APS

ORIGINAL

0000061601

Brian Brumfield
Supervisor
Regulatory Affairs

Tel. 602-250-2708
Fax 602-250-3003
e-mail Brian.Brumfield@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

Arizona Corporation Commission
DOCKETED
SEP 15 2006
DOCKETED BY nr

September 15, 2006

Docket Control
Arizona Corporation Commission
1200 west Washington
Phoenix, Arizona 85007

RE: Arizona Public Service Company –Rate Case Docket No. E-01345A-05-0816

Attached are the Rebuttal Testimonies of Arizona Public Service Company's witnesses in the above referenced matter. Excluded is a confidential Attachment (DEB-17RB) to the Rebuttal Testimony of Donald E. Brandt, which is being filed separately under seal.

Sincerely,

Brian Brumfield
Supervisor
Regulatory Affairs

RECEIVED
2006 SEP 15 A 10: 53
AZ CORP COMMISSION
DOCUMENT CONTROL

REBUTTAL TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

TABLE OF CONTENTS

I. Introduction 1
II. Summary of Rebuttal Testimony 2
III. Revised APS Revenue Requirement 8
IV. Staff and RUCO Recommendations 9
V. Regulatory Lag and Attrition 13
VI. Palo Verde Performance Plan 20
VII. Incentive pay and Government Affairs 21
VIII. Conclusion 25
Adjustment to SFR Schedule A-1 ..... Attachment SMW-1RB
Potential Adjustments to Maintain Financial Integrity ..... Attachment SMW-2RB

REBUTTAL TESTIMONY OF STEVEN M. WHEELER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Steven M. Wheeler. I am Executive Vice President, Customer Service and Regulation for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for customer service and regulatory matters affecting the Company before the Arizona Corporation Commission ("Commission") and the Federal Energy Regulatory Commission ("FERC"). I am also responsible for the planning, construction, maintenance and operation of the APS transmission and distribution systems.

Q. HAVE YOU PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony presents and summarizes a revised revenue requirement based on the rebuttal testimony of other APS witnesses. In this regard, I will sponsor Adjustment to SFR Schedule A-1 (Attachment SMW-1RB). I then briefly discuss the Company's overall reaction to the revenue requirement recommendations of Commission Staff ("Staff") and the Residential Utility Consumer's Office ("RUCO"). I also address the increasingly troublesome problem of regulatory lag and offer potential solutions. Next, I comment on Staff consultant Jacob's suggestion for an operating performance plan covering the Palo Verde Nuclear Generating Station ("Palo Verde"). Lastly, I will respond to

several of the specific adjustments to the Company's revenue requirements proposed by Staff and/or Intervenor witnesses.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. Yes. Each of the parties making a recommendation to this Commission on APS revenue requirements has acknowledged the need for an increase in base rates. There is, however, significant disagreement over how large that increase should be. APS has reviewed the proposals of Commission Staff and RUCO, and independent of the merit for some of the specific adjustments proposed by those two parties, their final recommendations simply do not produce a reasonable result even as measured by their own criteria. As is shown in APS witness Brandt's Rebuttal Testimony, APS will not earn a return on equity equal to even the lowest recommended cost of equity under either recommendation. Its key financial metrics will be in the junk category by the first year that rates based on these recommendations will have been in effect, and will drop further in 2008. We therefore ask the Commission to reject the major Staff and RUCO adjustments that lead to these dire circumstances.

In addition, APS has proposed, but not included in its test period revenue requirements, several potential adjustments to test year revenue requirements that are in response to and are necessary to compensate for the clearly inadequate revenue requirements recommendations of Staff and RUCO. One adjustment consists of the incremental revenue deficiency on a portion of the additional distribution, generation and general plant to be added through December 31, 2006. A second is an attrition adjustment to the cost of equity to recognize the fact that in the absence of such an adjustment, APS will have NO

opportunity to earn its cost of capital, irrespective of what the Commission finds that cost of capital to be. Yet another is based on our Constitution's "fair value" requirement. Similarly, APS witness Don Brandt discusses additional ratemaking techniques that can be used to preserve and improve the Company's financial condition. These are in response to a letter from Chairman Hatch-Miller. One of these, the inclusion of construction work in progress ("CWIP") in rate base is discussed in my Rebuttal Testimony while the other, accelerated capital recovery, is not. Taken together, there is the potential for adding up to 10.8% in additional revenue requirements to the Staff and RUCO recommendations. *See* Attachment SMW-2RB.

While these results realized under the Staff and RUCO revenue requirement recommendations are clearly disturbing and would represent a step backward from the level of regulatory support heretofore provided by this Commission, it was equally disturbing that neither Staff nor RUCO made any analysis themselves of the likely consequences of their overall revenue requirement recommendation. In its regulations, the Commission requires that APS provide information on the financial results produced by its rate proposals in the immediate future should they be adopted by the Commission. I have to presume that the purpose for this requirement is to determine the actual financial impact of the Company's proposals and that this information is an important factor in determining whether those proposals are "just and reasonable," as required by our state constitution. The lack of any similar analysis by Staff and RUCO is a significant shortcoming that clouds their overall recommendations in this proceeding.

Regulatory lag and the related problem of attrition are as old as regulation itself. However, given the Company's exploding growth and associated capital requirements, and especially combined with the protracted regulatory process in Arizona, they are problems that can no longer be ignored. Regulatory bodies throughout the country have used a variety of means to both address the issues of regulatory lag and attrition and mitigate their impacts. These include including CWIP in the utility's rate base, forward-looking test years, explicit adjustments to either test year plant or to the cost of equity, interim rates, and prompter rate proceedings. Another technique is based on the use of "fair value" rate base to produce rates that are, in practice, "just and reasonable." One of these, interim rates, has already been authorized by the Commission in the form of the interim PSA adjustor. Continuation of this interim rate past its present expiration date would be one easily accomplished means of both dealing with regulatory lag and avoiding a "yo-yo" effect on customer rates.

Regulatory lag and attrition are not just "utility" issues. The deterioration of the Company's financial condition will have direct and adverse impacts on APS customers in both the quality and the cost of their service. And as is discussed in Mr. Brandt's Rebuttal Testimony, these ratemaking techniques can and have been used for years by municipal utilities to smooth the impact of higher costs by getting out in front of them and adjusting rates more often and in smaller increments than has historically been possible for investor-owned utilities such as APS.

APS witness Robinson and APS witness Ewen present Rebuttal Testimony outlining the serious consequences (in terms of escalating fuel cost deferrals) of Staff consultant Aronuk's proposal to set the base fuel rate <u>below</u> the level of

what Staff itself believes to reasonably reflect anticipated fuel costs when the new base fuel rate would become effective, i.e., in 2007. This deficiency also partially explains the poor cash financial metrics discussed by Mr. Brandt under one of two possible sets of assumptions concerning Staff's proposals to modify the Power Supply Adjustor ("PSA").

Although, as discussed by Mr. Brandt, Mr. Robinson and Mr. Ewen, concurrent implementation of a prospective annual PSA adjustor could resolve much of the Company's concern relative to 2007 PSA deferrals, we still believe getting the base fuel rate right to begin with is important for several reasons. Setting the base fuel rate too low in the Company's last rate case led to spiraling fuel cost deferrals that eventually necessitated a series of PSA surcharge requests and an emergency rate application. I am sure the Commission has no desire to repeat this pattern in the present base rate proceeding and note that no other party has taken exception to the Company's calculation of base fuel costs, although AECC witness Kevin Higgins did modify that calculation for one and only one impact – the decline in fuel prices since November 30, 2005. Second, until we have some clarification from Staff concerning its specific PSA proposal, there remains the possibility that APS would have to absorb 10% of the difference between the Staff and APS base fuel cost numbers. Because 2007 fuel costs are essentially already fixed, this would be nothing less than an automatic disallowance of otherwise prudent fuel costs.

The Company's revised additional revenue requirement is $451.3 million per year. Thus, APS is reducing its overall base rate increase request by roughly $7 million, although as discussed in the Rebuttal Testimony of APS witnesses Fox and DeLizio, the requested Environmental Improvement Charge ("EIC") has

been increased by a little over $200,000. APS has also accepted Staff's proposal to institute an Environmental Portfolio Standard surcharge of $4.25 million. The net impact is to reduce the overall asking from 21.3% to 21.2%. The percentage of the overall request related solely to higher fuel costs has risen from 14% in our original filing to 15.6% in Attachment SMW-1RB.

In arriving at its revised annual revenue requirement, APS has accepted, in whole or in part, a number of Staff's and RUCO's proposed adjustments to the Test Period. In addition, APS has corrected or, in the case of fuel and purchased power expense, updated its previous *pro forma* adjustments to be more representative of the period new rates will become effective, which now appears to be sometime in the first quarter of 2007. The Company's revised revenue requirement is summarized on Attachment SMW-1RB to my Rebuttal Testimony.

Staff consultant Jacobs has suggested an operating performance plan covering Palo Verde. Other expert APS witnesses discuss this issue in more detail. I would only state that Dr. Jacobs' proposal does not address all the important and relevant issues in sufficient detail to support adoption of such a performance plan. Moreover, any consideration of a generating unit performance plan, at a minimum, should: (1) heed the NRC's warning not to create perverse incentives that could compromise safety; (2) be symmetrical in that it provides the opportunity for both penalties and reward; (3) be comprehensive in that it would cover all base load generation; (4) allow for a range of reasonable operating performance that provides neither rewards or penalties; (5) recognize extraordinary events and the unique characteristics of APS generation; and (6) cap both penalties and rewards at a reasonable amount.

APS has an employee incentive program that grants both cash and stock incentives as part of overall employee compensation. And as is indicated in the testimony of Mark Gordon, APS incentive compensation is in line with that of other electric utilities and is an important tool in retaining and motivating employees. RUCO's proposal to eliminate 20% of that compensation is arbitrary and based on no analysis of either the program itself or overall APS employee compensation levels, including stock and cash incentives. Staff consultant Dittmer, on the other hand, concluded that the cash incentive payments were reasonable but disallowed all stock incentives on the faulty premise that the goal of improving the Company's financial performance was somehow contrary to the interests of customers or at least did not benefit customers. Like RUCO, Mr. Dittmer did not find that overall APS employee compensation or even the compensation of employees receiving stock incentives was unreasonable. I must again note that in an effort to reduce the potential issues in this proceeding, APS had already eliminated ALL officer incentive payments from its test period cost of service.

APS also has departments that represent the interests of the Company and its customers at both the state and federal level both with legislative bodies and administrative agencies. Often APS representatives appear at the request of these governmental bodies to provide expert testimony and other information on pending matters. The cost to run these departments is allocated by APS between "below-the-line" activities that do not directly benefit APS' regulated utility operations and "above-the-line" activities that are intended to and do benefit APS customers. The resulting cost savings and other benefits are and should be reflected in rates, but then so should be the cost of activities that help to produce

these very savings. Staff consultant Dittmer's blanket dismissal of these costs as somehow *per se* unreasonable fails to acknowledge the contribution of these two departments to reducing costs to our customers.

In response to testimony from Staff and certain intervenors, as well as various Commissioner letters in this Docket, APS has also submitted: (1) revisions to its "Green Pricing" proposal; (2) a new optional "Total Solar" rate schedule; (3) new and revised partial requirements rates; and (3) discussions of topics ranging from the EPS to hook-up fees. Although some of these issues are specifically discussed in my own Rebuttal Testimony, as the lead Company witness in this proceeding, I believed it appropriate to mention these important aspects of our overall case before the Commission.

III. REVISED APS REVENUE REQUIREMENT

Q. WOULD YOU PLEASE SUMMARIZE THE COMPANY'S REVISED REVENUE REQUIREMENT?

A. APS is seeking to increase base rates by some $451.3 million, or 21.2% on average, based on annualized test period sales. Of that amount, approximately $331 million or 15.6% is directly related to fuel. This rate request produces a 6.37% return on the Company's fair value rate base of $6,110,995,000. *See* Attachment SMW-1R. Such return is approximately equal on a dollar basis to APS' cost-of-capital (expressed in terms of return on original cost rate base) of 8.73%, not including the aforementioned adjustment to the cost of equity for attrition. Consistent with our original filing, fair value rate base is simply the arithmetic average of original cost rate base and reconstruction cost new rate base. But as I will discuss later in my Rebuttal Testimony, changing the

weighting of these two components of "fair value" is another way of dealing with attrition.

Q. ARE YOU SPONSORING ANY OF THE SPECIFIC ADJUSTMENTS TO THE ORIGINALLY REQUESTED RATE INCREASE THAT HAVE RESULTED IN THE REVISED APS REVENUE REQUIREMENT?

A. No. However, I do discuss both the need to use the most updated estimates of fuel costs in determining base fuel costs, as also do APS witnesses Robinson, Ewen and Brandt, and the need to address regulatory lag and attrition in some meaningful fashion in this proceeding.

Q. WHY IS APS NOT INCREASING ITS BASE RATE REQUEST TO REFLECT THE INCREASED REVENUE REQUIREMENT ATTRIBUTABLE TO SOME OF THE ADJUSTMENTS YOU AND MR. BRANDT DISCUSS FOR REGULATORY LAG AND ATTRITION?

A. APS witness Brandt indicates that APS can achieve marginally acceptable financial results with the revenue requirements APS has proposed on Attachment SMW-1RB. It is only when you add in the numerous additional adjustments proposed by Staff and RUCO that APS and its customers are faced with the dire consequences of failing to maintain APS as a credit-worthy business. Thus, APS has brought these potential adjustments to the Commission's attention to allow the Commission to consider alternative means of achieving a financially stable and viable APS and NOT to increase our requested increase.

IV. STAFF AND RUCO RECOMMENDATIONS

Q. WHAT IS THE COMPANY'S OVERALL REACTION TO THE REVENUE REQUIREMENT RECOMMENDATIONS OF STAFF AND RUCO?

A. Both Staff and RUCO propose increases in APS base rates above the level established in Decision No. 67744. But, these increases in base rates will still leave APS far short of recovering its cost of providing service to customers even

if they were to become effective today, let alone in early 2007. Mr. Brandt's Rebuttal Testimony indicates a return on equity under the Staff and RUCO recommendations of 6.8% and 6.0%, respectively, for 2007 and sinking to 6.3% and 4.6% in 2008. Key financial metrics, such as FFO/Debt fall from the minimal levels they achieve by the end of this year to "junk" or near "junk" ranges. By the end of 2008, the first full year the rates set in this proceeding would be in effect, all metrics used by Standard & Poor's would be "junk" under the RUCO recommendation and two of the most important metrics would be in the "junk" range under the Staff proposal (the third is borderline). Mr. Brandt concludes that a downgrade of APS to "junk" bond status would be all but certain under either recommendation. Mr. Brandt goes on to discuss in great detail the very significant ADDITIONAL costs such a downgrade would impose on APS customers and the problems APS would encounter in raising the new capital necessary to serve their future needs.

Q. DID STAFF AND RUCO TEST THEIR REVENUE REQUIREMENT RECOMMENDATIONS TO DETERMINE WHETHER THEY PRODUCED REASONABLE FINANCIAL RESULTS FOR APS?

A. No. I find this failure to be especially disturbing after going through an entire emergency rate proceeding during which it was emphasized over and over that APS faced severe financial stress and was in very real danger of being downgraded to "junk" bond status.

In its regulations, the Commission requires that APS provide information on the financial results produced by its rate proposals in the immediate future should they be adopted by the Commission. *See* A.A.C. R14-2-103. I have to presume that the purpose for this requirement is to determine the actual financial impact of the Company's proposals and that this information is an important factor in

determining whether those proposals are "just and reasonable," as required by our state constitution.

Q. WHY DO YOU BELIEVE RATES MUST BE "JUST AND REASONABLE" WHEN ACTUALLY IMPLEMENTED AND NOT FOR SOME HISTORICAL PERIOD?

A. It is simply common sense. Ratemaking is inherently prospective in its application. As the Commission itself has stated: "The Commission's purpose in a rate proceeding is to set prospective prices and terms for utility service, not adjudicate the reasonableness of past profits." Decision No. 53537 at 8 (emphasis supplied). Moreover, in *Scates v. Arizona Corporation Commission*, 118 Ariz. 531, 533-34, 578 P.2d 612, 614-15 (Ariz. App. 1978), the Court held: "... the rates established by the Commission should meet the overall operating costs of the utility and produce a reasonable rate of return. It is equally clear that the rates cannot be considered just and reasonable if they fail to produce a reasonable rate of return . . ." The consistent use of prospective terms in this quote to describe both the operating costs to be recovered in rates and the return to be earned from such rates is a clear instruction to the Commission concerning the requirements of our Arizona Constitution.

Q. IN YOUR SUMMARY, YOU MENTIONED THE STAFF'S PROPOSED BASE FUEL RATE. WHY DO YOU BELIEVE THAT RATE TO BE INADEQUATE?

A. That's not just my conclusion. Staff consultant Antonuk concedes his base fuel rate based on partially adjusted 2006 costs is some $150 million less than APS fuel costs during the first year that base fuel rate would be in effect, thus producing massive PSA cost deferrals under the current PSA mechanism. *See* Antonuk Testimony at 35. It is clear from hindsight that the base fuel rate was set too low in Decision No. 67744, resulting in skyrocketing deferrals ($170

million by year-end 2005) and the need for multiple PSA surcharge requests. In this instance, we know Staff's proposed base fuel rate, standing alone, is inadequate, so there is no reason to repeat the same mistake.

As is explained in the Rebuttal Testimony of both Don Robinson and Pete Ewen, Staff's base fuel rate, if combined with a prospective and timely PSA adjustor and certain other PSA modifications discussed by those witnesses (which modifications are, we believe, consistent with Staff's PSA recommendation), could prove effective in recovering fuel costs in a timely manner. The most important of these "other modifications" is changing how the 90/10 sharing mechanism would apply such that APS does not face an automatic 10% cost disallowance of over $15 million in otherwise prudent fuel expenditures just because the base fuel rate is deliberately set at an artificially low level. Both Mr. Robinson and Mr. Ewen further emphasis this latter point. However, I also agree with Mr. Robinson and Mr. Ewen that we should get the base fuel rate right to begin with and then adopt a prospective PSA adjustor for 2008, when there will be more time to flesh out the procedural details for implementing such as adjustor.

This case will not be resolved until 2007, and any changes to the PSA will require amendments to the present Plan of Administration ("POA") for the PSA. To avoid the "chicken and the egg" problem we had after Decision No. 67744, APS has attached alternative POAs to Mr. Rumulo's Rebuttal Testimony – one incorporating the Company's proposed changes to the PSA and one incorporating Staff's to the extent we understand them. We ask that the Commission approve a POA in this proceeding so that there will be no lingering

questions as to the proper application of changes to the PSA, irrespective of what such changes may be.

Q. DID STAFF TAKE A POSITION ON THE 7 MILL INTERIM PSA ADJUSTOR APPROVED IN DECISION NO. 68685?

A. Not specifically, but Mr. Dittmer appears to believe it will terminate at approximately the same time as new rates in this proceeding are implemented. APS cannot tell whether that is a Staff recommendation or merely speculation as to how quickly this proceeding will be decided. In either event, it would be most appropriate to continue the 7 mill interim PSA adjustor to synchronize its expiration with the rates from this case. We ask the Commission to authorize such synchronization. It will lessen the marginal impact of new rates on APS customers, eliminate a rate "yo-yo" effect, and reduce PSA deferrals.

V. REGULATORY LAG AND ATTRITION

Q. WHY ARE YOU DISCUSSING THESE TWO ISSUES?

A. First of all, Chairman Hatch-Miller asked the parties in his letter dated July 21, 2006 to address ways of enhancing APS' financial strength. Second, the revenue requirements recommendations of Staff and RUCO highlighted the problems of regulatory lag and attrition and the increasing inadequacy of a historical test period "bottom up" approach to ratemaking that ignores foreseeable impacts, particularly during a period of rapidly rising costs.

Q. WOULD YOU PLEASE EXPLAIN WHAT IS MEANT BY THE TERM REGULATORY LAG?

A. Regulatory lag is the time between a request for a rate increase and the time when the Commission issues a decision on the rate increase. Some regulatory lag is inevitable, and I do not use the term pejoratively.

Q. HOW DOES REGULATORY LAG NEGATIVELY AFFECT A UTILITY COMPANY?

A. Regulatory lag will cause a shortfall in the utility's revenue requirement even if there are no increased costs subsequent to the rate filing. And where regulators set rates prospectively based on historic test-period costs, this shortfall is increased by whatever increase in costs occurs subsequent to that test-period but prior to new rates becoming effective.

Q. CAN REGULATORY LAG BENEFIT A UTILITY?

A. Yes. This can occur if unit costs (i.e., cost per customer, cost per kW, or cost per kWh) are decreasing in nominal (unadjusted for inflation) terms. Such decreasing nominal unit costs are an unusual circumstance and are certainly not the present circumstance with APS. However, even in these rare instances, it is in the interests of regulators to reduce regulatory lag to the extent possible.

Q. WHAT MECHANISMS ARE AVAILABLE TO REDUCE THE NEGATIVE EFFECTS OF REGULATORY LAG?

A. There are essentially only four ways to reduce regulatory lag: (1) reduce the need for general rate cases to recover costs; (2) allow new rates to become effective on an interim basis prior to the conclusion of a rate case; (3) shorten the time to process a general rate case; and/or (4) make some manner of explicit attrition adjustments to the final rates to compensate prospectively for the effects of such lag.

PUC's have adopted rate adjustment mechanisms including but not limited to a fuel adjustment clause. This permits rates to be adjusted to reflect the changes in specified costs without the need for a rate case. The more timely and predictable

such mechanisms are and the more frequently they can be exercised, the better they are in reducing regulatory lag.

Another method would be to identify a range of reasonable rates with the utility being able to change its prices within that range by a simple filing that is immediately effective. This has been permitted by this Commission for certain providers of so-called competitive services although there is no particular reason why this concept could not be expanded to cover other utility services.

The second technique to offset regulatory lag is to grant the utility interim rates. In Arizona, the Commission is able to grant interim rates (subject to refund) when it is unable to process a full rate case in a reasonable period of time. The Federal Energy Regulatory Commission ("FERC") and many states routinely permit such interim rates.

The third and most obvious step in reducing regulatory lag is to reduce the time it takes to process a rate case. This would involve requiring filing deadlines and overall "time-clock" provisions more similar to other jurisdictions.

Q. HOW EFFECTIVE IS AN ADJUSTOR MECHANISM IN REDUCING REGULATORY LAG?

A. That depends on whether the adjustment mechanism is itself timely. Although fuel adjustment mechanisms may alleviate the effects of costs of fuel and purchased power, the mechanism does not resolve other problems stemming from regulatory lag, such as increase of construction costs, an expanding rate base, and an increase in non-fuel operating costs. And unless base fuel costs are properly reflected in general rate cases (i.e., represent the level of fuel costs

anticipated for the period new base rates become effective), there can be significant lag in fuel cost recovery.

Q. EVEN IF REGULATORY LAG IS MINIMIZED, IT WILL STILL EXIST. ARE THERE STILL OTHER WAYS THAT THE EFFECTS OF REGULATORY LAG CAN BE MITIGATED?

A. Yes. As I indicated earlier, the use of historical test periods aggravates the impact of regulatory lag. The adoption of known and measurable *pro forma* adjustments to that historical test period is a step in the right direction. So is the routine inclusion in test period rate base of construction work in progress ("CWIP") that is expected to be in service within the period the new rates are anticipated to be effective. Indeed, the Commission authorized CWIP for APS during the 1980s when the Company was faced with a similar problem of chronic cash flow deficiencies. APS witness Brandt provides the revenue requirement impact of including the Company's June 30, 2006 CWIP balance in its test period rate base. In this proceeding, APS has also suggested another variant of this last approach by quantifying the impact of a *pro forma* adjustment to rate base to recognize jurisdictional plant in service as of the end of 2006. The validity of making post test-period adjustments to plant was upheld in Decision No. 54073 (June 13, 1984): "Plant additions made after the close of the historical TY <u>but prior to rates going into effect</u> should be treated no differently from other post-TY adjustments." *Id.* at 16 (emphasis in original).

Q. YOU HAVE DISCUSSED VARIOUS WAYS OF ADJUSTING AN HISTORICAL TEST PERIOD TO ADDRESS REGULATORY LAG. CAN REGULATORY AGENCIES ALSO USE FUTURE OR FORWARD-LOOKING TEST PERIODS?

A. Yes. The Federal Energy Regulatory Commission and at least 13 states permit or require consideration of some form of a future test period. Often the period

selected in the period that the new rates would be in effect, which in this instance would be in the 2007-2008 time frame. Although I am only aware of one instance in which this Commission has permitted use of a future test period, I am advised that there is no legal impediment to doing so.

Q. CAN YOU EXPLAIN WHAT IS MEANT BY ATTRITION?

A. Attrition is the tendency of the utilities rate of return to diminish over time because of operating costs that increase faster than revenues, capital costs growing faster than earnings or a combination of both.

Q. IS ATTRITION SIMILAR TO REGULATORY LAG?

A. Regulatory lag can and usually does exacerbate the rate of attrition but the latter can exist in the absence of extensive regulatory lag. Moreover, the existence of significant regulatory lag may also impact the need of a regulatory body to respond to attrition.

Q. COULD YOU PLEASE EXPLAIN YOUR LAST STATEMENT?

A. If the rate of attrition is very slow, and there is little regulatory lag to begin with, a regulatory agency may choose to concentrate on further reductions of that lag rather than on trying to explicitly address attrition in the rate setting process. Unfortunately, neither of those circumstances applies to APS.

Q. WHAT SHOULD THE COMMISSION'S RESPONSE BE TO ATTRITION?

A. If the Company can establish the existence of attrition, the Commission should evaluate the impact of this factor on the earnings of the utility and make an appropriate allowance. In this case, both the "F" schedules of the Commission's Standard Filing Requirements and the testimony of APS witnesses Brandt and

Avera clearly establish that attrition in the case of APS is both real and very significant.

Q. WHAT IS THE PURPOSE OF AN ATTRITION ADJUSTMENT?

A. The purpose of the attrition adjustment is to maintain and improve the financial health of the utility and to allow it a reasonable opportunity to actually earn its cost of capital.

Q. IS APS REQUESTING THAT THE COMMISSION IMPLEMENT AN ATTRITION ADJUSTMENT IN THIS CASE?

A. Yes, if the Commission is otherwise disposed to adopt Staff or RUCO's demonstrably inadequate overall revenue requirement based on their analyses of test period cost of service. Dr. Avera and Mr. Brandt both quantify the extent of that attrition adjustment as part of their Rebuttal Testimony.

Q. WHAT ARE THE FACTORS THAT WOULD SUPPORT AN ATTRITION ADJUSTMENT?

A. The regulatory lag attendant to filing a new rate request and the rate at which earned return declines in the period subsequent to establishing rates are the primary factors. The latter is determined by the overall level of cost increases relative to revenue growth, the size of incremental capital expenditures compared with the embedded investment per customer, and other factors.

Q. HOW WOULD AN ATTRITION ADJUSTMENT WORK?

A. An attrition adjustment could be added to the cost of equity in determining overall revenue requirements.

Q. IS THIS THE ONLY WAY OF RECOGNIZING THE EXISTENCE OF ATTRITION?

A. No. The Commission could increase the allowed return on "fair value" rate base to a level above that necessary to reflect the bare bones cost of capital. Prior Commission decisions have said that the cost of capital is the "minimum" standard for determining a reasonable return on "fair value rate base – not the maximum. In Decision No. 53537 (April 27, 1983) the Commission stated: "It is difficult to imagine a situation in which a reasonable return on FVRB would yield less than the cost of capital." *Id.* at 17 (emphasis in original). In that same vein, the Commission could give a greater weighting to reproduction cost new in establishing "fair value" rate base while keeping the allowed return on that rate base constant.

Q. WHAT IMPACT WOULD ONE OR MORE OF THESE ADJUSTMENTS (ATTRITION, CWIP, DEPRECIATION, POST-TEST PERIOD PLANT AND FAIR VALUE RATE BASE) HAVE ON THE STAFF AND RUCO RECOMMENDATIONS?

A. These are shown on Attachment SMW-2RB. As you can see, they range from as much as an additional 6.5% (prospective PSA adjustor implemented concurrently with Staff's new base fuel rate)[1] to less than .4% (incremental revenue requirement on 2006 plant additions). If adopted in conjunction with the balance of either the Staff or RUCO revenue requirement recommendation, it would produce a revenue requirement approximating or even exceeding that requested by the Company.

Q. WHAT DO YOU SEE AS THE COMMISSIONS' ROLE IN MAINTAINING A PUBLIC UTILITY'S FINANCIAL INTEGRITY?

---

[1] APS realizes that Staff has made a prospective PSA adjustor a part of its recommendation, but the concurrent implementation of that adjustor and the amount of that adjustor are APS proposals to which Staff has not had an opportunity to respond.

A. In *FPC v. Hope Natural Gas Co.,* the United States Supreme Court held that fixing of just and reasonable rates requires that rates must be sufficient to enable the company to operate successfully, maintain its financial integrity, attract capital, and compensate investors for the risks assumed. Each of these criteria is forward-looking in its application. Public utility commissions need to stay attuned to the realities of today's economic climate and costs to do business. Electing not to do so disadvantages both investor and consumer interests and denies the utility its constitutionally guaranteed right and need to earn a fair rate of return on investment so that it can properly perform its public service obligations. Regulatory lag and attrition both undermine the utility's ability to earn such a fair rate of return, and thus the Commission should seek to address both of these problems both in this and future APS rate cases.

VI. PALO VERDE PERFORMANCE PLAN

Q. HAS STAFF WITNESS DR. JACOBS SUGGESTED AN OPERATING PERFORMANCE PLAN FOR PALO VERDE?

A. Yes. Staff consultant Jacobs has suggested the general outline of an operating incentive plan covering Palo Verde. However, Dr. Jacobs has not presented a detailed proposal that reflects consideration of all the issues relevant to such a mechanism. For example, Dr. Jacobs does not:

- address the NRC's significant concerns over the safety implications of nuclear plant performance plans
- demonstrate how his proposal would improve performance at Palo Verde without creating perverse incentives
- address how penalties would be calculated and applied
- explain why APS should not have the opportunity to earn rewards for superior performance
- offer any specific plan of administration for his proposal.

APS witness Fitzpatrick presents in his Rebuttal Testimony some of the attributes and issues associated with the development of a generating plant operating incentive plan. I second his belief that if such a plan could be designed to overcome the perverse incentive problem and was otherwise found to be necessary (which it is not), it should: (1) be symmetrical in that it provides the opportunity for both penalties and rewards; (2) be comprehensive in that it would cover all base load generation; (3) allow for a range of reasonable operating performance that provides neither rewards or penalties (i.e., a "dead band"); (4) cap both penalties and rewards at a reasonable amount; (5) recognize the possibility of extra-ordinary events; and (6) clarify to what extent APS generation performance is still subject to application of the prudence standard.

VII. INCENTIVE PAY AND GOVERNMENT AFFAIRS

Q. PLEASE EXPLAIN THE APS EMPLOYEE INCENTIVE COMPENSATION PROGRAM?

A. APS has an employee incentive program that grants both cash and stock incentives as part of overall employee compensation. To reduce the potential issues in this proceeding, APS already eliminated ALL officer cash incentive payments from its test period cost of service.

Q. HAS STAFF PROPOSED AN ADJUSTMENT TO THE TEST PERIOD EMPLOYEE INCENTIVE PAY EXPENSE?

A. Yes. Staff consultant Dittmer concluded at pages 106-112 of his testimony that the cash incentive payments were reasonable but disallowed all stock incentives on the faulty premise that the goal of enhancing the Company's financial performance was somehow contrary to the interests of customers or at least did not benefit customers. Mr. Dittmer did not find that overall APS employee compensation or even the compensation of employees receiving stock incentives

was unreasonable or imprudent. Absent such evidence, I believe APS should be able to recover these costs.

Q. WHY DO YOU SAY THAT MR. DITTMER'S RATIONALE FOR DISALLOWING STOCK INCENTIVE PAY IS "FAULTY"?

A. It is clearly in the APS customer's interest that APS earn a reasonable return on investment. That is the only way APS can continue to attract on reasonable terms the capital investment necessary to provide this vital service to the public. The belief that the interests of investors and consumers are in conflict in this regard and that regulation is some sort of "zero sum game" in which customers benefit only to the detriment of investors (and vice versa) is a false dichotomy that leads to an overly adversarial regulatory climate. Customers have a large stake in the financial success of the utility because that is the only way the utility can attract needed capital investment at a reasonable cost.

