that time: short supply of natural gas, Fuel Use Act that prohibited burning of natural gas in new power plants perceived, environmental issues with coal, need for diversity in APS generation mix, etc. Economics at that time supported the construction of the baseload plants and provided diversity in APS fuel mix.

Conditions have changed dramatically since the 1980's, and thus the economics associated with generation alternatives have also changed. While economics play a very large role in the selection of new generation, fuel diversity and risk assessment are also an integral part. At the time a new resource decision is made, the relevant factors will be considered.

Witness-Ajit Bhatti

**Divestiture Costs Activity by Resource Category by Year - Major Vendors Identified**

| Major Vendor | Total | 2002 | 2001 | 2000 | 1999 |
|---|---|---|---|---|---|
| **Materials & Supplies** | **$462,282** | **$187,709** | **$274,534** | **$40** | **$0** |
| Detail: | | | | | |
| Cambell Fisher Design | $78,746 | | $78,746 | | |
| Cisco Systems | $85,449 | | $85,449 | | |
| US Business Interiors | $154,925 | $105,497 | $49,428 | | |
| **Payroll-Related (excluding Law Department)** | **$2,499,724** | **$314,739** | **$912,336** | **$759,188** | **$513,462** |
| **Transportaion & Travel** | **$37,216** | **$129** | **$19,369** | **$17,718** | **$0** |
| **Rating Agency Expenses** | **$260,000** | **$0** | **$235,000** | **$25,000** | **$0** |
| Detail: | | | | | |
| Moody's Investor Services | $235,000 | | $235,000 | | |
| **Utilites - TWX, Microwave, Phone** | **$92** | **$92** | **$0** | **$0** | **$0** |
| **Computer Hardware/Software Purchase** | **$208,437** | **$73** | **$200,450** | **$7,913** | **$0** |
| Detail: | | | | | |
| Cisco Systems | $153,324 | | $153,324 | | |
| **Memberships and Dues** | **$5** | **$5** | **$0** | **$0** | **$0** |
| **Land Rights - Applications, Processing Fees** | **$150** | **$0** | **($1,400)** | **$1,550** | **$0** |
| **Outside Services - Accounting, Audit** | **$75,000** | **$0** | **$0** | **$75,000** | **$0** |
| Detail: | | | | | |
| Deloitte & Touche | $75,000 | | | $75,000 | |
| **Outside Services - Computer Software** | **$197** | **$197** | **$0** | **$0** | **$0** |
| **Outside Services - Contractors/Construction** | **$777,325** | **$340,807** | **$436,297** | **$221** | **$0** |
| Detail: | | | | | |
| Stevens-Leinweber Construction | $689,170 | $291,787 | $397,383 | | |
| **Contract Maintenance** | **$2,056** | **$1,975** | **$81** | **$0** | **$0** |
| **Outside Services - Consulting** | **$392,696** | **$13,314** | **$127,813** | **$251,569** | **$0** |
| Detail: | | | | | |
| Arthur Andersen LLP | $302,762 | $0 | $51,193 | $251,569 | |
| **Outside Services - Engineering** | **$47,856** | **$36,953** | **$10,902** | **$0** | **$0** |
| **Outside Services - Environmental** | **$484,451** | **$0** | **$464,451** | **$20,000** | **$0** |
| Detail: | | | | | |
| S & W Consultants | $462,565 | $0 | $462,565 | $0 | |
| **Outside Services - Legal** | **$1,847,047** | **$252,672** | **$697,516** | **$896,858** | **$0** |
| **Legal Out-of-Pocket** | **$2,404** | $0 | **$1,096** | **$1,309** | **$0** |
| **Outside Services - Security** | **$61** | **$24** | **$36** | **$0** | **$0** |
| **Outside Services - Seminars & Workshops** | **$2** | **$2** | **$0** | **$0** | **$0** |
| **Outside Services - Contract Labor** | **$824** | ($412) | **$1,235** | **$0** | **$0** |
| **Outside Services - Contract Labor Overtime** | **$16** | **$0** | **$16** | **$0** | **$0** |
| **Non-Specific Contract Labor** | **$14,624** | **$1,907** | **$4,547** | **$8,169** | **$0** |
| **Outside Services - Other** | **$271,720** | **$17** | **$84,290** | **$187,414** | **$0** |
| Detail: | | | | | |
| PA Consulting Services | $155,589 | | | $155,589 | |
| Geotechnical & Environmental Consultants | $65,000 | | $65,000 | | |
| **Training Materials & Programs** | **$6** | **$6** | **$0** | **$0** | **$0** |
| **Other Expenses - General /1/** | **$2,030,157** | **$47,045** | **$579,543** | **$802,303** | **$601,266** |
| Detail: | | | | | |
| Bank of America | $97,165 | | $97,165 | | |
| Navajo Nation | $200,000 | | | $200,000 | |
| PA Consulting Services | $83,299 | | $83,299 | | |
| S & W Consultants | $523,050 | | | $523,050 | |
| Standard & Poors | $300,000 | | $300,000 | | |
| **Contruction Overhead Load** | **$252,124** | **$102,423** | **$149,701** | **$0** | **$0** |
| **TOTAL** | **$9,666,472** | **$1,299,680** | **$4,197,813** | **$3,054,251** | **$1,114,728** |

/1/ Includes $433,736 of in-house law department charges, both payroll and non-payroll.

Exhibit LS-4

## Competition Rules Compliance Costs
## Calculation of Balance to Collect via CRCC Surcharge

| | fn | Balance at Sep-02 | Oct-02 | Nov-02 | Dec-02 | Jan-03 | Feb-03 | Mar-03 | Apr-03 | May-03 | Jun-03 | Jul-03 | Aug-03 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Monthly Capitalized Interest Rate | | | 0.4365% | 0.4365% | 0.4365% | 0.4977% | 0.4977% | 0.4977% | 0.4983% | 0.4983% | 0.4983% | 0.4983% | 0.4983% |
| Direct Access Monthly Expenses | | | | | | | | | | 245 | 216 | 216 | 216 |
| Direct Access Capitalized Interest | | | | | | | | | | 167 | 169 | 171 | 173 |
| Company total | | | | | | | | | 35,019 | | | | |
| APS West Connect | a | | | | | | | | 876 | | | | |
| Desert Star | b | | | | | | | | 633 | | | | |
| Direct Access Balance | | | | | | | | | 33,510 | 33,922 | 34,307 | 34,694 | 35,083 |
| Asset Divestiture Monthly Expenses | | | 265 | (23) | 334 | - | - | - | - | - | - | - | - |
| Asset Divestiture Capitalized Interest | | | 40 | 26 | 26 | 31 | 31 | 32 | 32 | 32 | 32 | 32 | 32 |
| Company number | | 9,252 | | | | | | | | | | | |
| less Reduction for Payroll | c | 2,500 | | | | | | | | | | | |
| less Associated benefits at 45% | d | 1,125 | | | | | | | | | | | |
| Asset Divestiture Balance | | 5,627 | 5,932 | 5,935 | 6,295 | 6,327 | 6,358 | 6,390 | 6,421 | 6,453 | 6,486 | 6,518 | 6,550 |
| Track B Implementation Monthly Costs | | | | | | | 11 | 45 | (1) | 221 | 86 | 46 | 46 |
| Track B Implementation Capitalized Interest | | | | | | | - | 0 | 0 | 0 | 1 | 2 | 2 |
| Track B Implementation Balance | | | | | | - | 11 | 56 | 55 | 277 | 364 | 412 | 460 |
| Estimated CTC Recovery Balance @ 12/31/2004 | | | | | | | | | | | | | |
| Total CRCC $ | | | | | | | | | | | | | |

a from RC02100, response to RUCO 8-17
b from RC02100, response to RUCO 8-17
c from response to LCA 5-243
d Rate from DGR-WP18 p.12

**Competition Rules Compliance Costs**
**Calculation of Balance to Collect via CRCC Surcharge**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | *Projected* | | | | | | | | Total |
| Sep-03 | Oct-03 | Nov-03 | Dec-03 | Jan-04 | Feb-04 | Mar-04 | Apr-04 | May-04 | Jun-04 | Asset |
| 0.4983% | 0.4983% | 0.4983% | 0.4983% | 0.4983% | 0.4983% | 0.4983% | 0.4983% | 0.4983% | 0.4983% | |
| 216 | 216 | 216 | 216 | 216 | 216 | 216 | 216 | 216 | 216 | |
| 175 | 177 | 179 | 181 | 183 | 185 | 187 | 189 | 191 | 193 | |
| 35,474 | 35,866 | 36,261 | 36,658 | 37,057 | 37,457 | 37,860 | 38,264 | 38,671 | 39,080 | 39,080 |
| - | - | - | - | - | - | - | - | - | - | |
| 33 | 33 | 33 | 33 | 33 | 33 | 34 | 34 | 34 | 34 | |
| 6,583 | 6,616 | 6,649 | 6,682 | 6,715 | 6,749 | 6,782 | 6,816 | 6,850 | 6,884 | 6,884 |
| 46 | 45 | 45 | 45 | - | - | - | - | - | - | |
| 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | |
| 508 | 556 | 603 | 651 | 655 | 658 | 661 | 665 | 668 | 671 | 671 |
| | | | | | | | | | | (2,918) |
| | | | | | | | | | | 43,717 |

Exhibit LS-5

# ARIZONA PUBLIC SERVICE
## FUNCTIONALIZED REVENUE REQUIREMENT
## TEST YEAR ENDING 12/31/2001

STAFF RECONCILED REVENUE REQUIREMENTS

| | | Distribution (Substations) | Distribution (Primary Lines) | Distribution (Transformers, Secondary & Services) | Distribution (Customer Accounts, Cust. Service, Sales) | Metering | Billing | Meter Reading | System Benefits | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Rate Base** | | | | | | | | | |
| 1) | Rate Base (excluding Cust. Advances & Deposits) | $162,857,067 | $966,757,808 | $654,755,745 | $0 | $114,823,500 | | | $2,575,917 | $3,169,122,250 |
| 1a) | Misc. Rate Base pro forma | -$6,173,384 | -$36,805,980 | -$25,080,994 | -$1,786,171 | -$4,599,742 | -$264,428 | -$681,676 | -$103,189 | ($127,578,923) |
| 1b) | Production plant pro forma | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $12,418,483 |
| 1c) | Distribution plant pro forma | -$1,587,967 | -$9,467,526 | -$6,451,532 | -$459,453 | $0 | $0 | $0 | $0 | ($17,966,478) |
| 2) | Regulatory Assets | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $32,806,194 |
| 3) | Customer Accounts | $0 | $0 | $0 | $31,992,485 | $0 | $6,600,918 | $17,016,688 | $0 | $55,610,090 |
| 4) | Cust. Service & Info and Sales Expense | $0 | $0 | $0 | $12,595,759 | $0 | $0 | $0 | $0 | $12,595,759 |
| 5) | Customer Deposits | ($4,024,641) | ($23,284,016) | ($12,576,344) | $0 | $0 | $0 | $0 | $0 | ($39,865,000) |
| 6) | Customer Advances | ($4,726,047) | ($24,705,035) | ($16,081,794) | $0 | $0 | $0 | $0 | $0 | ($45,512,876) |
| 7) | Total Rate Base | $146,345,028 | $872,515,252 | $594,565,080 | $42,342,619 | $110,223,758 | $6,336,490 | $16,335,012 | $2,472,727 | $3,051,629,499 |
| 8) | 7.26% Retail Earned ROR @ 7.26% | | | | | | | | | |
| 9) | Return on Rate Base (Line 8 * Line 7) | $10,624,649 | $63,344,607 | $43,165,425 | $3,074,074 | $8,002,245 | $460,029 | $1,185,922 | $179,520 | $221,548,302 |
| | **Computation of Income Taxes** | | | | | | | | | |
| 10) | Weighted Cost of Long Term Debt @ 3.14% | | | | | | | | | |
| 11) | Tax Rate @ 39.50% | | | | | | | | | |
| 12) | Income Taxes ((Line 8-Line10)(Line 7)(Line 11))/(1-Line 11) | $3,940,793 | $23,495,175 | $16,010,506 | $1,140,206 | $2,968,116 | $170,630 | $439,871 | $66,586 | $82,174,574 |
| | **Expenses** | | | | | | | | | |
| 13) | Expenses | $27,936,239 | $103,061,418 | $74,405,503 | $0 | $38,069,037 | $0 | $0 | $36,899,438 | $1,405,163,457 |
| 13a) | Pro forma Non-energy expense | ($1,864,737) | ($6,879,325) | ($4,966,550) | ($4,587,351) | ($2,541,099) | ($1,355,295) | ($1,130,059) | ($2,463,029) | (57,635,013) |
| | Pro forma Energy expense | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | ($5,996,686) |
| 14) | Regulatory Assets | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,219,701 |
| 15) | Customer Accounts | $0 | $0 | $0 | $42,057,651 | $0 | $20,304,113 | $16,929,787 | $0 | $79,291,551 |
| 16) | Cust. Service & Info and Sales Expense | $0 | $0 | $0 | $26,666,947 | $0 | $0 | $0 | $0 | $26,666,947 |
| 17) | Total Expenses | $26,071,502 | $96,182,093 | $69,438,953 | $64,137,247 | $35,527,937 | $18,948,818 | $15,799,728 | $34,436,409 | $1,450,710,956 |
| | **Revenue Requirement** | | | | | | | | | |
| 18) | Return, Income Taxes, and Expenses (Line 9 + Line 12 + Line 17) | $40,636,944 | $183,021,875 | $128,614,884 | $68,351,528 | $46,498,298 | $19,579,477 | $17,425,520 | $34,682,515 | $1,754,433,832 |
| 19) | Less: Revenue Credits | $1,340,425 | $8,559,826 | $7,231,058 | $421,656 | $832,755 | $0 | $0 | $0 | $117,339,100 |
| 20) | Class Low Income, E-3 & E-4 Discounts | ($88,356) | ($310,441) | ($312,477) | ($255,720) | ($109,193) | ($73,689) | ($65,471) | $2,844,557 | $0 |
| **21)** | **REVENUE REQUIREMENT @7.26%** | **$39,228,163** | **$174,151,608** | **$121,071,349** | **$67,674,152** | **$45,556,351** | **$19,505,788** | **$17,360,050** | **$37,527,072** | **$1,637,094,732** |

1/29/2004

Exhibit LS-6

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DEC. 31, 2002
($)

Staff Class Revenue Requirements and Rate of Returns

| | TOTAL RETAIL | RESIDENTIAL | GENERAL SERVICE | IRRIGATION | STREET LIGHTING | DUSK TO DAWN |
|---|---|---|---|---|---|---|
| RATE BASE | $3,051,627,860 | $1,717,854,000 | $1,264,699,141 | $2,572,695 | $46,247,665 | $20,254,359 |
| Revenues from Rates | $1,839,197,107 | $911,780,435 | $908,197,108 | $2,257,000 | $11,567,156 | $5,395,408 |
| Proforma to Revenues from Rates | -$47,613,375 | -$21,882,852 | -$24,601,762 | -$157,808 | -$773,504 | -$197,449 |
| Other Electric Revenue | $117,339,100 | $56,948,046 | $57,491,138 | $171,643 | $2,448,729 | $279,545 |
| TOTAL OPERATING REVENUES | $1,908,922,832 | $946,845,629 | $941,086,484 | $2,270,835 | $13,242,381 | $5,477,504 |
| OPERATING EXPENSES | $1,532,885,486 | $795,770,148 | $715,370,556 | $2,128,252 | $14,025,352 | $5,591,177 |
| RETURN | **$376,037,346** | **$151,075,481** | **$225,715,927** | **$142,583** | **-$782,971** | **-$113,674** |
| RATE OF RETURN | 12.32% | 8.79% | 17.85% | 5.54% | -1.69% | -0.56% |
| INDEX RATE OF RETURN | **1.00** | **0.71** | **1.45** | **0.45** | **-0.14** | **-0.05** |

EXHIBIT
S-8
Admitted

**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | ) | DOCKET NO. E-01345A-03-0437 |

DIRECT TESTIMONY

OF

DOUGLAS C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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## I. INTRODUCTION

**Q. Please state your name and business address, and identify your employer.**

A. My name is Douglas C. Smith. I am the Technical Director for La Capra Associates, 20 Winthrop Square, Boston, Massachusetts.

LaCapra Associates ("La Capra") is a consulting firm specializing in electric industry restructuring, energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. For over twenty years, we have served a broad range of organizations involved with energy markets -- public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and research organizations.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Staff of the Arizona Corporation Commission ("Staff").

**Q. Please summarize your professional background and education.**

A. I am an electric power industry planning and transactions specialist with 17 years of experience in areas including power systems planning and analysis, wholesale and retail power transactions, and electric utility rates. I have participated in restructuring-related activities in Pennsylvania, Massachusetts, Vermont, New Jersey and Ohio. I have participated in numerous generation asset valuation and competitive market assessment projects on behalf of merchant generating companies, electric utilities, state regulatory and consumer agencies, and end-users. During the past two years I have assisted the California Bureau of State Audits in its review of approximately $50 billion of transactions conducted by the California Department of Water Resources ("DWR") in 2000 and 2001, and I have reviewed the power transactions of PacifiCorp (which serves six states in the western United States) and the Arizona Electric Division of Citizens Communications Company.

I have managed the electric power supplies of several electric utilities, and have advised electric utilities regarding their power transactions and risk management strategies. I presently assist several retail electricity customers, including the National Railroad Passenger Corporation ("Amtrak"), in the procurement of retail generation service from competitive suppliers. I have presented testimony before state regulatory authorities in Pennsylvania, Massachusetts, New Hampshire, New Jersey, Vermont, Wyoming, Arizona, Nevada and Puerto Rico.

A copy of my resume is included as Exhibit DCS-1.

## I. SUMMARY

**Q. Please summarize your testimony.**

A. I have reviewed the Company's proforma Test Year fuel and purchased power expenses, particularly as presented by APS witness Donald Robinson. On the basis of my review, I recommend several changes to the Adjusted Test Year fuel and purchased power expenses submitted by APS. I also discuss the merits and drawbacks associated with potential purchased power and fuel adjustment mechanisms, and recommend that the Commission not approve an adjustor for APS in this proceeding.

**Q. Please summarize your findings with regard to fuel and purchased power expenses.**

A. I recommend changes to the Company's pro-forma analysis of fuel and purchased power expenses, based on two issues: transportation costs for owned and purchased gas-fired resources; and the assumed availability of the Palo Verde generating units. I have developed an adjustment to the Company's pro forma purchased power and fuel costs to reflect these two issues.

As explained by Staff witnesses Linda Jaress and Harvey Salgo, Staff does not support APS' proposal to rate base the PWEC generating units. The amount of my recommended adjustment regarding natural gas transportation costs depends to a significant extent on whether or not the PWEC units are part of the

Company's power supply mix. Therefore, the effects of my proposed adjustments to the Company's pro forma fuel and purchased power analysis are as follows:

? A $5.08 million reduction (for both PWEC in and out) to reflect higher availability for the Palo Verde generating units. The jurisdictional component of this adjustment is $5.0 million;

? A $4.61 million reduction to reflect lower gas transportation costs (if the PWEC units are included in rate base), or a $1.48 million reduction if the PWEC units are not included in rate base. The jurisdictional components are $4.54 million and $1.46 million respectively.

I have provided these recommended adjustments to Staff witness James Dittmer, for incorporation in his analysis of the Company's total cost of service. These modifications to the Company's proposed revenue requirement provide an appropriate base from which to develop a fuel and purchased power adjustor, as they represent an updated view of fuel and purchased power costs. My fuel and purchased power recommendation, however, should be reduced by approximately $23 million if the Commission concludes that APS should not have an adjustor.

**Q. Please summarize your findings and recommendations with respect to a prospective power supply adjustor mechanism.**

A. The Commission's Decision No. 66567 in Docket E-01345A-02-0403 contemplates an adjustor that would address only changes in the Company's purchased power costs. Staff is concerned that an adjustor that addresses only purchased power expenses would not accurately depict changes in the Company's net power supply costs, including fuel expenses and revenues associated with sales for resale. In APS' present circumstances, this flaw is important because fuel expenses, purchased power expenses, and sales for resale revenues each can have a significant effect on the net power costs. An adjustor addressing only purchased power would also fail to provide incentives for APS to operate its system in a least-cost manner, and could actually encourage APS to make power supply choices that increase its net power supply costs.