Q. SHOULD IT REALLY MATTER IN THIS PROCEEDING WHAT ELEMENTS OF OVERALL COMPENSATION ARE FOUND MOST APPROPRIATE BY THE APS BOARD?

A. No. There is no disagreement that the efforts of APS employees directly and substantially contribute to the provision of electric service. The only relevant ratemaking issue is whether their compensation taken as a whole is reasonable, and not whether that compensation is in base salary, incentive pay, benefits, stock or whatever. There has been NO evidence that overall APS compensation is unreasonable. In contrast, APS has presented expert testimony both from its CFO, Mr. Brandt, and from an independent consultant, Mark Gordon, supporting the reasonableness of the specific employee compensation programs challenged by Staff and RUCO.

Q. HAS RUCO ALSO DISALLOWED A PORTION OF APS EMPLOYEE INCENTIVE COMPENSATION?

A. Yes. RUCO's proposal to eliminate 20% of all incentive compensation is arbitrary and based on NO analysis of either the incentive program itself or overall APS employee compensation levels, including stock and cash incentives. Rather, RUCO proffers a "share the pain" explanation that suggests that APS employees should subsidize the cost of providing electricity to APS customers because RUCO believes that rates would otherwise be too high. Aside from the implication that APS employees are somehow overpaid and should be able to absorb a 20% reduction in incentive pay, I am aware of no regulatory decisions in this or any other jurisdiction that would support such a concept.

As it is, APS has earned and is earning an inadequate return and will continue to do so irrespective of the results of this case. And as noted in Mr. Brandt's Rebuttal Testimony, Pinnacle West stock has performed well below the industry average.

Q. WHAT ABOUT SO-CALLED LOBBYING EXPENSES?

A. Staff has disallowed all the costs of APS' Federal and Public (State) Affairs Departments without any analysis of the nature of the activities of or results achieved by these groups. RUCO has also disallowed a portion of such costs. These departments represent the interests of the Company and its customers at both the state and federal level both with legislative bodies and administrative agencies. Often APS representatives appear at the request of these governmental bodies to provide expert testimony and other information on pending matters. The cost to run these departments is allocated by APS between "below-the-line" activities that do not directly benefit APS' regulated utility operations and

"above-the-line" activities that clearly do. As a result, nearly two-thirds of the Public Affairs Department budget is allocated "below-the-line."

Q. COULD YOU GIVE SOME EXAMPLES OF CUSTOMER BENEFITS ARISING FROM THE ACTIVITIES OF THESE TWO DEPARTMENTS?

A. Yes. Because of our efforts, APS received a waiver of the tariff on importation of the replacement steam generators at Palo Verde, thus saving APS customers some $10 million. APS also worked to include provisions in the Energy and Transportation Act of 2005 on tax incentives for new transmission investment. Estimated savings are $1.4 million per $50 million of eligible new transmission investment. APS supported the Production Tax Credit provisions of the American Jobs Creation Act – legislation that produced a $3 million benefit for APS customers in this very rate case – as well as expansion of the renewable energy tax credit at both the state and federal level. APS has also worked to make the provisions in and implementation of EPACT fair to native load customers and opposed a "one size fits all" Standard Market Design that would raise costs to our customers.

And speaking of state legislation, the record reflects the significant property tax benefits realized by APS customers in this proceeding ($1.7 million per Rebuttal Testimony of Laura Rockenberger) that are in part due to the efforts of the Public Affairs Department. APS has also been active in efforts to protect Luke Air Force Base ("Luke") from encroachment, thus preserving both the economic benefits of Luke to this State and an important APS customer. As does the Federal Affairs Department, the Public Affairs department also is instrumental in defeating or at least modifying legislation that is not in the best interests of our customers.

The savings discussed above are and should be reflected in rates, but then so should be the cost of activities that help to produce these very savings. Staff consultant Dittmer's blanket dismissal of these costs as somehow *per se* unreasonable fails to acknowledge the contribution of these two departments to reducing costs to our customers.

Q. HOW DO YOU RESPOND TO MR. DITTMER'S DISCUSSION OF THE FERC UNIFORM SYSTEM OF ACCOUNTS AND SPECIFICALLY ACCOUNT 426?

A. In two ways. First, Mr. Dittmer notes, and Ms. Rockenberger reiterates in her Rebuttal Testimony, that the FERC instructions for Account 426 do not provide for the automatic disallowance of such costs in setting rates. In fact, the instruction states that the fact that costs entered into that account are considered "non-operating" "does not preclude the [Federal Energy Regulatory] commission consideration of proof to the contrary for ratemaking or other purposes." I believe I have provided such proof. I would also point out that the test period cost at issue ($1.075 million) is far outweighed by the benefits conferred on customers now and in the future.

VIII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS is facing a financial emergency every bit as critical as it experienced last spring. The Company simply must receive adequate rate relief in this proceeding. Half measures will not suffice, and the Commission should consider every ratemaking tool in its arsenal to produce rates that will preserve the Company's financial integrity. The stakes for APS and its customers are too high to do anything else.

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

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
(Dollars in Thousands)

Line No.	Description	Electric - Updated 9/15/06 Original Cost	RCND	Fair Value	Line No.
1	**Adjusted Rate Base**	**4,456,937**	**7,765,052**	**6,110,995**	1
2	Adjusted Operating Income	119,411	119,411	119,411	2
3	Current Rate of Return	2.68%	1.54%	1.95%	3
4	Required Operating Income	389,091	389,091	389,091	4
5	**Required Rate of Return**	**8.73%**	**5.01%**	**6.37%**	5
6	Operating Income Deficiency	269,680	269,680	269,680	6
7	Gross Revenue Conversion Factor	1.6407	1.6407	1.6407	7
8	Adjusted Increase in Base Revenue Requirements	442,464	442,464	442,464	8
9	Environmental Improvement Charge	4,542	4,542	4,542	9
10	Environmental Portfolio Standard	4,250	4,250	4,250	10
11	**Total Increase in Revenue Requirement**	**451,256**	**451,256**	**451,256**	11
12	Total Sales to Ultimate Retail Customers	2,127,322	2,127,322	2,127,322	12
13	**Percentage Rate Increase**	**21.21%**	**21.21%**	**21.21%**	13

Potential Adjustments to Maintain Financial Integrity

Line #	Description	Notes	Revenue Requirement Increase (Millions)	Percent Increase %
1	Staff Base Increase	a	$ 204.0	9.57%
2	Staff RES/EPS	b	$ 4.3	0.20%
3	Staff Recommendation		$ 208.3	9.77%
4	Prospective 2007 PSA Adjustor	c	$ 137.8	6.46%
	Subtotal		$ 346.1	16.23%
	Additional Adjustments:			
6	Plant In Service	d	$ 7.9	0.37%
7	Attrition Adjustment	e,f	$ 99.7	4.68%
8	Depreciation	g	$ 50.0	2.34%
9	CWIP	h,i	$ 23.9	1.12%
10	.5% increase in ROR on Staff FVRB	j	$ 49.7	2.33%
	Total of Additional Adjustments		$ 231.2	10.84%

Notes:

a Dittmer Testimony page 6, line 9
b Dittmer Testimony page 6, line 22 to 7, line 2
c APS recommends that staff proposed 2007 PSA Adjustor (as corrected) be made effective concurrent with the base rate increase
d Plant In Service amount shown here is ACC jurisdictional and uses Staff recommended ROE of 10.25%; the APS Plant In Service Calculation shown in Laura Rockenberger Rebuttal Testimony used APS requested ROE of 11.5% and is Total Company amount
e As shown includes additional impact of Plant In Service (PIS) adjustment in rate base; without PIS, Attrition adjustment would be $92.0 million
f Uses low end (170 basis points) of range suggested in Donald Brandt Rebuttal Testimony; high end (350 basis points) for 2007 would result in adjustment of $205.3 million
g Described in Rebuttal Testimony of Donald Brandt
h CWIP adjustment shown here uses Staff Recommended ROE and is ACC jurisdictional; adjustment in Donald Brandt Rebuttal Testimony uses Company requested ROE and is total Company amount
i With minimum Attrition adjustment and Staff ROE, total CWIP adjustment would be $27.9 million
j Increase calculated using FVRB numbers from Staff witness Dittmer Schedule A line 1 - illustrative only (Commission could adjust FVRB return or FVRB or both to achieve necessary revenue requirement)

REBUTTAL TESTIMONY OF DONALD E. BRANDT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

Table of Contents

I. INTRODUCTION 1

II. SUMMARY 2

III. FINANCIAL RESULTS 6

IV. MEASURES TO IMPROVE CREDITWORTHINESS 19

V. ATTRITION ALLOWANCE 28

VI. STAFF'S PROPOSED 10.25% ROE 30

VII. RUCO'S PROPOSED CAPITAL STRUCTURE AND ROE 33

VIII. RESPONSE STAFF WITNESS ANTONUK AND RUCO WITNESS HORNBY 40

IX. PRO FORMA FOR UNDERFUNDED PENSION LIABILITY 55

X. RUCO'S PROPOSED SERP PRO FORMA 62

XI. PINNACLE WEST STOCK UNDERPERFORMANCE 67

XII. CONCLUSION 73

APS Financial Indicators with APS' Modified Proposed Rates ..... Attachment DEB-1RB

APS Financial Indicators with Staff's Proposed Rates (Projected PSA) ..... Attachment DEB-2RB

APS Financial Indicators with RUCO's Proposed Rates ..... Attachment DEB-3RB

S&P, *Regulation and Utility Credit Quality, NARUC Summer Committee on Gas Meeting*, Richard Cortright Jr., August 1, 2006 ..... Attachment DEB-4RB

S&P, *Summary: Arizona Public Service Co.*, August 31, 2006 ..... Attachment DEB-5RB

Moody's, *Credit Opinion: Arizona Public Service Co.*, May 9, 2006 ..... Attachment DEB-6RB

Wall Street Journal, *Investment-Grade Market Booms*, September 7, 2006, page C6 ..... Attachment DEB-7RB

Donald Brandt's Letter to Commissioners, July 26, 2006 ..... Attachment DEB-8RB

Jack Davis' Letter to Commissioners, August 17, 2006 ..... Attachment DEB-9RB

Financial Issues Report, APS, August 17, 2006 .....Attachment DEB-10RB

Chairman Hatch-Miller's Letter to Thomas Mumaw, July 21, 2006 .....Attachment DEB-11RB

S&P, *U.S. Public Power Utilities' Self-Governance Bolsters Credit Quality*, July 19, 2006 .....Attachment DEB-12RB

Moody's, *MOODY'S ASSIGNS Aa1 TO SALT RIVER PROJECT'S $296 MILLION REVENUE BONDS; OUTLOOK STABLE*, June 16, 2006Attachment DEB-13RB

APS 2005 10-K, cover page and pages 99-100.....Attachment DEB-14RB

APS' Response to RUCO's Data Request 7.1.....Attachment DEB-15RB

Thomas Mumaw's Letter to Commssioner Mayes, December 16, 2005 .....Attachment DEB-16RB

Pension Costs and Contributions.....Attachment DEB-17RB

Accelerated Recovery of Underfunded Pension Liability ...Attachment DEB-18RB

Lehman Brothers Equity Research, *Pinnacle West Capital*, Daniel Ford, August 21, 2006 .....Attachment DEB-19RB

REBUTTAL TESTIMONY OF DONALD E. BRANDT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald E. Brandt. I am Executive Vice President and Chief Financial Officer for both Pinnacle West Capital Corporation ("Pinnacle West") and Arizona Public Service Company ("APS" or "Company"). I have responsibility for the finance, treasury, accounting, tax, investor relations, financial planning, and power marketing and trading functions at Pinnacle West and APS. My business address is 400 North 5th Street, Phoenix, Arizona, 85004.

Q. DID YOU PROVIDE DIRECT TESTIMONY IN THE PROCEEDING THAT PROVIDES YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will address the following issues: (i) the Company's financial condition under both ACC Staff's and RUCO's recommendations as well as the Company's modified asking; (ii) APS' response to Chairman Hatch-Miller's July 21, 2006 request to submit testimony addressing actions that the Commission could take to improve APS' creditworthiness; (iii) an attrition allowance to enable APS to earn its allowed Return on Equity ("ROE"); (iv) certain aspects of Staff's proposed ROE of 10.25%; (v) certain aspects of RUCO's proposed capital structure of 50% debt and 50% equity, and ROE of 9.25%; (vi) the aspects of Staff witness Antonuk's testimony and RUCO

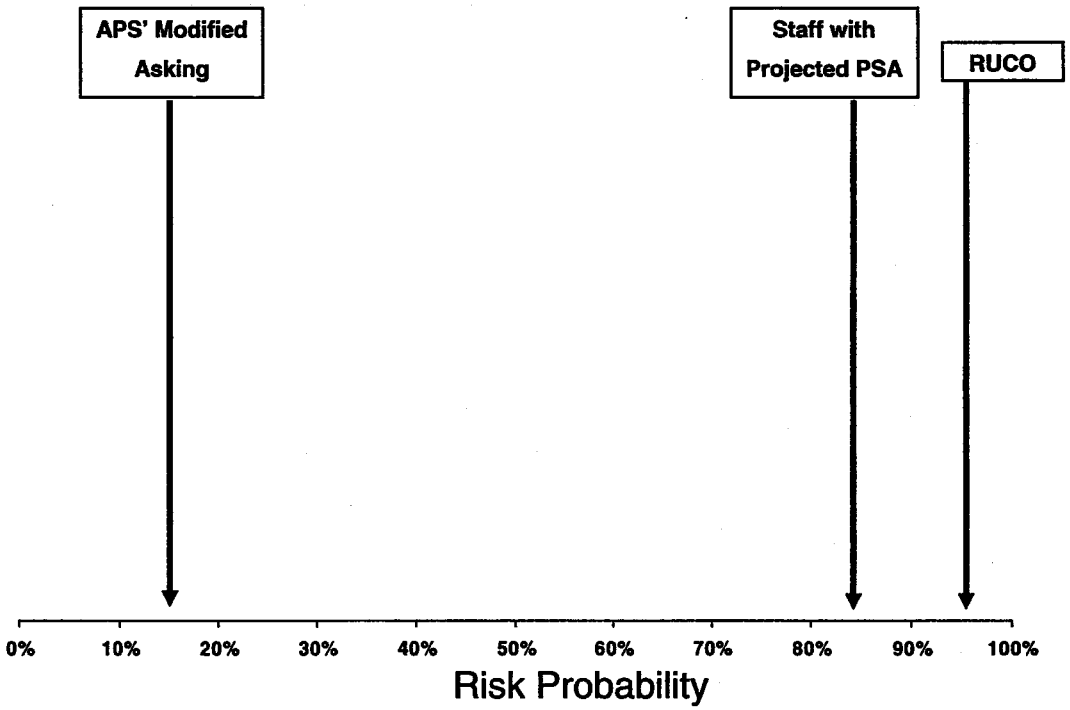
witness Hornby's testimony that address APS' hedging policy; (vii) Staff witness Ditmer's, RUCO witness Diaz-Cortez's, and AECC witness Higgins' pro forma adjustments regarding underfunded pension liability; (viii) RUCO witness Diaz-Cortez's pro forma adjustment for the removal of SERP costs; and (ix) the dramatic underperformance of Pinnacle West's stock over the past two years and the resultant impact on APS' customers.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Should the Commission accept either Staff's or RUCO's recommendations, I believe the Company's credit ratings will be downgraded to non-investment grade "junk" levels. Over the next ten years, APS will require access to the capital markets to issue several billion dollars of debt to fund its massive infrastructure additions and improvements. A downgrade of APS' credit ratings to "junk" status will severely limit this crucial access to the capital markets and will add over $1 billion of additional interest expense — a cost increase that customers would eventually shoulder. The following chart illustrates my expert assessment of the various recommendations currently before the Commission and their probable effect on APS' credit ratings:

Arizona Public Service Company
Risk of Credit Rating Downgrade to Junk



I prepared this illustrative chart utilizing my experience as a financial expert, as an executive with more than 22-years experience in the utility industry, as a chief financial officer of several major utilities over a period of more than 18-years, and as a senior financial executive who has dealt continuously with the major credit rating agencies since 1983.

The Commission should take several measures to help APS improve its credit quality, which I provide in response to the recent request by Chairman Hatch-Miller. Because we have responsibility for providing high quality electric service to one of the country's fastest growing economies, we regard the timely recovery of costs and the challenge of regulatory lag as being of the utmost

importance. Moreover, APS must have the ability to earn an adequate ROE to meet the significant financial tasks we will confront. I have offered several innovative ideas that the Commission should consider at this time.

Given the enormous infrastructure financing needs that lie ahead, APS must have ready access, on reasonable terms, to both the debt and equity capital markets. The Commission should establish an appropriate capital structure and ROE for APS that helps to attract and retain fixed income and equity investors. Unfortunately, the ROE proposals of both Staff and RUCO witnesses fail these critical requirements as does the capital structure suggested by RUCO. These recommendations would further exacerbate APS' already strained financial condition. I describe the recent significant underperformance of Pinnacle West's common stock that has resulted in enormous costs to shareholders and a resultant impact on APS customers.

Staff witness Antonuk and RUCO witness Hornby have provided testimony on the APS hedging program. In general, I concur with most of the observations made by Mr. Antonuk about APS' conservative hedging program, but I disagree with many of the characterizations and conclusions reached by Mr. Hornby.

The Staff, RUCO and AECC have all recommended the denial of the Company's request to accelerate the recovery of its underfunded pension liability. APS firmly believes this issue, which currently confronts companies nationally, warrants resolution at this time rather than postponing the day of financial reckoning.

I also disagree with RUCO witness Diaz-Cortez's pro forma adjustment to remove all SERP costs from the test period. SERP forms an integral part of the total compensation package to enable management employees to receive equitable pension benefits.

Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR TESTIMONY?

A. Yes. My testimony includes the following Attachments:

1. DEB-1RB -- APS Financial Indicators with APS' Modified Proposed Rates.
2. DEB-2RB -- APS Financial Indicators with Staff's Proposed Rates (Projected PSA).
3. DEB-3RB -- APS Financial Indicators with RUCO's Proposed Rates.
4. DEB-4RB -- S&P, *Regulation and Utility Credit Quality, NARUC Summer Committee on Gas Meeting*, Richard Cortright Jr., August 1, 2006.
5. DEB-5RB -- S&P, *Summary: Arizona Public Service Co.*, August 31, 2006.
6. DEB-6RB -- Moody's, *Credit Opinion: Arizona Public Service Co.*, May 9, 2006.
7. DEB-7RB -- Wall Street Journal, *Investment-Grade Market Booms*, September 7, 2006, page C6 .
8. DEB-8RB -- Donald Brandt's Letter to Commissioners, July 6, 2006.
9. DEB-9RB -- Jack Davis' Letter to Commissioners, August 17, 2006.
10. DEB-10RB -- Financial Issues Report, APS, August 17, 2006.
11. DEB-11RB -- Chairman Hatch-Miller's Letter to Thomas Mumaw, July 21, 2006.
12. DEB-12RB -- S&P, *U.S. Public Power Utilities' Self-Governance Bolsters Credit Quality*, July 19, 2006.
13. DEB-13RB -- Moody's, *MOODY'S ASSIGNS Aa1 TO SALT RIVER PROJECT'S $296 MILLION REVENUE BONDS; OUTLOOK STABLE*, June 16, 2006.

14. DEB-14RB -- APS 2005 10-K, cover page and pages 99-100.

15. DEB-15RB -- APS' Response to RUCO's Data Request 7.1.

16. DEB-16RB -- Thomas Mumaw's Letter to Commissioner Mayes, December 16, 2005.

17. DEB-17RB -- Pension Costs and Contributions.

18. DEB-18RB -- Accelerated Recovery of Underfunded Pension Liability.

19. DEB-19RB -- Lehman Brothers Equity Research, *Pinnacle West Capital,* Daniel Ford, August 21, 2006.

III. FINANCIAL RESULTS

Q. IF THE RATES PROPOSED BY APS IN ITS MODIFIED ASKING ARE IMPLEMENTED ON MAY 1, 2007, HOW DO APS' FINANCIAL METRICS COMPARE WITH THOSE NEEDED TO MAINTAIN INVESTMENT GRADE RATINGS?

A. As you can see in **Attachment DEB-1RB**, APS' Funds from Operations Interest Coverage ("FFO Interest Coverage") stays relatively flat at around 4.0 times throughout the forecast period. This places it solidly within the "BBB" range. We project Funds from Operations to Total Debt ("FFO/Debt") to end 2006 at 17.6%, slightly below the 18% minimum needed for the "BBB" range. However, it improves to 19.2% in 2007 before deteriorating again to 17.5% in 2008. With the assumed 4 mill annual PSA adjustments and the proposed base rate increase effective May 1, 2007, Total Debt to Total Capitalization ("Debt to Capital") remains in the "BBB" range, improving from 54.6% at year-end 2006 to 52.1% by 2007. (The first three ratios set forth in **Attachments DEB-1RB** through **DEB-3RB** reflect the effects of including imputed debt and interest expense attributable to power purchase obligations and operating leases such as the Palo Verde Unit 2 sale and leaseback, which adjustments the rating agencies always make to present an accurate picture of a company's true financial obligations.) ROE is very weak in 2006 at 8.5%, declines to a weaker 8.0% in 2007 despite implementation of

a 21.2% rate increase May 1, 2007, and falls further to 7.4% in 2008 even with the base rate increase in effect for the full year. The projected ROE levels remain below the Company's requested 11.5% ROE due to the continued high level of capital expenditures required to serve our rapidly expanding customer base, as well as inflationary impacts on operating costs. Of course, APS also has to absorb 10% of the difference between the price it pays for fuel and purchased power and amount of fuel in base rates, which further exacerbates the weak ROE.

Q. WHY HAVE YOU EMPHASIZED 2007 AND 2008 IN YOUR ANALYSES OF THE IMPACT OF THE VARIOUS REVENUE REQUIREMENT RECOMMENDATIONS?

A. I have emphasized these years because new rates first take effect during 2007, and 2008 would reflect a full year's impact of such rates. Should APS file another general rate case as soon as the current proceeding concludes, we doubt that APS could receive rate relief significantly before the end of 2008. Thus, the financial results described here would likely show little improvement until at least 2009.

Q. IF THE STAFF'S PROPOSED RATES INCLUDING THE USE OF PROJECTED 2007 COSTS IN THE PSA ARE IMPLEMENTED ON MAY 1, 2007, HOW DO APS' FINANCIAL METRICS COMPARE WITH THOSE NEEDED TO MAINTAIN INVESTMENT GRADE RATINGS?

A. When viewed in the aggregate, **APS' financial metrics fall far below the minimum levels required to maintain investment grade ratings.** As you can see in **Attachment DEB-2RB**, APS' FFO Interest Coverage steadily declines from 3.9 times at year-end 2006 to 3.4 times at the end of 2008. The FFO/Debt shows significant deterioration ending 2006 at 17.6% and falling to 15.1% by the end of 2008. This critical financial metric will definitely sink below investment grade. The Debt to Capital ratio worsens from 54.6% in 2006 to 59.6% by 2008, well outside the acceptable "BBB" range. In brief,

the absolute levels of the ratios and their ominously declining trend line will not enable APS to maintain investment grade credit ratings under Staff's recommendation. Additionally, the resulting grossly inadequate ROEs of 6.8% in 2007 and 6.3% in 2008 fall very significantly below Staff's recommended 10.25%.

Q. IF THE PROPOSED RUCO'S RATES ARE IMPLEMENTED ON MAY 1, 2007, HOW DO APS' FINANCIAL METRICS COMPARE WITH THOSE NEEDED TO MAINTAIN INVESTMENT GRADE RATINGS?

A. In general, RUCO's recommendations follow the same pattern as Staff's but result in even weaker financial metrics. As shown in **Attachment DEB-3RB**, APS' FFO Interest Coverage steadily declines from 3.9 times at year-end 2006 to 3.0 times at the end of 2008, the **bare minimum** needed for investment grade. The FFO/Debt shows significant deterioration, falling to 12.9% by the end of 2008. This critical financial metric will definitely decline below investment grade and will approach the **minimum** of the **"BB"** range – deeply in the range of "junk" debt. The Debt to Capital ratio worsens from 54.6% in 2006 to 60.9% by 2008, which is then also outside the "BBB" range. Should RUCO's recommendations be adopted, it will result in both the deterioration of the absolute levels of the ratios as well as their negative trends such that APS will not maintain investment grade credit ratings. Indeed, the resulting ROE of 6.0% in 2007 and 4.6% in 2008 will sink drastically below RUCO's own recommended 9.25%.

Q. WHY DO THE RATING AGENCIES CONSIDER FINANCIAL METRICS SO IMPORTANT?

A. Financial metrics measure a company's financial health, performance and risk. Although a strong relationship exists between earnings and cash flow, analysis of cash flow can reveal debt-servicing capability either stronger or weaker than otherwise apparent from earnings ratios. Thus, financial analysts use the

FFO Interest Coverage ratio to measure the sufficiency of a company's cash flow to pay its interest costs. Debt to Capital measures a company's leverage. FFO/Debt measures the sufficiency of a company's cash flow to service both debt components - interest and debt principal - over time. FFO/Debt captures aspects of both interest coverage and the degree of leverage and, consequently, carries the most weight with the credit rating agencies in determining ratings.

Q. WHAT ARE THE TARGET RANGES FOR APS' FINANCIAL RATIOS FOR "BBB" AND "BB" RATING LEVELS?

A. Primary financial metrics required by Standard & Poor's ("S&P") for a company, such as APS, with a business profile '6' to maintain "BBB" and "BB" category ratings are as follows:

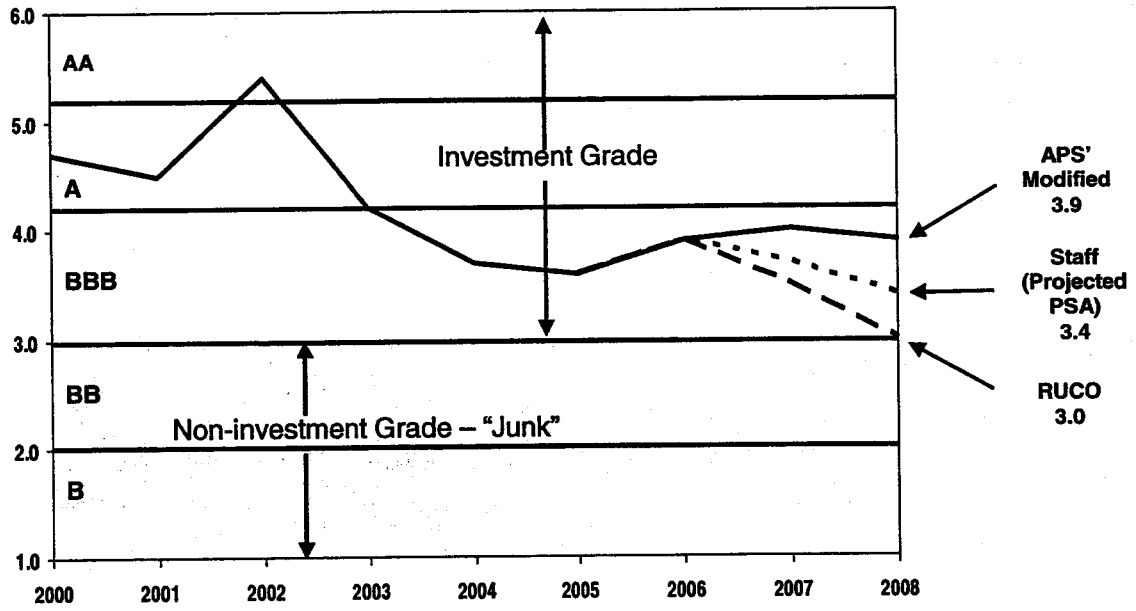
	BBB	BB
FFO Interest Coverage	4.2 - 3.0	3.0 - 2.0
FFO/ Debt	28% - 18%	18% - 12%
Debt to Capital	48% - 58%	58% - 62%

The other rating agencies use similar, although unpublished, criteria.

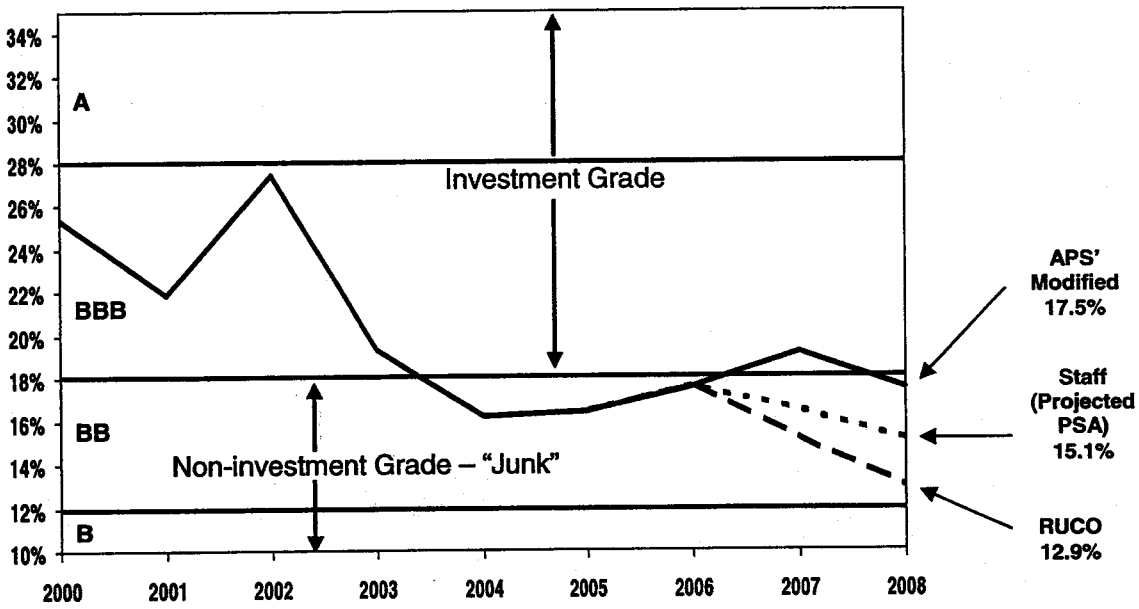
Q. HAVE YOU GRAPHED THE THREE PRIMARY CREDIT METRICS FOR EACH OF THE APS, STAFF AND RUCO PROPOSALS?

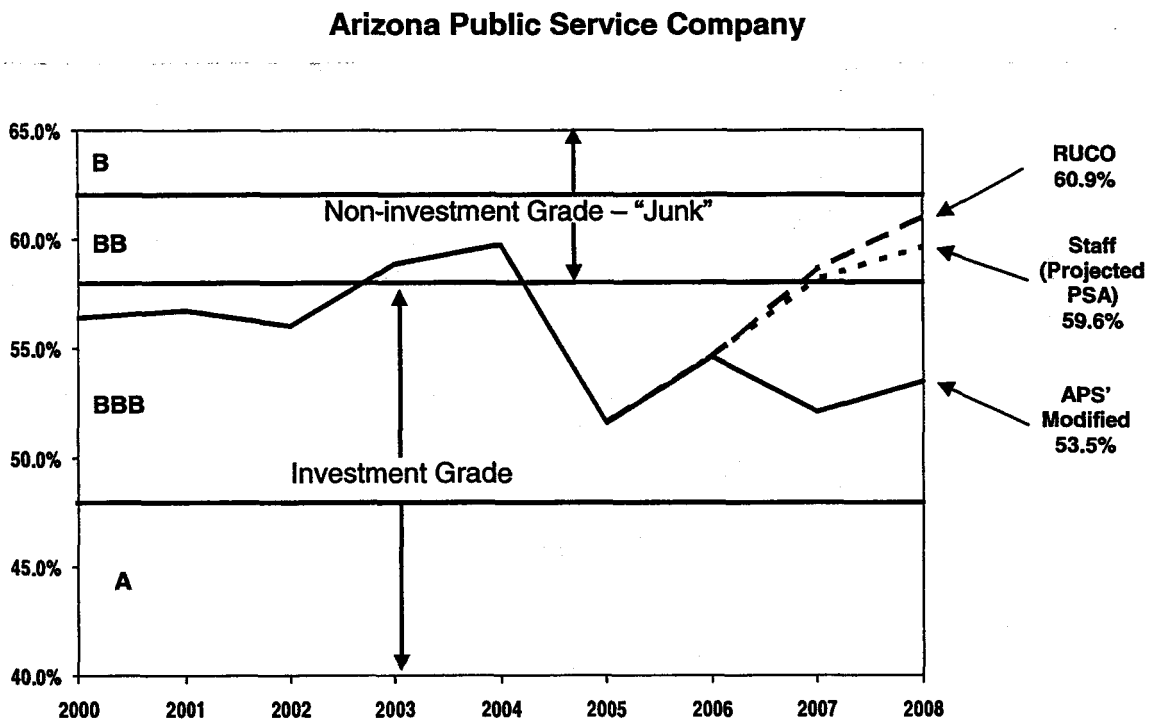
A. Yes. The following three graphs depict the financial metrics for FFO Interest Coverage, FFO/Debt and Debt to Capital for each of the proposed APS' rate increases. Also included are the applicable ranges for "BBB" and "BB". This helps visually depict APS' relative financial condition under each of the three proposals.