For these reasons, Staff recommends that the Commission not implement an adjustor mechanism that focuses solely on purchased power expenses. The preferable options range from no adjustor at all (i.e., a fixed retail rate) to a "full" adjustor designed to reconcile all changes in APS' fuel costs, purchased power costs, and resales.

Staff is concerned, however, that in the event of significant load growth an adjustor could lead to an unintended overrecovery of APS' total power supply costs. This is meaningful for APS because: (a) it has experienced significant load growth in the past, and expects to continue to do so; and (b) APS has relatively large fixed power costs, which would tend to decline on a cents/kWh basis as load grows but would not be included in an adjustor as presently envisioned. Staff's view is therefore that the adjustor currently proposed by APS would not be appropriate. If the concern with respect to potential overrecovery can be adequately addressed, Staff would support an adjustor that includes purchased power and fuel costs.

## II. FUEL AND PURCHASED POWER COSTS

**Q. Please provide an overview of the Company's power supply sources.**

A. In developing its pro forma fuel and purchased power costs, APS conducted an analysis using the Real Time Simulation ("RTSIM") production simulation software. This analysis is intended to approximate the dispatch of the APS system on a daily and hourly basis, taking into account the APS load shape and the characteristics of its owned generating plants and its committed purchase and sale transactions. The analysis also estimates the effects of short-term exchanges (e.g., daily and hourly purchases and sales for resale) with the regional wholesale electricity market.

I have summarized the results of APS' simulation analysis as follows. Exhibit DCS-2 shows APS' monthly energy mix, in terms of the major types of power plant and interchange, assuming that the PWEC units are included in ratebase.

Exhibit DCS-2 also presents the same summary, assuming that the PWEC units are not included in ratebase. Exhibit DCS-3 summarizes APS' annual energy mix, along with the average price of fuel (or purchases/sales, as applicable) for each category, for the PWEC "in" and "out" cases.

From the perspective of assessing APS' exposure to fuel and market price changes, the following observations are notable:

? Most of the APS energy supply comes from its nuclear units (with an average fuel cost of roughly $5 per MWh) and coal-fired units (with an average fuel cost of less than $13/MWh). From a system operations perspective, these units are almost always fully utilized to meet APS' present retail load requirements, with very little surplus available for resale.

? A substantial portion of the APS energy supply comes from gas-fired generating units – a combination of APS-owned units and the PWEC units. These gas-fired units tend to be the Company's marginal generating sources, following its seasonal and daily load requirements. The average fuel costs for the gas-fired units are much higher than for the Company's coal and nuclear units, and well above the system average cost per MWh for fuel and purchased power. As shown on Exhibit DCS-3, the gas-fired units are estimated to provide about 25% of total system energy requirements (assuming PWEC is ratebased) but represent a cost of about $299 million per year or over half of the Company's net fuel and purchased power cost. As a result, changes in natural gas prices can significantly affect the Company's total fuel and purchased power expense. Similarly, changes in the operation of the gas-fired units (e.g., due to demand growth, or unseasonably hot or cool weather) can have a significant effect on APS' total fuel expense.

? If the PWEC units are not included in rate base, APS will be a modest net purchaser in the spot market. Specifically, the net of daily and hourly transactions amounts to a net purchase of roughly 1 million MWh or about 4 percent of the APS system requirements. The APS analysis shows that if the PWEC units are included in rate base, APS will be a net seller in the spot market. Estimated net spot market sales amount to about 1.7 million MWh per year, or roughly 6.5 percent of APS system requirements.

In summary, the APS fuel mix has a significant amount of fuel diversity, but energy supplied by gas-fired generating units and purchased from the spot market represent a substantial portion of APS' net power supply costs.

**Q. How does APS' significant reliance on natural gas-fired generation and market power purchases affect its future rate path?**

A. Natural gas prices have shown considerable variance in recent years, as illustrated on Exhibit DCS-4.[1] As the Commission knows, electricity markets also tend to feature volatile prices, driven in part by natural gas prices as well as numerous other factors.

It is reasonable to expect that both gas and electricity market prices will continue to vary significantly in the foreseeable future. The Company's gas fuel costs and electricity market purchases, if not hedged, will represent a significant source of cost uncertainty in future years. Even if APS does conduct an aggressive hedging program, it will probably not be practical to eliminate all fuel cost uncertainty. Whether or not the PWEC units are included in rate base, it appears that APS' natural gas fuel requirements will represent a larger net expenditure in the near term (and, likely, a larger financial risk exposure) than the Company's projected spot market electricity transactions.

**Q. Are increases in fuel prices a primary driver of APS' requested rate increase?**

A. Yes. Recent spot prices for natural gas, and forward indicators for natural gas deliveries in 2004, are well above actual gas price levels that were experienced in the Test Year. The natural gas price environment also affects electricity market prices. Electricity forward prices for deliveries in 2004 have increased relative to Test Year spot market prices, as well. As I will explain below, APS' pro forma power cost analysis reflects this higher price environment.

These gas and market price increases are significant in the context of the APS power supply, even though APS gets most of its energy from nuclear and coal-fired units that feature lower and more stable fuel prices. In addition to a significant amount of owned natural gas-fired generation, APS has in place large

[1] Staff witness Barbara Keene submitted this same exhibit in Docket E-01345A-02-0403.

gas-fired purchases (i.e., Track B purchases from the PWEC units) during summer months. APS also makes short-term market purchases at prices that reflect, in part, marginal gas-fired units in the WECC region. If the PWEC units are ratebased, APS power supply costs will depend even more directly on natural gas prices. The increases in natural gas and (to a lesser extent) electricity market prices are the primary driver of APS' pro forma increase to fuel and purchased power costs.

**Q. What natural gas and electricity market price assumptions did APS utilize as inputs to its pro forma analysis in this case?**

A. In developing its pro forma adjustment to fuel and purchased power costs, APS relied on monthly market price quotations that were available in late April 2003, for gas and electricity deliveries in the following twelve months (May 2003 through April 2004). The forward gas prices were at key supply basins; APS added applicable variable transportation costs, losses and taxes to obtain effective delivered prices to its generating plants. The forward electricity price quotations were for monthly peak and off-peak deliveries at Palo Verde, a western trading hub close to the APS service territory. In its production simulation analysis, APS utilized the monthly Palo Verde forwards to develop prices for daily and hourly spot market purchases.

APS made one broad adjustment to those forward prices: a reduction of ten percent to the natural gas prices. APS explained this adjustment as compensating for what it believed were exceptionally low forward spark spreads (i.e., the difference between forward electricity and natural gas prices) being quoted in the market.

**Q. How do the Company's price assumptions for natural gas and electricity compare to recent conditions?**

A. Short-term market prices for gas and electricity have fluctuated noticeably between April 2003 and the present. Recent forward price quotations provided by the Company, however, indicate that the natural gas and electricity market prices

underlying the Company's pro forma analysis are reasonably representative of current market expectations for deliveries in the near future - including the period July 2004 to June 2005, the first year in which the rates set in this docket will be in effect. It therefore appears that the Company's assumptions about the natural gas and electricity price environment are suitable for use in setting the reference level of fuel and purchased power costs in this case, particularly if a PPFAC is adopted.

## III. NORMALIZATION OF FUEL & PURCHASED POWER

**Q. In developing its adjustment to fuel and power costs, did APS consider load growth beyond the test year?**

A. Yes. The Company's pro forma adjustment to fuel and purchased power costs, which is summarized in Mr. Robinson's Attachment DGR-5, page 7, relies in part on assumed load growth in 2003.

**Q. Please explain what sales levels were used to develop the normalized fuel and purchased power costs.**

A. First, APS estimated a normalized 2003 fuel and purchased power cost of 2.317 cents/kWh. This figure represents estimated normalized 2003 fuel and purchased power costs of $584.087 million, divided by normalized 2003 sales of about 25.2 million MWh. This sales level is associated with projected year-end 2003 customer levels, and is well above the Company's actual test year sales.

Next, APS compared the normalized 2003 fuel and purchased power cost of 2.317 cents/kWh to the test year fuel and purchased power cost of 1.8033 cents/kWh, determining that power costs per kWh will be higher by 0.5137 cents/kWh than average 2002 power costs. The increase is due both to higher fuel and purchased power costs and to a different dispatch of generating units to meet higher load.

Finally, APS multiplies this adjustment to its adjusted 2002 sales (which account for weather normalization, and year-end 2002 customer levels) of about 23.5

million MWh, to obtain its pro forma adjustment to fuel and purchased power expenses of $120.584 million. Thus, while APS' total proforma fuel and purchased power cost (in dollars) is not as high as 2003 power costs would be, the pro forma cost per kWh does reflect the impact of higher loads.

**Q. Are the nature of the Company's proforma adjustments appropriate?**

A. Both adjustments seem appropriate as a base power cost which would be adjusted by a PPFAC. However, if an adjustor is not adopted, I am concerned that the Company will have essentially proformed one component of its costs to reflect 2003 sales levels, while not all other components were similarly proformed to reflect those sales levels.

**Q. What is the effect of using 2003 loads to develop the average fuel and purchased power cost?**

A. Load growth tends to increase the Company's fuel and purchased power costs per kWh. To my knowledge APS has not provided an estimate of fuel and purchased power costs based on its lower adjusted 2002 sales, but the effect is substantial. Assuming that sales growth is served with incremental fuel and purchased power at a price of $50/MWh (which is consistent with the forward electricity prices used in the Company's pro forma analysis), the Company's use of the higher sales figure would increase the pro forma average fuel and purchased power cost by approximately $23 million.

APS has not, however, proformed a corresponding decrease in the cost per kWh of its fixed power supply costs. This raises a potential inconsistency, and a potential for APS to overrecover its total power supply costs.

**Q. What is your recommendation with respect to APS' use of 2003 sales levels in its derivation of pro forma fuel and purchased power costs per kWh?**

A. The Company's use of 2003 sales in this calculation would be reasonable in the context of a PPFAC. Therefore, if the Company is able to develop a PPFAC

mechanism that addresses the concerns that I have raised with respect to load growth, its pro forma fuel and purchased power costs would be – subject to the specific adjustments that I recommend below related to gas transportation costs and nuclear unit generation – an appropriate basis.

If the Commission instead determines that a PPFAC is not appropriate at this time, I recommend that the Company's pro forma fuel and purchased power expense be reduced to remove the effects of 2003 sales growth. I estimate that the associated reduction would be approximately $23 million.

## IV. PURCHASED POWER AND FUEL ADJUSTMENT MECHANISM

**Q. Please summarize your recommendations with regard to a purchased power and fuel adjustment mechanism.**

A. Staff recommends that if the Commission decides to approve an adjustor mechanism, the mechanism should include fuel as well as purchased power. However, Staff's primary recommendation is that the Commission should not approve such a mechanism for APS at this time. Below I will explain why Staff recommends against an adjustor that includes only purchased power, and will describe the unique circumstances that result in the recommendation that no adjustor be approved for APS.

**Q. Have you reviewed the Commission's findings, in Docket E-01345A-02-0403, with respect to a potential adjustment mechanism to track changes in APS purchased power costs?**

A. Yes, I have reviewed ACC Decision No. 66567, and also the October 2, 2003 recommendation of ALJ Farmer. The draft order recommended approval of a Power Supply Adjustor, including fuel and purchased power costs, subject to a number of specific conditions, but the final Order appears to contemplate a mechanism that adjusts APS rates for changes in its purchased power costs, but

not fuel costs. A specific methodology for implementing the adjustment mechanism was not adopted.

It is my understanding that in the context of the present docket, the Commission intends to determine whether an adjustor should be implemented for APS and, if so, what the broad features of the adjustor should be.

**Q. How would a purchased power adjustor for APS work?**

A. In Docket E-01345A-02-0403, the Commission addressed the prospect of a purchased power adjustor conceptually, but did not present all the details of how it would be implemented. For the purpose of this discussion, I will assume a relatively simple purchased power adjustor designed to track changes in the Company's purchased power expenses.

Under this type of mechanism the Company's reference level of purchased power expenses would be established by the Commission, presumably on an annual basis. Retail rates would initially be set to collect this reference level of purchased power expense, along with the other components of the Company's cost of service. The Company's actual purchased power expenses would subsequently be measured, and compared to the reference level periodically, on a cost per kWh basis. To the extent that actual purchased power expenses turned out to be greater (less) than the reference level, the difference would subsequently be collected (returned) by APS over a future period.

The specific design and implementation of a purchased power adjustor (or other forms of adjustors) would entail a number of details, many of which were raised in the adjustor proceeding. These include the accounts that would be included, the amount of information to be monitored and filed, how often the adjustor could change, amortization schedules, the amount that rates would be able to increase because of the adjustor, etc. However, a purchased power adjustor that does not include fuel raises additional issues.

**Q. Would a simple adjustor mechanism focusing only on the Company's purchased power costs have important limitations or drawbacks?**

A. Yes, the Commission should consider several significant drawbacks that would be associated with an adjustor that focuses only on changes in the Company's purchased power expenses. These drawbacks stem from the fact that APS' present power supply includes not only purchased power, but also substantial amounts of gas-fired generation, and these resources can substitute for one another.

First, a simple adjustor mechanism reflecting only changes in APS purchased power costs would not effectively capture how a number of practical developments would affect APS' **net power supply costs**, including fuel and purchased power. From the Company's standpoint, this type of adjustor may not "make them whole" when prices are rising, and from the customer' standpoint, this adjustor may not pass along all power cost reductions.

Second, under some conditions, a simple adjustor mechanism focusing only on purchased power expenses (a "PPA") would not provide incentives for APS to operate its system in a least-cost manner, and could encourage APS to make power supply choices that actually increase its net power supply costs. Alternative adjustor mechanisms that addressed only purchased power could potentially be developed, but to accurately track APS' net costs they would need to be fairly complex and would require extensive Commission review.

**Q. Please explain the first concern, that a purchased power adjustor would not effectively capture changes in APS' net power supply costs.**

A. The problem is that purchased power expenses are only one component of APS' net power supply costs. Changes in purchased power expense are often accompanied by offsetting changes to the other components: **fuel consumption and sales for resale**. Two simple examples may be illustrative.

First, consider an instance in which, shortly after the reference level of purchased power expense is established, wholesale power market prices decline significantly

(say, from 3.5 cents/kWh to 3 cents/kWh) while prices for fuel at APS' gas-fired generating units are unchanged (at, say, 3.3 cents/kWh). In response to this change, it will tend to be cost-effective for APS to increase purchases from the short-term power market at 3 cents/kWh, while backing down production from its marginal gas-fired units at 3.3 cents/kWh. In this example the PPA would show APS' purchased power expenses greater than the reference level, indicating that APS is undercollecting, even though APS' net power supply costs have declined.

Alternatively, consider an instance in which the Company's Palo Verde nuclear units are actually available to produce significantly more energy than assumed in the development of the reference level of purchased power expense. The additional production of nuclear energy at relatively low fuel cost will reduce APS' net power supply costs. But if APS has purchased its forecasted electricity needs for the year in advance, using forward contracts, the savings to APS would come through reduced dispatch of its higher-cost gas-fired units or additional resales in the short-term electricity market. In this example, APS' actual purchased power expenses would not decrease, because they are locked in through forward purchases. Instead, the additional Palo Verde energy would allow APS to make some unanticipated short-term resales. The related revenues, and the associated overcollection of power supply costs, would not be captured by the PPA.

These examples show that an adjustor designed to reflect only changes in purchased power expenses (and not fuel, or sales for resale) could realistically indicate that APS is undercollecting in instances where APS' net power supply costs have increased only modestly, or actually decreased. Similarly, a PPA may not capture instances in which APS' net costs have legitimately increased. Other practical examples could be developed to illustrate the limitations of an adjustor that focuses only on purchased power expenses. Note that in these examples APS is assumed to pursue the economic course of action in response to changing fuel prices or power market conditions. The concern is simply that the PPA would not accurately depict the changes in APS' net costs.

**Q. Please explain the second concern, that an adjustor focusing only on purchased power expenses could provide incentives that encourage APS not to pursue an economic course; i.e. to make power supply choices that increase its net power supply costs.**

A. The primary concern derives from the potential economic substitution between purchasing power and generating energy from APS-owned generating units. Because increases in purchased power expenses would be recoverable through the adjustor, while changes in fuel expenses at APS units would not, APS would generally have an incentive to maximize market purchases in lieu of generating energy from its own units, even if the latter were the cheaper option. This substitution dynamic can be significant in the APS power supply, which contains substantial amounts of dispatchable owned resources (particularly the Company's gas-fired steam and combined cycle units, along with Track B purchases from the PWEC units during summer months). APS has the ability to adjust output from these resources in response to changing prices for fuel and power.

**Q. Could a simple PPA be modified to address the concerns that you have raised?**

A. Possibly, but simple modifications would probably not make a PPA very effective at capturing changes in the Company's net power supply costs. This is because purchased power volumes and prices are each subject to significant variation from month to month and year to year, making simple approximations (e.g., applying observed changes in electricity market prices to the volumes of purchased power assumed in the reference cost analysis) subject to significant errors. In order to capture these net changes accurately, a more detailed analysis (resembling a full adjustor that tracks actual fuel expenses and sales for resale) would be needed.

**Q. In view of the foregoing, what is Staff's recommendation with respect to a purchased power adjustor?**

A. For the reasons above, and considering APS' particular power supply mix, Staff believes that an adjustor mechanism focusing solely on purchased power expenses

is not advisable. The preferable options range from no adjustor mechanism at all (i.e., a fixed retail rate) to a "full" adjustor designed to reconcile all changes in APS' fuel costs, purchased power costs, and resales (i.e., a purchased power and fuel adjustor, or "PPFAC").

**Q. May there be some circumstances in which a full adjustor, including fuel and purchased power, is preferable to a fixed rate?**

A. Yes, although, there are usually legitimate tradeoffs among these options. In Docket E-01345A-02-0403, Staff identified a number of advantages and disadvantages associated with a PPFAC; these remain valid today. Specifically, Staff identified the following **advantages**:

1. The reporting requirements and forecasts facilitate utility planning and Staff overview of costs;
2. An adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity capital in a rate case and result in lower rates;
3. Adjustors can create price signals to consumers, although the effectiveness is reduced considerably when a band is included and a twelve month rolling average is used;
4. Adjustors can help reduce the frequency of rate cases;
5. Regulatory lag between the incurrence of an expense and its recovery is reduced, and generational inequities are also reduced.

The **disadvantages** identified by Staff were as follows:

6. Adjustors can reduce incentives to minimize costs.
7. An adjustor that includes fuel or purchased power costs potentially biases capital investment decisions toward those with lower capital costs and higher fuel costs;
8. Adjustors create another layer of regulation, in addition to rate cases;
9. An adjustor can shift a disproportionate portion of the risk of forced outages and systems operations from shareholders to ratepayers;
10. Adjustors result in piecemeal regulation, in that they reflect an increase in one expense but ignore potential offsetting savings in other costs;

11. Adjustors are complex and often difficult for analysts to read and interpret, and are difficult to explain to customers;

12. Proper monitoring of adjustor filings and audits require the devotion of significant Staff resources;

13. Under an adjustor rates are less stable, resulting in rates changing frequently, making it difficult for customers to plan energy consumption and the purchase of energy consuming appliances.

**Q. What other empirical circumstances bear on the advisability of an adjustor mechanism?**

A. Empirical considerations which may affect the advisability of an adjustor mechanism include the prospective volatility of fuel and/or purchased power expenses, the proportion of the utility's revenue requirement which is subject to such volatility, and the rate of load growth which can be expected. Utilities with a large proportion of their costs subject to volatility, based on events outside of their control, and with relatively low load growth, are likely to be appropriate candidates for adjustor mechanisms.

In the specific circumstances facing APS, natural gas prices (including spot prices and futures contracts) have exhibited substantial volatility in recent years, and appear likely to continue to do so in the near future. As shown in Exhibit DCS-3, the Company's power supply mix in the near future will rely significantly on energy from natural gas-fired generating units and purchases, and (to a lesser extent) on short term power purchases. Gas costs represent a large fraction of the Company's net fuel and purchased power costs and a significant fraction of its total annual revenue requirement. These costs are not entirely out of APS' control, however, as APS can (and presently does) reduce its exposure to potential market price changes by hedging (e.g., by purchasing fuel well before it is consumed, or utilizing future contracts or options). In the context of considering an adjustor mechanism, it is also important to note that a very substantial portion of the Company's power supply costs are fixed.