Arizona Public Service Company
FFO Interest Coverage



Arizona Public Service Company
FFO/Debt





Q. IN DETERMINING CREDIT RATINGS, DO THE CREDIT RATING AGENCIES LOOK AT MORE THAN THE FINANCIAL METRICS YOU DETAILED ABOVE?

A. Yes. The determination of credit ratings includes more than financial metric analysis. The agencies determine their ratings based on a variety of both quantitative and qualitative factors. For their quantitative analysis, the agencies look not only at the financial metrics of a company, but also at significant trends in financial performance. They review financial projections and make an independent assessment of the likelihood of various future financial scenarios. The agencies gain confidence from financial metrics that stay within their specified target ranges. While S&P publishes their ranges, Moody's Investors Service ("Moody's") informs a company if any of the ratios do not meet the level they determine appropriate for the existing credit rating.

In addition to the quantitative analysis, the agencies perform an extensive qualitative analysis. The rating agencies routinely assess the regulatory

environment in which a regulated utility operates, the various business and financial risks a company faces, and the utility's management and prior track record. Rating agencies view the regulatory environment as a major factor in evaluating companies' credit and prospects. Only after analyzing all of the quantitative and qualitative factors, will the rating agencies determine a company's credit ratings. In a recent presentation before the NARUC Committee on Gas, Richard Cortright, Managing Director of Utilities, Energy & Project Finance Ratings for S&P (one of S&P's most senior executives), stressed that the tenor of both the regulatory and political environments in which a company operates has come "front and center once again." **Attachment DEB-4RB.** He made the following specific points regarding regulatory uncertainty:

- The character of regulatory decisions will perhaps be the major determinant of utility credit quality for many years,
- Uncertainty deprives utilities of credit strength, and
- Uncertainty is created by unsupportive actions: delaying decisions (regulatory lag), prudency disallowances, absence of pre-approved infrastructure investments.

Q. WHAT IS THE CURRENT STATUS OF APS' CREDIT RATINGS?

A. The table below lists the current credit ratings:

	Moody's	S&P
Senior Unsecured Debt	Baa2	BBB-
Commercial Paper	P-2	A-3
Ratings Outlook[1]	Negative	Stable

APS' credit ratings currently sit in the investment grade range. However, S&P's ratings of APS remain at the **absolute** lowest investment grade credit rating and Moody's has APS on **negative outlook, plainly stating that it may lower** the ratings.

S&P published an article dated August 31, 2006, entitled *Summary: Arizona Public Service Co.* **Attachment DEB-5RB.** In the article S&P expressed concern about the uncertainty of "how the Arizona Corporation Commission (ACC) will address APS' pending general rate case request". They describe the outlook for APS as follows:

> The stable outlook for PWCC and APS' rating is premised on the ACC continuing to provide sustained regulatory support that addresses permanent rate relief and manages the deferral balances downward over a reasonable time frame.

In the same article, S&P makes explicit their continuing concerns about the weakness of APS' credit metrics. They state, "Cash flow metrics for 2006 will be modestly assisted by the surcharges but funds from operations (FFO) to total debt is expected to be below S&P's benchmarks until going forward retail

[1] "Ratings Outlook" indicates the possible direction a rating may move over the intermediate to longer term. "Positive" indicates ratings may be raised; "Negative" indicates ratings may be lowered; and "Stable" indicates ratings are not expected to change absent some significant positive or negative event.

rates are brought more in line with current costs." They add that, "FFO to interest coverage is expected to remain in line with the rating". The debt to capital ratio remains within benchmarks for the current rating if they do not adjust for debt-like pension obligations, but could worsen with additional debt financings needed for critical capital expenditures.

Most recently, Moody's published a credit analysis of APS entitled, *Credit Opinion: Arizona Public Service Company,* **(Attachment DEB-6RB)** on May 9, 2006, shortly after the Commission's Decision No. 68685 on APS' Emergency Interim Rate Increase Request. In the Ratings Outlook section of the report, Moody's notes, "The outlook for APS is negative, reflecting the potential for downward pressure on the ratings if the Palo Verde nuclear facility does not return to normal operating performance by mid-summer as expected, or if outcomes in still pending rate proceedings are not supportive of relatively timely recovery of increased costs." Since that time, Palo Verde has returned to its normal operating performance, but Moody's has not removed its negative outlook.

Moody's also provides a fairly detailed description of their concern for continued weak financial metrics. They state:

> In light of its challenging regulatory environment, Moody's would look for APS to have financial metrics that are **somewhat stronger** than comparably rated utility operating companies that operate in more supportive environments.
>
> APS' key financial metrics reflect the fact that it has been unable to recover increased costs for fuel and purchased power on a timely basis. For example, the ratio of cash from operations prior to changes in current assets and liabilities to adjusted debt (incorporating Moody's standard analytic adjustments) is in the mid-teens and expected to remain there through at least 2006.

> This is at the lower end of the 13% to 25% range in the global rating methodology for Baa rated entities on a stand-alone basis within the medium risk category and suggests a rating that could be Baa3 or Baa2. The Baa2 rating considers the potential for key financial ratios to strengthen beyond 2006 if regulatory treatment is supportive of timely cost recovery. The rating also is supported by on-going strong growth in APS' service territory. [emphasis added.]

Plainly, both S&P and Moody's have serious concerns about APS' weak credit metrics and realize that only strong cash flow recovery in the pending general rate case will allow APS' metrics to improve.

Q. COULD APS RETAIN ITS INVESTMENT GRADE RATINGS IF THE COMMISSION ADOPTS EITHER STAFF'S OR RUCO'S RECOMMENDATIONS ?

A. No. APS' credit ratings would fall below investment grade, to "junk" levels. First, the financial metrics alone would not support a continued "BBB" rating, especially in light of the continued deteriorating trend. Second, the Company could not demonstrate to the rating agencies any prospect of stopping further declines in its financial condition, let alone demonstrate any prospect for potential improvement in its financial metrics.

Q. COULD YOU SUMMARIZE THE IMPACT OF A DOWNGRADE ON APS' FINANCING COSTS?

A. Yes. A downgrade of APS' credit ratings to non-investment grade would cause annual interest expense to increase approximately $15 million to $30 million in 2007. That annual increased interest expense would escalate to approximately $115 to $230 million by 2016. On a cumulative basis, over a ten-year period beginning in 2007, customers would have the burden of additional interest expense of $675 million to $1.3 billion, depending on actual interest rates paid at the time. The dramatic increase in costs would arise from a number of unavoidable sources. These would include the long-

term financing necessary to fund essential generation, environmental control projects, and transmission and distribution construction programs. The costs of the Company's tax-exempt remarketing program would increase dramatically. Similarly, APS would lose access to the commercial paper markets, thereby further increasing costs and reducing financial flexibility in the lower cost, short-term capital markets.

Q. WHAT OTHER FINANCIAL IMPACTS RESULT FROM A DOWNGRADING TO "JUNK" OF APS' CREDIT RATINGS?

A. APS' ability to access the often volatile capital markets, including both equity and debt, could suffer greatly. Should investors in general experience a decline in confidence, they regularly turn to what they perceive as less risky investments. In such a treacherous and shifting climate, non-investment grade issuers can find themselves shut out from sources of funding at the very time they require it most. APS must access the capital markets every year for the foreseeable future given its large capital expenditure program, and thus has no practical way to time or avoid declines in investor confidence or negative market sentiment. Assuming that APS could obtain the necessary financings, higher pricing would inevitably apply, and we would have to accept more onerous terms that enable the investors to influence certain APS' business operations. The Company and the Commission, both acting on behalf of APS' customers, would certainly prefer to avoid this dire and very expensive situation.

APS' fuel and energy procurement functions would also suffer as a result of the downgrade of APS to a non-investment grade rating. Most of APS' agreements with energy trading counterparties require, in the event of a downgrade to junk status, that APS provide the counterparty with cash collateral (termed a "collateral call") to cover the difference between the

contract price and the then-existing market price of the commodity. This could place a significant liquidity strain on APS at a time when the Company has restricted access to the capital markets.

In addition to cash collateral calls, energy trading counterparties place other onerous terms on their dealings with non-investment grade companies. APS would be forced to prepay for a large amount of the Company's power plant fuel and fuel transportation needs. Any form of longer-term commodity agreement would require the Company to provide up-front cash collateral. APS' costs of doing business in the wholesale markets would increase significantly and make it much more difficult to hedge the Company's commodity positions, further increasing the Company's risk profile. Such a situation would grow more costly and onerous as APS' dependence on long-term purchased power agreements grows substantially over the next decade.

Q. WOULD CUSTOMERS BENEFIT MORE BY PAYING HIGHER RATES IN THE FUTURE DUE TO A CREDIT DOWNGRADE THAN PAYING THEM NOW TO AVOID THAT DOWNGRADE?

A. Initially, allow me to note a critical presumption underlying this question: that APS could raise the enormous amounts of capital it will require to meet future energy demands without an investment grade rating. Based on my years of experience, this outcome appears highly unlikely. If APS cannot raise sufficient capital, our ability to serve our customers and to supply the electricity needs of Arizona's growing economy will suffer severely. Indeed, we cannot characterize this as an "either/or" choice. APS customers will bear BOTH the higher fuel, labor, and material costs that have necessitated the current rate request (and which factors will apply in future rate proceedings), but ALSO the higher financing costs attributable to credit downgrades. In reality, delay in addressing the ratings crisis will only aggravate the multiple interrelated problems of higher rates. Unlike higher costs for items such as

fuel, labor and materials, the higher interest and other capital costs imposed on our customers will not produce a single kWh, provide service to a single new customer, or build any new infrastructure.

Q. WHAT SHOULD BE THE ULTIMATE GOAL FOR APS IN TERMS OF CREDIT QUALITY?

A. We have spent much time discussing the problems attendant upon APS falling below an investment grade credit rating. In the best interests of customers and the State's economy, the Commission should not aim to establish rate levels such that APS just **barely** qualifies for an investment grade credit rating. Such a goal, given our dynamic and fluid situation and the increasingly and relentlessly critical view of the credit rating agencies, places APS in substantial peril of missing that goal at great cost. I have been the chief financial officer of an electric utility for more than 18 years, have almost 30 years of utility finance experience and, during that period of time, have worked with utilities rated from "BBB-" up through "AA-". Utilities rated "A" or better always have far more attractive financing options, covenants and pricing than those rated below an "A". The market for non-investment grade debt, the so-called "high-yield" or "junk bond" market occasionally closes for indefinite periods of time. At other times, such as right now (Wall Street Journal, September 7, 2006, page C6, *Investment-Grade Market Booms*), **(Attachment DEB-7RB)**, the market for investment grade offerings is markedly more attractive, and non-investment grade issuers lag behind with more costly, far wider spreads off Treasury rates.

Should APS fall to "junk" status, we can have no confidence that APS could successfully issue the billions of dollars of "junk" bonds required to fund our expenditures over the next ten years. Looking to the future, with the strong growth inherent in APS' service territory and APS' continuing need to make

capital investments to meet the growing energy needs of its customers, APS must eventually achieve a credit rating of "A" to provide it with the appropriate level of financial flexibility to minimize its financing costs and maximize its options over the long term.

Q. DID APS RECENTLY PROVIDE THE COMMISSION WITH INFORMATION REGARDING ITS CURRENT FINANCIAL CONDITION?

A. Yes. On July 26, 2006, I provided a letter to the Commissioners that detailed certain APS financial information. **Attachment DEB-8RB.** Then on August 17, 2006 Jack Davis, President and CEO of APS, provided a letter to the Commissioners (**Attachment DEB-9RB**) as well as a Financial Issues Report (**Attachment DEB-10RB**). The report provides detailed information regarding APS' current financial position in response to issues raised by the media and Commissioners following the second quarter earnings release. The report provides an appropriate context illustrating the strained financial situation APS currently faces. I cover many of the same subjects throughout my rebuttal testimony and I sponsor these attachments.

IV. MEASURES TO IMPROVE CREDITWORTHINESS

Q. HAVE YOU READ CHAIRMAN HATCH-MILLER'S LETTER TO APS' COUNSEL MR. MUMAW, DATED JULY 21, 2006?

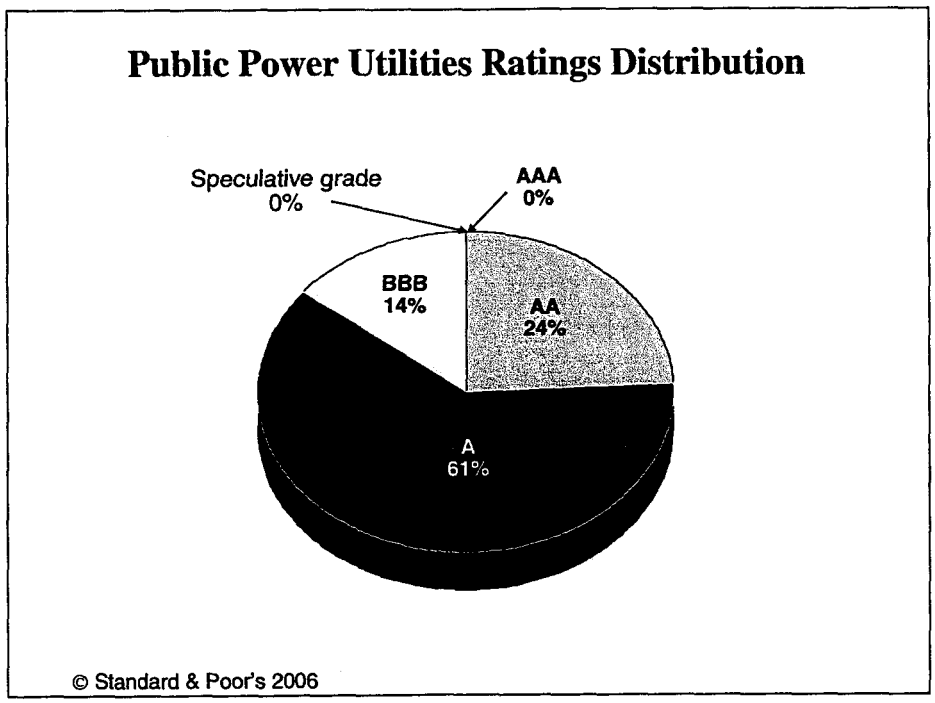
A. Yes. The Chairman's letter (**Attachment DEB-11RB**) discusses the report issued by S&P entitled *U.S. Public Power Utilities' Self-Governance Bolsters Credit Quality*, dated July 19, 2006 (**Attachment DEB-12RB**). In his letter, the Chairman not only discusses the substance of the report, but reflects upon the difficulties and challenges facing APS as it prepares to undertake a massive CAPEX budget of over $4.4 billion over just the next five years, 2007 through 2011, and a total of $8.6 billion over the next ten years. These figures do not include additional dollars the Company will have to spend to

build or buy additional generation resources. As Chairman Hatch-Miller notes appropriately, APS will fund a portion of this outlay with debt and, accordingly, credit ratings will determine long-term borrowing costs.

We face a critical juncture: lower credit ratings will cost customers more money in interest costs to finance the facilities which will supply them with dependable electric power. Higher credit ratings will save money on interest payments and also, at the same time, help to raise the value of the equity of Pinnacle West. Higher credit ratings thus work to improve the attractiveness and lower the costs of both the equity and debt components of our capital structure.

Q. PLEASE SUMMARIZE THE FINDINGS PUBLISHED BY S&P IN THE ABOVE-REFERENCED REPORT?

A. S&P justifiably has a highly favorable opinion of the credit ratings in the public power sector. Approximately 85% of these public entities have credit ratings of "A" or higher as depicted by the following pie chart:



In contrast, only 28% of investor-owned utilities (including electric, gas, pipeline, and water companies) have a credit rating of "A" or higher and an average rating of "BBB". As the report title suggests, S&P found that:

> Autonomous rate setting is an important driver of credit quality because it provides public power utilities with the tools needed to respond quickly to changes in operating costs or capital needs...This rate setting authority continues to be one of the key factors that distinguishes the ratings on public power utilities from those on investor-owned electric utilities. The credit quality of investor-owned utilities generally suffers as a result of the regulatory lag and the potential for regulatory disallowances of costs.

According to S&P,

> Last year, the advantages of autonomous rate setting authority and the benefits of pass through mechanisms were in evidence as public power utilities successfully weathered dramatic increases in natural gas prices, preserving their financial margins and credit ratings.

The ability of public power entities, such as the Salt River Project (SRP), to easily adjust rates in more timely and palatable increments enables them to preserve their financial performance and maintain their financial flexibility. In fact, Moody's upgraded SRP's revenue bonds from Aa2 to Aa1 on June 16, 2006 and cited, "SRP is the **highest** rated U.S. public power electric utility." **Attachment DEB-13RB.**

Q. HAVE THERE BEEN ANY MORE RECENT INSTANCES WHERE THE RATING AGENCIES ADDRESS UTILITY CREDIT QUALITY?

A. Yes, in the previously mentioned August 1, 2006, presentation of S&P's Mr. Cortright, he stated that the following supportive regulatory characteristics would "provide the foundation for strong utility credit":

- Consistency and predictability of decisions,
- Timeliness of orders, and
- Use of forward-looking measures.

Q. IN HIS LETTER CHAIRMAN HATCH-MILLER ASKED APS TO PROVIDE TESTIMONY ON MEASURES THE COMMISSION COULD TAKE TO HELP APS GRADUALLY IMPROVE ITS CREDITWORTHINESS. IN YOUR OPINION, WHAT DO THESE INCLUDE?

A. The Commission can implement now and/or in the future a number of actions to help APS improve its current financial condition. Timely recovery of costs sits atop the list. S&P specifically noted that investor-owned utilities suffer as a result of regulatory lag. Consequently, the Commission should strive to reduce the time necessary to process all APS' regulatory filings, including general rate cases and PSA adjustors/surcharges. Timely recovery of costs would not only aid APS in improving its credit ratings, but would also send appropriate price signals to our customers so they can adjust their electricity usage accordingly.

The Commission can also provide adequate recovery of non-fuel costs. The improvement of APS' credit ratings depends to a large extent upon the recovery of all prudently incurred costs. S&P noted that investor-owned utilities suffer as a result of the potential for ex post facto regulatory disallowances of costs. While we understand the nature of regulatory oversight, APS must conduct its business on a real-time basis and make thousands of decisions every day in its efforts to generate and deliver power in the most safe, reliable and cost-effective manner possible. All investor-owned utilities face the risk of regulatory disallowances. However, the manner and frequency with which the Commission requires disallowance has a significant impact on APS' credit quality. Furthermore, regulatory prudence reviews typically only result in cost disallowances. Rarely, if ever, do they result in the awarding of benefits to recognize superior performance.

Of paramount importance to the investment community, the Commission should provide APS the opportunity to earn an adequate ROE. APS serves one of the fastest growing service territories in the country necessitating continual capital expenditures and access to the capital markets to meet the growing energy needs of APS customers. We cannot finance with debt all of our significant capital expenditure requirements. We will have to raise and retain equity in order to finance in a balanced manner our large CAPEX budget. Equity investors require adequate and competitive compensation for the risks we ask them to assume. In the absence of an acceptable and attainable ROE, the price of our common equity will decline, and we may well not meet the equity levels necessary to maintain investment grade credit ratings in the face of burgeoning construction demands. The Commission should set rates that provide a reasonable earned ROE in light of APS' risk parameters in order to minimize overall financing costs necessitated by our rapidly growing service territory.

Q. YOU HAVE OUTLINED FAIRLY TRADITIONAL MEASURES THE COMMISSION CAN TAKE TO HELP APS GRADUALLY IMPROVE ITS CREDITWORTHINESS. DO YOU HAVE ANY OTHER SUGGESTIONS?

A. Yes. Two important measures come immediately to mind: (1) an allowance of accelerated depreciation, and (2) an allowance of Construction Work in Progress (CWIP) in rate base (or similar adjustment).

Q. WHY HAVE YOU IDENTIFIED THESE TWO MEASURES?

A. These are two areas where public power entities take advantage of their ability to raise rates earlier and thus in smaller increments than regulated investor-owned utilities. As I discuss below, both of these measures can improve financial metrics for APS while benefiting customers in the long run.

Q. COULD YOU PROVIDE AN EXAMPLE OF HOW EACH OF THESE MEASURES WOULD WORK?

A. Yes. Let me start with depreciation and assume APS is granted an across-the-board increase of $50 million per year in allowed depreciation expense.

Q. DOES THE CURRENT SPEED OF RECOVERY OF THE COMPANY'S INVESTMENT IN PLANT AND EQUIPMENT CAUSE FINANCIAL DIFFICULTIES?

A. Total Company depreciation expense in the September 30, 2005 test year ran approximately $350 million per year after pro forma adjustments. The Company projects spending in excess of $900 million per year, on average, from 2007 through 2009 to make the necessary capital investments to serve its rapidly growing customer base and maintain high service reliability. This large imbalance between expenditure and recovery, averaging $550 million annually, contributes dramatically to the financial strain on the Company's creditworthiness because APS must finance this "gap" in the capital markets.

Q. WOULD SUCH AN ADJUSTMENT UNFAIRLY RAISE THE COMPANY'S EARNINGS BY RAISING REVENUES?

A. No. The increased revenues and increased depreciation expense would offset, causing earnings to be unchanged.

Q. DOES INCREASING DEPRECIATION EXPENSE HAVE OTHER EFFECTS?

A. Yes. In addition to improving the Company's credit metrics, such an adjustment would serve to reduce future revenue requirements from customers.

Q. WHAT CAUSES THAT IMPACT?

A. Because the Company will increase its annual depreciation expense, accumulated depreciation will grow faster than it would otherwise.

Accumulated depreciation and amortization reduces rate base, so by increasing depreciation today, future rate base will be lower. Thus, future revenue requirements from customers will be lower.

Q. HOW WOULD THIS ADJUSTMENT IMPROVE THE COMPANY'S CREDITWORTHINESS?

A. This additional $50 million per year of revenues would generate $30 million, after income taxes, of additional positive cash flow thereby increasing funds from operations (FFO) by $30 million annually. As a result, the Company's FFO/Debt ratio would improve by approximately seven-tenths of a percent in each of the next several years.

Q. WOULD THE COMMISSION HAVE TO AUTHORIZE SHORTER BOOK DEPRECIATION LIVES TO ALLOW FOR SUCH AN ADJUSTMENT?

A. No. The Company could record the additional $50 million of annual depreciation expense to a non-specific accumulated depreciation account.

Q. YOU ALSO MENTIONED CWIP AS SOMETHING PUBLIC POWER ENTITIES CAN USE TO IMPROVE THEIR FINANCIAL POSITION AND SMOOTH OUT FUTURE RATE INCREASES. COULD YOU EXPLAIN?

A. Yes. In fact, this Commission has authorized this practice in the past, especially during periods of high CAPX needs. The Commission could place the Company's generation and distribution construction work in progress (CWIP) in rate base using the actual $261 million CWIP balance as of June 30, 2006.

Q. WHAT IMPACT WOULD THAT HAVE?

A. As of June 30, 2006, the Company's CWIP accounts included $261 million of generation and distribution plant expenditures. By placing these amounts in rate base, the Company would obtain cash revenues to pay the financing costs it currently incurs on these existing expenditures.

Q. WILL THAT UNFAIRLY RAISE THE COMPANY'S EARNINGS ON THOSE PLANT INVESTMENT DOLLARS THAT ARE STILL IN CWIP?

A. No. The Company would stop accruing AFUDC on those CWIP investments that are placed in rate base, so the loss of AFUDC would offset the earnings from the additional revenues.

Q. CAN YOU EXPLAIN AFUDC?

A. The Company incurs both debt and equity costs to finance its construction projects. If we do not include CWIP in rate base, we capitalize these financing costs as components of the total cost of each capital project over the course of their respective construction periods. The industry terms this accounting for construction financing costs: Allowance for Funds Used During Construction (AFUDC).

Q. IF RATE BASE DOES NOT INCLUDE CWIP AND THE COMPANY CAPITALIZES AFUDC, WHEN DO CUSTOMERS ACTUALLY PAY FOR FINANCING COSTS THE COMPANY HAS INCURRED DURING CAPITAL PROJECT CONSTRUCTION PERIODS?

A. Customers will pay for the financing costs as the Company depreciates the total capital cost of a project, including the related construction-period financing costs, over the life of the capital project.

Q. WHAT IMPACT ON REVENUE REQUIREMENT WOULD YOUR CWIP IN RATE BASE PROPOSAL HAVE?

A. By placing $261 million of generation and distribution CWIP in rate base, APS' annual revenue requirement would increase by $33 million.

Q. HOW WOULD THIS IMPROVE THE COMPANY'S CREDITWORTHINESS?

A. This additional $33 million per year of revenues would generate $20 million, after income taxes, of additional positive cash flow thereby increasing funds from operations (FFO) by $20 million annually. As a result, the Company's

FFO/Debt ratio would improve by an additional five-tenths of a percent in each of the next several years.

Q. ARE THERE OTHER IMPACTS OF PLACING CWIP IN RATE BASE?

A. Yes. In addition to improving the Company's credit metrics, CWIP in rate base would also reduce future revenue requirements from customers.

Q. WHAT CAUSES THAT IMPACT?

A. Because the Company would discontinue capitalizing AFUDC on $261 million of capital projects, the overall total cost of those projects would be lower by the amount of the AFUDC that would otherwise be capitalized. Accordingly, both future rate base and depreciation expense would be lower.

Q. WITH CWIP IN RATE BASE, WHAT WOULD BE THE ACCOUNTING TREATMENT WHEN THOSE PROJECTS IN CWIP AT JUNE 30, 2006 ARE COMPLETED AND TRANSFERRED TO COMPLETED PLANT ACCOUNTS?

A. The Company would continue to remove $261 million of generation and distribution CWIP from plant upon which it capitalizes AFUDC. As time goes by, new projects will enter CWIP as others are completed. Thus, an ongoing group of projects would benefit from CWIP in rate base treatment, lowering both their final total cost and lowering future revenue requirements to customers. Recent historical CWIP balances and our forecasts for the next several years indicate that $261 million represents the typical on-going CWIP balance.

Q. HAVE YOU INCORPORATED EITHER A DEPRECIATION ADJUSTMENT OR CWIP IN RATE BASE IN YOUR MODIFIED APS ASKING AS SHOWN ON ATTACHMENT DEB-1RB?

A. No. We ask the Commission to consider these concepts at this time.

Q. SHOULD THE COMMISSION CONSIDER OTHER MEASURES TO IMPROVE APS' CREDITWORTHINESS?

A. Yes, the Commission should consider allowing an earnings attrition allowance.

V. ATTRITION ALLOWANCE

Q. WHAT DO YOU RECOMMEND THE COMMISSION ORDER WITH RESPECT TO AN ATTRITION ALLOWANCE?

A. As discussed in Mr. Wheeler's and Dr. Avera's testimony, the Commission could provide for an adjustment to the ROE used for setting rates to compensate the Company for the structural inability to otherwise earn its allowed ROE.

Q. WHY IS THE COMPANY NOT ABLE TO EARN ITS ALLOWED ROE?

A. As discussed earlier, the Company plans to spend in excess of $900 million per year from 2007 through 2009 to fund capital investments to serve its rapidly growing customer base and maintain high service reliability. Additionally, we will make approximately $650 million in capital investments in 2006. The large gap between the timing of the Company's sizeable investment outlay and the recovery contributes greatly to the financial strain on the Company's creditworthiness and its inability to earn its allowed ROE.

Q. ARE THERE OTHER FACTORS CONTRIBUTING TO THE COMPANY'S INABILITY TO EARN ITS ALLOWED ROE?

A. Yes. As the Commission knows, fuel and purchased power prices remain high. By order, the Company must absorb 10% of its fuel and purchased power costs over (or under) those included in base rates. In a high-priced fuel environment, this 10% haircut virtually forces the Company into a situation where it will not earn its approved ROE. We must also consider the effects of

inflation, which have the effect of increasing operating expenses in addition to the already described CAPEX requirements.

Q. DOES THE TIMELINESS OF RATE CHANGES HAVE AN IMPACT?

A. Yes. Regulatory lag has a negative effect on the Company's ability to earn its sanctioned ROE. The entire process, starting with the information gathering for the test year, the associated filings, and the hearings and decision-making has taken 18 to 24 months. When costs rise faster than revenues, unfortunately the Company may not have the means to earn the allowed ROE.

Q. CAN YOU EXPLAIN ATTRITION AND WHAT FACTORS MIGHT JUSTIFY AN ATTRITION ADJUSTMENT IN THIS SITUATION?

A. Attrition is the tendency for a utility's rate of return to diminish over time as a result of high construction costs, an expanding rate base, and increasing operation costs. Operational attrition reflects the increased costs of labor and non-labor operation and maintenance expenses. Financial attrition reflects the increased costs resulting from changes in the embedded cost of debt.

Some of the factors that support an attrition adjustment include: regulatory lag, substantial population growth, significant uncertainty regarding general level of prices in view of the large national deficit, and continued instability in the Middle East which has caused great volatility in fuel prices.

Q. WHAT ATTRITION ADJUSTMENT IS APPROPRIATE IF THE COMMISSION ACCEPTS THE ORIGINAL JANUARY 2006 APS ASKING?

A. Based on Schedule F-1 from our January 2006 base rate filing, we assumed our proposed 21.3% base rate increase would become effective January 1, 2007. Given that premise, the Company would only earn a 9.8% ROE in 2007 versus our request for an allowed 11.5% ROE. The difference between the 11.5% and 9.8% yields an attrition adjustment of 1.7%. This would

compensate the Company for the revenue shortfall arising from costs increasing faster than revenues from the historical test year ended September 30, 2005 moving forward into 2007.

Q. BASED ON FACTS AND CIRCUMSTANCES AS THEY CURRENTLY EXIST, WHAT ATTRITION ADJUSTMENT WOULD YOU PROPOSE?

A. If our requested 21.2% increase becomes effective May 1, 2007, our projected 2007 ROE would be 8.0%, yielding an attrition adjustment of 3.5%.

Q. WOULD THE ATTRITION ADJUSTMENT DECREASE IN 2008 AFTER THE 21.2% RATE INCREASE WAS IN EFFECT FOR A FULL YEAR?

A. No. Unfortunately, due to the continuation of costs exceeding revenue increases, 2008 projected ROE falls further to 7.4%, indicating the need for an attrition adjustment of 4.1%.

Q. WHAT ATTRITION ADJUSTMENT WOULD YOU PROPOSE IF STAFF'S RECOMMENDATION WAS IMPLEMENTED?

A. Assuming the same May 1, 2007 rate increase effective date, we project the Company's ROE would fall to 6.8% in 2007, and 6.3% in 2008 under Staff's proposal. This would indicate an attrition adjustment of 3.45% to 3.95% when measured against Staff's lower recommended ROE of 10.25%.

Q. HAVE YOU INCORPORATED AN ATTRITION ADJUSTMENT IN YOUR MODIFIED APS ASKING AS SHOWN ON ATTACHMENT DEB-1RB?

A. No. We ask the Commission to consider this important adjustment.

VI. STAFF'S PROPOSED 10.25% ROE

Q. STAFF ASSERTS THAT THE CURRENT LOW INTEREST RATES JUSTIFY THEIR RECOMMENDATION FOR A 10.25% ROE. DO YOU BELIEVE A 10.25% ROE MEETS INVESTORS' EXPECTATIONS?