**Q. Do the empirical circumstances in APS' case raise concerns with a fuel and purchased power adjustor that were not discussed explicitly in the previous proceeding?**

A. Yes. Staff is concerned that if APS continues to experience substantial load growth (i.e., growth in retail kWh sales), a PPFAC could lead to overrecovery of total power costs.

Specifically, a large fraction of APS' power costs are fixed costs (e.g., depreciation, return on equity, fixed O&M) associated with its owned generating units. Customers pay for these fixed costs as part of their volumetric rate. The concern is that as sales grow, APS will essentially be collecting more money from retail customers for its fixed power costs, even though such costs do not increase commensurately. The PPFAC, at least in the form proposed by APS and discussed above, would not recognize this. That is, while a PPFAC would compensate APS for observed increases in its fuel and purchased power costs per kWh caused by load growth, it would not reflect offsetting declines in cost per kWh sold associated with the fixed components of power supply costs. This is an example of the "piecemeal regulation" concern cited by Staff in Docket E-01345A-02-0403; its effect is that APS stands to achieve increasing net power cost margins associated with load growth.

**Q. In this context, is growth in APS sales a significant issue?**

A. Yes, the Company's retail sales increased at an average rate of over 3 percent per year between 1997 and 2002[2], and APS projects growth to continue at an average rate of over 4 percent per year over the next five years.[3]

**Q. Have you been able to estimate what impact a PPFAC might have in these circumstances?**

A. Yes, Exhibit DCS-5 illustrates how load growth of 4 percent (equivalent to the annual growth forecast by APS) would affect the Company's power supply costs

[2] Supplement to APS 2002 Annual Report
[3] APS 2003 Long Range Forecast (August 2003)

and collections from ratepayers. Key points from this illustration are the following:

- Fuel and purchased power costs represent well under half of APS' total power supply costs.
- Much of the Company's power supply costs are fixed, and are not included in fuel and purchased power. These costs - which include depreciation, return on equity, and income taxes associated with APS owned generating plants - are not driven by sales. The actual fixed costs in APS rates will depend on several factors, including whether the PWEC units are rate based. For the purpose of this illustration I have used a figure of $500 million which is within the range of potential outcomes.
- Assuming that sales growth of 4 percent is supplied with a combination of purchased power and increased generation from APS units, at an average cost of about $50/MWh, APS' actual fuel and purchased power costs per kWh would increase, leading to an undercollection of about $27 million. Under a simple PPFAC, this amount would ultimately be collected from ratepayers in a future period.
- APS' fixed power supply costs are not driven by sales[4] in the near term, and therefore decline on a cents per kWh basis by 4 percent in this example. APS would effectively overcollect for these fixed power supply costs by about $20 million. Under a simple PPFAC mechanism, this overcollection would not be tracked or returned to ratepayers.

This example illustrates that if retail sales increase significantly, a simple adjustor combined with based rates could result in a windfall to APS on the order of $20 million. Undercollections in one portion of power supply costs – fuel and purchased power – would be reconciled through the PPFAC while overcollections in fixed power supply costs would not. Note that APS total power supply costs

[4] In actual practice, some of the fixed power supply costs (e.g., depreciation, return) would tend to remain constant or decrease over time, while others (e.g., power plant O&M) would tend to increase. Because a substantial fraction of APS' fixed power supply costs are of the former type, the results illustrated here are not strongly sensitive to this breakdown and may be conservative.

(including the components that are increasing and decreasing on a cents/kWh basis) track relatively closely to those being collected in rates.

**Q. Does the concern about net revenues associated with load growth need to be addressed?**

A. Yes. APS has experienced significant load growth during recent years and expects continued robust growth in the future. Further, fixed costs (which would not be included in the PPFAC) make up a large fraction of APS' total power supply costs. Due to these circumstances, Staff believes that the load growth issue is a particular concern in the context of the APS system. Staff believes that the Commission should not adopt an adjustor in this case if the issues associated with load growth cannot be adequately addressed. Staff would, however, be willing to review suggestions from the Company in its rebuttal case as to how to design an adjustor that appropriately addresses these issues.

**Q. Given the respective advantages and disadvantages, what is Staff's present recommendation?**

A. Considering the context of APS' present power supply, Staff recommends against a PPFAC.

**Q. Could a PPFAC potentially be developed that would address the concerns you have presented?**

A. Yes. A more complex adjustor could attempt to prevent windfall gains resulting from load growth. For example, the earnings test proposed by Staff in Docket E-01345A-02-0403 would have accomplished this objective. Similarly, in the past Colorado has taken steps (e.g., an earnings test, exclusion of purchased power capacity costs from the PPFAC) to address this problem. However, such steps would likely be fairly complex and more difficult to administer than the mechanisms that have thus far been considered in this proceeding and in Docket E-01345A-02-0403.

**Q. Would the concerns that you have presented exist without a PPFAC?**

A. Yes, the concerns would still be relevant in the absence of an adjustor. An adjustor would exacerbate the concern, however, because it would pass through to ratepayers the portion of APS power supply costs (fuel and purchased power) that is likely to increase as a result of load growth.

**Q. Could other modifications to the PPFAC concept help provide the Company with incentives to "hedge" and to otherwise keep down power costs?**

A. Yes, a PPFAC could contain a "deadband" range. Rather than triggering a full reconciliation when a certain amount of over- or under-collection was reached[5], as had been proposed in Docket E-01345A-02-0403, a deadband would define an amount of annual variation from the base that would never be collected.

**Q. Please explain more fully what you mean by a "deadband" range, and how it compares to the approach proposed by APS in the recent adjustor proceeding.**

A. The Power Supply Adjustor mechanism proposed by APS in Docket E-01345A-02-0403 would track over- and under-collections outside a bandwidth in a Balancing Account, with a maximum threshold of $50 million. APS proposed that if and when the Balancing Account passed the $50 million threshold, a new energy-based charge should be created to amortize the full balance over a one-year period, and the current Balancing Account reset to zero. In an instance when APS' cumulative actual power supply costs exceeded those in the current base power supply charge by more than $50 million, APS would have ultimately recovered the entire difference (along with interest) from customers.

Staff's recommendation is that if a PPFAC is implemented, it should incorporate a deadband range approach, with the following key features:

? Variances of net fuel and purchased power costs (i.e., the difference between APS' actual net costs and those that

[5] The trigger discussed in Docket E-01345A-02-0403 would only delay when the adjustor begins to provide recovery, rather than limiting the amount of the recovery.

APS collected in the base power supply charge) would be calculated once per year, on a regular cycle;

? If the annual variance in net fuel and purchased power costs exceeds the prescribed deadband range, the variance in excess of the deadband would be collected from (returned to) customers over the following year, via an energy-based charge (credit). To the extent that the variance in net fuel and purchased power costs is less than the deadband range, no adjustment would be made for that year.

? Over/under collections of fuel and purchased power costs would not be carried over from one year to the next.

? The base power supply charge would remain constant, at the level established in the present rate case, until modified in a future rate case.

**Q. Do you recommend a specific deadband range that would apply in the event that the Commission chooses to implement a PPFAC for APS?**

A. The choice of the deadband figure should balance several objectives. First, in order to provide the Company with an incentive to control its costs, the deadband range should be sufficiently large that the Company's actual costs have a substantial probability of actually falling within the range. Too small a deadband range would not accomplish this goal, and would also expose customers to PPFAC adjustments for relatively small changes in fuel and purchased power costs. Second, the deadband range should not be so large that the Company suffers serious financial harm if actual fuel and purchased power costs turn out in the high end of the range.

I believe that a deadband range of plus or minus $20 million would accomplish these objectives. I should note that, however, that this deadband could regularly be exceeded if APS load growth continues and the adjustor is not modified in some fashion to reflect the effect of load growth.

**Q. How does the "deadband" approach differ from APS' proposal in Docket E-01345A-02-0403, and from the adjustor contemplated in the Commission's Order in that docket?**

A. The primary difference is that under the approach that Staff presents in this case, only net cost changes outside the deadband range would be passed through to customers. Over a significant range of actual net costs, APS would bear the costs and rewards of the fuel and power procurement choices that it makes, giving APS a significant direct incentive to control its net power costs. This feature addresses, to a significant degree, one of the key concerns identified by Staff (and by other parties) that would otherwise be associated with a PPFAC. The annual review process proposed by Staff is intended to reduce the frequency and burden associated with the review of APS' actual power supply costs.

**Q. What is your recommendation regarding the conditions approved by the Commission in Decision No. 66567?**

A. Staff recommends that an adjustor include Condition 1, which would allow review of the workings of the adjustor after three years. Staff also believes that if an adjustor is implemented, it will be appropriate to adopt the conditions in Decision No. 66567 with the exception of Staff Conditions 6 and 11.

**Q. Please discuss how the Company's procurement choices will affect its future net power costs, and the considerations associated with how the Commission will review those choices.**

A. As discussed above, natural gas fired generation and short-term power purchases play significant roles in the APS power supply. As a result, APS actual future power costs will sometimes depend significantly on the procurement choices (e.g., when to purchase fuel or power on a forward basis, how much to purchase and for how long) that APS makes. The outcomes of such decisions are likely to attract scrutiny if a PPFAC is implemented, because customers may directly bear those outcomes.

In California and some other U.S. states, a lack of clarity about these parameters has sometimes resulted in disagreements as to whether utilities could have avoided substantial excess power costs, and whether the utilities should be allowed to collect them from retail ratepayers. In particular, in the aftermath of

the Western power crisis of 2000-01, some utilities argued that they failed to hedge their market exposure (e.g., by purchasing forecasted needs ahead of time through forward contracts) because there was uncertainty as to how such commitments would be evaluated for retail rate recovery.

APS has indicated that its present practice is to purchase (or otherwise hedge the cost of) a majority of its forecasted fuel and power needs ahead of time. While it is appropriate that APS has a strategy, and some degree of hedging is advisable, I am not aware that APS and the Commission have an understanding as to what the goals of APS' hedging strategy should be.

Particularly if an adjustor mechanism is adopted, it will be useful for Arizona regulators to maintain a dialogue (or at least an understanding of basic principles) with APS regarding the objectives of its procurement and hedging activities and the appropriate tools for it to use. Such a dialogue would help to avoid misunderstandings, and would maximize the likelihood that APS' hedging activities are oriented toward goals that the Commission supports.

In context of the present case, I would recommend that the Commission set some broad ground rules for the design and implementation of APS' procurement strategy. Specifically, I recommend that the Commission consider the following guidelines:

? The presence of a PPFAC does not mean that APS should adopt a strategy of purchasing its fuel and power primarily from the spot market. Rather, APS should continue to judiciously use forward purchases and other types of transactions to reduce the expected cost and/or risk of the portfolio.

? Forward purchases and sales, options, and other derivative transactions should be conducted solely for the purpose of hedging APS' retail book, and should not be used for speculation.

? APS should base its procurement decisions on appropriate risk management tools and analysis, and proper market intelligence, regarding its market exposures and the products available to hedge those exposures.

? APS' transaction strategy and implementation will be subject to after-the-fact review by the Commission. The prudency of APS' procurement choices will be evaluated based on the pertinent information (e.g., market fundamentals, forecasted power requirements, the price of the products available) that was available at the time the choices were made (and on the appropriateness of APS' strategy) rather than on how the transactions "turned out" in hindsight.

? APS should maintain proper records regarding its hedging strategy, the information that it reviewed in evaluating potential transactions for the APS system book, and the rationale for entering into (or choosing not to enter into) specific transactions.

While these guidelines may put some burden on APS, Staff believes that they are ultimately in the interest of both APS and ratepayers because they serve to define expectations and avoid potential costly outcomes of the type that can lead to disallowances.

## V. GAS TRANSPORTATION COSTS

**Q. Please summarize your concerns regarding APS' estimate of natural gas transportation costs.**

A. APS' pro forma analysis of fuel and purchased power costs includes an increase in natural gas transportation costs. The increase is based in part on the assumption that the Company will need to make significant monthly firm purchases of gas transportation service from the capacity release market. As I will explain more fully below, my review indicates that APS' estimate of gas transportation costs is somewhat overstated, in part because it understates the amount of firm transportation that will be available under existing contracts at more favorable prices. To address this issue, I recommend that the Company's pro forma gas transportation costs be reduced by about $4.6 million annually if the PWEC generating units are rate based, and by about $1.5 million if the PWEC assets are not rate based.

**Q. Please provide a brief overview of the Company's natural gas purchases.**

A. APS and PWEC purchase the vast majority of their natural gas requirements from producers located in the Permian Basin in west Texas and southeast New Mexico; the San Juan Basin in northwest New Mexico and southwest Colorado; and the Waha trading hub. Prior to September of 2003, the gas from these basins was transported by El Paso Natural Gas, a FERC jurisdictional interstate pipeline, under a full requirements (FR) contract jointly held by APS/PWEC. The FR contract contained no limit on the amount of gas that APS/PWEC could purchase, but it was subject to capacity constraints on El Paso's pipeline system including the primary receipt points specified in the contract. To the extent that customer nominations exceeded capacity at a given receipt point, nominations were reduced on a *pro rata* basis.[6] Customers unable to receive all of their nominated firm volumes were allowed to re-nominate service from other receipt points.

In order to reduce the incidence of pro rata allocations and improve the reliability of firm service on El Paso, the FERC in an Order issued July 9, 2003 directed that FR contracts be converted to contract demand (CD) contracts, effective September 1, 2003. CD contracts provide firm customers the right to transport gas up to specified quantity limitations at delivery points designated in the contracts. The primary source of capacity to support these new contract demands is El Paso's unsubscribed system capacity, which was historically being used to supply FR customers.[7] Unsubscribed capacity includes the rights to capacity on El Paso turned back by California local distribution companies. This turned-back capacity was divided into three blocks: Block I capacity has alternate receipt point rights unless the capacity is sold for maximum tariff rates and, in that event, it has

[6] In recent years, gas supplies from San Juan have been less expensive than gas from Permian and Anadarko, making San Juan the preferred gas supply area for El Paso customers. As a result, San Juan nominations have regularly exceeded available capacity resulting in frequent pro rata reductions in nominations. In contrast, nominations for gas supplies from the other basins connected to El Paso (Permian and Anadarko) were rarely reduced.

[7] In this context, unsubscribed capacity means El Paso's total available system capacity less the capacity under contract to CD customers plus a reasonable amount of reserved for small FR customers not subject the FERC's conversion order.

primary receipt point rights only to the Permian and Anadarko Basins. Block II turned back capacity has primary access to all system receipt points including the San Juan Basin, but can be recalled by northern California shippers. Block II capacity also has primary deliveries to Topock in California. Block III capacity has primary access rights to all system receipt points. The FERC also directed El Paso to make additional capacity available to former FR customers through the Line 2000 Power-Up Project ("Power-Up").[8]

**Q. How did El Paso allocate the unsubscribed capacity among the converting FR customers?**

A. The FERC directed El Paso to apportion the unsubscribed capacity among FR customers using each customer's pro rata share based on its monthly demand over the 12 months ending August 31, 2002. The APS/PWEC share of the allocated capacity comprises four categories: Base, Line 2000, Block and Power-Up. The Base and Line 2000 capacities have primary access to all system receipt points. As noted above, the Block capacity derives from capacity turned-back by California local distribution companies and is divided into three blocks. The vast majority of APS/PWEC's block capacity is associated with Block II. Finally, the Power-Up capacity has receipt point rights only to Permian. Exhibit DCS-6 shows monthly APS/PWEC transportation capacities on El Paso, including the firm and non-firm designations that APS has assumed in its pro forma analysis. As shown on the exhibit, the total CD capacity allocated to APS/PWEC varies monthly from a minimum of 98,000 MMBtu/day in February to a maximum of 385,000 MMBtu/day in August.

**Q. Please summarize the Company's calculation of gas transportation costs for the adjusted test year.**

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[8] Rates on El Paso were established pursuant to a Settlement entered into in 1996. The 1996 Settlement set the current rates and terms and conditions of service for a ten-year period, i.e., until January 1, 2006. Service under the new CD contracts will be charged at rates established in the 1996 Settlement.

A. The Company has assumed that a portion of the daily gas requirements for the APS/PWEC gas-fired generating units will be met with the allocated Base and Line 2000 CD entitlements from the FERC RP00-336 proceeding.[9] As shown in the "Firm Capacity" portion of Exhibit DCS-6, these entitlements vary monthly from a low of 53,000 MMBtu/day in February to a high of 172,000 MMBtu/day in August. To put these entitlements in context, the minimum and maximum daily gas requirements for the APS/PWEC units for February 2003 were estimated at approximately 51,000 and 226,000 MMBtu/day respectively. For August 2003, the corresponding quantities were 123,000 and 303,000 MMBtu/day.

Daily gas requirements in excess of the Base and Line 2000 entitlements are assumed to be met with firm purchases of pipeline capacity in El Paso's capacity release market, rather than with the Block and Power-Up CD entitlements allocated to APS/PWEC in Docket RP00-336. Capacity release is a FERC approved program that allows shippers of gas on El Paso to sell or purchase surplus capacity at market based rates. The Company's calculation assumes that APS/PWEC will purchase at the beginning of each month sufficient firm release capacity to meet the projected maximum daily requirement for the month at a rate of almost twice that paid for firm Base and Line 2000 CD service.[10]

On days when the sum of the Base and Line 2000 CD entitlements and the capacity release purchases exceed the projected daily gas requirements, the Company's calculation assumes that the excess will be released on a daily basis at a rate equal to one fourth of the price to acquire that capacity.[11] Based on the projected daily gas requirements for the APS and PWEC gas fired generating units in the adjusted test year, the assumed capacity release purchases and sales, and the assumed charges for CD and capacity release transportation services, the

[9] The Line 2000 capacity is an allocation of recently completed capacity. Base capacity is unsubscribed system capacity.

[10] The basis for this rate is Sheet 23 of the El Paso Tariff. That is, the Company assumes it will pay a blend of the maximum daily base reservation rates for transportation from the San Juan and Permian basins to Arizona.

[11] Although the Company was unable to provide support for this assumption, it contends that it is reasonable because daily releases of capacity are less valuable than monthly releases.

Company estimated a net transportation cost of $20.5 million. This calculation is summarized in Exhibit DCS-7.[12]

**Q. Why did the Company not utilize in its calculation of pro forma transportation costs the Block and Power-Up CD capacity allocated to APS/PWEC in RP00-336?**

A. The Company contends that the Block and Power-Up capacity allocated to APS/PWEC in RP00-336 is less firm than the Base and Lone 2000 capacity.[13] In comments filed with the FERC in Docket RP00-336, APS/PWEC argued that: (i) Block II capacity is recallable by California customers; and (ii) the primary delivery points associated with the Block capacity are not usable because they are located in California, thus requiring the Company to re-nominate to secondary delivery points in its market area. Since secondary delivery points would be scheduled at a lower priority than primary points, the risk of curtailment would be increased.[14] In addition, APS/PWEC has argued that there is insufficient pipeline capacity connecting El Paso's northern and southern systems to ensure that gas delivered to Topock will be delivered to the Arizona market area. A map depicting the major features of the El Paso pipeline system is shown in Exhibit DCS-8.

**Q. Do you agree with these arguments?**

A. First, it is true that California customers may recall Block II capacity. To do this, they must at least match the rate in the contract covering the capacity to be recalled and subscribe to the capacity for a term of longer than one month. If a customer seeks to recall the capacity for a term of less than one month, it must

[12] Note that I attempted to replicate the Company's calculation, but fell short by approximately $0.5 million. Our request for the workpapers supporting the Company's estimate is currently outstanding.
[13] See response to LCA 19-461, which is attached as Exhibit DCS-6.
[14] See Joint Answer of Arizona Public Service Company and Pinnacle West Energy Corporation to Request of El Paso Natural Gas Company for Clarification or Rehearing, Docket RP00-336, September 16, 2003.

agree to pay the maximum rate.[15] These recall conditions may limit the likelihood that recalls will be frequent.

There is almost no operating history under the new CD regime (which was implemented in September 2003) that would provide a basis for estimating with confidence how often Block II capacity will be recalled, whether recalls will be limited to peak periods, or how much of the Block II capacity might actually be recalled. Despite this lack of operating history, it seems reasonable to assume that if Block II capacity is recalled, it is more likely to occur in the on-peak months. Similarly, there is little market history upon which to base the likely availability and price of release capacity during periods when Block II capacity might be recalled. This is significant because if California customers were to recall Block II capacity for economic reasons (i.e., because it provides them access to gas priced below that available on other pipelines), APS/PWEC might be able to replace the recalled capacity with purchases in the release market at a limited incremental cost.

Regarding the second claim, the Company itself notes in comments filed in Docket RP00-336 that the FERC has already accepted its argument and directed El Paso to modify the transportation service agreements to incorporate primary delivery points located in its historic market area.[16]

Regarding the third claim, the Company itself has argued that the existing allocations of the north-to-south crossover capacity are based on customer delivery point preferences provided to El Paso in December 2002, long before the FERC clarified that APS/PWEC and other FR customers could re-designate delivery points on their Block capacity. Consistent with this argument, the Company has requested the FERC to direct El Paso to re-allocate the north-to-south capacity using allocation factors that reflect re-designated delivery points. While such a re-allocation would not guarantee APS/PWEC full use of the San

[15] FERC Order on Rehearing, July 9, 2003, Docket RP00-336, page 71

[16] See Joint Reply Comments of Arizona Public Service Company and Pinnacle West Energy Corporation to Technical Conference and Associated Filings, page 1, November 3, 2003 in RP00-336

Juan receipt points associated with its Block II capacity entitlements, it would clearly enhance the reliability of that capacity.

For the above reasons, I believe the reliability of Block II capacity is likely to be greater than that assumed by the Company in its calculation of transportation costs.

**Q. Are there other points that you would like to make regarding the issue of gas supply reliability?**

A. Yes, there are at least two additional points that I believe are relevant. The first relates to the Power-Up capacity allocated to APS/PWEC in RP00-336, which accounts for 41 percent of the total capacity that the Company classified as non-firm in its pro forma analysis. Since the Power-Up project makes new capacity available through the addition of compression to the Line 2000 project, and its primary receipt points are located in the Permian basin, this capacity will not be subject to the constraints that could limit the reliability of Block II capacity. Also, as I noted earlier, the Power-Up capacity is not subject to recalls by California shippers, as is Block II. Thus, it would appear that at least 41 percent of the capacity that APS has designated as non-firm in its pro forma analysis could be reasonably relied upon to displace more costly capacity release purchases.

My second point relates to the fact that in developing its pro forma gas transportation costs, APS assumed that it will need to purchase sufficient firm monthly transportation to meet the simulated gas requirements for the single highest day of usage in each month. These fuel requirements include generation to serve APS' own load requirements, as well as sales for resale on a daily or hourly basis. APS would only conduct such sales, and would only purchase firm transportation to support them, if it is cost-effective to do so. It is not clear that APS would purchase firm monthly transportation to support spot market energy sales (which typically feature limited profit margins), as the Company's pro forma analysis effectively assumes. It is reasonable to expect that APS will weigh the costs and risks associated with potential transaction strategies, choosing a strategy

that seeks to limit expenses while maintaining a reliable fuel supply. This process is likely to yield a less costly outcome than that assumed in the pro forma analysis.

**Q. Given the foregoing, what is your recommendation with respect to gas transportation costs?**

A. Some judgment is required here. On one hand, there are a number of uncertainties associated with the transition from the historical FR contract regime to a CD regime. As explained above, the Company's pro forma estimate of gas transportation costs is based on a number of significant assumptions (e.g., market prices for monthly capacity release purchases and daily capacity release sales, how often certain transportation rights will be recalled, APS' own procurement strategy under the new CD regime) that cannot be tested against any significant operating history. In fact, it is possible that the appellate court could choose to remand the case back to FERC for further action, raising uncertainty about the ultimate allocations and other details of the CD regime.

On the other hand, it does appear that a transition to a CD regime is in progress, and that this will increase costs to APS by some amount. I understand that on September 1, 2003, El Paso actually terminated FR transportation service to APS/PWEC and replaced it with CD service in a manner consistent with the FERC orders in RP00-336. My recommendation therefore reflects the new CD regime using the Company's general approach and assumptions, but adjusted to reflect the specific concerns raised above regarding the amount of additional firm transportation that APS will need to purchase.

Specifically, I believe that it is reasonable to assume that 75 percent of APS/PWEC's entitlement to Block and Power-Up capacity can be utilized to deliver gas to APS/PWEC generating units in all months, at a reservation rate of $0.1636/MMBtu/day.[17] This approach is equivalent to assuming full availability of the Power-Up project in all months and a substantial rate of recall for the Block allocations in certain high demand months. I assume that the balance of APS'

transportation needs will be purchased from the capacity release market on a monthly basis, using the Company's approach and price assumptions. Using this method, I estimate a total net transportation cost of about $15.9 million per year, a reduction of $4.6 million from the Company's pro forma analysis. Exhibit DCS-10 summarizes this calculation.

**Q. Did the Company also estimate the net transportation cost under a scenario in which PWEC units are not rate based?**

A. Yes. APS estimates that the net cost of transporting gas on the El Paso pipeline to meet its daily gas requirements (including those associated with the Track B purchases) in the adjusted test year at $11.98 million. As with the PWEC rate base scenario, the Company's calculation assumes that all of the Base and Line 2000 capacity allocated to APS/PWEC in FERC proceeding RP00-336 will be available to meet APS' gas requirements. Similarly, daily gas requirements in excess of the Base and Line 2000 entitlements are assumed to be met with firm capacity purchases in the capacity release market.

**Q. Do you agree with the Company's estimate?**

A. No. For the reasons given above regarding the Company's calculation under the PWEC rate base scenario, I believe that the APS analysis overstates the amount of capacity release purchases that it will need to make. Assuming that APS will retain 100% of the APS/PWEC CD entitlements, and that 75 percent of the Block and Power-Up capacity can be treated as firm, I estimate an adjusted test year transportation cost of approximately $10.5 million, or $1.48 million less than the cost estimated by the Company. This calculation is summarized in Exhibit DCS-11.

## VI. NUCLEAR UNIT AVAILABILITY

[17] See LCA 19-469, which is attached as Exhibit DCS-9

**Q. Please explain how the operation of the Palo Verde nuclear units can impact APS' adjusted test year fuel and purchased power expense.**

A. The Palo Verde nuclear units, in which APS has a 29% ownership interest, are the largest and lowest-cost generating units on the APS system. Thus, any increase in the availability of these units could avoid the need to burn expensive fuel in generating units with higher variable costs or, alternatively, avoid purchases of relatively high-priced wholesale power.

**Q. What assumptions did the Company make regarding operation of the Palo Verde nuclear plant in the adjusted test year?**

A. The Company used different capacity factors for the three units in its modeling of system fuel and purchased power costs.[18] Unit 1 was assumed to have an annual average capacity factor of 97.6% during the adjusted test year, reflecting no planned outages for refueling and limited unscheduled outages. Units 2 and 3 were assumed to have capacity factors of 86.8% and 87.7% respectively, reflecting planned refueling outages of over 30 days for each unit. Overall, the plant was assumed to have a weighted average capacity factor of 90.6%.

**Q. Do you agree with these assumptions?**

A. Not totally. While it is reasonable to assume that refueling outages at multi-unit nuclear plants will be staggered, thus resulting in each unit having a different capacity factor in any given year, those capacity factors should not be the basis of fuel and purchased power cost estimates in base rate proceedings. The Palo Verde nuclear units, like other pressurized water reactors, operate on a three year fuel cycle.[19] Thus, in order to avoid using a capacity factor that is not representative of future operations, I recommend using a three-year rolling average capacity factor to estimate the output of each unit. Using actual annual capacity factors for the Palo Verde units over the last three years results in a decrease in Unit 1 output and increases in the output of Units 2 and 3 relative to

[18] Capacity factor is a measurement of the plants' actual operation, compared to its rated capability.
[19] This means that each unit will be refueled in two of any three consecutive years.

the output levels assumed in the Company's pro forma analysis.[20] These historical unit operating levels are equivalent to weighted average capacity factor of 91.8%, which is just over 1% more than the Company's assumption.

**Q. How do your capacity factor assumptions compare to industry averages?**

A Data on US nuclear industry capacity factors is reported by the Nuclear Energy Institute. Those data show that most nuclear plant operators have been successful over the last decade in minimizing the frequency and duration of forced outages and minimizing the duration of scheduled outages. As a result, the industry average capacity factor has improved dramatically from just 71.3% in 1992 to 91.9% in 2002. The industry average does not, of course, show the variation in performance between plant operators. This is provided in Exhibit DCS-12, which presents industry capacity factor data by quartile. This exhibit shows that the top 25% of performers (i.e., 1st Quartile) had an average capacity factor of 96.5% in 2002, whereas the 4th Quartile averaged only 85.8% in the same year. Based on this analysis, the Palo Verde nuclear units would appear to rate as 2nd and 3rd Quartile performers. It is also significant that the weighted average capacity factor for Palo Verde that results from using the three-year rolling averages (91.8%) is less than the plant's weighted average capacity factor of 94.4% in 2002, the test year for this case. My recommendation represents a reduction in the Palo Verde production (and an associated increase in APS net power supply costs) relative to the test year actual results.

**Q. What is the basis of the capacity factors used by the Company in its pro forma analysis?**

A Despite requests for supporting workpapers and calculations, the Company did not clearly explain how it developed the capacity factors underlying the Palo Verde monthly generation quantities in its pro forma analyses.

[20] The three-year rolling averages for Units 1, 2 and 3 are respectively 92.5%, 90.7% and 92.1%. The corresponding factors in the Company's analysis are 97.6%, 86.8% and 87.7%.

**Q. What are the cost implications of your recommended capacity factors?**

A Based on the assumption that an increase in nuclear generation will displace wholesale market power purchases, I estimate that this would reduce APS' purchased power expense by approximately $5 million in the adjusted test year. This calculation is summarized in Exhibit DCS-13.

**Q. Does this conclude your testimony?**

A. Yes.

# DOUGLAS C. SMITH

*LA CAPRA ASSOCIATES*
Technical Director

---

Douglas Smith, Technical Director, has over 16 years of experience in the electric power industry. He is experienced and skilled in the areas of electricity markets, transactions and competitive procurement, resource planning, system simulation, and project feasibility analysis. While at La Capra Associates Mr. Smith has assisted utilities, generators, and regulatory agencies in the analysis of issues related to electric system planning, price forecasting, risk management and power transactions. Prior to joining La Capra Associates, Mr. Smith was employed as an Electrical Planning Engineer and Power Cost Analyst for the Vermont Department of Public Service.

As Technical Director, Mr. Smith has also taken a lead role in managing and directing La Capra Associates' work on renewable energy technologies and policies. His experience in wholesale market design and transactions has directed our clients to successfully purchase renewable power, as well as to understand how market conditions and the market's structure will influence sales of renewable electricity generation.

## RELEVANT EXPERIENCE

- On behalf of the California Bureau of State Audits, reviewed the power purchasing program conducted by the California Department of Water Resources during 2001. Mr. Smith managed La Capra Associates' investigation of the Department's $10 billion of short term power transactions, and participated in the investigation of the Department's $43 billion of long term purchases.
- Managed and conducted power transactions of several New England electric utilities, from 1991 to present. Responsibilities include risk management strategy and analysis, simulations of alternative procurement strategies, negotiation with potential trading partners, and development of contract terms. Presently responsible for managing the power supply portfolio of the Washington (VT) Electric Cooperative, Inc.
- Leads the procurement of competitive retail generation service contracts for Amtrak (the National Railroad Passenger Corporation). Responsibilities include analysis of utility "shopping credits," solicitation of competitive supplies, evaluation of proposals, and competitive negotiations with suppliers. This effort produced successful supply contracts with several suppliers, resulting in several million dollars of customer savings.
- Reviewed PacifiCorp's procurement practices in the western markets for power deliveries during the fall 2000 through fall 2001 period in the context of a request for recovery of deferred excess power costs. Mr. Smith analyzed historical spot market prices, forward market conditions and utility's net short position and procurement practices to assess the merits of the company's request. Findings were presented in written and oral testimony before the Wyoming Public Service Commission.

- Provided testimony and advice on behalf of the New Hampshire Public Utilities Commission Staff's review of a proposal by Unitil for the provision of Transition Service power supply regarding the design of POLR service, and the auction to divest Unitil's power supply.
- Led La Capra Associates team in assisting the Massachusetts Division of Energy Resources to implement the Massachusetts Renewable Portfolio Standard. Identified and evaluated program design options such as technology eligibility, applicability of RPS to retail generation providers, and provisions for "banking" of compliance. Performed cost analysis, presented technical policy options to stakeholder group, and facilitated discussion with stakeholder group and regulators on key issues.
- Led a detailed analysis of future wholesale electricity market prices in the PJM Interconnection, and presented the analysis in expert testimony before the Pennsylvania Public Utilities Commission. The forecast was adopted by the Commission as the basis for determining the stranded generation costs of Pennsylvania utilities.
- Led detailed dispatch simulations of electric utility systems -- including the NEPOOL, PJM and ECAR regions of the U.S., the state of Maharashtra (India), and numerous individual U.S. utilities -- to identify the implications of alternative resource choices and planning assumptions on market prices and revenues.

## EMPLOYMENT HISTORY

**La Capra Associates** — Boston, MA
*Technical Director* — *1990-Present*

**Vermont Department of Public Service** — Montpelier, VT
*Electrical Planning Engineer* — *1988-1990*

## EDUCATION

**Brown University** — Providence, RI
*B.S., Mechanical Engineering with Energy Conversion emphasis* — *1986*

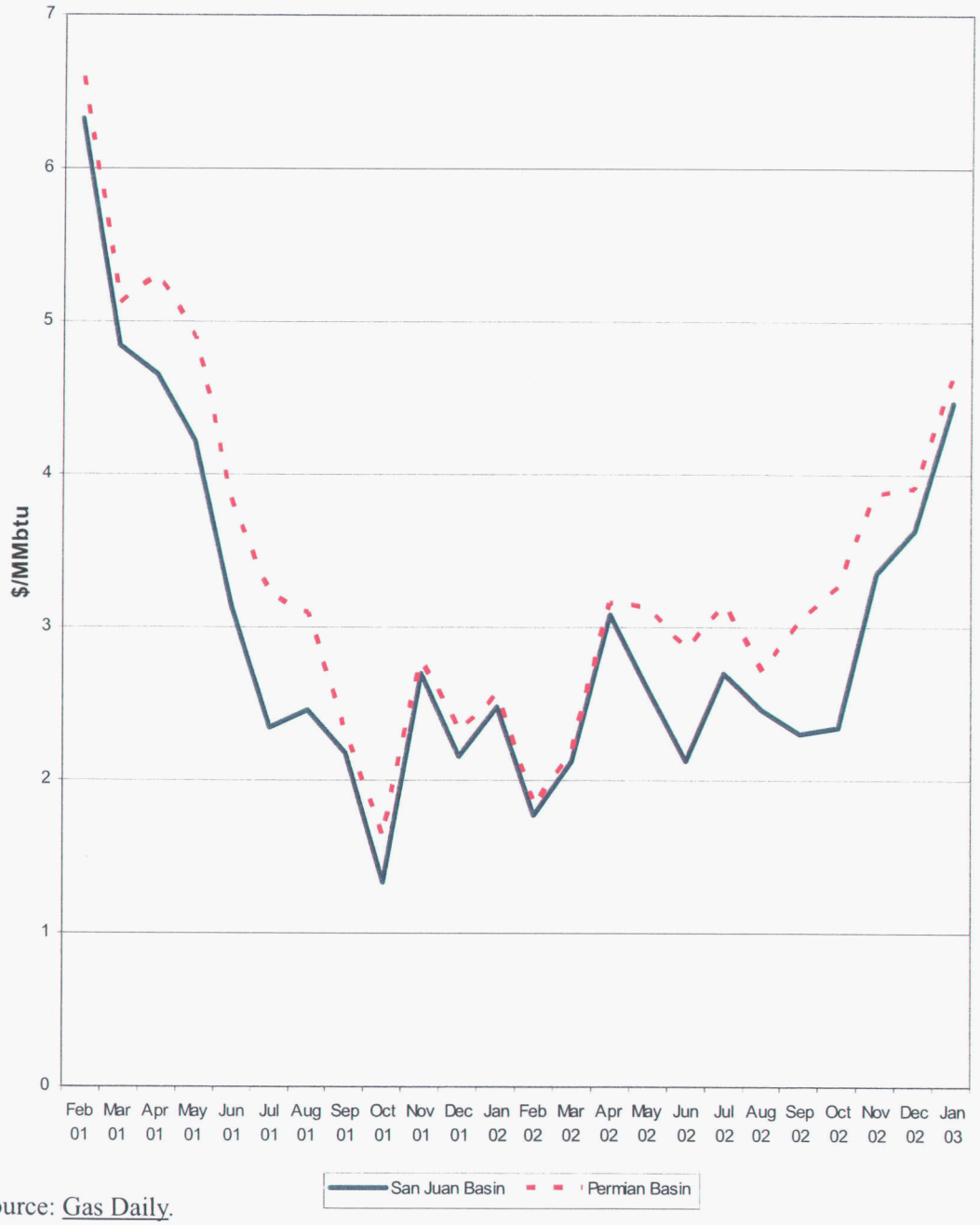
## RECENT REPORTS

*Massachusetts Renewable Portfolio Standard: Cost Analysis Report*, Massachusetts Division of Energy Resources, December 21, 2000. Senior Advisor and Co-Author.

*Massachusetts Renewable Portfolio Standard: Report on Sales from Existing Renewable Generating Sources*, Massachusetts Division of Energy Resources, May 25, 2000. Senior Advisor and Co-Author.

Exhibit DCS-4

# Recent Natural Gas Spot Market Prices

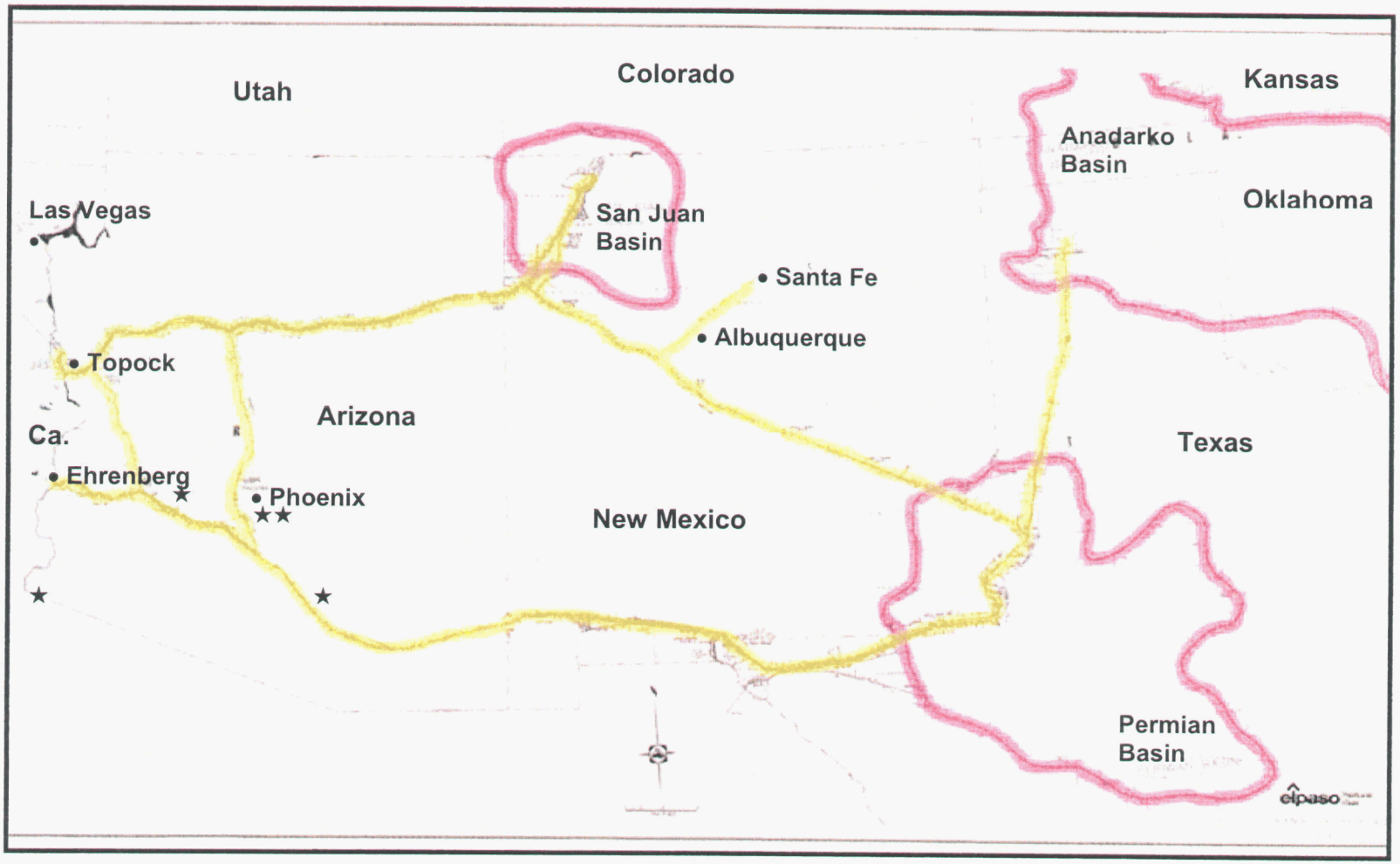



Source: Gas Daily.