A. No, I do not. A major part of my job involves maintaining ongoing dialogues with institutional investors. Over the past 20 years, I have dealt with

institutional utility equity investors and developed a comprehensive, in-depth understanding of their expectations regarding utility investments. They expect a relatively stable or growing share price, growth in earnings, and growth in the common stock dividend. A 10.25% ROE will not support these investor expectations.

Q. WHAT IMPACT WOULD ADOPTION OF STAFF'S RECOMMENDATIONS HAVE ON THE PINNACLE WEST DIVIDEND AND PROSPECTS FOR FUTURE DIVIDEND GROWTH?

A. Pinnacle West's 2007 forecast earnings declined by 18% after we adjusted our financial forecast to reflect Staff's recommendations. This decline in earnings resulted in a dividend payout ratio (dividends/earnings) of 90%. We cannot sustain such a dividend payout ratio and investors would know that it would eliminate the possibility of dividend growth. In addition, the financial community knows the dividend would face a substantial reduction, if not total elimination in the near future. Should Pinnacle West reduce or eliminate its dividend, Pinnacle West's stock price would plummet. Such a decline in the value of our common equity would frighten investors in both our debt and equity. None of our existing equity investors would have contemplated the Commission taking any action which would have this negative an effect on the value of their investment.

Q. WHAT RISK FACTORS DO EQUITY INVESTORS CONSIDER AND WANT TO BE COMPENSATED FOR WHEN EVALUATING THEIR DECISION TO BUY A UTILITY COMMON STOCK SUCH AS PINNACLE WEST?

A. There are several APS-specific factors that would substantially increase risk from an investor's perspective:

- Native Load Growth: We expect APS kWh sales to grow at three times the national average, second only to Nevada Power, necessitating continual capital expenditures and access

to the capital markets to meet the growing energy needs of APS customers.

- Fuel Prices: As a result of continuing kWh sales growth, APS will experience a continuously increasing dependence on natural gas as a fuel source. Risk will therefore continue to increase as a result of the highly volatile nature of natural gas prices. Investors recognize that the implementation of an appropriate regulatory fuel and purchased power adjustment clause can partially mitigate such risks.

- Wholesale Energy Markets: APS must rely on the wholesale energy markets for a significant portion of its energy needs. In addition, California's influence dominates the western energy market. Growth originating in California will drive the western energy markets to a capacity short position within the next few years.

- Risk of Credit Downgrade: APS sits on the edge of non-investment grade "junk" credit ratings. Without adequate and timely rate relief the Company's deteriorating financial condition will result in a downgrade. This will create additional risks commensurate with "junk" ratings, including lack of access to capital markets as well as unreasonable terms and conditions.

Q. BASED ON THE ADDITIONAL RISK FACTORS FACING APS, WHAT CONSTITUTES A REASONABLE ROE ASSUMPTION?

A. I agree with Dr. Avera's conclusion that APS needs a minimum 11.5% ROE to attract equity investors in today's unsettled environment. Based on the substantial risks currently facing APS, we require this yield to induce investors to purchase Pinnacle West common stock rather than alternative investments.

Q. DOES A LOWER GRANTED ROE ALSO IMPACT DEBT INVESTORS?

A. Yes. Fixed income investors and credit rating agencies look at both cash flow and income driven interest coverage ratios. Lowering a utility's revenue stream and ROE lowers the coverage ratio for its interest payments on its debt. All else being equal, a bond investor would more likely purchase the debt of a utility with a higher earned ROE than one with a lower ROE because the utility with the higher ROE would have a higher interest coverage ratio, thus giving the debt investor greater protection against default.

VII. RUCO'S PROPOSED CAPITAL STRUCTURE AND ROE

Q. HAVE YOU READ THE DIRECT TESTIMONY OF RUCO WITNESS STEPHEN G. HILL?

A. Yes.

Q. ON PAGE 4 OF MR. HILL'S TESTIMONY, HE STATES:

> **...THE CAPITAL STRUCTURE AND EQUITY RETURN I RECOMMEND IS SUFFICIENT TO SUPPORT AND IMPROVE THE COMPANY'S FINANCIAL POSITION AND FULFILLS THE REQUIREMENT OF PROVIDING THE COMPANY THE OPPORTUNITY TO EARN A RETURN WHICH IS COMMENSURATE WITH THE RISK OF THE OPERATION WHILE MAINTAINING THE COMPANY'S ABILITY TO ATTRACT CAPITAL.**

DO YOU AGREE WITH HIS CONCLUSIONS?

A. No, I do not.

Q. WHY NOT?

A. First, Mr. Hill declares his position will "support and improve the Company's financial position". This assertion is simply incorrect. We have not seen any evidence supporting Mr. Hill's declaration. Neither Mr. Hill, nor any other RUCO witness offers any financial modeling results to support such a declaration. As I have clearly demonstrated earlier in this rebuttal testimony,

adoption and implementation of RUCO's recommendations in this case would bring financial catastrophe and soaring costs to both APS and its customers. Mr. Hill's unsupported opinion, in combination with RUCO's other recommendations, would reduce the Company's credit metrics to non-investment grade or "junk" level – and achieve the exact opposite of what he professes to support in his testimony.

Second, Mr. Hill's assertion that his recommendation "fulfills the requirement of providing the Company the opportunity to earn a return which is commensurate with the risk of operation" does not square with financial reality. Again, as I discussed earlier, Mr. Hill's suggestions, in combination with RUCO's other recommendations, would virtually guarantee that the Company would have no opportunity to earn the 9.25% ROE recommended by Mr. Hill – much less the 11.50% ROE that the Company requests as recommended by APS' witness Avera. At best, APS could hope to earn a meager 4.6% to 6.0% ROE.

Adoption of Mr. Hill's and RUCO's recommendations would result in APS' customers eventually bearing the staggering and avoidable increase in financing costs of more than $1 billion over the next decade as a result of APS' credit ratings being downgraded to "junk".

Q. ON PAGE 5, LINES 14-20 OF HIS TESTIMONY, MR. HILL REFERENCES THE COMPANY'S 9% EXPECTED RETURN ON PENSION PLAN ASSETS THAT THE COMPANY DISCLOSED ON PAGE 99 OF ITS 2005 FORM 10-K. MR. HILL CITES THIS DISCLOSURE AS "PERHAPS THE MOST COMPELLING EVIDENCE THAT INVESTOR EQUITY RETURN EXPECTATIONS ARE LIKELY TO BE BELOW" HIS 9.25% ESTIMATE OF THE COMPANY'S CURRENT COST OF EQUITY CAPITAL. DO YOU AGREE?

A. Absolutely not. To the contrary, that very disclosure provides compelling evidence to the contrary and demonstrates that his 9.25% recommendation falls **far below what investors consider an adequate ROE**.

Q. PLEASE EXPLAIN YOUR VIEWS OF EXPECTED EQUITY RETURNS.

A. Mr. Hill states on page 5, lines 19-20, that the Company expects to earn a 9% return on its pension fund assets "**comprised mostly of equity investments**". On page 100 of the Company's Form 10-K[2], the Company discloses that equity securities comprised **only** 59% of its pension plan assets at December 31, 2005 and that we target 60% for equity asset allocation. The Company invests the remaining 40% of pension plan assets principally in fixed income securities.

The following table summarizes **Attachment DEB-15RB,** that APS provided in response to RUCO data request 7.1:

---

[2] Form 10-K is APS' annual report to the U.S. Securities and Exchange Commission ("SEC"). A public document, the Form 10-K contains, in addition to much other information, APS' audited financial statements. Pages 99 and 100 (**Attachment DEB-14RB**) contain these financial statements' pension related information.

Asset Category	Target Allocation Percentage	Expected Return
Equity	60%	11%
Fixed Income	30	6
Real Estate	10	8
Total	100%	9%*
*weighted average return		

As this table clearly demonstrates, APS expects an **11%** return on **EQUITY** securities and a **6%** return on **fixed income** (debt) securities. Due to the lower inherent risk profile, investors typically expect fixed income returns to be lower than riskier equity securities. Because we set the pension asset equity allocation at 60%, a simple weighted average of the expected returns yields the 9% cited by Mr. Hill.

Thus, Mr. Hill should have focused on the 11% expected equity securities return. If he had done so, he would have realized the total inadequacy of his recommended 9.25% ROE.

Q. ON PAGE 6, LINE 29, AND PAGE 7, LINE 1-3, MR. HILL STATES THAT APS AND ITS PENSION FUND MANAGERS "ACTUALLY BELIEVE THAT, OVER THE LONG-TERM, THE COMMON EQUITY RETURN EXPECTATIONS ARE IN THE SINGLE-DIGIT RANGE". DO YOU AGREE?

A. No. We do not agree with Mr. Hill's statement. As the documentary evidence we provided to RUCO demonstrates clearly, APS has expected long-term common equity returns of 11%.

Q. MR. HILL RECOMMENDS A HYPOTHETICAL CAPITAL STRUCTURE COMPOSED OF 50% COMMON EQUITY AND 50% DEBT IN LIEU OF THE COMPANY'S PROPOSED ACTUAL CAPITAL STRUCTURE OF 54.5% COMMON EQUITY AND 45.5% DEBT. ON PAGE 24, LINES 14-19, OF HIS TESTIMONY, MR. HILL ASSERTS THAT DURING THE YEARS 2003, 2004, AND 2005, APS MAINTAINED INVESTMENT GRADE BOND RATINGS WITH ONLY A 45% EQUITY COMPONENT IN ITS CAPITAL STRUCTURE. DO YOU HAVE AN OPINION REGARDING THIS ASSERTION?

A. First, Mr. Hill's footnote 15 on page 24 of his testimony references the Company's SEC Form 10-K for the years 2003, 2004 and 2005. The 10-K for **2005** evidences a 54% equity component in APS' capital structure as of December 31, 2005, not the 45% that Mr. Hill suggests by his footnote.

Second, and more significant, regarding the 45% equity component of APS' capital structure in 2003 (three years ago), Mr. Hill essentially concludes *if it was good enough in 2003, it will be good enough today* to maintain investment grade credit ratings. Mr. Hill ignores the crucial facts that (1) APS' credit metrics have steeply deteriorated over the last three years; (2) since December 2005, all three credit rating agencies (S&P, Moody's and Fitch) have downgraded APS' credit ratings, which in the case of S&P now sits perilously close to a "junk" credit rating, and (3) APS' most significant credit metric, FFO/Debt, has fallen deeply into the "junk" range.

Mr. Hill does correctly state that, "the parent company infused equity into its regulated subsidiary so that the common equity ratio of the latter is approximately 54%" (Hill testimony, pp. 24-25). My direct testimony in this case, pages 24 through 31, explains exactly what we did and why:

> During the 2000 to 2002 time frame, APS' FFO/Debt ratio fell within the parameters for a credit rating of "A". See the graph attached as Attachment DEB-4. Over the period 2002 to 2004, however, this financial metric rapidly deteriorated into the category of non-investment or "junk" grade of "BB". Beginning in the fall of 2004 and continuing into the spring of 2005, Pinnacle West and APS came under **intense pressure from both**

> **S&P and Moody's to issue common equity to offset the amount of debt and to strengthen the deteriorating credit metrics**. In response to this pressure, in May 2005, Pinnacle West sold approximately $250 million of common stock and announced the sale of the Silverhawk Power Plant. These two transactions generated approximately $460 million which we prudently transferred to APS to reduce debt levels. (pages 29-30, emphasis added)

Further, with respect to Pinnacle West's application to the Commission to increase its equity interest in APS (Docket No. E-01345A-05-0520), the Commission unanimously approved the equity infusions in Decision No. 68295. That decision states, "Staff concluded that: the proposed equity infusion would strengthen APS' capital structure and increase its ability to obtain more favorable financing in the future". At the hearing, Commissioner Spitzer stated, "the infusion of capital from the unregulated entity into the regulated entity is a positive thing." I do not recall anyone taking issue with his statement.

Additionally, without the benefit of hindsight and in light of the facts and circumstances known only at the time of the sale of the common stock and the Silverhawk power plant, Pinnacle West clearly acted prudently and conservatively. However, if we examine that May 2005 decision with the knowledge of Hurricanes Katrina and Rita and the resultant wildly escalating natural gas prices, the soundness of those sales and subsequent infusions of equity in APS becomes unassailable. Again, with the confirming and fortuitous benefit of hindsight, had we not committed to and completed the equity infusions, APS would now carry a non-investment grade "junk" credit rating, and APS customers would suffer the resultant increased prices for years to come.

Q. ON PAGES 26 THROUGH 30, MR. HILL COMPARES THE CAPITAL STRUCTURE OF APS WITH THAT OF PINNACLE WEST AND VOICES HIS CONCERNS ABOUT FINANCIAL CROSS-SUBSIDIZATION AND OFFERS HIS OPINION AS TO WHY PINNACLE WEST SHOULD HAVE MORE OF AN EQUITY COMPONENT IN ITS CAPITAL STRUCTURE THAN DOES APS. DO YOU HAVE ANY VIEWS ABOUT MR. HILL'S CONCERNS?

A. First, Pinnacle West presently has no external financing needs. Second, Mr. Hill exaggerates Pinnacle West's business risk by dwelling on the extent of its unregulated operations. Allow me to place the risks of those unregulated operations in their proper perspective:

1. Real estate – SunCor, a self-financing entity, pays dividends to its parent Pinnacle West. Pinnacle West has not invested any amount into SunCor in almost 20 years.

2. Pinnacle West energy trading segment – a small energy marketing business in a "maintenance" mode, administering a mere handful of short-lived wholesale energy contracts which will completely expire by mid-year 2008.

3. APS Energy Services – an extremely small energy services business that earns less than $2 million per year.

In summary, Pinnacle West does not have the risky, conglomerate structure that Mr. Hill implies.

It appears that Mr. Hill implies that Pinnacle West could extract from APS a substantial amount of equity so as to increase the equity component of the parent's capital structure and decrease that of APS. Certainly, such an action would bring the respective capital structures into the alignment that Mr. Hill suggests is somehow appropriate. On the other hand, it would be imprudent of us to redistribute equity in this manner under the present circumstances, and it

would result in a quick downgrade of APS' credit ratings. Pinnacle West and this Commission have acted prudently to preserve APS' investment grade credit ratings for the benefit of APS and its customers. It is now time to recognize in rates Pinnacle West's substantial additional equity investment in APS.

VIII. RESPONSE TO STAFF WITNESS ANTONUK AND RUCO WITNESS HORNBY

Q. HAVE YOU REVIEWED THE TESTIMONY FILED BY STAFF WITNESS JOHN ANTONUK AND RUCO WITNESS J. RICHARD HORNBY?

A. Yes.

Q. WHAT IS YOUR REACTION TO MR. ANTONUK'S TESTIMONY?

A. Because other APS witnesses will respond to certain portions of Mr. Antonuk's testimony, I will concentrate on his findings regarding the APS hedging program. In general, I concur with most of the observations made by Mr. Antonuk about the APS hedging program. As Mr. Antonuk describes, APS employs a conservative hedging program that pursues the dual objective of price stabilization and limiting APS exposure to the volatility inherent in the always-unsettled energy market. A core principle of the APS hedging program restricts traders from attempting to "outguess" the market. In finding that "APS handled fuel and energy procurement and management in a manner that produced appropriate costs during April through December 2005," Mr. Antonuk recognizes the validity of this underlying premise:

> The APS hedging program does not operate on the basis of discretionary amounts or timing. It in fact discourages, as we believe it should, traders from timing hedges on the basis of expected future movements in market prices...Most importantly, there should be no incentive to change strategy or methods or as to invite the introduction of speculation into the utility hedging program. Liberty believes it is not sound to promote utility efforts to out-guess the energy market. (Antonuk testimony, pp. 6-7)

Mr. Antonuk also confirms the adequacy of the design and structure of the APS hedging program and that the APS Marketing and Trading personnel have the requisite skill and experience to operate the plan effectively (p. 12). Mr. Antonuk further acknowledges the appropriateness of the APS' hedging policies and procedures ("APS bases its marketing and trading activities on sound hedging policies and procedures, and conducts electricity sales and purchases consistently with least-cost dispatch guidelines") (p. 14). Additionally, Mr. Antonuk acknowledges the effectiveness of APS' economic dispatch procedures and operations (p. 14). With respect to APS' off-system sales, Mr. Antonuk concluded:

> We concluded that APS has acted to maximize off-system sales opportunities from the utility perspective...We also found that the off-system sales and margins of APS were consistent with market prices and with the resources that APS had available for such use, after considering the relationship between its assets and its native usage. (Antonuk testimony, p. 25)

Q. ARE THERE AREAS OF MR. ANTONUK'S TESTIMONY TO WHICH YOU WOULD LIKE TO RESPOND IN GREATER DETAIL?

A. Yes. A few issues would benefit from the provision of greater detail, including: (1) the scope of the Liberty audit and the access given to Liberty by APS during the audit; (2) the necessity of meetings between APS and the Commission to review the APS hedging program and its objectives and implementation; (3) the possible need for a separation of utility and non-utility trading desks; and (4) recommendations regarding the Power Supply Adjustor filings made by APS with the Commission.

Q. WHAT COMMENTS DO YOU HAVE REGARDING THE SCOPE OF LIBERTY'S AUDIT OF THE APS HEDGING PROGRAM?

A. Liberty conducted an extensive and thorough audit of the APS Marketing and Trading practices and policies. A number of APS Marketing and Trading personnel spent considerable time with Mr. Antonuk and numerous other

Liberty representatives during their audit of APS' hedging policies and procedures, as did various personnel from APS' accounting and regulatory groups. We also provided Liberty with literally thousands of documents underlying the APS hedging program and its implementation. In addition, a team from Liberty, including Mr. Antonuk, spent time interviewing various APS officers involved in the design and implementation of the hedging program, including Mr. Jack Davis, APS' President and Chief Executive Officer (and a member of APS' Board of Directors), Mr. David Hansen, APS' Vice President of Marketing and Trading, and myself. In the end, Liberty conducted one of the most extensive fuel audits I have seen, and I certainly commend Liberty for the depth of their efforts. In a rare instance of dissatisfaction with the APS audit process, Mr. Antonuk expressed his desire to have had access to some members of the APS Board of Directors. I must address his concerns in his testimony.

Mr. Antonuk acknowledged APS' cooperation with Liberty during the audit, although he indicated that APS "declined to make members of its board" available to Liberty during the audit:

> APS made timely and generally full responses to all requests save one. The resources it assigned to the audit showed dedication to making people and data available, and to providing explanations and supplemental information when Liberty and Staff needed them. The exception was that APS declined to make members of the board of directors available for interview. (Antonuk testimony, p. 9)

Mr. Antonuk goes on to state that this failure to interview APS board members did not negatively affect the thoroughness of the audit process or impair or limit the audit's findings, stating:

> Liberty was ultimately able to gain sufficient information to conclude there was no failure of information flow to the board. APS offered access to Board minutes and the views of senior

> executives on what role the directors play in fuel and energy matters and how they exercise that role. Liberty was able to conclude that the directors received sufficient regular reporting on fuel and energy matters. . .We have no reason to believe there is a gap in senior oversight of fuel and energy matters. (Antonuk testimony, pp. 9-10)

Thus, Mr. Antonuk acknowledges that lack of access to APS board members did not impair or limit Liberty's audit findings. In view of the corporate governance issues his comments raise, I must respond on behalf of APS.

First, APS provided Liberty broad access to all of its employees and officers, including Mr. Davis. In addition to his executive officer roles with APS, Mr. Davis also sits on the APS Board of Directors. Accordingly, Liberty did interview at least one APS board member. Second, I explained during my interview with Liberty that I provided the information on APS' energy procurement and hedging program to the board, and therefore could supply insight to Liberty on the information the APS board received on such issues. Moreover, as the Liberty audit acknowledged, we provided access to the relevant board minutes. Accordingly, Liberty gained a thorough understanding of the information provided to the APS board on APS' energy procurement and hedging program. Under these circumstances, I do not believe that we limited the Liberty audit by failing to provide additional board members for Liberty to interview. In addition, we indicated to Staff that if they believed our efforts insufficient, APS would reconsider its position on broader access to other board members. We never heard back from Staff on this issue, and thus, concluded the matter resolved satisfactorily.

Clearly, the Commission understands that outside directors provide valuable and indispensable services and experience to a corporation. These independent directors, all extremely accomplished individuals in their own sphere of

activities, provide guidance, judgment, and seasoned analysis of corporate policies and issues. In order for APS to maximize the benefits that accrue to it from the collective wisdom of this group of highly qualified people, in common with most other investor-owned corporations, we have to maintain the highest degree of confidentiality regarding their discussions. Confidentiality encourages the sharing of ideas and frank discussion.

To encourage open and frank discussion by directors, APS has a policy of keeping director discussions and board of director minutes confidential to the fullest extent possible within and outside the Company. We believe that most other corporations have a similar policy, and we believe the policy is supported by sound business justifications and is in furtherance of the public interest. Thus, absent extenuating circumstances or lack of other sources of knowledge, we do not believe it is in the best interest of the Company or its customers for directors, particularly outside directors, to be routinely examined about their knowledge of corporate affairs or their service as a director.

Moreover, all of these directors have extremely busy schedules and multiple demands on their time. We have no desire to make service on our board any more time-consuming or onerous than necessary. Under the circumstances, wherein we provided Liberty with sufficient alternate means of information gathering – which Liberty admits satisfied their requests – we believe we have fulfilled our duty of responsible disclosure while preserving the confidentiality and honoring the time constraints our directors merit. The quality and relevance of the information already provided and the strength of the demonstrated importance and need for additional access to directors must be considered before a valid corporate policy and the public interests are put aside.

In this instance, there were more than sufficient sources of information available to Liberty concerning the audit that it conducted without the need to make outside directors available for interview, and it appears that Mr. Antonuk acknowledges that in his testimony.

Q. IN HIS TESTIMONY, MR. ANTONUK SUGGESTS THERE SHOULD BE A DIALOG BETWEEN APS AND THE COMMISSION AS TO APS HEDGING PROGRAM. DO YOU AGREE?

A. Yes. Mr. Antonuk testified that:

> APS has designed and it operates a sound hedging program. The amounts of natural gas and purchased power that it hedges fall at the high end of the range of experience. The program has been successful in meeting its primary objective, which is to promote price stability. It protects substantially against price increases, but will not operate to allow costs to fall when the market does. This lack of downward flexibility is not necessarily a problem; there exists a range of perspectives on the question. For example, the available market options that would allow APS to reduce costs when market prices fall either involve speculation or transaction costs that make their benefits dubious. There should, however, be a dialog with stakeholders and with the Commission to make clear what goals the program should have and the extent to which it should produce hedged prices. This dialog may not lead to a change in goals or hedge levels, but it will promote a common understanding of program operations and verify that it is meeting the needs and expectations of all customers. (Antonuk testimony, pp. 17-18)

In general, I agree with Mr. Antonuk's recommendation that APS should maintain a dialog with the Commission about APS hedging program, including its particular levels and overall objectives. Although industry experts have reviewed and approved the current APS hedging program, APS recognizes that this program, designed primarily to stabilize the cost of fuel and purchased power, might face future alteration in the face of altered risk or objectives. Ultimately, APS has to have the freedom to effectuate the business decisions it deems most appropriate and in the best interests of the Company, its customers, and its shareholders. A dialog with the Commission that promotes a common

understanding of hedging program operations and objectives may facilitate appropriate course corrections and eliminate any misunderstandings regarding the program and its objectives in the future. If the Commission wants APS to change the goals, objectives, or implementation of our hedging program, I welcome their directives in this regard.

Q. CAN YOU BRIEFLY DESCRIBE THE APS HEDGING PROGRAM?

A. Yes, although I would also refer to Tom Carlson, the Portfolio Manager of the APS System, who provides a more thorough, detailed description of the program in his testimony. The program provides that at any moment in time, APS system will have hedged 85% of its forecasted natural gas and purchased power needs for the next twelve month period. Simultaneously, we will have hedged 50% of the system's forecasted natural gas and purchased power needs for the immediate twelve-month period thereafter, and 35% of the requirements for the following twelve months. Thus, at any point in time, we will have hedged, to some extent, three years of requirements.

These hedge levels relate to amounts of forecasted natural gas and purchased power needs derived by a computerized simulation model called Real Time Simulation ("RTSIM"). Through this plan, as Mr. Antonuk correctly explains, APS develops a strategy to focus on "stability" by "locking in the prices that it will pay for fuels and purchased power well in advance of when those fuels will be used." (Antonuk testimony, p. 43)

As detailed in Mr. Carlson's testimony, and as I discuss later, the program permits APS to achieve a certain level of price stability in the always volatile energy market. APS also derives certain economic benefits inherent in the implementation of the program, including the optimization of its hedge purchases between natural gas and purchased power.

We have charged APS' Director of Enterprise Risk Management with the responsibility of overseeing the implementation of the hedging program. Unaffiliated with the trading floor, the Director provides independent oversight of hedging practices and their implementation, including verification that traders have maintained requisite hedge parameters.

Although Mr. Antonuk states the 85% hedge levels are "at the high end of the range" of his experience, we note the 85% hedge level applies only to the immediately following twelve-month period. Given the lower hedge levels in years two and three of the plan, we achieve a rolling average for the entire three-year period of approximately 58%.

Q. CAN YOU ADDRESS MR. ANTONUK'S TESTIMONY REGARDING THE POSSIBLE NEED FOR A SEPARATION OF UTILITY AND NON-UTILITY TRADING DESKS?

A. Yes. Mr. Antonuk believes not enough physical separation exists between the utility and non-utility trading desks:

> The principle negative finding in this area of fuel and energy management is that APS does not separate its utility and non-utility activities sufficiently. They operate in the same markets and with common counterparties, but they do so without physical separation. These factors create too great a risk of opportunity sharing between utility and non-utility traders, who are separate individuals. Locating the APS and non-utility trader next to each other on the trading floor fails to assure clear separation of their trading activities.
>
> Verification that no such sharing has harmed utility customers is extremely difficult. APS should physically separate its utility and non-utility traders, unless it can demonstrate that non-utility trading, which has been at very large levels, will very soon diminish substantially. APS also needs to complete promptly its efforts to assure there is no non-utility co-opting of utility resources or opportunities. (Antonuk testimony, pp 15-16)

We recently addressed these separation issues in APS' Code of Conduct proceeding. The Company acknowledged that one trading floor provided the

site for wholesale trading for both APS' system and the "non-utility" trading referenced by Mr. Antonuk. As a result of the recent revisions to the Code of Conduct reviewed and approved by the Commission, we adopted new policies and procedures that prohibit traders who handle APS' system from providing trading services for APS energy affiliates.

Mr. Antonuk's audit of actual transaction data, which predated the new Code of Conduct and the new policies and procedures governing the trading floor, discovered no indications of any deliberate favoritism to any party, including any APS affiliate. In fact, APS has consistently had in place a structure that prohibits any actions by traders which would disadvantage the APS system. Any trader's deliberate action that takes inappropriate advantage of the APS system results in employment termination.

Moreover, Mr. Antonuk noted APS could ease his concerns about the lack of physical separation should it decide to "very soon diminish substantially" non-utility trading (Antonuk testimony, pp. 15-16.) As we have advised Commission Staff and Liberty, we are winding down non-utility trading, with a current proposed end date of May 2008 that coincides with the termination date of some existing non-utility wholesale contracts that have been in place for a number of years. Nevertheless, between now and mid-2008, APS will limit non-utility trading activities to managing and winding down existing non-utility wholesale contractual positions, as well as some limited wholesale sales to APS Energy Services ("APSES") to supply APSES' California retail commercial and industrial load. In meantime, we have begun the implementation of additional physical separation and controls to respond to Mr. Antonuk's recommendations. We expect to complete these additional

measures, which exceed those required by the Code of Conduct, by November 1, 2006.

Q. LIBERTY'S REPORT SUGGESTS THAT APS UNDERTAKE CERTAIN STEPS REGARDING CONTROLS AND DOCUMENTATION RELATING TO THE POWER SUPPLY ADJUSTER ("PSA"). DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. Yes. Although we address the PSA accounting issues raised in Mr. Antonuk's testimony in the testimony of APS witness Pete Ewen, I can confirm that APS does place an emphasis on the accounting and audit support required to make the PSA filings and documentation transparent. APS will continue to implement and improve, as Mr. Antonuk suggests, our procedures regarding PSA controls and documentation, including those relating to annual internal audits of the PSA.

With respect to Mr. Antonuk's statement that, although "APS documents its filing information well, [APS] should adopt a formal written procedure addressing preparation of the monthly PSA filings" (Antonuk testimony, p. 20.), APS has already begun to implement this recommendation.

In short, we appreciate and will implement Mr. Antonuk's recommendations regarding the need for further transparency of APS' PSA filings.

Q. IN ADDITION TO REVIEWING THE TESTIMONY OF MR. ANTONUK, DID YOU REVIEW THE DIRECT TESTIMONY OF RUCO WITNESS J. RICHARD HORNBY?

A. Yes. I would note that, in contrast to Mr. Antonuk and Liberty, with whom APS personnel spent innumerable hours and provided thousands of pages of documents, we never actually met with Mr. Hornby or had any direct communication with him.

Q. IN HIS TESTIMONY, MR. HORNBY ARGUES THAT THE PRIMARY GOAL OF THE APS HEDGING PROGRAM, PRICE STABILIZATION, IS "NOT A MAJOR BENEFIT TO APS RATEPAYERS." DO YOU AGREE WITH THIS ASSESSMENT?

A. Absolutely not. In fact, I think we need look no further than the California energy crisis of 2000-2001, which came about in part as the result of a lack of forward hedging by the California utilities, to understand the benefit to customers of a hedging program designed to stabilize natural gas and purchased power prices. We have designed the APS hedging program, centered on price stability, to reduce the volatility inherent in the wholesale energy markets. This greatly benefits APS customers. On this issue, I would point to the testimony of Mr. Antonuk I discussed earlier, which expressly supports the APS approach and contradicts Mr. Hornby's assertions.[3]

Q. HOW DO YOU RESPOND TO MR. HORNBY'S STATEMENT THAT WITH RESPECT TO APS' HEDGING PROGRAM, APS HAS NO "EXPLICIT STRATEGY TO MINIMIZE" ITS NATURAL GAS AND PURCHASED POWER COSTS? (Hornby testimony, p.2)

A. To have an express, stated goal of minimizing energy commodity costs conflicts with the essential purpose of a rational hedging program. In the utility context, we believe it inappropriate to regard hedging as a money making tool. I am not aware of any responsible utility energy hedging program that is expressly designed to lower prices. Liberty's Mr. Antonuk writes, "the available market options that would allow APS to reduce costs when market prices fall either involve speculation or transaction costs that make their benefits dubious." (Antonuk testimony, p. 18.) A proper hedging program does not focus on attempting to reduce the cost of energy – rather, it attempts to stabilize such costs. Instead, we employ operating and

[3] "APS has designed and it operates a sound hedging program. . . The program has been successful in meeting its primary objective, which is to promote price stability. It protects substantially against price increases...." (Antonuk testimony, pp. 17-18.)

procurement policies to reduce our energy costs. Noting this distinction, and as detailed in Mr. Carlson's testimony, APS does in fact have a "cost minimization" strategy designed in its implementation procedures. Specifically, as Mr. Carlson's testimony discusses, APS, on a continuously updated and revised basis, uses the least-cost mix of generation and purchased power for the hedge. This process generates significant savings -- or "cost minimization" -- for APS customers.

Q. IN FACT, AND NOTWITHSTANDING WHAT MR. HORNBY SAYS, DID NOT APS "SAVE" MONEY FOR ITS CUSTOMERS THROUGH ITS HEDGING PROGRAM?

A. Yes, with the benefit of hindsight, we paid lower costs for fuel and power than we would have had APS instead purchased fuel and power at the market prices prevailing at or shortly before the respective delivery dates. On the other hand, even with the optimization techniques used by APS in the hedging program, we could have had a different outcome. In fact, prices in the energy markets could have gone down rather than up after APS entered into its hedge positions. If that had happened, then the hedging program would have "lost money" when viewed after the fact. This, of course, does not render the hedging program unwise or unsound. To reiterate, utility hedging aims to reduce risk and volatility, not to make money. In this context, to "reduce risk" means to reduce the range of possible future energy costs and minimize the potential for large, unexpected increases in energy costs. We cannot know these costs in advance of delivery unless we make purchases at prices fixed in advance – prices that may appear either "high" or "low" when viewed after the fact.

Q. DO YOU AGREE WITH MR. HORNBY'S ASSERTION THAT THE APS HEDGING PROGRAM SHOULD NOT BE MEASURED IN TERMS OF "SAVINGS" VERSUS SPOT MARKET PRICES?

A. Yes. In making the above assertion, Mr. Hornby refers to statements by APS witnesses Steve Wheeler and Pete Ewen wherein both discuss in their filed testimony the "savings" of the APS hedging program relative to making like purchases on the spot market. The witnesses simply noted, in fact, the real and actual savings to APS customers. That said, their testimony does not suggest that APS designed the hedging program to achieve a specific "savings" versus the energy spot market price. Given the unpredictable nature of natural gas and power pricing, price volatility will inevitably result in some instances where APS' fixed energy costs obtained through its hedging program will exceed spot energy prices.

A hedging program that attempts to predict the course of gas or purchased power prices invites peril. Accordingly, I agree with Mr. Hornby on this issue – we should not measure the performance of a hedging program by savings relative to spot market prices. Hedging should reduce risk, so we would employ an inappropriate yardstick to measure its effectiveness if we used cost reduction. APS understands this reality. In fact, as Mr. Carlson stated in the very testimony referenced by Mr. Hornby, "economic impact" does ***not*** drive a well-considered hedging program, nor has APS ever used it as such:

> APS believes that price stability, and not speculative gain, is the goal of hedging. As a result, the "economic impact" of hedging can and will vary with the swings in commodity prices in short term markets. That said, under certain conditions, it is possible to also achieve positive economic value from hedging practices. Specifically, if the hedge is priced at a cost below the current market value, the "market" value of the hedge itself is positive, and can result in lower costs to the customer versus relying on spot market prices for procurement. (Carlson testimony, Docket Number E-01345A-05-0526, September 30, 2005, p. 13.)

After some discussion of the costs of the existing hedge positions versus spot market prices, Mr. Carlson explains hedge's economic value will invariably swing and we should avoid measuring its effectiveness by the sole criterion of value:

> It is important to note, however, that the economic value of hedging can be reduced or even turn negative if the short term price of gas and purchased power turns lower than the hedge costs. In those instances, even though price stability is realized, the final costs of hedging may be higher than purchasing needs short term (monthly or daily). That does not mean that the hedges were imprudent or even that they had no value to customers. Hedging is essentially price insurance. Insurance does not lose its value nor is its purchase imprudent simply because the risk insured against does not, in any particular instance, materialize. (Carlson testimony, Docket Number E-01345A-05-0526, September 30, 2005, p. 14.)

In sum, we believe people should not judge a hedging program by purported "savings" versus the spot market. As Commissioner Gleason correctly opined at a recent hearing, APS should not employ hedging as a trading tool designed to make money:

> The purpose of hedging is not to get the best price but to establish stability in price. We have established that it is to establish stability in price. If you guys were out there trading the market for trading purposes, I would be very disturbed. You don't trade, you hedge. . . (Commissioner Gleason, APS – Open Meeting, E-01345A-06-0009, May 2, 2006, p. 146).

Q. HOW DO YOU RESPOND TO MR. HORNBY'S CONCLUSION THAT THE APS HEDGING PROGRAM DOES NOT APPEAR TO BE BASED UPON QUANTITATIVE ANALYSES?

A. Mr. Hornby is simply wrong. We developed the APS hedging program utilizing APS' management and APS' Marketing and Trading team, which has vast experience in the procurement and sale of energy. We consulted with industry experts, and implemented the program in light of the opportunities, constraints, and costs in the Southwestern energy markets. The soundness and validity of this program has withstood the tests of time and the markets as

verified by Mr. Antonuk in his testimony, and has served to protect APS customers over the last decade from the historic price volatility that has occurred in the surrounding states. In formulating the program, we understood that hedging costs correlate closely with market liquidity, and that liquidity varies by commodity (e.g., natural gas versus electric power), type of hedge instrument (e.g., forward contracts being more liquid than options), and time to delivery (e.g., contracts of one year forward exceed the liquidity of those that deliver three years forward). The APS hedging program appropriately emphasizes the most liquid instruments (natural gas futures contracts) and the more liquid end of the forward price curve (short-dated contracts) to manage the costs associated with hedging.

Q. MR. HORNBY ALSO COMMENTS ON THE INDIVIDUALS INVOLVED IN THE DEVELOPMENT OF THE APS HEDGING PROGRAM. HOW DO YOU RESPOND TO THOSE COMMENTS?

A. In his testimony, Mr. Hornby states:

> APS long-term hedge strategy for gas and purchased power to serve its native load is developed by two senior executives from its Marketing and Trading group and one from its regulated operations. My understanding is that the Marketing and Trading group is not part of APS regulated operations, but instead participates for its own account as a marketer and trader in power and natural gas markets. Based on that understanding I do not believe it is appropriate for anyone from the Marketing and Trading Group to be involved with the development or implementation of the hedging program applicable to APS regulated operations. I recommend that APS review the relationship between Marketing and Trading personnel and its regulated personnel. (Hornby testimony, p. 9)

Mr. Hornby is mistaken on this assertion. First, the APS hedging program, as stated in the testimony of Mr. Carlson, has evolved with APS and the natural gas and power market risks since the 1990's. The most recent changes to the program in 2005, drew upon the experience and expertise of APS' management and APS' system traders, and input from a leading industry expert on risk

management and energy hedging issues. It does not owe its development to the non-utility portion of the Marketing and Trading group.

Second, and even ignoring the above failing, Mr. Hornby has a basic misunderstanding of the structure of the APS Marketing and Trading group. We have divided the APS Marketing and Trading group between utility and non-utility traders, with the vast majority of the trading activity involving APS' utility system activities. (As mentioned earlier, we have placed the non-utility operations in a wind-down mode.) We review and assess this program on a bi-annual basis by a group that includes Mr. Davis, Mr. Hansen, Mr. Carlson and me, all of whom focus on the community of interests of APS and its customers. The implementation and optimization of the hedging program rests primarily with Mr. Carlson, the Portfolio Manager of the APS System, who has nothing whatsoever to do with the non-utility side of the business. Oversight of the APS hedging program falls to the Director of Enterprise Risk Management, who has no affiliation with the trading floor and, instead, provides independent oversight of hedging practices and implementation.

IX. PRO FORMA FOR UNDERFUNDED PENSION LIABILITY

Q. STAFF, RUCO AND AECC HAVE ALL RECOMMENDED THE COMMISSION DENY THE COMPANY'S REQUEST TO ACCELERATE THE RECOVERY OF ITS UNDERFUNDED PENSION LIABILITY OVER A FIVE-YEAR PERIOD BEGINNING IN 2007. HOW DOES THE COMPANY RESPOND TO THESE RECOMMENDATIONS?

A. We firmly believe that we and the Commission should address pension funding at this time. Companies in all industries across the nation face this important issue. Without additional funding the Company's pension plan will likely remain in an underfunded position for the foreseeable future.

Q. STAFF WITNESS DITTMER OPPOSES THE COMPANY'S PROPOSAL AND PROVIDES SEVERAL ARGUMENTS. WOULD YOU LIKE TO ADDRESS EACH OF THOSE ARGUMENTS?

A. Yes. Mr. Dittmer characterizes a significantly underfunded Projected Benefit Obligation ("PBO") pension liability as neither unusual nor alarming. He adds that this situation arises from 1) "underperformance" of return on plan assets for a short period of years and 2) lower than "normal" interest rates used for purposes of discounting the pension obligation.

I must note that the APS pension plan did not "underperform" relative to the market. In fact, despite generally unfavorable market conditions, the performance of our pension plan has compared favorably versus a peer group of 250 U.S. corporate pension plans and the S&P 500 Index, a broad market measure. The following table demonstrates the excellent performance of the APS pension plan showing its investment performance has consistently **outperformed** the peer group and S&P 500 index over the entire six and one-half year period:

	2000	2001	2002	2003	2004	2005	Year to date 6/30/2006
APS Plan	1.0%	-2.7%	-4.4%	23.3%	12.3%	7.7%	3.9%
Peer Group[4]	0.3%	-3.8%	-9.3%	22.3%	11.6%	7.5%	3.6%
S&P 500	-9.1%	-11.9%	-22.1%	28.7%	10.9%	4.9%	2.7%

As a result of the overall substandard financial market returns over the last several years, the APS pension plan, as did most other pension plans, earned less than historically normal returns. In addition, record low interest rates over the last several years resulted in the application of unusually low discount rates in the valuation of pension liabilities. The atypically low financial market

[4] Median rate of return of approximately 250 U.S. corporate pension plans, Source: State Street Bank & Trust Co.

returns coupled with the low liability discount rates, have led to a growing and persistently underfunded pension liability for several years. We previously explained both the favorable relative performance of our pension plan and the ongoing underfunded position in a letter dated December 16, 2005 from APS' counsel Thomas Mumaw to Commissioner Mayes. **Attachment DEB-16RB.**

Higher interest rates or more favorable market returns would certainly decrease the funding gap. However, we cannot sensibly rely on the uncertainty of fortuitous changes in financial market conditions to address the underfunded pension issue. Obviously, these factors could easily move in the opposite direction, further aggravating the underfunding. Prudent management should address existing conditions, rather than trust the future will yield favorable results.

Q. WHAT ABOUT MR. DITTMER'S ARGUMENT THAT ADOPTION OF THE COMPANY'S PROPOSAL WOULD LEAD TO A "DOUBLING UP" OF RECOVERY OF PENSION COSTS?

A. Mr. Dittmer argues that because current pension expense levels, as calculated in accordance with FAS 87[5], already include a component that amortizes a portion of shortfalls from earlier projections (i.e., the underfunded liability), any increase in pension expense would "double up" recovery of pension costs.

Clearly, the Company does not propose the doubling up of pension costs. As described in APS witness Rockenberger's direct testimony, the accelerated recovery over five years will reverse over the subsequent ten-year period. Pension cost recovery will not double up, but merely accelerate. Furthermore, customers in the near term would fund a liability that has already been incurred. We believe that by accelerating the recovery of underfunded pension

[5] Statement of Financial Accounting Standards No. 87, *Employers' Accounting for Pensions*

expense over the next five years, customers would benefit over the subsequent ten years, as we amortize the balance recorded in the first five years. This lowering of revenue requirements in the future would have a stabilizing impact as the reversal partially mitigates higher costs related to infrastructure additions to serve customers' growing energy needs.

Q. HOW DO YOU ADDRESS MR. DITTMER'S AND RUCO WITNESS DIAZ-CORTEZ'S ARGUMENTS THAT ADOPTION OF THE COMPANY'S PROPOSAL WILL LIKELY LEAD TO "INTERGENERATIONAL INEQUITY" BETWEEN EXISTING AND FUTURE CUSTOMERS?

A. Mr. Dittmer states that the PBO considers **future years of service** as well as future pay raises. Mr. Dittmer's statements have incorrectly described the PBO. In fact, the PBO does **not** consider **future years of service** (as discussed in the Company's response to one of the Staff's data requests - UTI 16-376). The PBO only considers employment service provided **prior** to the current measurement date. The PBO reflects estimated future pay levels discounted to present-day dollars. Thus, APS does **not** request accelerated recovery of pension costs attributable to **future** employee service, but only the accelerated recovery of pension costs attributable to **prior** employee service.

Mr. Dittmer and Ms. Diaz-Cortez argue that the proposal will likely lead to "intergenerational inequities" because it front-end loads pension costs onto existing customers – while future customers will significantly benefit from services yet to be provided by active employees in the future. Again, we must emphasize that the PBO does not consider **future years of service**. Future customers will still pay their share of pension costs in the year employees provide service. Again, customers in the near term would be funding a liability that has already been incurred.

Mr. Dittmer also argues that "intergenerational inequities" arise when APS asks current customers to fund pension costs that are capitalized as a component of utility plant. However, he fails to acknowledge the timing differences that already exist between pension cost recovery in rates and pension funding contributions. When APS capitalizes a portion of pension costs, APS cannot reduce its required minimum pension contribution by the same amount. While the Company collects the capitalized portion from customers over many years through depreciation expense, the Company must currently fund the required pension contribution related to the capitalized portion. Therefore Mr. Dittmer's arguments based on "intergenerational inequity" do not withstand analysis.

Q. HOW DO YOU ADDRESS MR. DITTMER'S ARGUMENT THAT ADOPTION OF THE COMPANY'S PROPOSAL IS INCONSISTENT WITH PAST ACC PRECEDENT, AS WELL AS THE RATEMAKING AFFORDED PENSION EXPENSE IN OTHER REGULATORY JURISDICTIONS?

A. While this proposal may be somewhat unique, the aforementioned underfunded issue requires corrective relief. As has been discussed at length recently, APS has significant cash constraints. Given its fast-growing service territory, APS does not have sufficient cash flow from operations to fund its significant capital expenditure program. Consequently, the Company turns to the debt capital markets to raise additional debt to finance its needed infrastructure additions. This cash flow situation has created intense pressure on APS' already weak credit ratings metrics.

As Mr. Dittmer noted in his testimony, a number of other jurisdictions throughout the country have already addressed the issue of underfunded pension obligations. Other utilities may not face the "identical" situation we face and may not have offered the "identical" solution we have requested.

However, we all face similar situations. Although the ACC has not provided specific rate relief for underfunded pension obligations in the past, we believe current circumstances call for consideration of the issues confronting APS in this regard.

Q. MR. DITTMER HAS ALSO ARGUED THAT APS HAS NOT MADE CLEAR HOW IT WOULD ALLOCATE THESE ADDITIONAL MONIES. WHAT IS YOUR RESPONSE?

A. As stated in APS witness Rockenberger's direct testimony, APS has made it clear that we would allocate the annual $44 million accelerated recovery to the pension fund. Because we expect the annual IRS maximum limits to lie in the $400 million range, we should not encounter any funding limitations.

Mr. Dittmer argues that in his opinion, "it would be reasonable to expect APS to at least fund the pension trust in the amount being collected within rates before requesting customers to fund additional liability deficiency on an accelerated basis." Mr. Dittmer references Table C on page 76 of his testimony to emphasize that APS has contributed less than the total pension cost over the last five years. The contributions to the trust disclosed in Mr. Dittmer's Table C are **not** correct. The actual total contributions over the last five years ($205 million) have actually exceeded the total pension cost ($197 million). See **Attachment DEB-17RB** for the correct amounts of costs and contributions for the years 2001 through 2005. The contributions have in fact exceeded amounts charged to cost-of-service and thus are indicative of corporate intent.

Q. HOW DO YOU ADDRESS MR. DITTMER'S FINAL ARGUMENT THAT ADOPTION OF THE COMPANY'S PROPOSAL WILL NOT LEAD TO LONG-TERM SAVINGS FOR CUSTOMERS?

A. As discussed throughout this testimony, APS faces a severely underfunded pension plan with limited resources to cure the problem. Our proposal

provides a method to accelerate funding in the short term and to stabilize rates in the future as the pension cost reversal partially mitigates higher costs related to infrastructure additions. In fact, additional cash contributions will actually reduce future years' pension expense as a result of higher investment earnings on the higher pension fund balance. Customers will enjoy the benefit of long-term savings because of reductions in pension expense in future years' cost-of-service.

Q. DOES THE COMPANY ALREADY RECEIVE PENSION EXPENSE IN CURRENT RATES?

A. Yes. However, providing rate relief at normal, current-period cost levels will not suffice. A $249 million deficiency exists in the APS' pension fund. In order to close this funding gap, APS requires additional contributions to the pension fund in excess of current-year expense.

Q. STAFF'S WITNESS MR. DITTMER AND AECC'S WITNESS MR. HIGGINS ALSO DISCUSS ANOTHER MEASURE OF UNDERFUNDING, THE ACCUMULATED BENEFIT OBLIGATION ("ABO"). THE COMPANY USED THE PBO MEASURE IN ITS PRO FORMA ADJUSTMENT. DO YOU HAVE ANY COMMENTS REGARDING THE ABO ALTERNATIVE?

A. The ABO also measures the funded status of a pension plan. Both the ABO and PBO only consider service rendered as of each measurement date. The ABO assumes employees do not receive pay increases between the measurement date and their retirement dates. The PBO assumes employees continue to receive pay increases until they retire. Because the ABO does not consider future pay increases, the ABO yields a smaller liability than the PBO; hence, it results in a smaller funding deficiency. APS faces an underfunded position under both the ABO and PBO measures and has been in that situation since 2002.

Disclosed in financial statement footnotes, the financial community regards the PBO as the most widely recognized measure of a pension's funded status Additionally, the Financial Accounting Standards Board is expected to issue new rules later this year that will require companies to record on their balance sheets the funded status of their pension plans using the PBO measure. Importantly, the rating agencies use the PBO when calculating credit metrics. For all these reasons, the financial community prefers to use the PBO as the measure of pension liability.

Q. WHY DOES APS PREFER THE PBO CALCULATION TO THE ABO METHOD?

A. In addition to the reasons set forth above – the near universality of its acceptance in the professional accounting and financial communities – the PBO measures the **full** pension liability, whereas the ABO is a partial measure (i.e., a subset of the PBO). APS needs to confront this liability in a realistic and timely manner so that all parties involved – customers, employees, the Commission, and the Company – know where they stand and can have their doubts removed. Utilizing the ABO measure, the annual accelerated amortization would be $18 million – a mere 41% of the PBO-based amount required to fully address the issue. **Attachment DEB-18RB**. Addressing only the ABO simply postpones the day of financial reckoning.

X. <u>RUCO'S PROPOSED SERP PRO FORMA</u>

Q. DO YOU AGREE WITH RUCO WITNESS DIAZ-CORTEZ THAT A PRO FORMA ADJUSTMENT SHOULD BE MADE TO REMOVE ALL SERP RELATED COSTS FROM THE TEST PERIOD?

A. No, I do not. The Company offers a Supplemental Excess Benefit Retirement Plan ("SERP") to its senior management employees. The vast majority of companies that offer a "qualified" defined benefit pension plan offer a SERP to employees as a component of their total compensation. In fact, I do not

know of any company that provides a "qualified" defined benefit pension plan that does not also provide a SERP.

We employ experienced and highly qualified professionals with a long-term employment perspective in mind. In order to attract and retain these employees, we must compete with companies in other sectors of the economy and country. An important element of that competition centers on compensation, including retirement benefits, and the SERP forms an integral part of the total compensation package. We could not compete for executive and management talent without offering a SERP unless APS were to substantially increase base compensation.

Q. IN THE CONTEXT OF PENSION PLANS, WHAT DOES THE TERM "QUALIFIED" MEAN?

A. The Internal Revenue Service ("IRS") has published under the Internal Revenue Code ("IRC") an extensive list of specific requirements a pension plan must meet in order to obtain "qualified" status. If the IRS deems a pension plan qualified, numerous favorable tax treatments accrue to the benefit of the provider of such a plan. As a result, most employee pension benefits arise from "qualified" pension plans. Provided an employer meets all the extensive requirements for maintaining such a plan, an employer can, for corporate income tax purposes, deduct contributions to such a plan's qualified trust. Furthermore, earnings on the qualified trust's investment assets accrue on a tax-free basis. In other words, the IRS does not tax investment income (dividends, interest, and capital gains) that accumulates to the benefit of the employees covered by the qualified plan.

However, at present, the IRC caps at $220,000 the amount of an employee's annual earnings that may be included in the benefit calculation formula under a

qualified pension plan. The IRS periodically revises this cap to reflect cost-of-living increases.

Q. SHOULD WE INFER THAT THE $220,000 CAP SIGNIFIES IRS OR CONGRESSIONAL DISAPPROVAL OF COMPENSATION PACKAGES THAT EXCEED THAT AMOUNT?

A. Absolutely not. From a federal tax policy perspective, compensation levels allowed under a "qualified" pension plan trigger a myriad of tax and other consequences including: tax deductions for plan funding contributions, tax-free earnings on pension plan asset investments, and the nature and extent of "qualified" pensions guaranteed by the Pension Benefit Guaranty Corporation (a federal corporation). Each of these tax benefits comes at a cost to the U.S. Treasury. The compensation ceiling represents an exercise of federal tax policy to limit the cost to the U.S. Treasury, much like the application of the Alternative Minimum Tax. There is no determination, presumption, or even inference that pension benefits attributable to earnings above the "cap" are in any manner excessive or unreasonable.

Q. WHY IS A SERP NEEDED FOR MANAGEMENT EMPLOYEES?

A. As previously mentioned, the IRC limits the amount of annual compensation that may be considered for benefits under a "qualified" pension plan. Accordingly, APS provides a SERP to enable the payment of pension benefits such that an employee's pension is calculated based on the employee's total salary, not just the salary amounts under the "cap." We require such a plan to provide equitable pension benefits, which we need to attract and retain management employees and to compensate competitively such individuals for their responsibilities, skills, knowledge, and work experience.

Q. WHY SHOULD CUSTOMERS HAVE SERP COSTS INCLUDED IN COST-OF-SERVICE?

A. Quite directly, the senior management employees have a significant impact on the operations and condition of APS, all of which accrues to the benefit of our customers. In order to motivate and retain the wealth of experience and knowledge of this group, APS must provide them with currently competitive market pay and benefits. As a result, SERP forms an essential part of their total compensation and ratemaking should reflect that.

Q. HAS RUCO CLAIMED THAT THE SERP PROGRAM RESULTS IN EXCESSIVE OR UNREASONABLE OVERALL COMPENSATION TO THE RECIPIENTS?

A. No, and there has certainly been no evidence presented in this case that total compensation for APS management employees, including SERP benefits, is excessive. Companies need to provide their employees competitive compensation and benefit packages. Senior management employees' salaries tend to be higher than the rest of the workforce for a number of legitimate economic reasons. Indeed, the finest distinctions and gradations between various levels of compensation occur throughout our society. In a market economy, that market eventually determines the price or economic value for any one individual's services. We do not determine our employees' compensation levels in a vacuum: all of those who compete for their services in an extremely broadly defined universe set the appropriate benchmarks. A higher salary should not perversely result in penalizing an employee regarding pension benefits. SERP benefits enable us to make management employees whole instead of being limited to IRS "qualified" pension plans.

Q. TO THE BEST OF YOUR KNOWLEDGE, HAS THIS COMMISSION EVER DISALLOWED APS' SERP EXPENSE?

A. No. Past practice has held that normal compensation expense – including SERP expense – should be recovered in cost-of-service.

Q. RUCO WITNESS DIAZ-CORTEZ REFERS TO THE APS' SERP AS AN "EXECUTIVE PERK" AND STATES THAT THE SERP IS PROVIDED TO A "SMALL SELECT GROUP OF HIGH-RANKING OFFICERS". WHAT IS YOUR REACTION TO THESE SECTIONS OF HER TESTIMONY?

A. Her testimony mischaracterizes SERP pension benefits. SERP benefits clearly do not constitute a "perk" anymore than wages and salaries are "perks" – all make up the integral components of a total compensation package. As I stated earlier, the SERP provides a layer of pension benefit not otherwise available under the qualified pension plan. Further, we provided SERP benefits to senior management employees as a result of their compensations levels, not as a result of membership in a "select group" or status as a "high-ranking officer". Yes, these employees have compensation levels higher than other employees, but this results from competitive market forces and the nature and extent of their responsibilities. The term "perk" inappropriately ascribes a negative connotation to a SERP. A SERP cures the inequity these employees would otherwise suffer as a result of the IRC-imposed compensation limitation applicable to the "qualified" pension plan.

Q. DOES MS. DIAZ-CORTEZ'S RELIANCE ON A COMMISSION DECISION IN A SOUTHWEST GAS RATE CASE JUSTIFY HER RECOMMENDATION <u>HERE</u>?

A. No. Her citation indicates the Commission based its decision on the specific "record in [that] case" and not on a general policy pronouncement that would overturn past precedent in APS' cases. Moreover, the Commission appeared to conclude it did not consider overall compensation for Southwest Gas management "reasonable" with the inclusion of SERP costs. Neither RUCO nor any other witness has offered evidence to support such a finding in this case. As we have stated, competitive market forces determine such compensation levels.

XI. PINNACLE WEST STOCK UNDERPERFORMANCE

Q. WHAT HAS BEEN THE REACTION OF THE INVESTMENT COMMUNITY TO THE STAFF'S AND RUCO'S TESTIMONY?

A. Investors had a negative reaction. On August 21, 2006, Mr. Daniel Ford of Lehman Brothers Equity Research (one of the most respected and highly rated Wall Street utility analysts) stated:

> On 8/18, the ACC Staff and RUCO issued recommendations in the APS rate case. The recommendations mark the likely worst case in this proceeding. We view fair treatment by the ACC as essential to APS's investment grade rating and attraction to equity investors... Should the final order reflect financial parameters approximating these filings, it would be difficult for Arizona Public Service (APS), the utility subsidiary of Pinnacle West Capital Corp. to maintain investment grade ratings or provide support for the current stock value in our view. **Attachment DEB-19RB**

Q. OVER THE LAST FEW MONTHS, PINNACLE WEST'S STOCK PRICE HAS INCREASED AND HAS APPROACHED A 52-WEEK HIGH. DOES THIS INDICATE THAT THE FINANCIAL MARKETS BELIEVE THE FINANCIAL HEALTH OF PINNACLE WEST, AND ITS PRIMARY SUBSIDIARY APS, HAVE IMPROVED?

A. No. Many factors, both exogenous and company-specific, influence the price of Pinnacle West and other utility stocks. Exogenous considerations include: interest rate moves and expectations; the global price of energy-related commodities, principally oil and natural gas; the overall health of the economy; and energy supply implications of the instability in the Middle East. Company-specific items include: service territory health and growth factors; regulatory climate reality and perception; and utility operating performance. Financial and investment professionals always assess a particular company's stock price performance relative to similar utilities or, better yet, relative to an index of utility stocks.

Q. PLEASE DESCRIBE AN INDEX OF UTILITY STOCKS?

A. An index of utility stocks, or any form of stock index, measures the aggregate performance of the constituent "basket" of individual stocks. The two most typical electric utility stock indices include "S&P 500 Electric Utilities Index" and the "S&P Composite 1500 Electric Utilities Index."

Q. PLEASE EXPLAIN THE S&P 500 ELECTRIC UTILITIES INDEX.

A. S&P composed its "500 Electric Utilities Index" from electric utilities included in the S&P 500 Index.

Currently, the S&P 500 Electric Utilities Index encompasses 11 companies. The member companies include: Allegheny Energy, Inc.; American Electric Power Company, Inc.; Edison International; Entergy Corporation; Exelon Corporation; FirstEnergy Corp.; FPL Group, Inc.; Pinnacle West Capital Corporation; PPL Corporation; Progress Energy, Inc.; and The Southern Company.

Q. PLEASE EXPLAIN THE S&P COMPOSITE 1500 ELECTRIC UTILITIES INDEX.

A. S&P formed the S&P Composite 1500 Index to represent approximately 90% of U.S. equities. It consists of the members of the S&P 500 Index, the S&P MidCap 400 Index and the S&P SmallCap 600 Index – for a total of 1,500 companies of varying sizes.

S&P has assembled its Composite 1500 Electric Utilities Index from companies included in the S&P Composite 1500 Index and those that S&P has classified as electric utilities.

Currently, the 27 members of the S&P Composite 1500 Electric Utilities Index include: Allegheny Energy, Inc.; Allete, Inc.; American Electric Power Company, Inc.; Central Vermont Public Service Corporation; Cleco

Corporation; DPL Inc.; Duquesne Light Holdings, Inc.; Edison International; El Paso Electric Company; Entergy Corporation; Exelon Corporation; FirstEnergy Corp.; FPL Group, Inc.; Great Plains Energy, Inc.; Green Mountain Power Corporation; Hawaiian Electric Industries, Inc.; Idacorp, Inc.; Northeast Utilities; Pepco Holdings, Inc.; Pinnacle West Capital Corporation; PPL Corporation; Progress Energy, Inc.; Sierra Pacific Resources; The Southern Company; UIL Holdings Corporation; UniSource Energy Corporation; and Westar Energy, Inc.

Q. WHICH OF THE S&P ELECTRIC UTILITIES INDICES DO YOU BELIEVE APPROPRIATE FOR COMPARISON WITH PINNACLE WEST'S STOCK PERFORMANCE?

A. The S&P Composite 1500 Electric Utilities Index provides for superior comparison because as a "broader" index, it contains electric utilities of more diverse size.

Q. HOW HAS PINNACLE WEST'S STOCK PRICE PERFORMED RELATIVE TO THESE TWO ELECTRIC UTILITY STOCK INDICES?

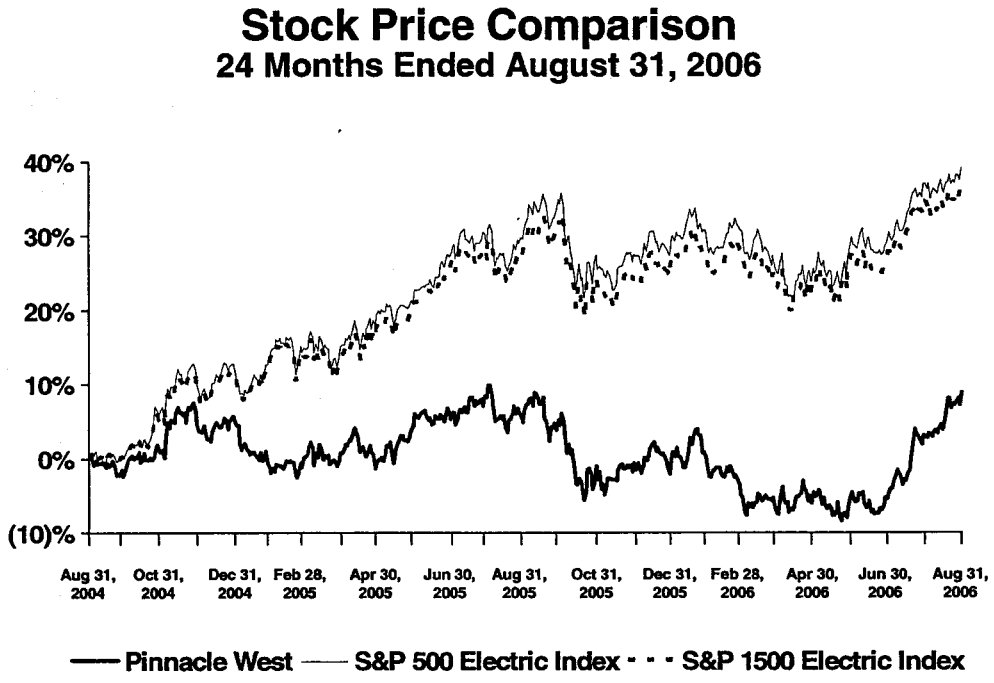
A. Over the 24-month period ended August 31, 2006, Pinnacle West's stock significantly underperformed both of these indices.

While Pinnacle West's stock price increased 8.8% over this period, such an increase amounted to less than one-fourth the average price appreciation of either of these indices. The table below summarizes the performance of the Company's stock and the indices during the period:

Price Change – 24 Months Ended August 31, 2006

Pinnacle West	8.8%
S&P Composite 1500 Electric Utilities Index	36.6%
S&P 500 Electric Utilities Index	39.1%

The relative underperformance of Pinnacle West stock during this period is demonstrated graphically below:



Pinnacle West's stock price growth ranked in the bottom quartile of companies in the S&P Composite 1500 Electric Utilities Index. Pinnacle West's increase of 8.8% ranked 22nd lowest out of the 27 companies in the index. The stock price change for the 27 companies in the index ranged from a positive 184.1% to a negative 1.0%, with an index average of 36.6%.

Pinnacle West's stock price increase ranked next to last among the 11 companies in the S&P 500 Electric Utilities Index. The stock price change for the 11 companies in the index ranged from a positive 184.1% to a negative 1.0%, with an index average of 39.1%.

Q. HOW HAS PINNACLE WEST'S STOCK PERFORMANCE OVER THE LAST TWO YEARS IMPACTED SHAREHOLDERS?

A. Had Pinnacle West's common stock merely kept pace with the growth rate of the S&P Composite 1500 Electric Utilities Index, our investors would not

have **lost $1.2 billion** in market capitalization for the 24 months ended August 31, 2006. This dismal performance has limited our stock's attractiveness to investors, which further aggravates its price performance and portends difficulties when we next have to finance in the equity capital markets.