# Illustrative Effect of Load Growth Under a PPFAC

| | | MWh/year | Annual Cost | Average $/MWh |
|---|---|---|---|---|
| **Base Case, per APS Filing** | | | | |
| | **Normalized Ownload Sales (MWh)** | **25,208,287** | | |
| (a) | **Normalized Fuel & Purchased Power Expenses** | | **$584,087,000** | **$23.17** |
| (b) | **Fixed Power Supply Costs** | | **$500,000,000** | **$19.83** |
| **Illustrative Costs, Assuming 4 Percent Load Growth** | | | | |
| | **Additional System Energy Requirements (MWh)** | **1,008,331** | | |
| | **Adjusted System Energy Requirements (MWh)** | **26,216,618** | | |
| | **Incremental Fuel & Purchased Power ($/MWh)** | **$50.0** | | |
| | **Incremental Fuel & Purchased Power Cost** | **$50,416,574** | | |
| | **Adjusted Fuel & Purchased Power Expenses** | | **$634,503,574** | **$24.20** |
| | **Fixed Power Supply Costs** | | **$500,000,000** | **$19.07** |
| **Summary of Rate Recovery** | | | | |
| | **Fuel & Purchased Power Expenses** | | | |
| | **Collected in Rates** | | **$ 607,450,480** | **$23.17** |
| | **Actual Expenditure** | | **$ 634,503,574** | **$24.20** |
| | **Over/(under) Collection - Reconciled in PPFAC** | | **$ (27,053,094)** | **-$1.03** |
| | **Demand-Related Power Supply Costs** | | | |
| | **Collected in Rates** | | **$ 520,000,000** | **$19.83** |
| | **Actual Expenditure** | | **$ 500,000,000** | **$19.07** |
| | **Over/(under) Collection - Not Reconciled** | | **$ 20,000,000** | **$0.76** |

(a) Normalized 2003 Fuel & Purchased Power Cost, DGR workpaper 12, page 3
(b) Illustrative value, representing rough magnitude of depreciation, return, and income taxes related to production

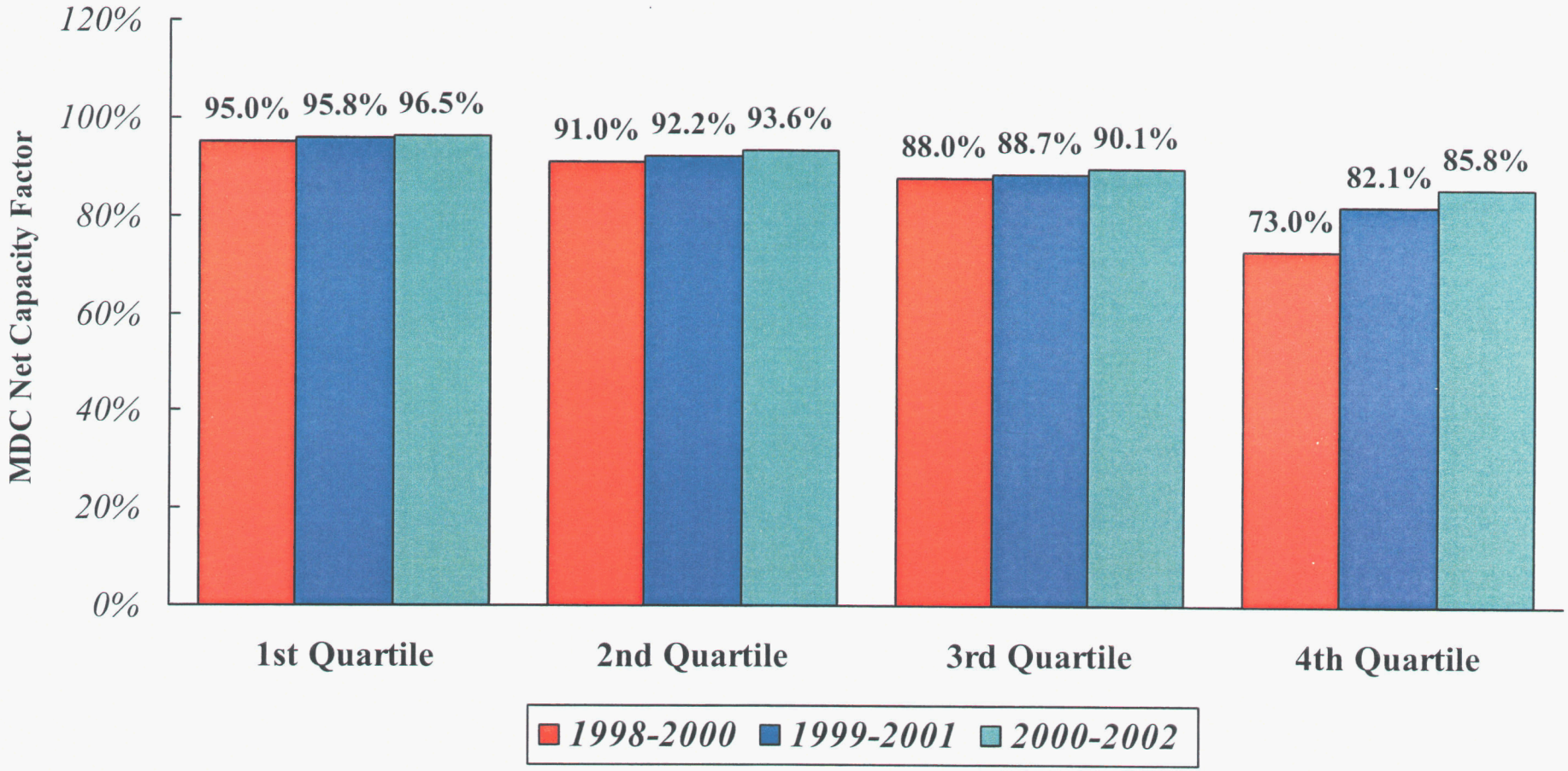



**Legend**

- Basin
- Pipeline
- Population Center
- APS/PWEC Gas Power Plants

Exhibit DCS-12

# U.S. Nuclear Industry
# Capacity Factors by Quartile
*(3-year rolling average for 103 units)*




*Source: UDI*

NEI

Exhibit DCS-13

**LA CAPRA ASSOCIATES**
**PRO FORMA ADJUSTMENT TO PURCHASED POWER COSTS**
**DUE TO ADJUSTMENT IN NUCLEAR OUTPUT**

| | January | February | March | April | May | June | July | August | September | October | Novemeber | December | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Palo Verde Unit 1 | (13,827) | (12,454) | (13,822) | (13,339) | (13,755) | (13,261) | (13,776) | (13,833) | (13,289) | (13,751) | (13,246) | (13,787) | (162,141) |
| Palo Verde Unit 2 | 12,826 | 11,526 | 12,764 | 12,275 | 12,748 | 12,213 | 12,771 | 12,676 | 10,687 | 0 | 11,506 | 11,225 | 133,218 |
| Palo Verde Unit 3 | 13,353 | 12,038 | 11,990 | 0 | 11,549 | 12,955 | 13,288 | 13,229 | 12,847 | 13,293 | 12,815 | 13,243 | 140,600 |
| Total Plant | 12,353 | 11,110 | 10,931 | (1,064) | 10,542 | 11,908 | 12,283 | 12,071 | 10,246 | (458) | 11,074 | 10,681 | 111,676 |
| | | | | | | | | | | | | | |
| On-Peak (MWh) | 6,831 | 6,144 | 6,045 | (588) | 5,830 | 6,585 | 6,792 | 6,676 | 5,666 | (253) | 6,124 | 5,907 | 74,451 |
| Off-Peak (MWh) | 5,522 | 4,966 | 4,886 | (476) | 4,712 | 5,323 | 5,490 | 5,396 | 4,580 | (205) | 4,950 | 4,774 | 37,225 |
| | | | | | | | | | | | | | |
| On-Peak Price ($/MWh) | $50.05 | $48.66 | $47.54 | $43.49 | $47.13 | $56.63 | $69.67 | $70.81 | $57.52 | $48.56 | $48.03 | $50.41 | |
| Off-Peak Price ($/MWh) | $32.10 | $31.12 | $29.40 | $27.32 | $27.88 | $31.00 | $38.17 | $39.66 | $37.67 | $33.67 | $32.92 | $33.92 | |
| | | | | | | | | | | | | | |
| Power Cost Adjustment ($) | $519,142 | $453,498 | $431,029 | -$38,585 | $406,139 | $537,908 | $682,786 | $686,699 | $498,425 | -$19,201 | $457,106 | $459,697 | $5,074,643 |

EXHIBIT
S-9
Admitted

**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT | ) | DOCKET NO. E-01345A-03-0437 |

***REDACTED***

DIRECT TESTIMONY

OF

HARVEY SALGO

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

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VII. RECOMMENDATIONS TO THE COMMISSION ..... 24

## I. INTRODUCTION

**Q. What is your name and business address?**

A. My name is Harvey Salgo and my business address is La Capra Associates, 20 Winthrop Square, Boston, Massachusetts.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the Arizona Corporation Commission (Commission) Staff.

**Q. Please describe your background and experience.**

A. I am a Principal at La Capra Associates, where I have been since 1992. I am both an economist and an attorney, although any legal work I do now is quite limited in both scope and subject matter. Prior to joining La Capra Associates, I was an assistant professor of economics at the University of Vermont (1969-74), an attorney/economist at the then-named Massachusetts Department of Public Utilities (1977-78), a partner in the law firm of Salgo&Lee (1978-87), and a consultant at the Tellus Institute (1987-92).

Throughout my experience, I have worked extensively in regulation, industry structure and competitive markets, competitive procurement, and planning. In addition to numerous U.S. clients, I have been a long-term advisor to the World Bank and have worked extensively for it and other development banks or agencies in a number of countries. I have recently worked in matters related to the Western markets for the California Bureau of State Audits, the Wyoming Industrial Energy Consumers and the Nevada Bureau of Consumer Protection. I have been an invited speaker on numerous occasions and have previously testified in Massachusetts, Vermont, Rhode Island, Colorado, and Pennsylvania.

My resume is attached as Exhibit HS-1.

**Q. What is the purpose of your testimony?**

A. I am testifying regarding the APS (Company) proposal to acquire and to ratebase the PWEC generating units.

## II. SUMMARY OF TESTIMONY

**Q. APS is requesting approval to ratebase five generating units owned and operated by its Pinnacle West Energy Company ("PWEC") affiliate. What is your view of APS' proposal?**

A. The ratebasing of the five PWEC generating facilities would substantially increase APS' revenue requirement and rates to APS' customers. The Company has failed to demonstrate that approval of its request is warranted.

**Q. Please summarize your conclusions and recommendations.**

A. My conclusions and recommendations are as follows:

(1) The Commission should review the Company's proposal to ratebase the PWEC generating units on a prospective basis and in the same manner as it would review a comparable acquisition from an unrelated entity.

(2) The adverse impacts of the Company's proposal are significant.

(3) The Company's proposal would require that the winning short-term bids and associated PWEC contracts in the Track B solicitation – which were from PWEC itself – be foregone. .The foregone benefits are substantial and in the long run, APS' proposal would impose significant net costs on ratepayers.

(4) A Commission disapproval of the Company's proposal to ratebase the PWEC units would not mean that the Company would have to rely entirely on the market as a replacement. For example, were the Company to retain the Track B PWEC contracts and construct (and ratebase in 2007) new units that are similar to the PWEC units (i.e., 1,700 MW of combined cycle plants), the total costs to ratepayers would be comparable to the costs of the Company's proposal.

(5) Nor would disapproval mean that the Company and its customers would have to face a lower level of reliability. The Track B contracts secure the supplies for APS in the near term and longer term options can be developed.

(6) The foregoing example (paragraph 4) should be seen as a "ceiling" price or cost and is not recommended as an alternative resource plan for APS because, with proper resource planning and implementation, the Company should do no worse than the example and perhaps could do significantly better.

(7) I recommend that the Commission reject APS' ratebasing proposal.

(8) However, if the Commission decides for some reason that the PWEC assets should be ratebased, the amount allowed in ratebase should be no more than the current value of the units, which is below their book value, adjusted to reflect the value lost in foregoing the PWEC Track B contract.

(9) APS' proposal to ratebase units that it would acquire from another entity is, in terms of its implications for industry structure, no different than were it to ratebase power plants that it built itself. Hence, if the Commission determines that, in principle, the ratebasing of purchased or self-built power plants is consistent with its views regarding industry structure, the Commission should make clear that APS has the authority to build, own and operate new generating facilities.

**Q. Please provide an overview of the balance of your testimony.**

A. (1) In Section III important background information is provided.

(2) In Section IV, I discuss the principles that the Commission should consider in order to evaluate APS' proposed resource acquisition.

(3) Section V is a discussion of APS' Application.

(4) Section VI is a discussion of generation supply options.

(5) In Section VII, I summarize my conclusions and recommendations.

## III. BACKGROUND

**Q. Please describe the generating assets that APS is proposing to add to its ratebase.**

A. APS is proposing to add to its ratebase five generating facilities owned and operated by PWEC within the State of Arizona (the "PWEC Assets"). These units are Redhawk Units 1 and 2 (1,060 MW total), West Phoenix 4 (120 MW), West Phoenix 5 (530 MW), and the Saguaro Unit (80 MW). All but the Saguaro CT 3 facility are natural gas-fired, combined cycle generating units. The Saguaro unit is a natural gas-fired combustion turbine. The sum of their peak season, summer capacities, as identified in Table 1 to Company Witness Bhatti's Direct testimony, is 1,700 MW.

**Q. What are the essential features of APS' PWEC ratebasing proposal?**

A. The proposed ratebasing of the PWEC Assets would affect both ratebase and the income and expense items that contribute to revenue requirements.

**Q. How will ratebase be affected?**

A. The amount that APS proposes to add to ratebase would equal the gross plant investment in the PWEC Assets as of June 30, 2004 (including some transmission plant associated with the Redhawk facilities), adjusted downward to reflect accumulated depreciation and accumulated deferred income taxes. This calculation is reflected in Mr. Robinson's workpapers (see Workpaper DGR_WP 1, at 1) on a system level (i.e., including some small non-jurisdictional wholesale contracts). The amount to be added to ratebase, $889.2 million, equals the amount in that workpaper (i.e., the $895.1 million in the "Ratebase" line for June 30, 2004), multiplied by an ACC-jurisdictional allocator (see Schedule B-2, page 1 of 3). The Company's revenue requirement will increase as a function of the allowed rate of return applied to this ratebase increase.

**Q. In what other manner will rates be affected?**

A. Ratebasing the PWEC Assets would also affect various expense items and offsetting revenues. The Company's revenue requirement will increase as a function of the net amount of the return, the expense, and the revenue adjustments.

**Q. Has the Company indicated what the overall impact of adding the PWEC Assets to ratebase would be?**

A. Yes. In its August 7, 2003 letter to Commissioner Gleason the Company explains the impact of adding the PWEC Assets to ratebase by describing the net impact on the revenue requirement. The Company indicates that, by adding the PWEC Assets to ratebase, revenue requirements would increase (on an annualized basis) by $106.6 million.

**Q. What are the rate implications of a $106.6 million increase to the revenue requirement?**

A. A $106.6 million increase to the revenue requirements corresponds to an approximately 6 percent increase in rates, based on the figures introduced by the Company in Schedule A-1.

**Q. Has APS made any investment in the PWEC Assets?**

A. No. To my knowledge the PWEC assets were built by and currently belong to APS' affiliate, PWEC.

**Q. Does APS currently use the PWEC assets to serve its customers, as APS Witness Bhatti claims?**

A. APS has a contract with PWEC that entitles APS to purchase the output of PWEC's Redhawk, West Phoenix and Saguaro units during the summer peaking season (i.e., June through September) starting in 2003 and ending in 2006. APS does not, however, own these assets, and they are not part of APS' investment in generation plant.

**Q. Is approval from the Federal Energy Regulatoy Commission ("FERC") necessary before the ratebasing transaction proposed by APS can proceed?**

A. The Company indicates that PWEC would be required to make an application under Section 203 of the Federal Power Act and receive FERC authorization to transfer the PWEC Assets to APS (see response to AzCPA 1-92). Until FERC issues its ruling, there will be uncertainty regarding whether, when or under what conditions FERC would allow the transfer to proceed. If FERC imposes conditions that have cost implications for APS, the economics of the proposed transfer may be affected.

## IV. STANDARD OF REVIEW

**Q. According to the Company, how should the Commission evaluate the prudence of adding the PWEC Assets to APS' rate base?**

A. The Company's view, described broadly, is that since PWCC's planning was "APS-centric", it is the prudency of PWCC's planning and PWEC's implementation of those plans that should be scrutinized and evaluated by the Commission. The Company proposes that the Commission's evaluation focus on what was known at the time of those PWEC actions.

**Q. Is this the proper timeframe to evaluate in this case?**

A. No, it is not. APS' investment in the PWEC facilities should be evaluated relative to circumstances at the time that APS proposes to make the investment. As described by Staff Witness Linda Jaress, the Company's claim that these assets should be viewed as if APS had itself built these units to meet APS loads is unfounded.

**Q. Do you agree with the Company's claim that planning was "APS-centric"?**

A. No, I do not. A better way to describe the planning for these assets is that it was Pinnacle West-centric. First, as described by Linda Jaress, the Company's quarterly and annual reports issued contemporaneously make clear that the generation planning done at that

time was focused on developing merchant (unregulated) generation to sell into competitive markets in the West, not exclusively the APS market. This can be construed to be "APS-centric" only to the extent that the APS service territory was central to the portions of the western markets to which the PW merchant strategy was targeted.

Second, while Mr. Hieronymus points to 1999 planning studies that, he contends, support the "APS-centric" assertion, that seems to be unlikely. He points out that these studies demonstrated that PWEC's low-cost competitive position would enable it to be the successful bidder for 100 percent of APS's load requirement. My interpretation of Mr. Hieronymus' statement is that a more plausible conclusion is that the study was focused on PWEC as a market-based competitor for APS load, not as an "agent" or other form of dedicated provider. PWCC and PWEC may have concluded that they had a distinct market advantage in competing for the APS load as part of their overall strategy, which would include sales, not only to APS, but to other potential purchasers as well.

**Q. Please describe the approach you utilized in assessing APS' request to include the PWEC Assets in ratebase.**

A. I reviewed the Company's proposal on a going-forward basis. Also, my review was indifferent to the affiliate relationship between APS and PWEC. That is, it is my view that the proposal should be reviewed in the same manner as would a transaction between APS and an unaffiliated seller of generation assets. More specifically, I examined whether APS has demonstrated that the PWEC Assets represent the best, most cost-effective additions to APS' supply portfolio, given full consideration of the attendant benefits, costs and risks to ratepayers as evaluated relative to the full range of alternatives. In my view, the appropriate measure of the merits of APS' proposal to acquire the PWEC assets in question is on a current market economics basis.

From this perspective, I have assumed that the Track B contracts are commitments already made by APS. This is important on a going-forward basis as the APS ratebasing proposal includes the elimination of the PWEC Track B contract.

**Q. Does the Company's application satisfy the foregoing standard?**

A. No, it does not. The Company focuses a great deal of its attention on the applicability of the prudency standard to actions by PWCC and PWEC when these facilities were planned and built. Company Witness Hieronymus asserts that an analysis of the contemporary economics of these assets is inappropriate and, accordingly, the Company does not present any systematic appraisal of the current market value of these assets.

On the other hand, the Company does reference several analyses that, it argues, demonstrate the value of the PWEC assets to APS ratepayers. These analyses assess the purported ratepayer benefits of the PWEC units on a going-forward basis; but, as I will describe, they are limited in scope and inappropriate to addressing the standard I propose. What the Company's analyses do not do is assess the PWEC assets in relation to the options available to APS today, using current cost assumptions, and performed in light of proper supply planning objectives and constraints regarding, for example, reliability, resource mix, fuel diversity, location, exposure to price volatility, water use, emissions, and efficiency.

**Q. Even if one were to apply the prudence standard that APS appears to have proposed, has APS demonstrated that the PWEC assets were prudent?**

A. If the Commission accepts the Company's request to review PWEC's planning at the time those investments were made by PWEC, I would recommend that APS (as the regulated entity) be required to demonstrate both that (a) PWEC's planning was indeed focused on meeting APS' requirements for additional generation supplies and (b) that its planning was tied to what would have been optimal for APS rather than for PWEC (or Pinnacle West Capital Corporation). In addition, for inclusion in rate base, APS would need to demonstrate that the acquisition is "used or useful" in light of present circumstances.

To satisfy the foregoing, PWEC's investments should be evaluated individually rather than as a group. With respect to prudency, APS should be required to demonstrate that,

for each unit, at the time the investments were made, it represented the best option available for APS. To do so, the Company should be required to produce planning documents prepared at the time that show that the PWEC investment was optimal for APS, given due consideration of all pertinent factors, including but not limited to the following:

- Whether the PWEC unit would be part of a generation expansion plan (specific for APS' requirements) that would have been cost-effective (for APS) relative to other supply- and demand-side options. By way of example, the Company could produce production cost runs and results for APS' own load, similar to those included in its 2003 Long Run Forecast (see the response to LCA 16-365) that existed at the time of the investment in a given PWEC unit;
- Whether the PWEC unit would contribute to meeting APS' need (as distinct from a more general need in the region) for incremental generating capacity and/or energy. By way of example, the Company could produce load and energy balances for APS' own load, with and without the PWEC unit in question, as existed at the time of the investment in a given PWEC unit; and
- Whether the PWEC unit would offer a hedge against outcomes that would be adverse to the interests of APS ratepayers. By way of example, the Company could produce "stress tests," as existed at the time of the investment in the PWEC unit, that show how ratepayers might benefit during a run up in fuel prices if the PWEC unit in question were available as part of APS' supply portfolio.

The Company's application does not provide the contemporary information that would allow the Commission to evaluate in a systematic, comprehensive manner PWEC's decision processes relative to APS' needs and APS' options in light of conditions known at the time that each PWEC investment decision was made.

## V. ASSESSMENT OF APS' APPLICATION

**Q. Does APS have an immediate need for incremental generation supplies?**

A. APS' needs for incremental generating capacity are summarized in Attachment AB-2 to the Direct Testimony of Company Witness Bhatti. Attachment AB-2 provides a view of APS' need for additional generating capacity (i.e., MWs) – it does not address APS' energy needs or other aspects of its resource requirements. Attachment AB-2 indicates that the Company has sufficient generation supplies during 2003. A relatively small capacity need appears in 2004, the year in which APS proposes to include the five PWEC units in ratebase. Attachment AB-2 identifies a need for 161 MW of additional generating capacity in 2004, increasing steadily thereafter.

**Q. Does the Company's filing address its overall needs for incremental generating capacity?**

A. No. The Company's ratebasing proposal would have no effect on its incremental capacity needs during 2004 through 2006. The Company's filing addresses only a part of its incremental capacity needs for 2007. As I explain in more detail below, the Company's filing focuses on whether ratebasing the PWEC Assets is a good choice relative to (1) ratebasing a similar set of new generating units in 2005, and (2) relative to purchasing a like amount of power (i.e., quantities that the PWEC Assets would be able to produce) from the wholesale power market. The Company's filing does not address whether replacing the Track B PWEC contract with the PWEC Assets would be appropriate. Nor does the Company address important resource planning questions within the context of the overall capacity (or energy) needs of the Company.

**Q. Does APS need to acquire 1,700 MW of generating capacity to serve its customers in 2004 when it proposes to put the PWEC Assets into ratebase?**

A. No. But for a relatively few megawatts – i.e., the 161 MW need for 2004, representing an amount less than 10 percent of the PWEC capacity, and which could be met through

short-term market purchases – additional capacity is not needed in the immediate future because of the Track B contract with PWEC.

**Q. In his Direct Testimony, Company Witness Bhatti describes a load pocket in the Phoenix area. Does APS have a need for incremental generation supplies to effectively respond to this load pocket?**

A. I have not performed an independent assessment of the situation, although I would like to comment on it. A load pocket can introduce problems both from the standpoint of reliability and costs. APS should certainly take all reasonable steps to evaluate its system to determine the degree to which a load pocket does or will exist, and should respond to its findings in an appropriate manner. That said, APS has contractual rights to the output of the PWEC facilities during the summer peak season through 2006. It seems unlikely that ratebasing those same generating units would affect its position relative to potential load pocket concerns. APS may identify needs relative to the load pocket in 2007 and beyond, but an appropriate response -- whether it includes some of the PWEC Assets, or other strategies – should be developed in the context of a comprehensive resource plan.

**Q. Does the state of the wholesale power market affect APS' power supply options?**

A. The Company states that it cannot rely on the wholesale power market that serves Arizona as a reliable source of low-cost power, implying that it has a need for owned generation supplies.

APS witness Bhatti warns that the current capacity surplus in Arizona could disappear by 2006, leading to potential shortages and higher prices. In addition, Dr. Hieronymus projects that the western power market will cease to be surplus sometime between 2005 and 2008. I have not performed a study of the supply/demand balance in Arizona, so I cannot comment directly on these forecasts.

**Q. What are your views regarding the foregoing?**

A. If the market is such that the Company should have additional owned generation, that case should be made by a full examination of all options, and the associated risks, on a going forward basis. This would necessarily include a demonstration that the present acquisition of the PWEC Assets is the best option.

I have examined a simple alternative to this option: that is, retention of the Track B PWEC contract through 2006 and the construction by the Company of 1,700 MW of natural gas-fired combined cycle units to be ratebased in 2007. See Exhibit HS - 2. The cost of this alternative is comparable to, and probably slightly lower than, the Company's proposal in this case. It appears that the Company has reached essentially the same conclusion. See Exhibit HS - 3.

Given this option, which I assume the Company can improve upon, there is assurance that the alternative to the PWEC Assets need not be either a lower level of service reliability or a heavier reliance on the market. Another advantage is that the Company would have some time to explore other options, which might provide either short or long term benefits to its customers. In other words, if the Company is persuaded that market prices will quickly increase, and that the potential benefits of the market are associated with unacceptable risks, options other than the PWEC Assets are available.

If the build option I just alluded to were indeed to be available, the Commission may need to clarify that APS has the authority to build, own, and operate its own power plants. As I state elsewhere, I do not believe that there are fundamental differences, as regards industry structure, between ratebasing a power plant that is purchased from another entity and one that is self-built.

**Q. Given the foregoing, what are the shortcomings of the Company's application?**

A. The Company did not make a presentation based on the current market value of these assets. Nor does the application contain the information needed to assess the current

value of these assets and the suitability of these assets to meet the requirements of APS customers. More specifically:

1. The Company has not presented an estimate of the current value of these assets based upon a comprehensive resource plan, which in my view, is essential.
2. In addition, it is my view that, as a matter of policy, where major transactions – such as the Company's proposal here – are contemplated between affiliated entities, there should be proper, independent (that is, qualified third party) verification of the operating history and present condition of the assets. It does not appear that such a review has been undertaken.
3. The Company's analysis does not reflect the benefits of the power supply commitments made by PWEC to APS in Track B.
4. The Company has failed to provide a clear view of its target resource portfolio and related supply planning objectives. Without this essential context, it is impossible to evaluate the extent to which the acquisition of the PWEC assets would contribute to or detract from important planning goals.

**Q. Why do you believe it is important for the Commission to have accurate information on the current market value of these assets?**

A. In any situation wherein a regulated entity is seeking approval of a major asset acquisition, a comprehensive and transparent resource plan that demonstrates its value should be required. In this case, where the buyer and seller are affiliated entities, the need is exacerbated.

Even under the APS-proposed alternative standard, a current market valuation is important for the Commission to have so that the amount of "consideration" that is provided to PWEC by APS ratepayers is quantified and the terms of the deal are transparent.

**Q. Why are you concerned that the APS analysis does not reflect the benefits of the Track B contracts?**

Ratebasing the PWEC Assets in July 2003 would negate the very substantial ratepayer benefits achieved through APS' Track B contract with PWEC, which the Company's analysis indicates is quite favorable to the Company compared to market alternatives. The present value of these lost ratepayer benefits is estimated to be roughly $[redacted] million, based upon the Company's August 2003 market price projections. See Exhibit HS - 4.

**Q. Please explain your concern regarding the fact that APS has not addressed its broader portfolio planning objectives.**

A. The Company has failed to properly define its need for additional generating resources. While it has indicated its need for additional generating capacity (i.e., MWs), the basic planning objectives that should govern additions to the Company's resource portfolio are unclear. In my view there are many planning considerations that bear on this proposal that would be important to the Company and to the Commission. These may include the following:

Reliability – Testimony presented by APS witnesses raises questions regarding reliability of supply to its customers. However, the Company's filing contains no comprehensive presentation regarding the resources that it should acquire to ensure supply reliability, or the degree to which it would be appropriate to rely on owned versus contract supplies.

Price Security – Testimony presented by APS witnesses also raise concerns regarding risks (levels, volatility) in the price of power to customers. However, the Company does not explain in an effective manner how its supply plan, which is dependent on prices in natural gas markets, would hedge against electricity market price volatility.

Generation Mix – The PWEC supply additions proposed by the Company are dominated by combined cycle generating capacity. It has not

demonstrated that such additions would best serve the energy requirements (i.e., as distinct from capacity requirements) of its customers. For example, there is no indication whether a supply plan that relies more heavily on peak season purchases (similar to that implicit in the Track B PWEC contract), or combustion turbines might be more beneficial to APS' customers. Environmental goals also might affect APS' optimal generation mix.

Fuel Mix – APS' filing makes a limited presentation on the fuel mix that would be achieved by ratebasing the PWEC assets. However, it does not explain why it is the best mix for ratepayers.

Open Access Policy – The Company should address the impact that its supply plan would have on efforts to open Arizona's wholesale and retail power markets to competition. Moreover, APS has not addressed its anticipated role in securing power supplies for its customers, or why such approach is consistent with overall planning objectives.

Rate Impacts – As noted above, ratebasing the PWEC proposal would have a substantial near term impact on rates. Other near- and long-term (including contract) supply options could have significantly different rate implications. The Company's filing is silent on this important issue.

In short, the Company has failed to set a foundation that would enable the Commission to understand why the PWEC Assets represent the best means by which to meet the needs of APS' customers relative to its alternatives available today and in the future.

**Q. Is the Company familiar with the critical elements of a proper resource plan?**

A. Certainly, it is. For example, in his July 2003 presentation to the Pinnacle West Board of Directors, Company Witness Wheeler made a presentation entitled "[redacted]." That presentation included a slide entitled "[redacted]" which includes "[redacted]

[redacted]" See Exhibit HS - 5.

**Q. Should the Company be expected to provide the Commission with the critical elements of a resource plan?**

A. As with any new acquisition of new generating assets, APS should be expected to demonstrate how its chosen supply plan would reasonably balance important policy considerations and compliment its overall resource plan.

**Q. What statements has the Company made in its filing regarding the benefits that it claims will result from ratebasing the PWEC Assets?**

A. The Company points to a total of five different amounts reflecting the savings projected to accrue to ratepayers if its application is approved. In each instance, the savings identified consider neither current conditions in wholesale power markets nor the full range of supply options that currently may be available to APS. The Company's savings estimates leave unanswered the question of whether it currently has access to other supply options that would outperform the proposed PWEC ratebasing.

**Q. Do these savings estimates offer a clear view of the costs and benefits if the PWEC Assets are included in ratebase?**

A. No, they do not. My view is that, contrary to the Company's estimates, the rate base proposal will be more costly to ratepayers in both the near and longer term; one important reason for this is that the Company's proposal would negate the favorable Track B contracts.

As for the Company's going-forward savings estimates, it is my view that the figures presented are inadequate, leaving the Commission without the information necessary to evaluate its request. An assessment of the savings that its proposal would offer relative to a full range of resource options would have been more proper. Instead, and for example, two of the Company's savings estimates derive from analyses that show only that the

However interesting that may be for other reasons, it does not answer the key question here: of the options that are or may be available -- including the Track B contracts, which indeed are available – is this the right choice? In other words, such assessments, particularly with respect to major proposals, should be based upon a comprehensive resource plan. By way of example, if one compares the Company's proposal to an alternative wherein it (a) keeps the PWEC Track B contract, (b) builds units comparable to the PWEC Assets (1,700 MW of gas turbine-based generation) and (c) puts them into service and in rate base in 2007, the overall capital cost to APS' customers would be comparable, with no consideration of the likely efficiency improvements in newer equipment. With the inclusion of some reasonable estimates of the efficiency (heat rate) improvements, the alternative plan improves substantially. This example, which is offered as an upper bound ("ceiling"), is not intended as an alternative resource plan; but it does indicate that there are indeed likely to be preferable resource options which do not compromise reliability. This example is discussed in more detail in Section VI and in Exhibit HS - 2.

**Q. What is the Company's second claim regarding PWEC savings?**

A. Mr. Wheeler states in his Direct Testimony at 12 that "compared to the cost of APS constructing new generation assets in 2004 of comparable size and type, life cycle savings [are] nearly $500 million." Mr. Bhatti also restates this figure in his Direct Testimony at 4.

**Q. What is the nature of the $500 million savings figure identified by Messrs. Wheeler and Bhatti?**

A. The $500 million figure simply reflects a comparison of some of the costs of new generating units (assumed to be in service in 2005) to used ones (i.e., the PWEC units). The analysis presented is limited because it considers only the relative costs of the "initial investment" and a return. See Workpaper SMW_WP 17. The analysis excludes consideration of a range of factors relevant to a comparison of the PWEC assets to a similar set of new units. The omissions include the foreseeable improved performance

characteristics of newer units, differences in operating and maintenance costs, differences in property and income taxes, etc. The Company's basic conclusion is that, from the standpoint of investment costs, new units cost more than used ones.

**Q. What are your concerns with this analysis by the Company?**

A. In general terms, the Company compares the future value of revenue requirements (in nominal dollars) of the PWEC Assets to the revenue requirements associated with new generating units that are "of comparable size and type." Wheeler Direct Testimony at 12. On a stand-alone basis, the analysis does not consider various performance and cost factors that are essential to a proper savings analysis. The Company's conclusion is that the foregoing comparison demonstrates that ratebasing the PWEC units would bring savings.

Passing aside my concerns with what the Company did, perhaps the more important concern with the estimate is what it does not do. That is, as with the others, it is not based upon an assessment of properly identified alternative options; nor does it account for the costs associated with the loss of the Track B PWEC contracts. In short, the foregoing analysis should not be relied upon as a reasonable estimate of the going-forward benefits of the Company's ratebase proposal.

**Q. What are the Company's third and fourth sets of claims regarding PWEC savings?**

A. Mr. Bhatti states in his Direct Testimony at 5 that "cost-of-service treatment of the PWEC Assets was shown by the Company's economic analysis to potentially save APS customers over $519 million (net present value over the life of the assets)." In addition, Mr. Bhatti states in his Direct Testimony at 68 that "ratebasing the PWEC Assets could have been anticipated to yield a benefit ranging from approximately $496 million to $615 million in net present value over the life of the projects.

And as with the other Company going-forward savings estimates, the failure to include the costs associated with negating the Track B contracts renders it incomplete. Despite my differences with the Company's assumptions here, the analysis does compare the ratebase proposal to another option. However, the exclusion of an available, inexpensive resource – from Track B – means that, all else equal, the claimed savings are overstated.

**Q. Please summarize your conclusions regarding the Company's analyses of the savings from its ratebase proposal.**

A. While it is proper to assess the potential benefits from the proposal on a going-forward basis, I do not agree with the Company's methodologies, as I have just described. Although there are other issues, which I do not reiterate here, a common theme has been the exclusion of the Track B contracts. Nor do these analyses demonstrate that ratebasing the PWEC Assets would be the best choice after the Track B PWEC contract expires. There are likely to be options other than complete reliance on the market and these should figure into the analyses.

## VI. OTHER GENERATION SUPPLY OPTIONS

**Q. Does the Company have resource options that are likely to be more cost effective than ratebasing the PWEC Assets?**

A. Yes, it does. As I stated earlier, a fundamental problem with the Company's proposal is that it would negate the benefits that could be obtained from the Track B solicitation. The winning short-term bids – from PWEC itself – would provide substantial savings as compared to other near term options. When these contracts are included in the resource mix, the picture changes significantly.

In addition, I would note that the Company received long-term bids [redacted] in the Track B solicitation that over 10- and 20-year time frames provided savings, as the Company itself concluded. The savings depended crucially, however, on

how the winning short-term bids [redacted] were treated in the Company's evaluation of the long-term proposals. Specifically, the long-term proposals provided benefits to APS only when the short-term bids were excluded from consideration. Once the short-term bids were included, those results no longer obtained. The upshot is that APS accepted the short-term Track B bids – which it would now negate – and rejected the long-term proposals.

**Q. Please explain the importance of the Track B results to the Company's proposal to ratebase the PWEC Assets.**

A. The winning bids fill an important need and provide power to APS through 2006 at quite favorable prices. Note that had another entity been the successful bidder to meet APS' needs through 2006, the Company's proposal to ratebase the PWEC Assets – had it been made – would have had to address a near term excess capacity situation, as it would not be in a position to recommend that the winning bids be negated.

The point here is straightforward. The Company's ratebase proposal should be evaluated in the same manner as if the assets were to be acquired from an unrelated entity. Correspondingly, how one treats the results of Track B should not depend upon who was the winning party. The Company's proposal here is in fact to implicitly treat them differently, as it assumes that favorable contracts with the affiliated PWEC can be negated. Contracts with unrelated third parties clearly would have to be dealt with differently.

**Q. You mentioned that the Company has more cost-effective alternatives than its ratebase proposal here. Please explain that statement.**

A. First, as I mentioned earlier, the Company prepared an assessment of the revenue requirement differences between its proposal in this case and a scenario in which the Track B PWEC contract was retained and new units were built (otherwise obtained) and ratebased in 2007. The Company, using a production costing tool,

concluded that the latter had lower long term revenue requirements on a present value basis. See Exhibit HS – 3.

We did something similar, essentially as a check of the Company's analysis, albeit in spreadsheet form.[1] Specifically, we compared the Company's proposal to a scenario in which (1) the short-term bids from Track B were in APS' resource mix until 2006 (per Track B) and (2) APS constructed (and added to rate base in 2007) 1,700 MW of natural gas-fired power plants. As shown in Exhibit HS - 2, on a capital cost basis only, our analysis shows that this alternative is approximately the same as the Company's ratebase proposal. That exhibit also shows the impact of the potential improvements in the efficiency of new generating plants relative to the PWEC Assets.

Because there has been a rather steady improvement in gas turbine-based power plant efficiencies, it is also reasonable to assume that units that are newer than the PWEC Assets would have improved heat rates. Based upon reasonable assumptions about gas prices and hours of generation, a conservative one percent improvement in heat rates would save on the order of $22 million in present worth terms. As shown in Exhibit HS - 6, a 2.5 percent improvement would lead to roughly $56 million in savings. The efficiency gains should be considered in the comparison of the Company's proposal with the foregoing alternative. I would also note, however, that while it is reasonable to expect efficiency gains, the proper way to assess their magnitude would be to utilize a production costing tool, so as to model the entire system. Hence, the forgoing estimates should be considered to be indicative only.