Q. IF ONE LOOKS AT JUST THE LAST YEAR, HOW HAS PINNACLE WEST STOCK PERFORMED RELATIVE TO THE INDICES?

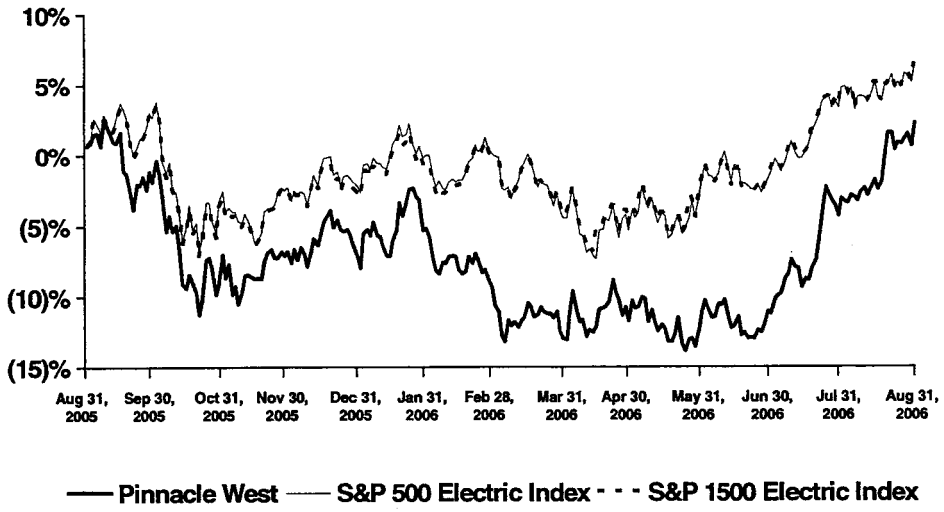
A. In the twelve-month period ended August 31, 2006, Pinnacle West's stock significantly underperformed both electric utility stock indices. The increase in the Company's stock price amounted to about one-third the average price appreciation of the electric utility indices. The table below summarizes the performance of the Company's stock and the indices:

Price Change – Twelve Months Ended August 31, 2006

Pinnacle West	2.3%
S&P Composite 1500 Electric Utilities Index	6.4%
S&P 500 Electric Utilities Index	6.4%

We can clearly see the relative underperformance of Pinnacle West's stock during this period in the following graph:

Stock Price Comparison
Twelve Months Ended August 31, 2006



Pinnacle West's stock price growth ranked in the bottom one-third of companies in the S&P Composite 1500 Electric Utilities Index. The stock price change for the 27 companies in the index ranged from a positive 38.4% to a negative 3.1%, with an index average of 6.4%. Pinnacle West's increase of 2.3% ranked 19th lowest out of the 27 companies.

Pinnacle West's stock price increase ranked in the bottom one-half of companies in the S&P 500 Electric Utilities Index. The stock price change for the 11 companies in this index ranged from a positive 38.4% to a negative 3.1%, with an index average of 6.4%. Pinnacle West's increase of 2.3% ranked 7th lowest out of the 11 companies.

Q. TO WHAT FACTORS DO YOU ATTRIBUTE THE SUBSTANDARD PERFORMANCE OF PINNACLE WEST'S STOCK?

A. Based upon my experience and ongoing communications with financial analysts and institutional investors, the major determinants of the poor stock performance include both the reality and the perception of a regulatory climate that results in APS' chronic inability to earn a reasonable allowed ROE. APS underearns in comparison with other electric utilities and, consequently, the performance of our stock price cannot keep pace with theirs.

Q. HOW HAS PINNACLE WEST'S STOCK PERFORMANCE IN THE PAST YEAR IMPACTED SHAREHOLDERS?

A. Put simply, the Company's shareholders have lost $200 million over the past twelve months compared with what their investments would be worth if they had invested in the electric utility industry as a whole. Stated more technically: because Pinnacle West's stock price underperformed the electric utility industry during the twelve months ended August 31, 2006, its market capitalization is approximately $200 million less than it would have been if

the Company's stock price had grown at the same pace as the S&P Composite 1500 Electric Utilities Index.

Q. WHILE PINNACLE WEST SHAREHOLDERS APPEAR TO HAVE LOST $1.2 BILLION OVER THE LAST TWO YEARS, IS THERE ANY IMPACT ON APS CUSTOMERS?

A. Yes, absolutely. APS' overall weak financial condition permeates both the equity and debt markets. With credit rating downgrades, APS' cost of debt has increased. Likewise, when APS (through Pinnacle West) needs to access the equity markets for additional equity capital, the depressed stock price will ultimately translate into additional expense for APS and its customers.

XII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR REBUTTAL TESTIMONY?

A. Yes. We must maintain APS' investment grade credit ratings and access to the capital markets at reasonable costs for the customers' best interests and the future economic growth of Arizona. APS needs this rate increase to achieve and maintain financial metrics consistent with merely low investment grade credit ratings. In the long run, such investment grade credit ratings benefit APS customers because they allow the Company to fund at a reasonable cost the significant infrastructure required to meet the needs of its customers.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Arizona Public Service Company
Financial Indicators with APS' Modified Proposed Rates

	Financial Indicator	2006	Projected 2007	2008
1	Funds from Operations Interest Coverage /1/ ("Interest Coverage")	3.9	4.0	3.9
2	Funds from Operations to Debt /1/ ("FFO/Debt")	17.6%	19.2%	17.5%
3	Debt to Capital /1/	54.6%	52.1%	53.5%
4	Return on Common Equity ("ROE")	8.5%	8.0%	7.4%

/1/ Includes impacts of imputed debt

Arizona Public Service Company
Financial Indicators with Staff's Proposed Rates (Projected PSA)

	Financial Indicator	2006	Projected 2007	2008
1	Funds from Operations Interest Coverage /1/ ("Interest Coverage")	3.9	3.7	3.4
2	Funds from Operations to Debt /1/ ("FFO/Debt")	17.6%	16.4%	15.1%
3	Debt to Capital /1/	54.6%	58.1%	59.6%
4	Return on Common Equity ("ROE")	8.5%	6.8%	6.3%

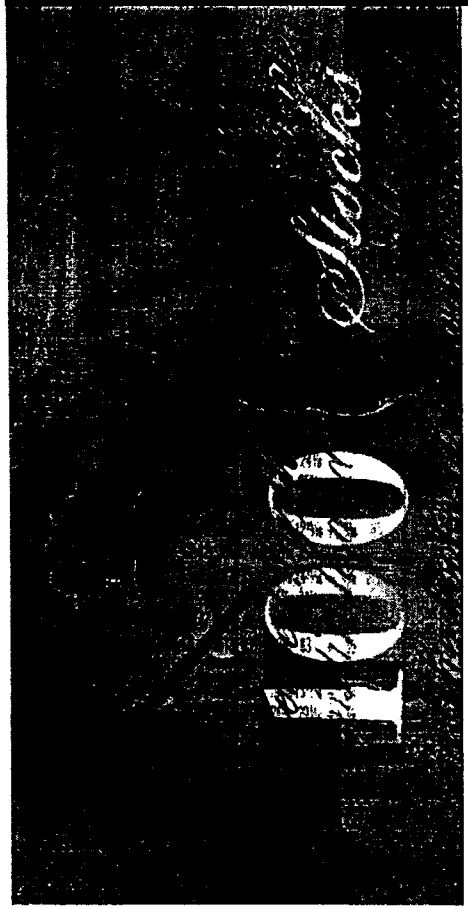
/1/ Includes impacts of imputed debt

Arizona Public Service Company
Financial Indicators with RUCO's Proposed Rates

	Financial Indicator	2006	Projected 2007	2008
1	Funds from Operations Interest Coverage /1/ ("Interest Coverage")	3.9	3.5	3.0
2	Funds from Operations to Debt /1/ ("FFO/Debt")	17.6%	15.1%	12.9%
3	Debt to Capital /1/	54.6%	58.6%	60.9%
4	Return on Common Equity ("ROE")	8.5%	6.0%	4.6%

/1/ Includes impacts of imputed debt

STANDARD
&POOR'S



REGULATION AND UTILITY CREDIT QUALITY

NARUC Summer Committee Meetings: Committee on Gas San Francisco, California August 1, 2006

Richard W. Cortright, Jr., Managing Director
Utilities, Energy & Project Finance Ratings

What is A Credit Rating?

- A credit rating is an assessment of the likelihood that an issuer will default on its financial obligations
- It indicates the capacity and willingness of an issuer or obligor to pay principal and interest, and in general, to satisfy its financial obligations, in accordance with the terms of the obligation
- It is the result of independent, objective analysis
- A rating is **not** a recommendation to buy, sell or hold a security

Standard & Poor's Ratings: Overview

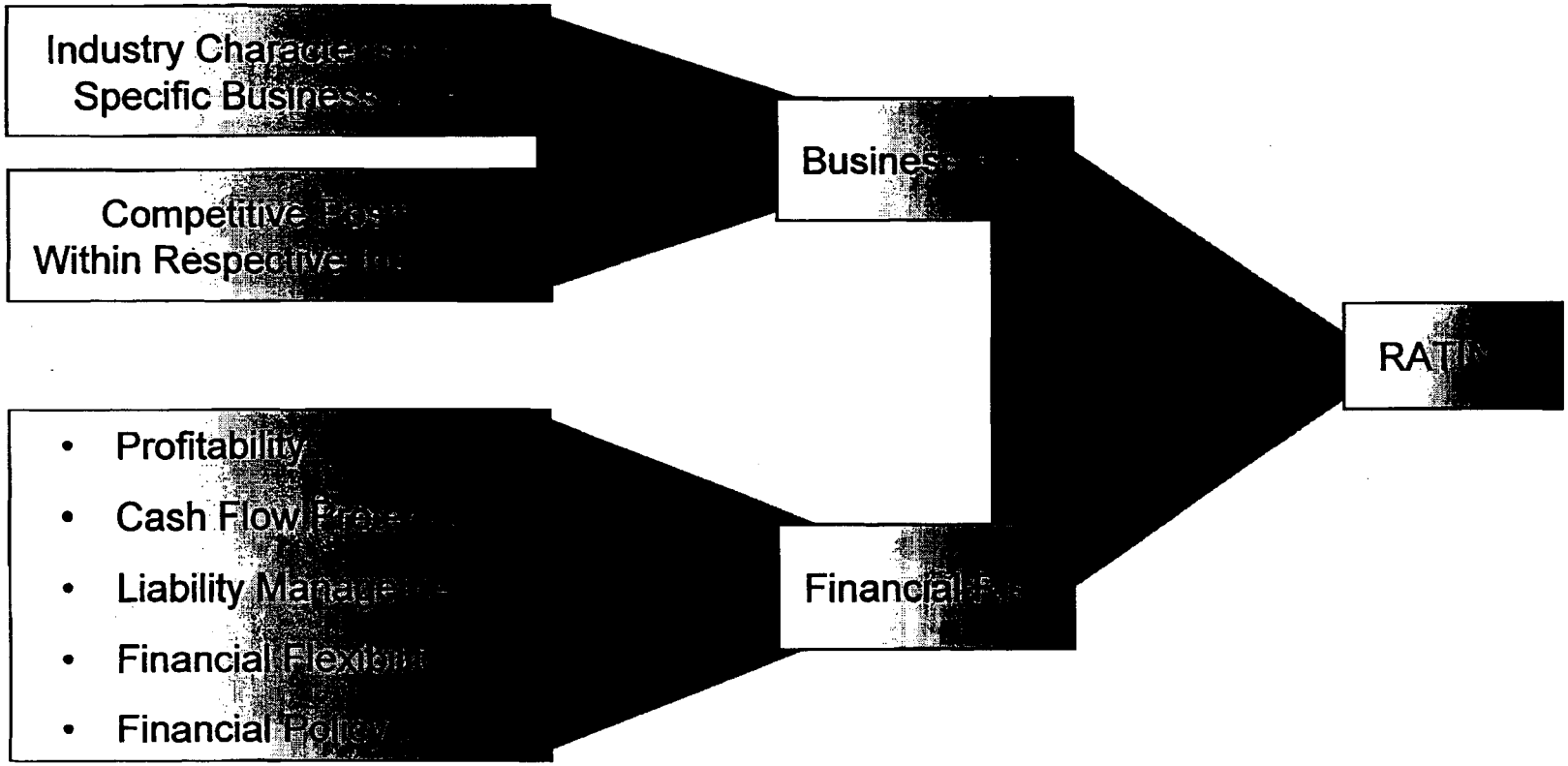
Investors and **Issuers** rely on Standard & Poor's because we provide:

- An independent, objective opinion of creditworthiness
- Global and local risk assessment
- A global benchmark that helps price credit risk and helps compare credit risk among peers

Standard & Poor's Ratings: Overview (cont'd)

- A rating is:
  - A forward-looking opinion of relative creditworthiness
  - A key component in pricing debt
- Rating scale runs from "AAA" (highest; e.g. GE) to "D" (default; e.g. Calpine)
- Higher rating = lower default risk = lower cost of capital

Getting to the Corporate Credit Rating



Ratings Matrix

Business Assessment	Financial Assessment
Excellent (1-2)	Minimal
Strong (3-4)	Modest
Satisfactory (5-6)	Intermediate
Weak (7-8)	Aggressive
Vulnerable (9-10)	Highly Leveraged

Energy Industry: Business Risk Scale

GAS

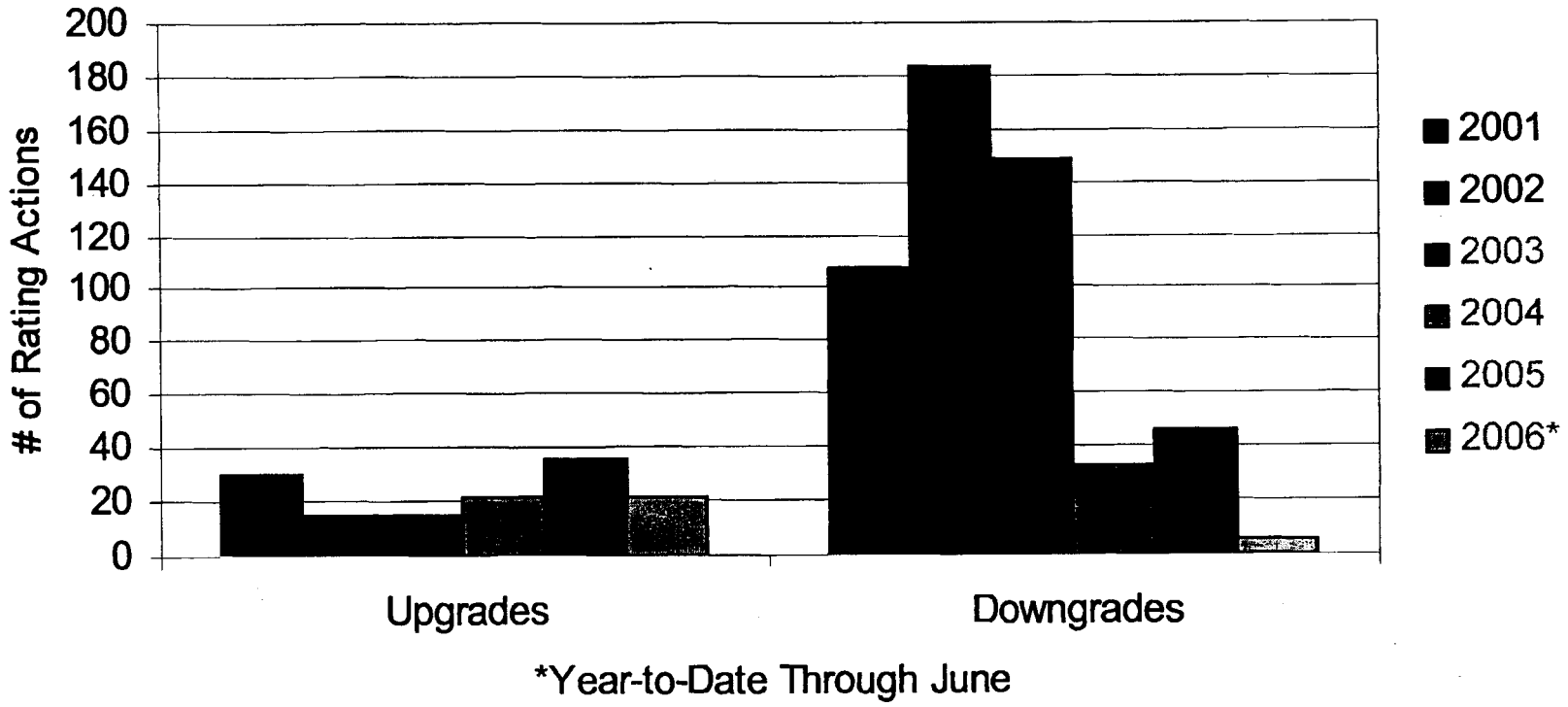
E&P | Processing & Gathering | Transmission | Distribution

High ⟷ Low

Energy Marketing | Generation | Transmission | Distribution

ELECTRIC

Utility-Related Rating Actions



*Year-to-Date Through June

The Re-Emergence of the Regulatory Arena

- Regulatory/Political Environment – Front and Center Once Again
- Utilities Across the Country Are Filing Rate Cases Following a Prolonged Hiatus
- Rate Case Filings Are Likely To Be A Sustained Characteristic of Utility Activity for Several Years:
  - Commodity Price Unpredictability
  - Capital Spending & Related Financing Activities
  - Event Risk (M&A, Asset Rationalization)

The Re-Emergence of the Regulatory Arena (con't)

- Regulators Will be Challenged to Balance Priorities:
  - Customer Protection
  - Reliability
  - Conservation
  - Financially Healthy Utilities

Regulatory Uncertainty

As a Result…

- The Character of Regulatory Decisions Will Perhaps Be The Major Determinant of Utility Credit Quality For Many Years
- Uncertainty Deprives Utilities of Credit Strength
- Uncertainty Is Created by Unsupportive Actions: Delaying Decisions (Regulatory Lag), Prudency Disallowances, Absence of Pre-approved Infrastructure Investments

Regulatory Challenges

- Soaring Natural Gas Prices > Elevated Wholesale Rates > High Anxiety Among Ratepayers
  - **Illinois' Distribution and Supply Surprise Actions**
  - **Maryland**
  - **Delaware**

PLUS...

- Aging Infrastructure and Concern Over Long-Term Reliability > Rate Base Additions (Generation, Transmission, Environmental)

Credit Characteristics of Supportive Regulation

- Consistency and Predictability of Decisions
- Timeliness of Orders
- Use of Forward-Looking Measures

...Provide the Foundation for Strong Utility Credit

Supportive Regulatory Structures And Actions

Public Service Co. of Colorado Comanche 3 Construction Settlement

- Designed to Ensure Credit Quality During Construction
- Incorporates Equity Building Mechanism
- Directly Tied to Standard & Poor's Financial Metrics

Supportive Regulatory Structures And Actions (2)

Kansas City Power & Light Co. Capital Program Settlement

- Interim Power Cost Adjustment Clause
- The Right to File Annual Rate Cases
- Directly Ties to Standard & Poor's Financial Metrics

Northwest Natural Gas: The Quintessential High Quality Credit

- Decoupling Mechanisms/Tariffs
  - Weather Normalization
  - Conservation
  - Purchased Gas Adjustment
- Future Test Year
- Earnings Sharing

>>> Business Profile of '1' and Ratings of AA-/Stable/A-1+

Event Risk

M&A as a Dynamic but Unpredictable Force ...

- Rising Cost Pressures (Pension, Fuel)
- Desire for Regulatory Diversity
- Meld Complementary Strategies
- Option Expansion in Wake of PUHCA Repeal
- Ample Current Liquidity Undergirding M&A and Asset Sale Activity (Banks, Term B Loans, Private Equity, Hedge Funds), But Always Tenuous

Rationales for Negative Rating Outlooks

- Sustained High Leverage and Weaker than Expected Credit Protection Measures (Con Ed)
- Increased Exposure to Non-Regulated Pursuits (TXU)
- Increased Debt-Financed Acquisitions or Capital Investments; M&A (Exelon)
- Uncertainty as Transition Periods Come to a Close (Commonwealth Edison)

PRINCIPAL CONCERNS OF REGULATORY COMMISSIONERS (2005 RKS SURVEY)

Principal Concerns

- The Cost of Energy and the Level of Rates
- Resource Adequacy – Generation and Delivery

Significant Concerns

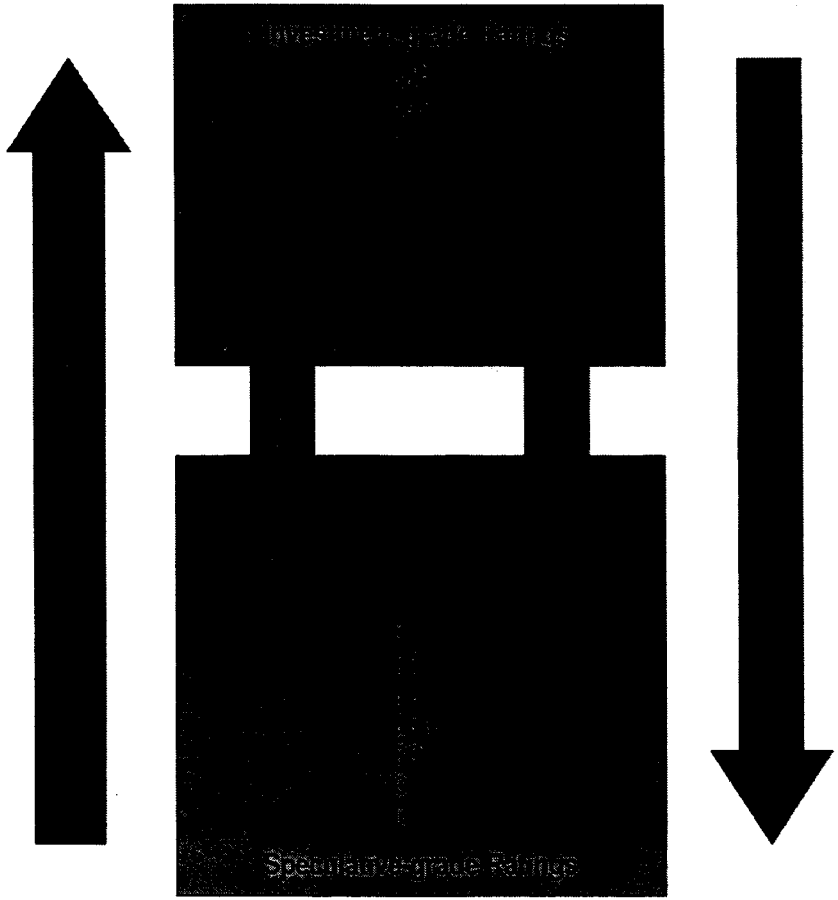
- Utility Financial Profiles
- Energy Efficiency
- New Ratemaking Methodologies
  - Weather Normalization,Revenue Decoupling, Advanced Infrastructure Approvals

PRINCIPAL CONCERNS OF REGULATORY COMMISSIONERS (2)

Modest Concerns

- Level of Commissioner and Staff Experience/Expertise
- Corporate Governance
- Mergers and Acquisitions
  - Acceptable Rationales Include Improved Efficiency of Service, Ratepayer Savings, Improved Financial Stability, and Economies of Scale

Standard & Poor's Rating Scale



RESEARCH

Summary:

Arizona Public Service Co.

Publication date: 31-Aug-2006
Primary Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: BBB-/Stable/A-3

Rationale

Arizona Public Service's (APS) 'BBB-' corporate credit rating is based on the consolidated credit quality of Pinnacle West Capital Corp. (PWCC), of which APS is the principal subsidiary. APS is a vertically integrated investor-owned utility that provides retail electric service to about one million customers throughout Arizona, including about half of the Phoenix MSA. PWCC's unregulated subsidiaries contributed about 27% of income from continuing operations in 2005, with the balance provided by APS.

PWCC and APS' satisfactory business profile score of '6' (on a 10-point scale where '10' represents the highest risk) reflects the uncertainty concerning how the Arizona Corporation Commission (ACC) will address APS' pending general rate case request and operational performance at its Palo Verde nuclear station.

As of June 30, 2006, APS had about $175 million in deferred fuel and purchased power costs. Deferrals are resulting from the fact that APS' retail electric rates are based on a 2003 test year, but actual fuel and power costs have risen sharply since then. APS' currently authorized base rates reflect a fuel and purchased power costs of about 2.047 cents per kilowatt-hour (kWh). In contrast, APS' current general rate case request is for base rates to reflect 3.1904 cents/kWh for fuel and purchased power costs.

Due to a total of about 9% of temporary surcharges implemented on May 1, 2006, APS' accumulation of new deferrals of about $93 million through June 30 are being roughly offset by about $95 million in adjustor and surcharge recovery, resulting in current deferred balances that are in line with year-end 2005 levels of about $173 million. With respect to 2006 deferrals, in April the ACC approved a 7 mill/kWh surcharge, or an 8.3% increase in rates, is designed to recover about $138 million of whatever additional deferrals are actually incurred in 2006. The company has estimated a deferral balance of about $110 million by year-end 2006 to be addressed through the February 2007 adjustor.

The majority of APS 2005 deferrals now have ratemaking mechanisms in place to address their eventual pay down. That is, the 4 mill/kWh power supply adjustment made in February 2006 is expected to recover by February 2007 about $110 million of the 2005 balance. A $15 million or about 0.6 mill/kWh surcharge was approved in April 2006. This leaves about $45 million in incurred 2005 deferrals related to Palo Verde unplanned outages. APS' February 2006 application to collect this amount through a temporary 1.9% rate increase is pending before the ACC. Staff recommendations issued in August, however, suggest granting recovery of only $28 million, on the basis that about $17 million of the outage-related request was avoidable. ACC staff has also requested that this issue be considered as part of APS' general rate case request. If this occurs, the recovery of this remaining balance will not be determined until the rate case is resolved, which is not likely until 2007.

Cash flow metrics for 2006 will be modestly assisted by the surcharges but funds from operations (FFO) to total debt is expected to be below Standard & Poor's Ratings Services benchmarks until going forward retail rates are brought more in line with current costs. Any permanent rate adjustments will be considered as part of APS' pending rate case, as will any changes to the utility's power supply adjuster (PSA). While FFO to interest coverage is expected to remain in line with the rating, PWCC's consolidated total debt was 52% at year-end 2005 (adjusted for power purchase obligations and operating leases), and in 2006 Standard & Poor's expects consolidated leverage to increase to around 57%, just inside the 58% benchmarks for the current 'BBB-' rating. These consolidated ratios exclude APS' sizable pension obligations. Treating pension obligations as debt-like, 2006 consolidated leverage is expected to be about 61%. Standard & Poor's anticipates that this liability will be recovered over time in retail customer rates.

Importantly, the consolidated capital structure is not likely to improve in 2007. Although the company has no significant maturities next year, it is forecasting the need to issue additional debt for general corporate purposes that include capital expenditures. This is likely to further increase leverage, possibly outside of the benchmark. With respect to cash flow credit metrics, consolidated FFO to interest coverage is in line with the rating at about 3.3x at June 30. At June 30, PWCC adjusted FFO to total debt was around 15% (Our calculation excludes changes in collateral and risk management activities from operating cash flow).

APS' general rate case is in the discovery phase. In August 2006, ACC staff and other parties filed testimony responding to APS, which is requesting a $454 million or 21.3% increase in base rates. Staff testimony supports instead a 9.8% increase, or $208 million. Of the staff's recommended increase, about 9.1% is related to base fuel and purchased power rates, but falls short by about $105 million of APS' requested increase for these costs. The remainder of the $141 million staff-recommended reduction is based on non-fuel items, with a large portion of the difference attributable to staff's suggestion that APS' authorized ROE be set at 10.25%, relative to the 11.5% ROE that APS is seeking. Hearings begin on Oct. 10, 2006.

Palo Verde 1 returned to service in mid-July following an extended outage to repair vibration problems on a cooling line. Year-to-date capacity factors for the units have been hampered by this outage. While it is too early to conclude that Palo Verde's performance will recover to historically strong levels, the near-term risks posed by Palo Verde 1's uncertain return to service during APS' peak summer period have been abated.

Short-term credit factors

PWCC and APS' short-term rating is 'A-3'. Consolidated liquidity remains adequate, but utility liquidity continues to display some weaknesses under adverse market and credit event stress tests.

Consolidated cash and investments stood at $16 million at June 30, 2006, down significantly from year-end cash balances of $154 million at Dec. 31, 2005 and from $315 million as of March 31, 2006. Elevated cash balances in the first quarter were principally driven by PWCC's $175 million private placement borrowings that, along with cash, were used to repay a $300 million parent note that came due April 3.

PWCC has a $300 million credit facility that supports the issuance of up to $250 million of CP or for bank borrowings, including LOCs. The facility expires December 2010. APS has a committed line of $400 million available to support the issuance of up to $250 million in CP or for borrowing or LOCs. The line also matures in December 2010. Consolidated short-term borrowings were $174 million as of June 30.

Based on our analysis, consolidated liquidity is sufficient to support cash demands if a credit event were to occur. However, APS' standalone liquidity is weak, and the combined impact of a lowered credit rating, concomitant with a stress in market prices could result in available liquidity being insufficient to support utility operations. In such an instance, APS would need to rely on secondary sources of cash, such as debt issuances, to support liquidity demands. Standard & Poor's also assumes that in such an instance parent liquidity would be available to support any APS cash shortfalls. APS had no cash balances at June 30, down from $77 million as of March 31, 2006. Liquidity demands typically peak during the summer, and as a result, of the total consolidated short-term borrowings, about $118 million is associated with APS' CP borrowings.

APS has hedged 85% of its 2006 power and gas requirements, which provides some protection against further escalation in fuel and purchased power costs. Consolidated capital expenditures continue to be large, due to significant growth in APS' service area, and are estimated at about $890 million in 2006, in line with the approximately $930 million spent in 2005.

Outlook

The stable outlook for PWCC and APS' rating is premised on the ACC continuing to provide sustained regulatory support that addresses permanent rate relief and manages the deferral balances downward over a reasonable time frame. A negative rating change or outlook could result if the size of the deferred balances materially increases, as a result of Palo Verde nuclear performance or other factors. Given the regulatory challenges over the near term and the potential for continued operational challenges at Palo Verde there is little opportunity for a positive rating action at this time.

Analytic services provided by Standard & Poor's Ratings Services (Ratings Services) are the result of separate activities designed to preserve the independence and objectivity of ratings opinions. The credit ratings and observations contained herein are solely statements of opinion and not statements of fact or recommendations to purchase, hold, or sell any securities or make

any other investment decisions. Accordingly, any user of the information contained herein should not rely on any credit rating or other opinion contained herein in making any investment decision. Ratings are based on information received by Ratings Services. Other divisions of Standard & Poor's may have information that is not available to Ratings Services. Standard & Poor's has established policies and procedures to maintain the confidentiality of non-public information received during the ratings process.

Ratings Services receives compensation for its ratings. Such compensation is normally paid either by the issuers of such securities or third parties participating in marketing the securities. While Standard & Poor's reserves the right to disseminate the rating, it receives no payment for doing so, except for subscriptions to its publications. Additional information about our ratings fees is available at www.standardandpoors.com/usratingsfees.

Copyright © 1994-2006 Standard & Poor's, a division of The McGraw-Hill Companies.
All Rights Reserved. Privacy Notice

The McGraw Hill Companies

Credit Opinion: Arizona Public Service Company

Arizona Public Service Company

Phoenix, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Negative
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Subordinate Shelf	(P)Baa3
Commercial Paper	P-2
Parent: Pinnacle West Capital Corporation	
Outlook	Negative
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3

Contacts

Analyst	Phone
Laura Schumacher/New York	1.212.553.1653
A.J. Sabatelle/New York	
Daniel Gates/New York	

Key Indicators

Arizona Public Service Company

ACTUALS	2005	2004	2003	2002
(CFO Pre-W/C + Interest) / Interest Expense [1][2][3]	3.6x	3.8x	4.5x	4.7x
(CFO Pre-W/C) / Debt [2][3]	14.7%	16.0%	20.0%	22.7%
(CFO Pre-W/C - Dividends) / Debt [2][3]	9.9%	11.3%	15.1%	17.1%
(CFO Pre-W/C - Dividends) / Capex [2][3]	26.3%	73.3%	112.1%	95.3%
Debt / Book Capitalization	47.8%	54.0%	52.1%	48.4%
EBITA Margin	19.9%	24.5%	23.4%	25.7%

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Excludes the impact of a tax refund in 2002 and tax reversal in 2004. [3] $131 million of change in risk management and trading assets and liabilities backed out of the 2005 CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Rationale

The Baa2 senior unsecured rating of Arizona Public Service Company (APS) reflects the stability of its regulated cash flows, the economic strength of its service territory and its position as the primary wholly owned subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 Issuer Rating, negative outlook). The key credit concern is the need for rate increases in a challenging regulatory environment in Arizona, which is expected to contribute to

financial ratios that are weak for the rating category over the near term.

Almost all of APS operations are regulated and its low level of unregulated activities (80%-99% regulated) ranks the company in Category 2 of 4 in accordance with the global rating methodology for electric utility companies. A strong ranking on this key factor is offset by a weak regulatory position with Arizona being ranked in global category 3 of 4, with Arizona being below average for U.S. regulatory jurisdictions.

APS' operations are regulated by the Arizona Corporation Commission (ACC). As evidenced by the recent rate case activity noted below, the company's weak regulatory position reflects below average assurance of timely recovery of costs and investments. APS' 2003 rate case was not concluded until April 2005, and the increase received was less than half of the amount requested. A fuel surcharge mechanism requested as part of the 2003 rate case was not implemented until February 2006. Fuel and purchased power costs continue to rise and accumulate as a deferred expense. In January 2006, APS requested a 14% emergency interim rate increase (later revised to 11%) to begin recovery of these excess costs in 2006. On May 2nd the ACC approved a rate increase of approximately 8%. In its pending general rate case, APS has requested an increase of approximately 21% (inclusive of the 14% increase for fuel and purchased power costs), to be effective January 2007. Hearings will begin in October 2006. It is possible the case could take longer than expected or result in an increase that is less than requested. In light of its challenging regulatory environment, Moody's would look for APS to have financial metrics that are somewhat stronger than comparably rated utility operating companies that operate in more supportive environments.

APS' key financial metrics reflect the fact that it has been unable to recover increased costs for fuel and purchased power on a timely basis. For example, the ratio of cash from operations prior to changes in current assets and liabilities to adjusted debt (incorporating Moody's standard analytic adjustments) is in the mid-teens and expected to remain there through at least 2006. This is at the lower end of the 13% to 25% range in the global rating methodology for Baa rated entities on a stand-alone basis within the medium risk category and suggests a rating that could be Baa3 or Baa2. The Baa2 rating considers the potential for key financial ratios to strengthen beyond 2006 if regulatory treatment is supportive of timely cost recovery. The rating also is supported by on-going strong growth in APS' service territory.

Customer growth has been above 3.5% per annum and the company growth will remain at this level through 2007. APS increasing customer base has resulted in a need for capital investment, but also provides a source of revenue growth outside of base rate increases which could be expected to improve financial metrics assuming there is relatively timely recovery of fuel and purchased power costs.

Pinnacle, APS' parent company, derives approximately 90% of its operating cash flow from APS. In comparison to other U.S. utility holding companies, Pinnacle's unregulated business represents a smaller than average portion of the consolidated company and the amount of debt at the holding company level is also lower than average at less than 10% of consolidated debt. Pinnacle's non-regulated operations, which include energy-related products and services, and a commercial and residential real estate development subsidiary that completed an accelerated asset sales program in 2005, are not expected to meaningfully contribute to, or detract from, consolidated cash flows.

Rating Outlook

The outlook for APS is negative, reflecting the potential for downward pressure on the ratings if the Palo Verde nuclear facility does not return to normal operating performance by mid-summer as expected, or if outcomes in still pending rate proceedings are not supportive of relatively timely recovery of increased costs.

What Could Change the Rating - Up

In light of the negative outlook, APS' rating is not likely to be revised upward in the near-term. Key financial ratios could strengthen beyond 2006 if regulatory treatment is supportive, but the initial impact would likely be to stabilize the rating outlook rather than supporting an upgrade. Longer term, the rating could be revised upward if there were to be a sustainable improvement in key credit metrics, such as a ratio of CFO pre-WK to adjusted debt in the high teens to low twenty percent range.

What Could Change the Rating - Down

A downgrade could result if Palo Verde does not return to normal operating performance by mid-summer as is planned, or if outcomes in still pending regulatory proceedings are not supportive of relatively timely recovery of increased costs.

Rating Factors

Arizona Public Service Company

62000

Select Key Ratios for Global Regulated Electric

Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	Medium	Low	Medium	Low	Medium	Low	Medium	Low
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

© Copyright 2006, Moody's Investors Service, Inc. and/or its licensors including Moody's Assurance Company, Inc. (together, "MOODY'S"). All rights reserved.

ALL INFORMATION CONTAINED HEREIN IS PROTECTED BY COPYRIGHT LAW AND NONE OF SUCH INFORMATION MAY BE COPIED OR OTHERWISE REPRODUCED, REPACKAGED, FURTHER TRANSMITTED, TRANSFERRED, DISSEMINATED, REDISTRIBUTED OR RESOLD, OR STORED FOR SUBSEQUENT USE FOR ANY SUCH PURPOSE, IN WHOLE OR IN PART, IN ANY FORM OR MANNER OR BY ANY MEANS WHATSOEVER, BY ANY PERSON WITHOUT MOODY'S PRIOR WRITTEN CONSENT. All information contained herein is obtained by MOODY'S from sources believed by it to be accurate and reliable. Because of the possibility of human or mechanical error as well as other factors, however, such information is provided "as is" without warranty of any kind and MOODY'S, in particular, makes no representation or warranty, express or implied, as to the accuracy, timeliness, completeness, merchantability or fitness for any particular purpose of any such information. Under no circumstances shall MOODY'S have any liability to any person or entity for (a) any loss or damage in whole or in part caused by, resulting from, or relating to, any error (negligent or otherwise) or other circumstance or contingency within or outside the control of MOODY'S or any of its directors, officers, employees or agents in connection with the procurement, collection, compilation, analysis, interpretation, communication, publication or delivery of any such information, or (b) any direct, indirect, special, consequential, compensatory or incidental damages whatsoever (including without limitation, lost profits), even if MOODY'S is advised in advance of the possibility of such damages, resulting from the use of or inability to use, any such information. The credit ratings and financial reporting analysis observations, if any, constituting part of the information contained herein are, and must be construed solely as, statements of opinion and not statements of fact or recommendations to purchase, sell or hold any securities. NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER. Each rating or other opinion must be weighed solely as one factor in any investment decision made by or on behalf of any user of the information contained herein, and each such user must accordingly make its own study and evaluation of each security and of each issuer and guarantor of, and each provider of credit support for, each security that it may consider purchasing, holding or selling.

MOODY'S hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MOODY'S have, prior to assignment of any rating, agreed to pay to MOODY'S for appraisal and rating services rendered by it fees ranging from $1,500 to $2,400,000. Moody's Corporation (MCO) and its wholly-owned credit rating agency subsidiary, Moody's Investors Service (MIS), also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually on Moody's website at www.moodys.com under the heading "Shareholder Relations - Corporate Governance - Director and Shareholder Affiliation Policy."

This credit rating opinion has been prepared without taking into account any of your objectives, financial situation or needs. You should, before acting on the opinion, consider the appropriateness of the opinion having regard to your own objectives, financial situation and needs.

C6 THURSDAY, SEPTEMBER 7, 2006 THE WALL STREET JOURNAL.

Investment-Grade Market Booms

With Deal Supply Strong, Swap Spreads Tighten; Foreign Issuers Are Key

By EMILY BARRETT
And MARINE COLE

More deals keep flooding the investment-grade corporate market, deepening the mark left on other fixed-income markets, especially that of interest-rate swaps.

"We're off to a blistering pace" for September, said Scott MacDonald, co-head of research at Aladdin Capital, a Stamford, Conn., hedge fund that manages about $10 billion in assets.

CREDIT MARKETS

More than $4 billion of new investment-grade bonds was sold Tuesday and about $10 billion more priced yesterday. That has already put total supply within the $10 billion to $15 billion range that some market participants had anticipated for the entire week.

Financial-services companies and banks continue to make up the bulk of new supply. **Capital One Financial** Corp. sold a $2.2 billion two-part offering late Tuesday night. Financial issuers in the market yesterday included **BB&T** Corp., **Citigroup** Inc., **Bank of America** Corp. and **National Australia Bank** Ltd.

Such heavy supply typically narrows risk premiums of interest-rate swaps over Treasurys, as the issuers, especially financial institutions, tend to swap the fixed-rate debt for a floating-rate liability.

A swap is a contract that enables two parties to exchange fixed- and floating-rate cash flow exposure for a specified period of time.

Yield Comparisons

Based on Merrill Lynch Bond Indexes, priced as of midafternoon Eastern time.

	9/6	9/5	52-WEEK HIGH	52-WEEK LOW
Corp. Govt. Master	5.27%	5.25%	5.72%	4.37%
Treasury				
1-10 yr	4.81	4.79	5.27	3.86
10+ yr	4.99	4.97	5.40	4.34
Agencies				
1-10 yr	5.17	5.16	5.62	4.14
10+ yr	5.34	5.32	5.80	4.71
Corporate				
1-10 yr High Quality	5.39	5.37	5.87	4.45
Medium Quality	5.73	5.72	6.19	4.81
10+ yr High Quality	5.98	5.96	6.40	5.32
Medium Quality	6.39	6.37	6.80	5.60
Yankee bonds (1)	5.67	5.65	6.14	4.74
Current-coupon mortgages (2)				
GNMA 6.00% (3)	5.84	5.83	6.38	5.01
FNMA 6.00%	5.97	5.96	6.43	5.24
FHLMC 6.00%	6.00	6.00	6.47	5.28
High-yield corporates	8.26	8.27	8.65	7.65
Tax-Exempt Bonds				
7-12 yr G.O. (AA)	3.90	3.89	4.28	3.59
12-22 yr G.O. (AA)	4.22	4.20	4.59	3.95
22+ yr revenue (A)	4.50	4.47	4.85	4.29

Note: High quality rated AAA-AA; medium quality A-BBB/Baa; high yield, BB/Ba-C.
(1) Dollar-denominated, SEC-registered bonds of foreign issuers sold in the U.S. (2) Reflects the 52-week high and low of mortgage-backed securities indexes rather than the individual securities shown. (3) Government guaranteed.

"Pipeline issuance is keeping pressure on spreads to come in," says Mike Pond, Treasury and inflation-linked strategist at Barclays Capital.

After Tuesday's session, swap spreads tightened as much as 0.02 percentage point in the 10-year sector—the most active one.

Inter-American Development Bank sold $1 billion of 10-year bonds at 0.35 percentage point over Treasurys yesterday morning. BB&T's offering also contained 10-year notes.

"It's a sweet spot," Mr. MacDonald said. "It fits everybody's portfolio."

Even nonfinancial issuers such as **Walt Disney** Co. and **CRH American** Inc. were in the market to sell 10-year notes in split deals yesterday.

While Mr. MacDonald anticipates new issuance for September to be around $40 billion, other market participants expect as much as $80 billion.

RBS Greenwich Capital analyst Fidelio Tata noted that September could "could run as high as two times the monthly average," which was $35 billion a month in 2005 and $45 billion a month in 2004.

But, "only fixed-rate issuance has the potential to be swapped back to floating, causing swap spread tightening pressure," said Mr. Tata in a research note. "Issuance by financial institutions as well as foreign issuers is particularly important because those investor classes tend to swap back to [London interbank offered rate] in roughly 80% of the cases," he said.

That activity is expected to drive swaps spreads tighter throughout the month.

Decline for Treasurys

Treasury-bond prices ended lower after mixed news from the Fed's "beige book" and stronger-than-expected data.

The market largely shrugged off news from the beige book, a summary of economic activity prepared for use at the central bank's next Federal Open Market Committee meeting Sept. 20. In earlier trade, bond prices fell after data showed a rise in second-quarter unit labor costs and a higher-than-expected reading in August for the Institute for Supply Management's nonmanufacturing index.

Unit labor costs and the failure of key data, such as the ISM's nonmanufacturing index, to worsen were the market movers yesterday, said Richard Gilhooly, senior fixed-income strategist at BNP Paribas in New York, keeping prices in the red.

At 4 p.m., the benchmark 10-year note was down 4/32 point, or $1.25 per $1,000 face value, at 100 19/32. Its yield rose to 4.801% from 4.787% Tuesday. The 30-year bond was down 8/32 point at 93 2/32 to yield 4.951%. Yields move inversely to prices.

Evidence of rising labor costs could bolster the argument of central-bank officials who may want higher rates to stem price pressures.

Some investors took heart from signals of weakness in residential real estate and slow advances in consumer spending.

Michael Cheah, portfolio manager at AIG Sun America Asset Management in Jersey City, N.J., said, "There's nothing here that says the Fed will tighten rates again," for this cycle.

—Deborah L. Blumberg contributed to this article.

PINNACLE WEST
CAPITAL CORPORATION

Donald E. Brandt
Executive Vice President and
Chief Financial Officer

July 26, 2006

Chairman Jeff Hatch-Miller
Commissioner William A. Mundell
Commissioner Mike Gleason
Commissioner Kristin E. Mayes
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, AZ 85007

Re: Recent Media Coverage of Pinnacle West and Arizona Public Service Company Earnings; Docket No. E-01345A-05-0816

Dear Commissioners:

Recently, there have been a number of media reports that inaccurately characterize the company's second quarter earnings. One of those stories in the Saturday edition of The Arizona Republic was highly misleading with respect to both Pinnacle West's and APS' financial results, which their Monday edition "correction" did little to remedy. With respect to Pinnacle West, the media seems determined (I assume in the interest of a colorful headline) to ignore, among other facts, the most significant cause of the total increase in our reported results: a $59 million (after tax) write-off a year ago related to the loss associated with the sale of the unregulated Silverhawk Power Station in Nevada.

As to APS itself, the first quarter financial information provided to Staff reflects a twelve-month ended return on equity ("ROE") of a meager 5.0 percent. Second quarter information that we will soon file will reflect a ROE of only 5.7 percent. Much of this modest improvement is attributable to record hot weather and one-time tax credits – events that will not be repeated soon if at all. Our allowed ROE, as you know, is 10.25 percent. This ROE deficit translates into a $134 million earnings shortfall for just the past 12 months. Furthermore, our FFO/Debt ratio, a critical measure of creditworthiness, while improved somewhat as a result of recent Commission actions, is at 16.5 percent – significantly below the credit rating agencies' standard for an investment grade rating. Even taking into account the record June temperatures, the continuing record-setting weather into July, and one-time tax credits, we forecast that the FFO/Debt ratio, while continuing to improve somewhat, will still remain below the investment grade threshold through the end of 2006 and will fall further thereafter in 2007 absent rate relief.

Pinnacle West Capital Corporation Station 9042 P.O. Box 53999 Phoenix, AZ 85072-3999 602-250-5602 Fax 602-250-3902 E-Mail: donald.brandt@pinnaclewest.com

Regardless of whether one is a financial analyst or a journalist, the goal should be to communicate the story behind the numbers. We will continue to work with the media to clarify any misunderstandings that have occurred regardless of how or why they occurred.

Sincerely,

Donald E. Brandt/cmc

Donald E. Brandt

cc: Brian McNeil
Ernest Johnson
Christopher Kempley
Lyn Farmer

A subsidiary of Pinnacle West Capital Corporation

Jack Davis
President and Chief Executive Officer

Tel 602/250-3529
Fax 602/250-3002

Mail Station 9080
P.O Box 53999
Phoenix, AZ 85072-3999

RECEIVED
2006 AUG 17 A 9:55
AZ CORP COMMISSION
DOCUMENT CONTROL

August 17, 2006
Hand-Delivered

Jeff Hatch-Miller, Chairman
William A. Mundell, Commissioner
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner
Barry Wong, Commissioner
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, AZ 85007-2996

Dear Commissioners:

Re: APS Financial Issues Report; Docket No. E-01345A-05-0816

This letter and the accompanying Financial Issues Report attempt to respond to your questions regarding APS' current financial situation. Our customers read and hear media reports, and we should all be concerned if they are led to believe something that is not accurate. It does a disservice to both of us. This letter and the attached Financial Issues Report establish a foundation upon which to understand APS' current financial condition and clear up any potential misunderstandings.

The conclusions to be drawn from the attached Financial Issues Report are as follows:

- APS' earnings so far this year (not just for the second quarter) are **lower** than the same period in 2005 by $2.7 million. Adjusted for one-time events, earnings are **down** $9.7 million.

- APS' return on shareholders' invested capital (a key measure of financial health) has dropped to 5.7 percent – almost 50% below the Commission-approved return of 10.25 percent.

- APS' key financial ratios continue a slide towards a "junk bond" rating, which would cripple the Company and raise costs to customers by more than an additional $1 billion.

- APS appreciates recent measures taken by the Commission to help address its financial situation and needs continued regulatory support to maintain its financial integrity and its ability to finance critical electric infrastructure at a reasonable cost.

I would also like to make two other observations. First, while it is common to report on a public company's quarterly earnings and compare them with the same quarter in the prior year, such a comparison does not present an accurate or complete picture of APS' overall condition. The Financial Issues Report shows why any conclusions drawn from such a "snapshot" look can be very misleading and unhelpful. For example, in the first quarter of this year, APS had a loss of $5.5 million compared with first quarter 2005 earnings of $27.5 million. Thus, a comparison of first quarter performance for 2005-2006 would likely yield entirely different observations on our financial health. As described in our earnings conference call, our 2006 earnings guidance first disclosed in November 2005 ("within a reasonable range of $3.00 per share") has not changed.

Second, with respect to the suggested rate stabilization fund, we understand the spirit and intent of the proposal. However, as presented in more detail in the report, APS has no excess revenues to put in what would essentially be a "rainy day fund."

Thank you for the opportunity to submit this information.

Sincerely,

Jack Davis

JED:DN
Enclosures
cc/encl: Brian McNeil
Ernest Johnson
Heather Murphy
Docket
Parties of Record

ARIZONA PUBLIC SERVICE COMPANY
FINANCIAL ISSUES REPORT
Docket No. E-01345A-05-0816
AUGUST 17, 2006

This Financial Issues Report addresses the following topics:

- Information relative to the current financial condition of Arizona Public Service Company ("APS"),
- APS' position on the creation of a rate stabilization fund, and
- Details regarding recent APS officer stock option exercises.

FINANCIAL INFORMATION

Historical Context:

A number of historical factors account for APS' current financial condition. One should avoid the easy but misleading characterization of APS' overall financial health from a review derived from a particular point of time (*e.g.*, a three-month quarter) or from numbers excerpted out of context in press releases or media accounts. Also, one must parse out extraordinary items, nonrecurring events, and unusual expenses and benefits. All financial and investment analysts eliminate these factors, whether they have a positive or negative effect on earnings. They do so in order to understand better the level of earnings they can reasonably expect a company to achieve on a recurring annual basis. In sum, earnings for any particular quarter, while meaningful, do not present a comprehensive picture of a company's financial health or future prospects. In addition, a quarter-to-quarter earnings increase does not reveal whether the company is earning the reasonable return that regulation requires or is maintaining the financial ratios sufficient to raise the capital necessary to properly serve its customers.

To facilitate analysis by investors, analysts, and others, Pinnacle West Capital Corporation ("Pinnacle West") typically reports (as do many other companies) "on-going earnings" (*i.e.*, reported earnings excluding extraordinary, nonrecurring and unusual items) as a supplement to the traditional earnings determined in accordance with generally accepted accounting principles ("GAAP earnings"). Further, for a utility such as APS whose quarterly earnings exhibit exceptional volatility due to seasonal weather patterns, earnings for any particular quarter rarely present a complete picture. As a result, financial analysts prefer to examine a utility's earnings for the last twelve-month period (*i.e.*, a full-year perspective). To illustrate these points specifically with respect to APS, Attachment A demonstrates the seasonal peaks and valleys in APS' net income (*i.e.*, GAAP earnings) by quarter over the last three and one-half years. With this graph in mind, APS' recently released financial results can be better understood.

Recently Released Financial Results

Certain nonrecurring factors may have given the erroneous impression that APS has made an abrupt financial about-face. Unfortunately for APS, the shareholders of Pinnacle West,

and APS' customers, the truth differs markedly. To make this point clear, APS' year-to-date earnings (both on GAAP and on-going bases) are actually lower than for the comparable 2005 period – a point expanded on later. The table below displays these earnings in millions of dollars:

APS GAAP Earnings

	2006	2005	Increase (Decrease)
First quarter	$ (5.5)	$ 27.0	$ (32.5)
Second quarter	93.8	64.0	29.8
Year-to-date	88.3	91.0	(2.7)

APS On-Going Earnings

	2006	2005	Increase (Decrease)
First quarter	$ (5.5)	$ 27.0	$ (32.5)
Second quarter	86.8	64.0	22.8
Year-to-date	81.3	91.0	(9.7)

For the second quarter of 2006, Pinnacle West reported GAAP earnings of $112.2 million, reflecting an $85.5 million increase over GAAP earnings of $26.7 million reported for the second quarter of 2005. The primary cause of this apparent reversal stems from the $59 million write-off Pinnacle West (not APS) incurred in the second quarter of 2005 related to its loss on the sale of the unregulated Silverhawk Power Station in Nevada. To a much lesser degree, the positive impact of $10 million of income tax credits recorded in the second quarter of 2006 related to prior tax years 1985 through 1998 (APS' share amounts to $7 million) further exacerbated the apparent difference. Excluding these unusual items, Pinnacle West reported second quarter 2006 on-going earnings of $102 million, reflecting a $16 million increase over second quarter 2005 on-going earnings of $86 million. Of this $16 million "on-going" increase, $10 million was attributable to electricity sales driven by the record-setting June 2006 temperatures. Pinnacle West disclosed these details in its July 21, 2006, press release announcing 2006 second quarter earnings (See Attachment B).

In light of this information and the Pinnacle West July 21st press release, the questions that have arisen over the reported "320% rise in profits" result from a misunderstanding of the relevant financial information. On a superficial level, the mathematics behind 320% are correct. However, most knowledgeable business people and financial analysts would not characterize the absence of another write-off in 2006 as a "surge" in profits as described by the media. APS has concerns that similar misinterpretation may accompany the release of earnings for the third quarter of 2006. In the third quarter of 2005, Pinnacle West and APS recognized an $87 million write-off attributable to the regulatory disallowance related to the transfer of the Pinnacle West Energy generating plants to APS under the settlement approved by the Commission. Alone, the absence of a comparable write-off in the third quarter of 2006 would show a very significant increase in the companies' GAAP earnings over third quarter 2005 results. Consequently, a simplistic mathematical comparison of third quarter 2006 results with third quarter 2005 results will likely yield a large percentage change that also will not reflect the Company's true financial condition.

For the second quarter of 2006, APS reported GAAP earnings of $93.8 million, reflecting an increase of $29.8 million over GAAP earnings of $64 million reported for the second quarter of 2005. Excluding the $7 million of nonrecurring tax credits recorded in the second quarter of 2006, APS' second quarter 2006 on-going earnings totaled $86.8 million, reflecting an increase of $23 million, about half of which came from the aforementioned $10 million attributable to June 2006 weather.

When year-to-date results are reviewed, a different, but much more meaningful picture emerges. In the first quarter of 2006, APS reported a GAAP net loss of $5.5 million, reflecting an earnings decline of $32.5 million from the GAAP earnings of $27 million reported in the first quarter of 2005. On a year-to-date basis through June 30th, APS' 2006 GAAP earnings amounted to $88.3 million, $2.7 million lower than net income for the comparable 2005 period.

Effect of Recent Rate Changes

Recent regulatory actions have been supportive and have led to a very modest positive impact on APS' 2006 second quarter earnings. The annual rate increase of 4.21% that became effective on April 1, 2005, has added $1.1 million to earnings. The PSA adjustors approved by the Commission during the first and second quarters of 2006 provided much needed incremental cash flow, but did not (and were not expected to) contribute any earnings benefit because the additional revenues collected were offset by the amortization of accumulated fuel deferral balances. Thus, the poor APS financial condition the Company witnesses recently testified to in the interim proceeding has not changed significantly.

Earnings Outlook

Pinnacle West, as a publicly-traded company, must scrupulously adhere to all federal securities laws, and rules and regulations of the U.S. Securities and Exchange Commission ("SEC"), especially regarding the disclosure of earnings forecasts. On November 4, 2005, Pinnacle West filed a Form 8-K with the SEC which, among other matters, disclosed under the caption "**2006 Earnings Outlook**", "We expect earnings for 2006 to be within a reasonable range of $3.00 per share". During Pinnacle West's February 1, 2006, earnings conference call, Pinnacle West confirmed this 2006 earnings guidance saying, "Our earnings guidance for 2006 has not changed." During Pinnacle West's May 9, 2006, first quarter earnings conference call, Pinnacle West again confirmed this 2006 earnings guidance adding, "Our earnings outlook for 2006 has not changed. We still expect earnings to be in a reasonable range around $3.00 a share." Most recently, during Pinnacle West's July 21, 2006, second quarter earnings conference call, Pinnacle West again confirmed this guidance with, "We are not changing our earnings outlook for 2006. We still expect earnings to be in a reasonable range around $3.00 a share."

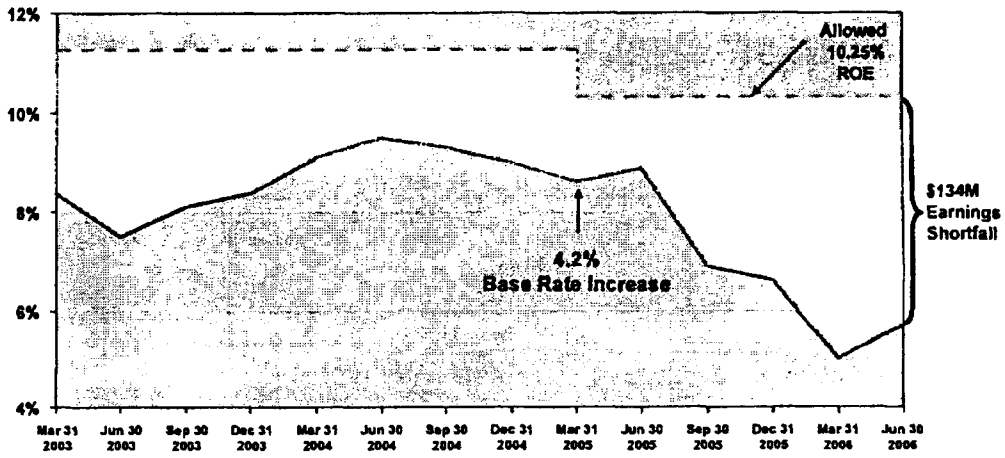
Commissioner Mayes' August 2, 2006, letter to Mr. Davis indicated that, during Pinnacle West's July 21, 2006 second quarter earnings conference call, Mr. Brandt did not answer a question posed by an analyst from SAC Capital (Mr. Ashar Khan) regarding 2006 earnings expectations. (Mr. Khan does not represent a "traditional" investment firm. SAC Capital is a $10 billion group of hedge funds.) Included as Attachment C is the transcript of the entire dialogue between Mr. Khan and Mr. Brandt during this call. Mr. Brandt did respond appropriately to the questions posed. Pinnacle West officers cannot legally engage in an ad-lib dialogue on the subject of earnings guidance, and most analysts understand and respect this

limitation. Pinnacle West has consistently affirmed 2006 earnings guidance as "a reasonable range around $3.00 per share."

Overall Financial Condition

The following chart presents APS' return on average equity ("ROE") for the twelve-month periods that ended on each quarter-end from the first quarter of 2003 through the second quarter of 2006. Over this period of time, APS' ROE has eroded from 8.4% for the twelve months ended March 31, 2003, to an ROE of 5.7% for the twelve months ended June 30, 2006, representing a total decline in the measure of 32%, or a 2.5% average decline per quarter. This performance weighs heavily in the assessments of securities analysts, and contributes to the substantial underperformance of Pinnacle West common stock relative to the equity securities of most other utilities over the last two years. The most recent ROE of 5.7% reflects a $134 million annual earnings deficit relative to APS' most recently allowed ROE of 10.25%. As APS prepares to build the facilities to serve Arizona's growing population and economy, the inability to earn an adequate ROE, combined with weak credit metrics described below, will burden the Company and customers with greater financing costs and more limited financing options.

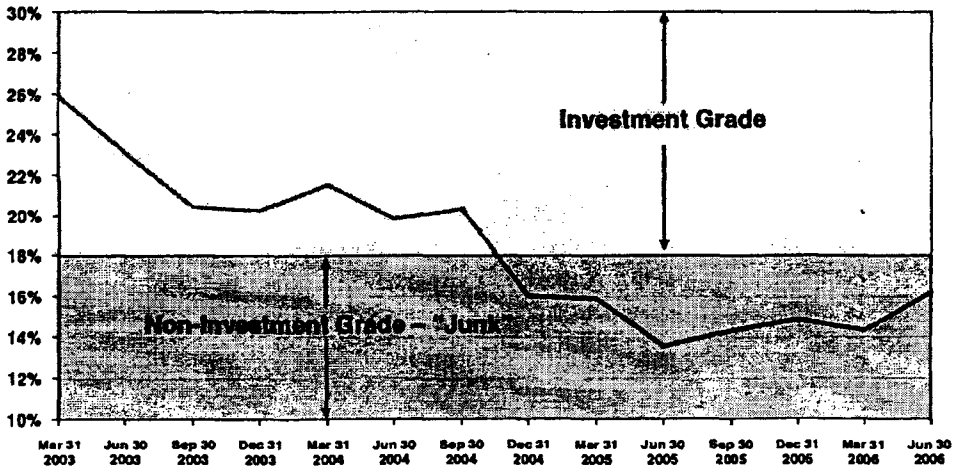
Arizona Public Service Company
Return on Equity
Twelve-Month Periods Ended March 31, 2003 to June 30, 2006



The deterioration of APS' financial position can also be seen in Attachment D, a compilation of financial reports filed by APS with the Commission at its direction since 2003 (these reports are in addition to Pinnacle West's publicly available SEC filings). These reports provide financial results and information on key financial metrics such as Funds From Operations to Debt ("FFO/Debt ratio"), net cash flow, return on equity, debt to capital, non-cash income, and interest coverage ratios in order to keep the Commission current on APS' financial condition.

As the Commission has heard from APS on prior occasions, its FFO/Debt ratio continues to languish significantly below the investment-grade credit rating threshold. Second quarter earnings have not altered this bleak reality. Although the ratio has climbed slightly, the improvement falls short of the level required by the credit rating agencies for an investment-grade rating. The chart below graphs the FFO/Debt ratio as measured at the end of each quarter over the three and one-half years ended June 30, 2006. As of June 30, 2006, the ratio reached 16.2%, and is expected to improve to between 17.0% and 17.5% by December 31, 2006, although it will fall further thereafter in 2007 absent rate relief. Even at this percentage, the rating agencies may downgrade APS' credit ratings to a noninvestment grade or "junk" level. In a July 31, 2006 publication, Standard & Poor's stated, "The consolidated credit profile of PWCC and its utility, APS, continue to be stressed." A downgrade of APS' credit ratings to "junk" would likely cost APS and its customers more than $1 billion of additional interest cost over the next decade in addition to the other negative consequences described in the interim rate proceeding.