**Q. What do you conclude from the foregoing analysis?**

A. Obviously, the spreadsheet analysis summarized in Exhibit HS – 2 is not a "least cost" plan. The plan to implement should be much more comprehensive and be developed by the Company. With proper planning, the Company should do no

[1] The methodology is explained in Exhibit HS – 2.

- Reject the Company's rate-basing proposal for the PWEC assets;
- Retain the Track B contracts; and
- Clarify the Company's authority to build generation assets for the purposes of serving its load obligations.

**Q. What is your recommendation in the event that the Commission determines to include the PWEC Assets in ratebase?**

A. Two things are clear from the Company's presentation. First, because APS has failed to consider a full range of resource options available at this juncture, it has not shown what level of net benefits, if any, would be achieved through ratebasing the PWEC Assets. Second, ratebasing the PWEC Assets would eliminate $[redacted] million in ratepayer benefits implicit in the Track B PWEC contract, resulting from the Track B costs being less than market prices. The amount of the Track B benefit is calculated from APS' own estimates and is consistent with the view of market prices that APS takes in this case. Under the circumstances, protecting ratepayers requires that if the Track B PWEC contract is to be eliminated, the associated savings should be preserved.

**Q. How might the Commission act to protect ratepayers?**

A. There are probably several approaches that could be implemented to ensure that ratepayers do not lose the benefits of the Track B PWEC contract. I recommend that the Commission implement a $[redacted] million downward adjustment to the revenue requirement calculated under the "ratebase PWEC" scenario. See Exhibit HS – 4. This $[redacted] million downward rate adjustment would be applied across the term of the Track B PWEC contract, and is sufficient to ensure that the $[redacted] million in Track B savings would be preserved for ratepayers.

**Q. Are you concerned by the fact that APS has not engaged a qualified third-party to perform a current, independent assessment of the condition and value of the PWEC Assets?**

A. In my view, as I alluded to earlier, there should be a "standard procedure" under the circumstances. The problem might best be seen in relation to the RFP for assets currently being conducted by the Company. If APS determines to purchase assets from another generation developer, it may be sufficient for the Company to rely on its (internal) expertise to verify that the assets are worth the selling price. This is a proper approach in an arm's length transaction. But it is improper to ask the Commission to ratebase the PWEC Assets on the basis of either the Company's or its affiliate's representations regarding, for example, the physical condition of the assets. In this instance, the proposed transaction between PWEC and APS is not at arm's length. A reputable entity should have been engaged to opine on the condition of the power plants.

I should stress that I have no information that would lead me to believe either that APS does not have the requisite expertise or that there are any problems with the generating plants. Nonetheless, I think that it is proper as a general policy matter to require, in major transactions between affiliates, that there be third party due diligence.

**Q. How does the lack of a proper due diligence assessment affect your recommendation to the Commission in this proceeding?**

A. In my view, if the Commission determines to ratebase the PWEC assets, it should establish performance standards (e.g., regarding such matters as availability and heat rate) whereby APS is penalized if the units perform at levels below what would be expected of units of their type and vintage.

**Q. Has APS asked the Commission to approve the PWEC contract that resulted from the Track B solicitation?**

A. Yes. APS witness Wheeler requested that the Commission approve and "assure cost recovery" of the recently executed Track B contract between APS and PWEC.

**Q. Does Staff recommend that the Commission approve the APS/PWEC contract?**

A. It is my understanding that the Commission does not ordinarily provide approvals for contracts of this type. Instead, the Commission reviews the reasonableness and prudence of the *costs* incurred under the contract. This review generally takes place after the fact. Because the costs incurred under this contract are so favorable for ratepayers, I recommend that the Commission take the highly unusual step of approving them in this proceeding.

**Q. Does this conclude your testimony?**

A. Yes, it does.

# EXHIBIT HS - 1

## HARVEY SALGO

*LA CAPRA ASSOCIATES*
Principal

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Harvey Salgo, Principal of La Capra Associates, is an economist and attorney with extensive experience in electric industry restructuring and regulation. His recent work (from 1992-2001) includes assisting in the India effort (supported by the World Bank) to restructure (and privatize certain functions of) the power sector in India and has worked (to a lesser extent) on similar issues in Pakistan. He has prepared for the World Bank an energy strategy for Montenegro (2002) and has reviewed and particpated in the development of a new energy law (2002-03). He has also drafted a power sector reform law in Zimbabwe (along with local counsel) and has prepared detailed comments on the evolving law in Vietnam and China. Among his experiences, Mr. Salgo was formerly an Assistant Professor of Economics at the University of Vermont (1969-74), an economist/ attorney at the Massachusetts Department of Public Utilities (1977-79), and an attorney and consultant in private practice with the firm of Salgo and Lee (1979-87). Mr. Salgo has represented numerous clients and has, as a consultant, testified as an expert witness on numerous occasions. He has provided consulting services to a wide variety of domestic (US) clients and has worked abroad for the World Bank, Inter-American Development Bank and U.S. Agency for International Development.

### RELEVANT EXPERIENCE

- **University of Vermont.** Assessment of cogeneration options at the university.
- **World Bank: Zambia.** Assessment of the possibilities and likelihood of success of the commercialization of the state-owned power utility of Zambia. 2003.
- **World Bank: Cambodia.** Advice regarding power supply arrangements between Cambodia and Vietnam.
- **World Bank: Nigeria.** Conducted a peer review of a major World Bank project to assist in the reform of the Nigerian power sector. 2003
- **Massachusetts Technology Collaborative.** Manager of project to assist the MTC in its development of new and creative ways to utilize its funds to leverage the development of renewable energy projects. The MTC is a state agency that administers a large fund to be used to support – through loan, grant, equity, or other means – renewables projects so as to facilitate their development in the state. 2003.
- **Town of Weymouth, MA**

  The town is host to a nearly complete power project that is in default on its loans. Advisor to the town regarding its commercial rights and obligations. 2003.

- **California Office of Ratepayer Advocate.** Review of power purchasing activities of Pacific Gas & Electric Company in a period during the crisis in Western Power Markets. 2003.
- **World Bank: Montenegro.** Preparation of a power sector strategy for Montenegro; review of drafts of the new law (establishing a regulatory body and other matters), preparation of detailed comments regarding the law; due diligence review of later draft. 2002-03.
- **Massachusetts Technology Collaborative.** Provided assistance in the due diligence review of proposed renewables projects in Massachusetts. The MTC is a state agency that administers a large fund to be used to support – through loan, grant, equity, or other means – renewables projects so as to facilitate their development in the state. 2002-03.
- **Nevada Office of the Attorney General.** Assisted in the review of certain power purchases undertaken by the Nevada Power Corporation during and after the power crisis in the US Western markets. 2002-03.
- **Wyoming Industrial Energy Consumers.** Provided assistance in the review of certain power purchases undertaken by PacifiiCorp before and during the power crisis in the US Western markets. 2002-03.
- **Pennsylvania Office of Consumer Advocate.** Provision of advice regarding various matters associated with FERC's proposed Standard Market Design: assistance in the preparation of alternative proposals and detailed comments to FERC. 2002-03.
- **California Bureau of State Audits.** Audit of the performance of the Department of Water Resources, which was given emergency statutory authority to purchase the 'net short' position of the bankrupt California utilities. The purchasing authority amounted to thousands of megawatts; and the audit was mandated by statute. 2001.
- **Narragansett Bay Commission.** Provided assistance to the Commission (the primary water supplier in Rhode Island) in the assessment of whether to obtain future power requirements from the local utility or from an on-site power project (or some combination of the two); other ongoing tasks. 2001-02.
- **World Bank: India.** Member of team established to assess technical, market, and regulatory constraints to rural access to electricity service. Principal responsibility: paper concerning key regulatory issues and policies. Provided advice concerning the approach to the privatization of distribution in Andhra Pradesh, a large southern state.
- **World Bank and GTZ (Germany): Zimbabwe.** Ongoing work in Zimbabwe regarding power sector reform and the near term privatization of a generating station. Preparation of power sector reform legislation (supported by GTZ) in conjunction with local attorneys. 2001.
- **World Bank Peer Review.** Review of the proposed approach to reform as prepared by the Bank's Nigeria team; discussion with senior Bank management. 2001.
- **California Office of Ratepayer Advocate.** Review of the power purchasing strategy of California utilities in light of recent problems in the power markets; assessment of the

extent to which the high prices for wholesale power may have been mitigated by hedging strategies. 2001.

- **World Bank and Asian Devlopment Bank: Vietnam.** Review of draft legislation regarding power sector reform; preparation of comments and suggested revisions of the draft; participation in high-level workshop regarding reform. Advisor to Ministry of Power working group concerning the drafting of power sector reform legislation; participation in second high level workshop regarding reform. 2000-2001.
- **World Bank: China.** Particpation in high level reform workshop; presentation of review of present China law and whether it is consistent with the next stages of power sector reform.. 2000.
- **World Bank: India.** (2000). Continuation of work (begun in 1992-) with the Bank regarding power sector restructuring, including sector unbundling, establishment of regulatory agencies, distribution privatization and numerous other matters. The work in India was extensive and virtually full time and covered a broad range of tasks. Tasks included:
    - participation in the development of power sector reform programs at various stages in Orissa, Andhra Pradesh, Haryana, Uttar Pradesh, Rajasthan, Karnataka;
    - ·advisor to the Orissa government and GRIDCO in developing a plan for a management contract for one distribution area, soliciting proposals, selection of company as contractor, contracting with company;
    - ·advisor to the Orissa GRIDCO regarding the privatization (now complete) of its entire distribution business (four companies); assistance to merchant bankers in the preparation of documents for a transpapernt bidding process (preparation of draft RFQ and RFP);
    - ·review of major gas combined cycle project (Dahbol Project) south of Mumbai; assessment of whether the power would be economic for purchase by Maharashtra State Electricity Board;
    - ·organization of nationwide conference (on behalf of Indian Ministry of Power and World Bank) concerning competitive bidding for power (Hyderabad, 1994) and privatization of distribution (Bangalore, 1995);
    - ·preparation of a widely distributed handbook on competitive bidding;
    - ·ongoing review and assessment of draft legislation, secondary legislation (regulations) for newly formed state and central regulatory agencies;
    - ·ongoing review and assessment of various planning documents, including the methodology for analyzing the disaggregation of the statewide distribution territories (in the reforming states) into smaller companies (as a prelude to privatization).
- **World Bank: Pakistan.** Continuation of work with the Bank (begun in 1997) regarding power sector restructuring and related matters. Primary work in Pakistan was assistance

to the regulatory authority (NEPRA) regarding the implementation of its law and the development of secondary legislation (regulations). 1999.

- **Infrastructure Leasing & Financial Services (New Delhi, Mumbai).** Advice regarding the development of privately owned and operated infrastructure projects (roads, etc.) in India; specific tasks include preparation of competitive procurement documents, contract review, liaison with World Bank which provided funding. 1997.
- **New Hampshire Public Utilities Commission.** Advice to the Commission regarding the utility restructuring process in New Hampshire, as mandated by the Legislature. 1996.
- **Rhode Island Public Utilities Commission.** Advice concerning the restructuring of the utilities under the jurisdiction of the Rhode Island PUC. 1996.
- **Commonwealth Gas Company.** Continuation of work begun several years earlier. Strategic consultant to the company on matters concerning the implementation of a major gas conservation program including the post-implementation process and impact evaluations. The task includes participation in, and review of, major decisions; and assistance in the hiring of technical consultants, and review of their work. 1996.
- **Commonwealth Gas Company.** Advice concerning certain regulatory settlement matters concerning DSM and competitive market issues. 1996.
- **New Hampshire Legislature.** Advice concerning the approach to restructuring the electricity industry in New Hampshire. In addition to advice regarding legislative policy, the tasks included calculation of the estimated stranded costs in the state.
- **Nantucket Electric Company.** Preparation of solicitation and review of proposals for the development of an undersea cable to the island of Nantucket and for the sale of power to supply the island's long term needs. NEC intends to phase out its own generation over time. 1993.
- **Rhode Island Public Utilities Commission.** Assistance to the Commission concerning its review of a power supply proposal for the state. The Commission has the statutory authority to purchase power for resale and is evaluating an offer for a substantial number of megawatts. 1993.
- **Colonial Gas Company.** Preparation of RFP for DSM services from energy services companies. Assistance in the review of ESCO proposals and in the selection of winning vendors. 1992.
- **Gas Ventures Advisors.** Review of a variety of Power Purchase Agreements to determine the relationship between certain contract provisions and the structure of project pricing. The review will examine energy-only pricing, simple fixed/variable agreements, and more complex arrangements. 1992.
- **Washington, D.C. Office of People's Council.** Assistance in the analysis and review of the Washington Gas Company's Integrated Resource Plan, including participation in periodic IRP planning meetings with the Company and other parties. 1992.

- **Vermont Electric Cooperative.** Preparation of Integrated Resource Plan for the Cooperative. 1992.
- **Gas Evaluation and Monitoring Study (GEMS).** Consultant to the 11 gas utilities in New England which are participating in GEMS. GEMS is the joint analysis of DSM impacts utilizing end-use meters located in the Boston Gas service territory. Tasks included work on the design of the study, statistical consultation and other matters. 1992.
- **Inter-American Development Bank.** Review and analysis of DSM potential in Costa Rica's electric utility industry; development of priorities for DSM pilot programs. 1992.
- **Vermont Department of Public Service.** Negotiation of contracts for power from private power generators. 1992.
- **Massachusetts Division of Energy Resources.** Assistance in the preparation of a DOER proposal to develop a windpower project. The prospective power purchaser is New England Power Company, which has issued solicitation for renewable power projects. 1992.
- **International Institute for Energy Conservation.** Work with IIEC to prepare draft Terms of Reference for the Asian Development Bank; the TOR concerns energy efficiency technical and economic assessments. 1991.
- **University of Missouri.** Analysis of the university's energy options, including whether or not to privatize its coal cogeneration plant; development of a strategic plan for the university. 1991.
- **Long Island Power Authority.** Consultation concerning the conversion of the Shoreham Nuclear facility to a gas-fired combined cycle unit and for the use of project revenues to finance DSM investments. Assistance in the preparation of requests for proposals for the conversion and for the DSM projects. 1991.
- **Consumers Gas Company, Canada.** Preparation of process and impact evaluation scoping study as part of the Company's Integrated Resource Plan. 1991.
- **U.S. Agency for International Development.** Manager of energy price reform studies for Czechoslovakia and Romania. Provide strategic advice to governments regarding energy price reform and energy planning, including methods for the incorporation of environmental costs into resource planning and pricing decisions. 1991.
- **District of Columbia Office of People's Counsel.** Review of the process and impact evaluation efforts undertaken by DC Natural Gas. 1990.
- **Rhode Island Governor's Office of Housing, Energy, and Intergovernmental Relations.** Assessment of cogeneration (district/heating) potential at Manchester Street Station, a gas-fired combined cycle retrofit to be undertaken by New England Power Company. 1990.
- **Institute of International Education.** Conduct a week long training session for delegation from five Southeast Asian countries on matters related to project solicitation

and evaluation. Training will include contract and finance issues, as well as appropriate methods for the calculation of avoided costs. 1990.

- **Wisconsin Gas Company.** Assistance in the preparation of an RFP for vendors to provide conservation services to the Company's large commercial customers. Assistance in the evaluation and selection of winning proposals. 1990.
- **City of Lowell, MA.** Negotiation of contract for a regional recycling facility, in consultation with attorney for the City. 1990.
- **Vermont Department of Public Service.** Assistance in the preparation of an RFP and related material for the VDPS' solicitation of Qualifying Facilities and Independent Power Producers; review and initial evaluation of proposals received by the VDPS. 1989.
- **U.S. Agency for International Development.** Presentation to delegation of senior utility personnel from the Philippines concerning various private power solicitation and contract issues. Meetings arranged for the delegation with Massachusetts regulatory officials and utility executives. 1989.
- **World Bank: Thailand Mission.** Development of a framework for private ownership of electric generating facilities and review of specific projects to determine if appropriate for private sector development. The task includes interviewing key government and utility officials, outlining areas in which resolution of differences is necessary, preparing specific proposals for the implementation of privately owned projects in Thailand. 1989.
- **Boston Gas Company.** Strategic consultant to the company on matters concerning the implementation of a major gas conservation program including the post-implementation process and impact evaluations. The task includes participation in, and review of, major decisions; and assistance in the hiring of technical consultants, and review of their work. 1989.
- **U.S. Agency for International Development.** Preparation of two major sections of a report: Biomass Projects and Private Power Regulations. The two sections concern (1) the identification and management of private power risks to the utility, developers, financial entities, governments, and others; and (2) assessment of the skill areas which utilities and governmental bodies will require to implement a successful private power program. 1989.
- **Rhode Island Energy Coordinating Council.** Consultant to the ECC, established by an Executive Order from the Governor, to assess the electricity options for the state, and matters such as energy security and environmental impacts. 1989.
- **Minnesota Department of Public Service.** Assist the Department concerning proposed rules for least-cost planning and regulatory incentives; assess the Department's staffing and other needs to allow it to effectively participate in the planning process. Project Manager and Principal Investigator. 1989.
- **U.S. Agency for International Development.** Paper and presentations concerning the methods for soliciting and evaluating private power projects and structuring necessary

contractual arrangements between utility and producer. Presentations were made to A.I.D. sponsored conferences in Jakarta, Indonesia. 1989.

- **Pennsylvania Office of Consumer Advocate.** Review and analysis of a supply and DSM bidding proposed by Orange and Rockland Utilities. 1989.
- **Madison Gas & Electric Company.** Assist in the preparation of an RFP for DSM resources, as required by the PUC; assist in other aspects of the solicitation process; assist in the selection of DSM providers. 1988.
- **Massachusetts Port Authority.** Conduct a seminar for MassPort executives concerning the feasibility of cogeneration at Logan Airport in Boston. 1987.
- **Rhode Island Department of Central Services.** Assist in the preparation of an RFP, and review of proposals, for a cogeneration system at the University of Rhode Island; assist in the preparation of necessary contracts. 1987.
- **Rhode Island PUC.** Head of Task Force (which included utilities, financial entities, qualifying facility developers, state agencies) seeking to "negotiate" a methodology for the regulatory treatment of utility/qualifying facility relationships under PURPA. 1990.
- **Massachusetts Executive Office of Energy Resources.** Preparation of proposed comprehensive regulations regarding PURPA (re: utilicy qualifying facility sales and other relationships); legal representation in related matters. Preparation of proposal concerning the regulatory treatment of new utility plant consistent with regulations regarding utility/qualifying facility relationship under PURPA and, more generally, with least-cost integrated planning. Testimony on these matters before the Massachusetts Department of Public Utilities. 1984.
- **Northeast States for Coordinated Air Use Management.** Assistance in the preparation of, and participation in, workshops designed to bring together utility planning and air quality professionals. The task is to facilitate a discussion between the two groups so as to examine the impact of air quality constraints on electric generation (utility and non-utility) planning. NESCAUM consists of representatives of various state agencies concerned with air quality issues. 1986, 1988.
- **Rhode Island Governor's Office of Energy Assistance.** Attorney for the GOEA in rate case focus on conservation and rate design (Blackstone Valley Electric Co., Docket No. 1849). 1986.
- **Massachusetts Energy Facilities Siting Council.** Preparation of analysis of certain aspects of New England Power Pool planning and pricing with focus on cogeneration, small power production, and conservation. 1986-87.
- **Vermont Electric Cooperative, Inc..** Special consultant to the Vermont Electric Cooperative, Inc., which was in serious financial difficulty. Coordinate necessary analyses (energy and demand forecast, power needs, power sales possibilities, financial condition); assist in the evaluation of bankruptcy as an option; negotiate with major creditors (Rural Electrification Administration and Cooperative Finance Corporation);

coordinate with Vermont regulators and Congressional delegation; provide general advice and counsel to the VEC Trustees and management. 1986.

- **Coalition of Northeast Governors.** Preparation of analysis of certain aspects of PURPA (utility/qualifying facility relation-ships) with emphasis on biomass facilities; delivery of paper at conference; continued consultation. 1986.

## EMPLOYMENT HISTORY

**La Capra Associates** — Boston, MA
*Principal* — *1992 - present*

**Tellus Institute** — Boston, MA
*Manager of the Energy Group's international work*
*Manager of Integrated Least Cost Planning Group* — *1988 - 1990*

**Salgo & Lee** — Boston, MA
*Private Practice: Attorney and Economic Consultant* — *1979 - 1987*

**University of Massachusetts Dept. of Economics** — Amherst, MA
*Instructor* — *1980 - 1984*

**Goddard College** — Plainfield, VT
*Instructor in Economics* — *1979*

**New England Energy Congress**
*Director, Low Income Backup Project* — *1978 - 1979*

**Massachusetts Deptartment of Public Utilities** — Boston, MA
*Attorney and Economist* — *1977 - 1978*

**University of Vermont** — Burlington, VT
*Instructor (Part-time while in Law School)* — *1975 - 1977*

**University of Vermont** — Burlington, VT
*Assistant Professor of Economics* — *1969 - 1974*

## EDUCATION

**Northeastern University School of Law** — Boston, MA
*J.D.* — *1977*

**Admitted to Massachusetts Bar** — *1977*

**University of Wisconsin** Madison, WI
*M.A. in Economics; all requirements for Ph.D. complete except for dissertation; Distinction on the written examination for the PhD.* *1967*

**Hunter College** New York, NY
*B.A. in Economics, with Honors, Phi Beta Kappa and Cum Laude* *1964*

## SELECTED RESEARCH

*The Potential Impact of Environmental Externalities on New Resource Selection and Electric Rates*, Principal Investigator, for and with the Massachusetts Division of Energy Resources. 1991.

*District Heating from the Manchester Street Station: A Public Policy Perspective*, A report to the Rhode Island Governor's Office of Housing, Energy, and Intergovernmental Relations. Tellus Study No. 90-034. Principal author. 1990.

*Review of Southern Connecticut Gas Company's Conservation Impact Model.* Prepared for The Conservation Collaborative Group: Southern Connecticut Gas Company; Connecticut Department of Public Utility Control (DPUC); Prosecutorial Division, DPUC; Office of Policy and Management/Energy Division; Office of Consumer Counsel. Tellus Study No. 90-084. Co-author. 1990.

*Methodology for the Incorporation of Environmental Externalities in the Selection of Resources.* Co-Author of Report to the Massachusetts Department of Energy Resources. 1990.

*Evaluation of Staffing Requirements for the Minnesota Department of Public Service Imposed by Potential Least Cost Planning Processes.* Co-Author. A report to the Minnesota DPS. 1989.

*Rhode Island's Options for Electric Generation.* Co-Author. A report to the Rhode Island Energy Coordinating Council. 1989.

*A Survey of Selected States' Implementation of Least Cost Integrated Planning Processes for Electric Utilities.* Co-Author. A report to the Missouri Office of the Public Counsel. 1988.

*Fuel Procurement Planning of Gas-Fired Cogeneration Projects Proposed for Massachusetts.* Co-Author. A report to the Massachusetts Executive Office of Energy Resources. 1988.

*An Overview of the Processes by which Power is Purchased from Qualifying Facilities in New England.* Principal Investigator. A report to the New England Cogeneration Association. 1988.

*Analysis of the Economic and Financial Aspects of a Proposed Hazardous Waste Incinerator in the Town of Braintree, Massachusetts*. For the Town of Braintree Local Assessment Committee. 1987-89.

*Feasibility of a Power Authority in the State of Vermont.* A report to the Vermont Department of Public Service. Principal Investigator. 1987.

*Assistance in the Development of a Regional Management Plan.* Co-author. A report to the Northeast Interstate Low-Level Radioactive Waste Commission. 1987.

**PRESENTATIONS AND REPORTS**

Invited Speaker, National Association of Regulatory Utility Commissioners (NARUC): *What happened in California? The La Capra audit of the state's Department of Water Resources*, Washington DC. 2002.

Invited Chair, Panel of PUC Commissioners, Roundtable Session: "Retrench, Reregulate, or Proceed: Experiences with Restructuring and Future Directions" at the Michigan State University Institute of Pubilc Utilities 33rd Annual Regulatory Policy Conference, Williamsburg, Virginia. 2001.

Invited speaker, Consistency of present Chinese Power Sector Law with Competitive Markets, Beijing, November, 2000

Invited expert participant, Need for Power Sector Reform in Vietnam, Ha Long City, October, 2000

Author, *The India Power Sector: the Need for Reform*, Pacific and Asian Journal of Energy, Vol. 7, No. 2, December 1997.

Invited Speaker, Conference on Improving the Health of the Indian Power Sector, jointly sponsored by the Indian Ministry of Power and the German Government, New Delhi, January 1997.

Conference Chair, Nuclear Power in the Competitive Era, Infocast, Washington, DC, January 1997.

Author, *India Faces Restructuring: The Need is with the States*, The Electricity Journal, March 1996.

Co-author, *India: Energy Sector -- Issues and Options*, World Bank. 1996.

Invited speaker (and a principal conference organizer), Private Sector Participation in Indian Distribution, Bangalore. 1995.

Invited Speaker, Retail Wheeling Issues, NARUC IRP Conference, Kalispell, Montana. May 1994.

Invited speaker (and a principal organizer), conference on Competitive Bidding in India, Hyderabad. 1994.

Author, *Update on the Power Market in India*, Power Magazine. 1994.

Invited Speaker, Joint Delivery of Gas and Electric DSM Programs: Barriers and Opportunities for More Efficient Program Delivery. Massachusetts Energy Efficiency Council DSM Conference, Boston. March 1994.

Invited Speaker, "International Diversification and the Utility Ratepayer", Ninth Annual Cogeneration and Independent Conference, McGraw Hill, New Orleans (March); (paper presented by colleague). 1994.

Invited Speaker, Conference: Private Power in India, Infocast, Washington, D.C. 1993.

Invited Speaker, DSM Impact Evaluation: How Much is Just Enough?, Washington Gas Light Co., Least Cost Planning Conference, Washington, D.C. 1992.

Invited Speaker, DSM Impact Evaluation: Costs and Benefits, NASUCA, Washington, D.C. 1992.

Co-author, *Bidding for Performance: The Large Commercial Gas Conservation Program at Wisconsin Gas Company*, presented (by co-author) at DSM implementation conference, Philadelphia. 1992.

Invited Speaker, Treatment of Environmental Externalities: Issues and Perspectives, New England Cogeneration Association, Waltham, MA. 1991.

Invited Speaker, Project Development Opportunities in the Developing World, International Private Power Conference, New York. 1991.

Invited Speaker, Structuring DSM Programs for Gas Utilities, New England Gas Association. 1990.

Co-Author, Tracking Activity and Results in DSM Programs, accepted for presentation at annual ACEEE Summer Conference. 1990.

Invited Speaker, Financial Incentives to Utilities for DSM Implementation: In What Circumstances?, presentation to National Association of State Utility Consumer Advocates (NASUCA), Santa Fe, NM. 1990.

Invited Speaker, Least Cost Planning and Gas Utilities, Presentation at Gas Utility Conference sponsored by the Bar Association of the District of Columbia and the District of Columbia Natural Gas Co., Washington, D.C. 1989.

Invited Speaker, Regulatory Frameworks in New England for Utility/Private Power Arrangements, Presentation to Delegation from Thailand, Sponsored by the U.S. Agency for International Development, Boston, Mass. 1989.

Invited Speaker, Framework for the Development of a Private Power Program, International Workshop on Opportunities for Private Power Sector Power Generation in Indonesia, Sponsored by the U.S. Agency for International Development, Jakarta, Indonesia. Paper presented. 1989.

Invited Speaker, Implications of Changing Environmental Regulations for Utility Regulators, New England Cogeneration Association Conference on Energy and Environmental Issues, Boxborough, Mass. 1988.

Invited Speaker, Bidding Systems: Some Theoretical and Practical Issues, NARUC Biennial Regulatory Information Conference, Columbus, Ohio. Paper published in Proceedings. 1988.

Invited Speaker, Innovative Supply-Side and Demand-Side Projects: A National Sampler, Conference on Least-Cost Energy Planning for the Carolinas. Sponsored by the North and South Carolina PUCs, the North Carolina Dept. of Commerce and the North Carolina Alternative Energy Corp. 1988.

Invited Speaker, Renewable Energy Resources and Least-Cost Planning, Sponsored by Renewable Resource Associates (under U.S. Dept. of Energy grant), Golden, Colorado. 1988.

Invited Speaker, The QF Market in New England, Cogeneration Market Conference, Sponsored by Cogeneration Report and Power Magazine, New Orleans. Paper published in Proceedings. 1988.

Invited Speaker, Development and Implementation of Least-Cost Plans, Northeast States Coalition for Air Use Management, Annapolis. 1988.

Invited Speaker, New England Energy Task Force, U.S. Dept. of Energy, The Changing Environment for Non-Utility Resources, Boston. 1988.

Invited Speaker, Regional Transmission Issues, New England Conference of Public Utilities Commissioners, New Hampshire. 1987.

Invited Speaker, PURPA Bidding Systems, American Cogeneration Association, Houston. 1987.

Invited Speaker, Bidding and Least-Cost Planning, NASUCA, New Orleans. 1987.

Invited Speaker, Massachusetts QF Bidding Regulations, sponsored by Boston Edison for prospective bidders. 1987.

"PURPA Implementation: Policy Issues and Choices." Coalition of Northeast Governors: Biomass Project, Montpelier, VT. Presentation. 1986.

Law and Society Association Annual Meeting, Denver, Colorado. Invited Discussant. 1983.

"New England Utilities: Conservation Incentives and Their Impact on Financial Health." Sponsored by New England Energy Congress. Invited Panelist. 1981.

Co-author, "An Introduction to Statistical and Rate Making Issues Underlying Load Data and Costing Requirements of Section 133 of Public Utility Regulatory Policies Act (PURPA)," for the Legal Services Corporation. 1981.

Co-author, "Ratemaking, Financing Arrangements, and Diversification: Utility Proposals and Regulatory Responses." Eastern Economic Association. Invited paper. 1981.

**TESTIMONY**

| Forum | Case or Docket No. | Date | Topic |
|---|---|---|---|
| Department of Public Utilities Massachusetts | DPU Nos. 90-55/ 90-17 / 90-18 | 6/90 | Concerning DSM Implementation |
| Vermont Public Service Board | No. 5330 | 1/90 | Concerning solicitation of Non Utility Generation |
| Michigan Public Service Commission | No. U-8871 | 6/88 | Analysis of the MCV et al. Cogeneration Project |
| Colorado Public Service Commission | No. 38771 | 4/88 | Analysis of Utility Bidding Proposal |
| Department of Public Utilities Massachusetts | DPU 86-36 | 5/88 | Implementation of All-Resources Bidding |
| South Carolina Public Service Commission | No. 80-251 | 1/88 | Bidding for Qualifying Facilities |
| Public Utility Commission of Pennsylvania | I-860025 | 11/87 | Bidding Systems for Small Power Producers Cogenerators |

| | | | |
|---|---|---|---|
| Public Service Board of Vermont | No. 5248 | 11/87 | Reasonableness of Certain Wholesale Transactions |
| Department of Public Utilities, Massachusetts | DPU 86-36 | 9/87 | Cost Recovery for New Utility Generation |
| Public Utilities Commission of New Hampshire | DR 86-41 | 1/87 | Bidding Systems for Small Power Producers and Cogenerators |
| Public Utilities Commission of Rhode Island | No. 1549 | 9/86<br>11/87 | Utility/Qualifying Facility Contracting On behalf of R.I. Task Force |
| Department of Public Utilities, MA | DPU 86-36/ 89-239 | 4/86<br>9/89 | Cost recovery for New Generation, Environmental Externalities |
| Department of Public Utilities Massachusetts | DPU 84-276 | 3/85<br>10/85<br>3/86 | Utility/QF Contracting, Incl. Bidding |
| Energy Facilities Siting Council, Massachusetts | EFSC-90-RM-100 | 9/89 | Resource Planning Regulations |
| Department of Public Utilities Massachusetts | DPU 89-141, et.seq. | 12/89 | Incorporation of Environmental Externalities in Utility RFPs |

*REDACTED*

**EXHIBIT HS - 2**
**A COMPARISON OF PWEC TO A 2007 NEWBUILD OPTION**
**(A Differential Revenue Requirements Analysis -**
**ACC Jurisdictional, in $ millions)**

| | PWEC RR [1] | NewBuild RR [2] | Difference RR | Cumulative PV | Efficiency Benefits PV [6] | Cumulative PV |
|---|---|---|---|---|---|---|
| 2004 | | | ($53.3) | [3] | | |
| 2005 | | | | [4] | | |
| 2006 | | | | [5] | | |
| 2007 | $151.0 | $205.5 | $54.5 | | $1.6 | |
| 2008 | $146.5 | $199.8 | $53.4 | | $1.5 | |
| 2009 | $142.0 | $194.2 | $52.2 | | $1.4 | |
| 2010 | $137.5 | $188.6 | $51.1 | | $1.3 | |
| 2011 | $133.0 | $183.0 | $50.0 | | $1.2 | |
| 2012 | $128.5 | $177.4 | $48.9 | | $1.2 | |
| 2013 | $124.1 | $171.8 | $47.8 | | $1.1 | |
| 2014 | $119.6 | $166.2 | $46.6 | | $1.0 | |
| 2015 | $115.1 | $160.6 | $45.5 | | $1.0 | |
| 2016 | $110.6 | $155.0 | $44.4 | | $1.0 | |
| 2017 | $106.1 | $149.4 | $43.3 | | $0.9 | |
| 2018 | $101.6 | $143.8 | $42.2 | | $0.9 | |
| 2019 | $97.1 | $138.2 | $41.0 | | $0.8 | |
| 2020 | $92.6 | $132.6 | $39.9 | | $0.8 | |
| 2021 | $88.1 | $127.0 | $38.8 | | $0.7 | |
| 2022 | $83.7 | $121.3 | $37.7 | | $0.7 | |
| 2023 | $79.2 | $115.7 | $36.6 | | $0.7 | |
| 2024 | $74.7 | $110.1 | $35.4 | | $0.6 | |
| 2025 | $70.2 | $104.5 | $34.3 | | $0.6 | |
| 2026 | $65.7 | $98.9 | $33.2 | | $0.6 | |
| 2027 | $61.2 | $93.3 | $32.1 | | $0.5 | |
| 2028 | $56.7 | $87.7 | $31.0 | | $0.5 | |
| 2029 | $52.2 | $82.1 | $29.8 | | $0.5 | |
| 2030 | $47.8 | $76.5 | $28.7 | | $0.5 | |
| 2031 | $43.3 | $70.9 | $27.6 | | $0.4 | |
| 2032 | $38.8 | $65.3 | $26.5 | | $0.4 | |
| 2033 | $34.3 | $59.7 | $25.4 | | $0.4 | |

**NOTES:** * Negative numbers indicate 2007 NewBuild option costs less than PWEC ratebasing option.

** An extended version of this analysis shows that 2033 is the year in which the differential savings attributable to the 2007 NewBuild option is at a minimum.

*** Present values (PV) are calculated as of January 2004 using future capital costs identified in the 2003 Long Run Forecast, as provided in response to LCA 16-365, at 4.

[1] PWEC revenue requirements are calculated as the after tax sum of depreciation expense, property tax expense, return on undepreciated investment and income tax savings. These costs are based on the ratebase amount for December 31, 2004 as identified in DGR_WP1.

[2] NewBuild revenue requirements are calculated as the after tax sum of depreciation expense, property tax expense, return on undepreciated investment and income tax savings. NewBuild investment costs in 2007 are assumed to be ten percent greater than the PWEC gross plant costs in DGR_WP 1.

[3] The NewBuild option would include savings to total revenue requirements from retaining the Track B PWEC contract. The 2004 amount is calculated as half of the $106.6 million annual revenue requirement impact reported to Commissioner Gleason in an 8/7/03 APS letter in this proceeding.

[4] The 2005 revenue requirements savings from retaining the Track B PWEC contract is identified in the Company's 2003 Long Run Forecast, as provided in response to LCA 16-365, at 31 (see Alt 3).

[5] The 2006 revenue requirements savings from retaining the Track B PWEC contract is identified in the Company's 2003 Long Run Forecast, as provided in response to LCA 16-365, at 31 (see Alt 3).

[6] This analysis assumes a minimum savings level ($22 million NPV) from efficiency gains in the NewBuild facilities (see Exhibit HS - 6).

## EXHIBIT HS - 3

## APS' COMPLETE RESPONSE TO LCA 20-491(a)

LCA 20-491 Substitute

a. Please confirm that, but for the analysis identified in response to LCA 16-365, during 2003 (and prior to this data request) APS has **not** performed a comparison (e.g., using its GEMAPS model or its RTSim model) to compare (i) the long-run production costs of its supply portfolio with the PWEC units "in" the supply mix (i.e., in ratebase) to (ii) those costs with the PWEC units "out" of the supply mix. If the preceding statement is incorrect please so indicate, describe the analysis and provide a copy of the inputs and outputs to that analysis.

RESPONSE:

a. In April 2003 an analysis was made of the revenue requirement impacts of ratebasing the PWEC assets (including the PWEC assets) vs building new assets (excluding the PWEC assets) in 2005 and in 2007. In the case where new assets were placed in service in 2007, the PWEC Track B contracts were assumed to be in place for years 2005 and 2006. The results of this analysis showed ratebasing the PWEC assets had $144 million lower revenue requirements (CPV) for customers than building new assets in 2005 and **$36 million higher revenue requirements (CPV) than building new assets in 2007** after the Track B contracts. See attached RC02641 through RC02643 or redacted file RC02641R through RC02643R annual revenue requirement analysis which is being provided pursuant to a protective agreement on a yellow-labeled CD. [Emphasis in response added by H. Salgo.]

# EXHIBIT HS - 4

**REDACTED**

ESTIMATED SAVINGS FROM TRACK B PWEC CONTRACT
RELATIVE TO MARKET PURCHASES

| | Track B Savings (millions) | *Note:* |
|---|---|---|
| **2004** | | *1* |
| **2005** | | *2* |
| **2006** | | *3* |
| **NPV 1** | | *4* |
| **NPV 2** | | *5* |
| **Annual** | | *6, 7* |

**Notes:**

*1* One-third of $ million (a three-year total, see response to LCA 21-499), then multiplied by three-quarters to reflect savings in July 04 through September 04 (but not June 04).

*2* Year 2005 revenue requirements with Track B "in" ($ million, see Alt. 3) less Year 2005 revenue requirements with Track B "out" ($ million, see Alt. 4), as identified in APS' August 2003 Long Range Forecast, provided in response to LCA 16-365, at 31.

*3* Year 2006 savings, similarly based on the response to LCA 16-365, at 31.

*4* Present value of the savings as of January 1, 2004, using Staff's recommended 7.26 percent cost of capital.

*5* Present value of the savings as of July 1, 2004, using Staff's recommended 7.26 percent cost of capital.

*6* Levelized amount necessary to recapture savings in rates over 2.5 years, based on an end-of-period convention and Staff's recommended 7.26 percent rate of return.

*7* Ideally, these calculations would be performed with monthly savings data.

# EXHIBIT HS – 5

A selection from APS' response to LCA 16-365 (RC01925).

***Redacted***

***REDACTED***

# Exhibit HS - 6

## Present Value of Efficiency Savings Achieved Through Generating Units Built in 2007

| | Efficiency Improvement Implicit in New Units | | |
|---|---|---|---|
| | 1% | 2.50% | 5% |
| 984 MW P Verde CCs | $13,809,832 | $34,524,581 | $69,049,161 |
| 112 MW Valley CC | $885,550 | $2,213,874 | $4,427,749 |
| 506 MW Valley CC | $7,921,559 | $19,803,897 | $39,607,794 |
| **Total** | $22,616,941 | $56,542,352 | $113,084,704 |

Notes:

1. Discount rate used in PV calculation is %, the Company's long-run weighted average cost of capital, as identified in response to LCA 16-365, at 4.
2. Analysis is based on operating costs and characteristics of the PWEC units from Company's August 2003 Long Run Forecast as provided in response to LCA 16-365.
3. Fuel Prices are from the 2003 Long Run Forecast, see LCA 16-365, at 10.
4. Capacity Factors as approximated based on the 2003 Long Run Forecast (see LCA 24-531.

   Redhawk: % RC02627, at 2
   WPCC 4: % RC02625, at 2
   WPCC 5: % RC02624, at 2
5. Heat Rates as approximated based on the 2003 Long Run Forecast (see LCA 24-531).

   Redhawk: RC02627, at 3
   WPCC 4: RC02625, at 3
   WPCC 5: RC02624, at 3