Arizona Public Service Company
Funds from Operations (FFO) to Debt
Twelve-Month Periods Ended March 31, 2003 to June 30, 2006



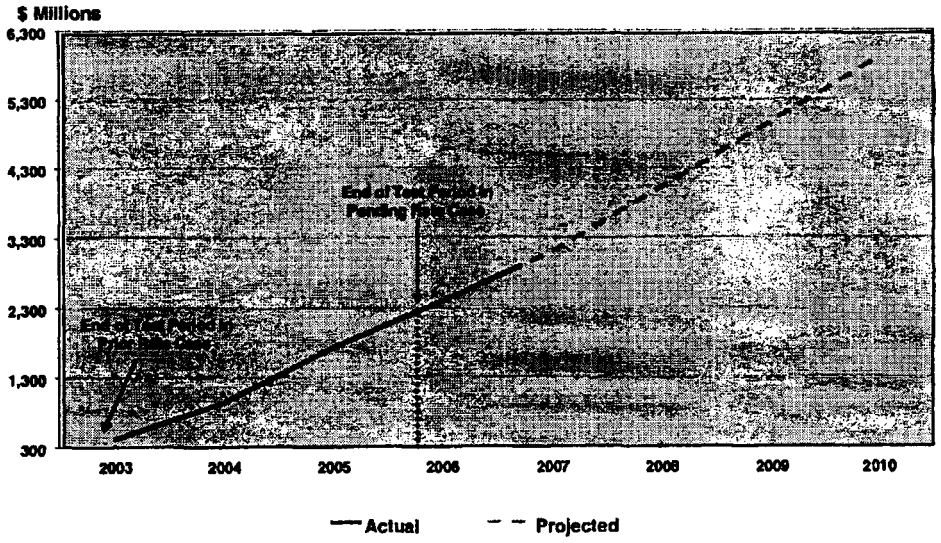
Note: Standard & Poor's changed APS business position to 6 from 5 on December 21, 2005

Attachment E displays net cash flow after capital expenditures as of the end of each quarter during the three and one-half years ended June 30, 2006. As can be seen, this measure of liquidity turned negative in the fourth quarter of 2004 and rapidly declined through a number of quarters thereafter. By the end of the second quarter of 2006, it reflected a $272 million cash flow deficiency. APS expects this measure for the year 2006 to amount to a deficit of between $205 million and $235 million, reflecting 2006 net cash flow of between $415 million and $445 million being overwhelmed by 2006 capital expenditures of $650 million.

A discussion of APS' current financial condition would not be complete without an examination of its massive capital expenditure program necessary to meet and anticipate

customer needs. Attachments F-I demonstrate the magnitude of these expenditures (Attachment F), the increasing inability to fund necessary projects from internal cash flow (Attachments G and H), and the Company's consequent growing external financing needs (Attachment I). Perhaps the most dramatic indication of the Company's financial predicament is shown in the following graph, which reveals how regulatory lag has led and will continue to lead (absent further Commission action) to almost $3 billion in investments to serve customers that are not reflected in current rates and which cause the earnings attrition and falling financial measures shown in the preceding attachments.

Arizona Public Service Company
Cumulative Capital Expenditures
2003 - 2010



Clearly, Pinnacle West and APS have not seen a return to the days of more stable investment-grade debt ratings. A few extraordinary, nonrecurring items do not a financial recovery make. In any event, in relative terms, they do not constitute a reversal of financial fortunes that eliminate the need for supportive Commission action. In order to provide customers with the high quality electric service they deserve and to prepare for the continuing economic and population growth, APS should earn a return that keeps the Company solidly in investment-grade territory. Solutions which fall short of that do a disservice to customers, shareholders, and the State.

RATE STABILIZATION FUND

In an August 1, 2006, letter to the Commission, APS set forth the reasons why it had determined that the establishment of a rate stabilization fund would not be practical. APS supports the goal of minimizing future price increases, but after further consideration, the Company continues to maintain its position on such a fund.

Currently, APS' revenue deficiency is tens of millions of dollars annually. If APS were ever in a situation where it was receiving excess revenues, a rate stabilization fund could be an option to consider. However, APS' current financial situation does not provide the opportunity to explore that alternative.

Second, APS and the Commission already have the means to utilize some of the rate mechanisms specifically cited by Commissioner Mayes as adopted by Salt River Project ("SRP") – except that APS credits any savings to customers on a more or less current basis (rather than deferring them to a later time), thus producing greater benefits to customers than would a rate stabilization fund. These mechanisms include reflecting APS' savings in O&M expenses in customer rates through commission-approved rate procedures, and crediting to customers the gross margin (revenues net of energy costs) from off-system sales in accordance with the PSA approved by the Commission. APS believes these approaches are preferable to a rate stabilization fund.

Third, the Company disagrees with any notion that shareholder funds should be used to establish a rate stabilization fund. Sound regulation must allow a utility to recover its costs, including the opportunity to earn a fair rate of return on its invested capital. If APS' shareholders were forced to fund additional "stabilization" costs that should otherwise be reflected in rates, such a requirement would undermine the Company's already tenuous financial health, conflict with fundamental regulatory principles, send a highly negative message to the investment community (including investors and lenders), and would clearly be illegal.

Finally, with respect to Commissioner Mayes' reference to the sources of SRP's rate stabilization fund, APS does not know the details of this device. Suffice it to say, however, that comparisons between investor-owned utilities such as APS and governmental or quasi-governmental entities such as SRP can be misplaced. Such public entities have no obligation to earn a return for shareholders who have put their capital at risk. Moreover, SRP's published financial information indicates it fully recovers its costs (unlike APS) and can therefore fund such a program without damage to its strong financial position. APS is not aware of any investor-owned utility in the Company's weak financial condition that has either established or been forced to implement a rate stabilization fund.

TAX MATTERS

Regarding recent property tax reductions enacted by the Arizona Legislature, APS' property tax savings will not be realized until credits appear in APS' tax bills payable on November 1, 2006, and May 1, 2007, dates well beyond the end of the September 30, 2005 test period required by ACC Staff in the current rate filing. Also, APS' overall costs have increased since the end of the test period, and would more than offset such tax reductions.

The $7 million of income tax credits recorded in the second quarter of 2006 and referenced earlier in this report were also received by APS well after the end of the September 30, 2005, test period and relate to tax years substantially before the current test period. In addition, $3 million of these tax credits take the form of investment tax credits related to APS tax years 1986 through 1990. Flowing such investment tax credits through to customers would violate Decision No. 58644 (1994) which directed below-the-line amortization of all investment tax credits, and would constitute a normalization violation under the Internal Revenue Code.

RECENT STOCK OPTION EXERCISES

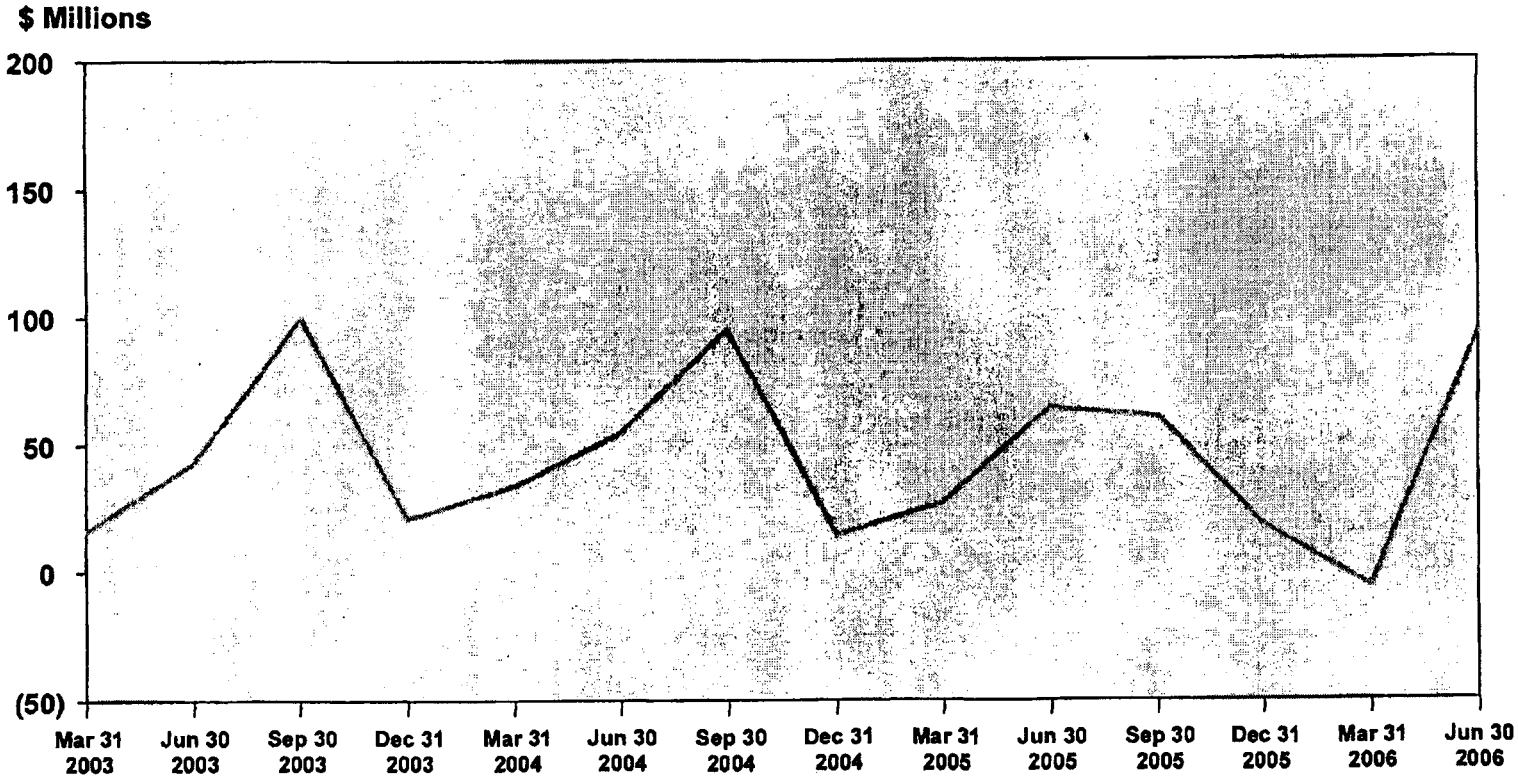
On August 11, 2006, the Arizona Republic published a story titled, "Executives at APS Take Stock Awards." The complete facts are:

- None of the named officers received any cash proceeds as a result of these option exercises.
- Each officer essentially converted one "paper" financial instrument (*i.e.*, a stock option) into another "paper" financial instrument (*i.e.*, shares of Pinnacle West stock).
- With respect to the option exercises referenced in the story, the executives received the options over the 1996 through 2003 time period. The Company's stock option program was designed to encourage officers to increase their ownership of Pinnacle West stock, and to retain qualified executives. The Company is currently exploring other mechanisms for executive retention.
- Pinnacle West and APS did not incur any expense or cash outflow impact as a result of these recent option exercises.
- As executives of a publicly-traded company, these officers may only exercise options during the period beginning two days after announcing quarterly earnings and ending on the 15th day of the third month of each quarter. All other times constitute a "blackout period". Furthermore, officers are prohibited from exercising options at any time they have knowledge of material, nonpublic information. In this most recent instance, the period for exercising options extended from July 25th through September 14th, but was subject to immediate curtailment if officers came into possession of material non-public information. In practice, Company officers have had very narrow time periods in which they have been permitted to exercise options. The recent exercises of options occurred during just such a time period.

CONCLUSION

As APS reviews its financial circumstances and restrictions on funding flexibility, the pressing need for a rate case to review these vital factors and produce a supportive outcome becomes ever more evident. In the face of rising expenses and energy demand, APS should have the means by which it can recover its costs and earn a fair rate of return on invested capital. The discrepancy between the allowed ROE and actual earned ROE denies shareholders the full value of their investment and, as a result, ultimately punishes Pinnacle West and APS in the capital markets. Further, the deficiency in credit metrics from investment-grade standards increases the Company's cost of capital and perpetuates the very significant risk that APS' credit ratings could be downgraded to "junk." The shortfall needlessly increases the cost of providing high-quality electric service to customers.

Arizona Public Service Company
Net Income (GAAP Earnings)
Three-Month Periods Ended March 31, 2003 to June 30, 2006



NEWS PINNACLE WEST CAPITAL CORPORATION

FOR IMMEDIATE RELEASE **July 21, 2006**
Page 1 of 2

Media Contact: Alan Bunnell, (602) 250-3376
Analyst Contacts: Rebecca Hickman, (602) 250-5668
Lisa Malagon, (602) 250-5671
Web site: www.pinnaclewest.com

PINNACLE WEST REPORTS 2006 SECOND QUARTER RESULTS

Strong APS Customer Growth Continues

PHOENIX - Pinnacle West Capital Corporation (NYSE: PNW) today reported consolidated net income for the quarter ended June 30, 2006, of $112.2 million, or $1.13 per diluted share of common stock. This result compares with net income of $26.7 million, or $0.28 per diluted share, for the same quarter a year ago.

On-going consolidated earnings in the 2006 second quarter were $102 million, or $1.03 per share, compared with $86 million, or $0.89 per share in the comparable 2005 quarter. The 2006 results exclude income tax credits related to prior years of $10 million, or $0.10 per share. On-going earnings for the second quarter of 2005 exclude an after-tax loss of $59 million, or $0.61 per share, related to the sale of the Silverhawk Power Station.

"Growth in our service territory remains robust," said Pinnacle West Chairman Bill Post, citing Arizona's population growth, which is three times the national average. "Successfully serving this growth will require continuing cooperation from state regulators as our company invests in new, long-term resources to meet the ever-increasing demand for electricity."

Results for the quarter were positively impacted by higher retail sales at Arizona Public Service (APS) due to customer growth of 4.6 percent; fuel and purchased power cost deferrals; and warmer weather, punctuated by the hottest June on record. The average temperature during June was almost 5 degrees above normal. The warmer weather added $0.10 per share compared with last year's second quarter.

These positive items were partially offset by higher fuel and purchased power costs; and an increase in operating costs primarily related to higher generation maintenance and customer service costs.

APS reported net income of $93.8 million for the second quarter of 2006, compared with net income of $64.0 million for the same period a year ago. In addition, SunCor Development Co., Pinnacle West's real estate subsidiary, reported net income of $9.6 million, compared with $11.3 million in the 2005 second quarter.

For more information on Pinnacle West's operating statistics and earnings, please visit www.pinnaclewest.com/financials.

Conference Call

Pinnacle West invites interested parties to listen to the live web cast of management's conference call to discuss the Company's 2006 second quarter earnings and recent developments at 1:00 p.m. (ET), today, Friday, July 21, 2006. The web cast can be accessed at www.pinnaclewest.com/presentations and will be available for replay on the web site for 30 days. To access the live conference call by telephone, dial (877) 356-3961 and enter Conference ID Number 2026344. A replay of the call also will be available until 11:55 p.m. (ET), Friday, July 28, 2006, by calling (800) 642-1687 in the U.S. and Canada or (706) 645-9291 internationally and entering the same ID number as above.

Pinnacle West is a Phoenix-based company with consolidated assets of about $11 billion. Through its subsidiaries, the Company generates, sells and delivers electricity and sells energy-related products and services to retail and wholesale customers in the western United States. It also develops residential, commercial, and industrial real estate projects.

-30-

PINNACLE WEST CAPITAL CORPORATION
NON-GAAP FINANCIAL MEASURE RECONCILIATION – NET INCOME (GAAP MEASURE) TO ON-GOING EARNINGS (NON-GAAP FINANCIAL MEASURE)

	Three Months Ended June 30, 2006		Three Months Ended June 30, 2005	
	$ in Millions	Diluted EPS	$ in Millions	Diluted EPS
Net Income	$ 112	$ 1.13	$ 27	$ 0.28
Adjustments:				
Income tax credits related to prior periods	(10)	(0.10)	--	--
Loss from discontinued operations – Silverhawk Power Station write-down	--	--	56	0.57
Loss from discontinued operations – Silverhawk Power Station operations	--	--	3	0.04
On-going Earnings	$ 102	$ 1.03	$ 86	$ 0.89

Excerpt from
Pinnacle West Capital Corporation
2nd Quarter 2006 Earnings Conference Call
July 21, 2006

Operator:	Your next question comes from Ashar Khan of SAC Capital.
Ashar Khan:	Good afternoon, how are you guys doing? Don, could you tell me, based on the results first half, are you running above expectations, on expectations, in reference to your earnings target of around $3, if I'm right? That is still the restated target, right, for the year?
Don Brandt:	I don't think we restated it. As Bill mentioned earlier, we're staying with our guidance of a reasonable range of around $3. So far this year, we're on target within a reasonable range of where we expected to be at this point in the year.
Ashar Khan:	So you're saying you're on target, you're not ahead or anything?
Don Brandt:	We're on track.
Ashar Khan:	Okay. But can I just ask you, LTM I'm getting around 3.20ish of earnings. What are the negatives in the last half that we should look at to get us back to around $3?
Don Brandt:	I'm not sure what kind of a base you're coming off of. Maybe if you--Ashar, give Becky a shout afterwards, she'd be happy to help you walk through some of it.
Ashar Khan:	Okay. But is there anything visibility negative in terms of any factors in the next half?
Don Brandt:	No, I don't think there's any negatives.
Ashar Khan:	Okay. Thank you.

Attachment D

APS

A subsidiary of Pinnacle West Capital Corporation

Brian Brumfield
Supervisor
Regulation, Pricing & Administration

Tel. 602-250-2708
Fax 602-250-3003
e-mail Brian.Brumfield@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

June 2, 2006

RECEIVED
2006 JUN -2 P 4: 45
AZ CORP COMMISSION
DOCUMENT CONTROL

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

RE: DOCKET NO. E-01345A-06-0009
DECISION NO. 68685

Dear Madam or Sir:

Attached is the monthly report on Arizona Public Service Company and Pinnacle West Capital Corporations cash position and financial ratios, as required by Decision No. 68685.

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

Sincerely,

Brian Brumfield
Supervisor
Regulation, Pricing and Administration

BB/bec

Cc: Brian Bozzo
Ernest Johnson

RECEIVED
JUN 0 2 2006
AZ CORP COMM
Director Utilities

Monthly Cash Position and Financial Ratio Report (1)

	March 31, 2006
Ending cash position (in millions):	
APS	$ 77
PNW	$ 315
APS Financial ratios (12 months ending):	
Funds from operations to debt	14.3%
Debt to capital	50.5%
Funds from operations interest coverage	3.2x
Projected APS funds from operations (in millions):	
12 months ending 12/31/06	$ 585

(1) Required by Decision No. 68685 until resolution of general rate case

APS

A subsidiary of Pinnacle West Capital Corporation

Brian Brumfield
Supervisor
Regulation, Pricing & Administration

Tel. 602-250-2708
Fax 602-250-3003
e-mail Brian.Brumfield@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

June 28, 2006

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RECEIVED
JUN 28 2006
AZ CORP COMM
Director Utilities

RE: DOCKET NO. E-01345A-06-0009
DECISION NO. 68685

Attached is the monthly report for Arizona Public Service Company and Pinnacle West Capital Corporation's cash position and financial ratios, as required by Decision No. 68685.

Portions of this filing are confidential and therefore will not be docketed.

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

Sincerely,

Brian Brumfield
Supervisor
Regulation, Pricing and Administration

BB/vld

Attachment

CC: Brian Bozzo
Docket Control

RECEIVED
2006 JUN 28 P 4: 57
AZ CORP COMMISSION
DOCUMENT CONTROL

Monthly Cash Position and Financial Ratio Report (1)

	March 31, 2006	April 30, 2006
Ending cash position (in millions):		
APS	$ 77	$ -
PNW	$ 315	$ 90
APS Financial ratios (12 months ending):		
Funds from operations to debt	14.3%	14.2%
Debt to capital	50.5%	50.5%
Funds from operations interest coverage	3.2x	3.2x
Projected APS funds from operations (in millions):		
12 months ending 12/31/06	$ 585	$ 585

(1) Required by decision no. 68685 until resolution of general rate case

APS

A subsidiary of Pinnacle West Capital Corporation

Brian Brumfield
Supervisor
Regulation, Pricing & Administration

Tel. 602-250-2708
Fax 602-250-3003
e-mail Brian.Brumfield@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

RECEIVED
JUL 27 2006
LEGAL DIV.
ARIZ CORPORATION COMMISSION

RECEIVED
JUL 27 2006
AZ CORP COMM
Director Utilities

July 27, 2006

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: DOCKET NO. E-01345A-06-0009
DECISION NO. 68685

Attached is the monthly report for Arizona Public Service Company and Pinnacle West Capital Corporation's cash position and financial ratios, as required by Decision No. 68685.

Portions of this filing are confidential and therefore will not be docketed.

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

Sincerely,

Brian Brumfield
Supervisor
Regulation, Pricing and Administration

BB/vid

Attachment

CC: Brian Bozzo
Docket Control

RECEIVED
2006 JUL 27 P 4: 51
AZ CORP COMMISSION
DOCUMENT CONTROL

Monthly Cash Position and Financial Ratio Report (1)

	May 31, 2006
Ending cash position (in millions):	
APS	$ -
PNW	$ 47
APS Financial ratios (12 months ending):	
Funds from operations to debt	15.1%
Debt to capital	51.7%
Funds from operations interest coverage	3.4x
Projected APS funds from operations (in millions):	
12 months ending 12/31/06	$ 585

(1) Required by decision no. 68685 until resolution of general rate case

Justin H. Thompson
Manager
Regulation, Policy & Analysis

Tel 602/250-2060
Fax 602/250-3003
E -Mail: Justin.Thompson@aps.com
http://www.aps.com

Mail Station 9708
P.O. Box 53999
Phoenix, AZ 85072-3999

RECEIVED

MAY 25 2006

AZ CORP COMM
Director Utilities

May 25, 2006

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
FIRST QUARTER ENDING MARCH 31, 2006

Dear Mr. Johnson:

Attached are the First Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending March 31, 2006.

If you have any questions regarding this filing, please contact me at (602) 250-2060.

Sincerely,

Justin Thompson DE

Justin H. Thompson
Manager
Regulation, Policy & Analysis

JHT/jd

Attachment

CC: Brian Bozzo
Compliance and Enforcement

ARIZONA PUBLIC SERVICE COMPANY

2006 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2005 Yr End	Q1	Q2	Q3	Q4	2006 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	49.9	76.6	$0.0	0.0	0.0	0.0
FINANCING: (a)	YTD					YTD
Long-Term Debt	411.8	0.0	0.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	411.8	0.0	0.0	0.0	0.0	0.0
Change in S-T Debt	0.0	0.0	0.0	0.0	0.0	0.0
Total	$411.8	$0.0	$0.0	$0.0	$0.0	$0.0
Repayments and Reacquistions (b)	($568.2)	($0.8)	$0.0	$0.0	$0.0	($0.8)
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	46.2%	46.1%	0.0%	0.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	46.2%	46.1%	0.0%	0.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	53.8%	53.9%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Adjusted Debt Ratio (c)	50.6%	50.5%	0.0%	0.0%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	41.9%	61.0%	0.0%	0.0%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	36.9%	33.0%	0.0%	0.0%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.50	2.21	0.00	2.46	0.00	0.00
Before Tax excl. Non-Cash Inc. (d)	2.40	2.10	0.00	2.36	0.00	0.00
After Tax Incl. Preferred Div.	1.95	1.77	0.00	1.92	0.00	0.00
Return on Average Equity	6.6%	5.0%	0.0%	0.0%	0.0%	0.0%
Adjusted Return on Average Equity (e)	6.6%	5.0%	0.0%	0.0%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.0%	5.0%	0.0%	0.0%	0.0%	0.0%
Return on Avg. Total Capital	6.2%	5.4%	0.0%	0.0%	0.0%	0.0%

NOTES:

(a) Financing is shown net of issuance cost for period referenced.

(b) Includes premiums on reacquired debt and preferred stock.

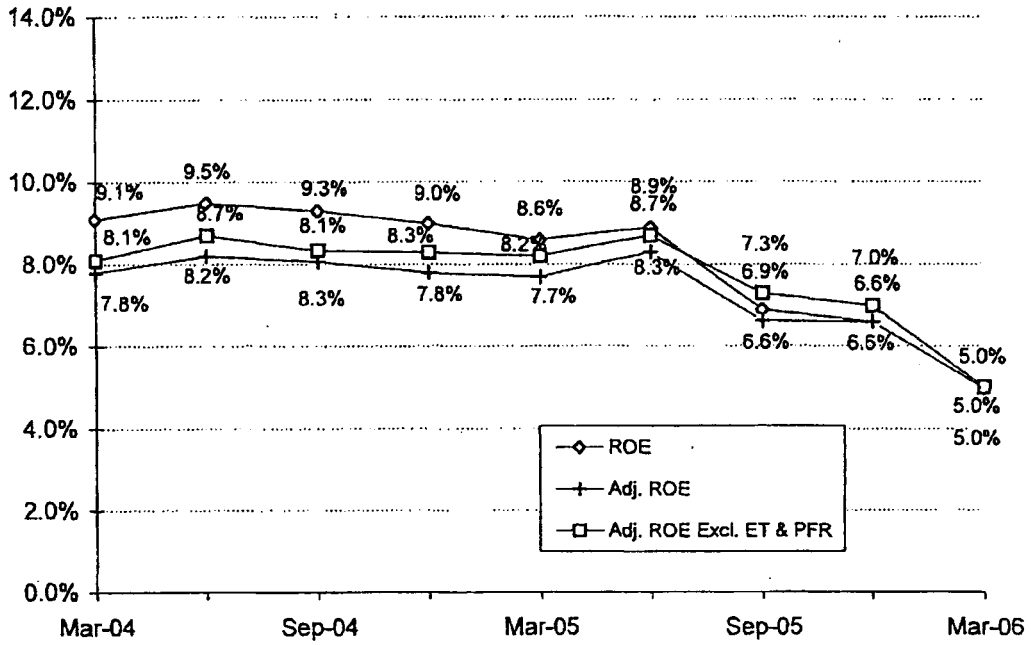
(c) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback and imputed debt on purchased power agreements.
Beginning December 2004 APS included purchased power agreements to the adjusted debt ratio.

(d) Non-cash income is defined as Capitalized Interest, AFUDC Equity and Deferred Fuel Costs beginning April 2005, using cumulative twelve month ended values.

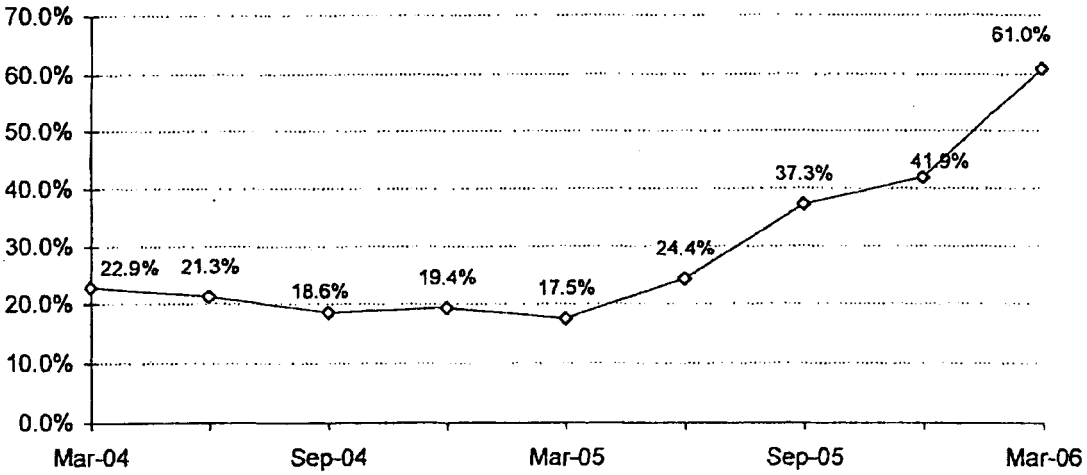
(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results and ending 11/05.

(f) Excludes Competitive Energy Trading and Purchases For Resale.

**Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale***



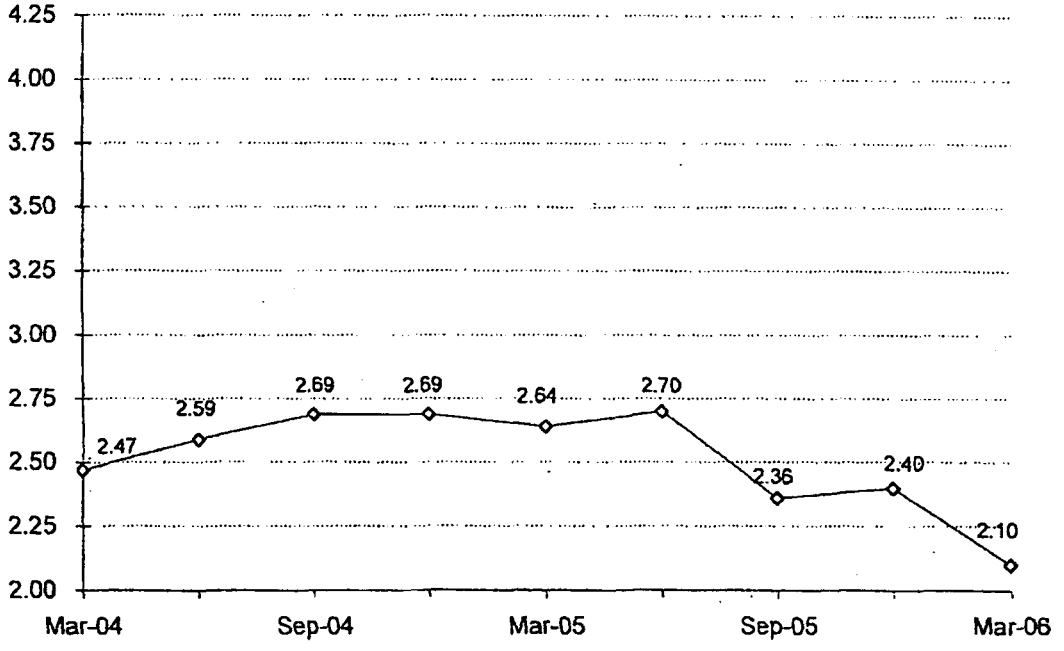
**Non-Cash Income
as a % of Earnings ***



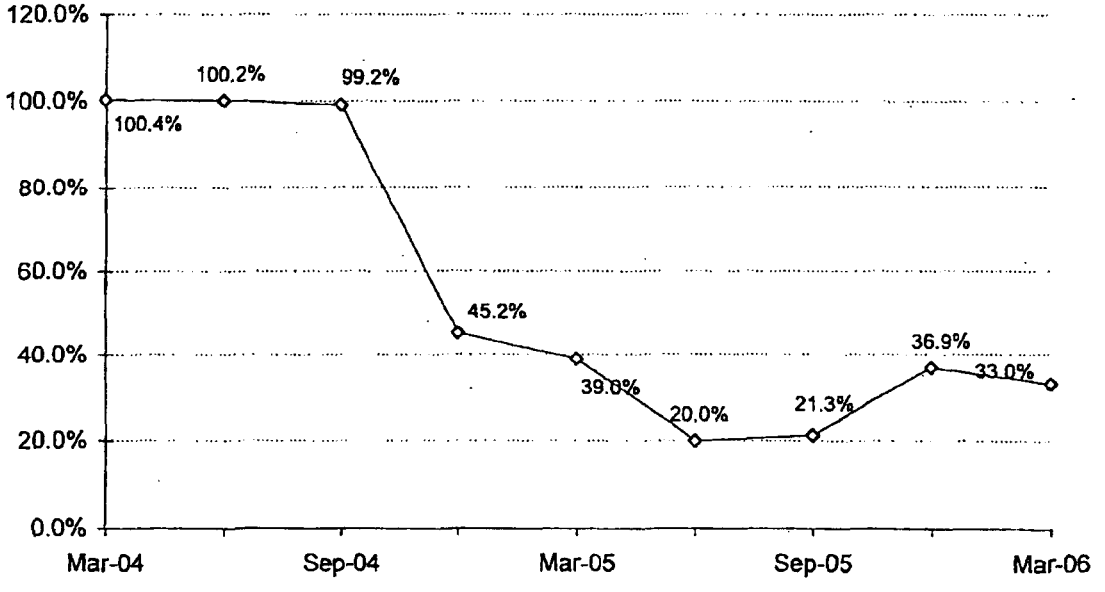
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



* See notes on Financial Results page for explanation of calculations.

Justin Thompson
Manager
Regulation, Policy & Analysis

Tel 602-250-2060
Fax 602-250-3003
e-mail:Justin.Thompson@aps.com
http://www.aps.com

Mail Station 9708
P.O. Box 53999
Phoenix, AZ 85072-3999

March 31, 2006

RECEIVED
MAR 31 2006
Z Corporation Commissic
Director of Utilities

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
FOURTH QUARTER ENDING December 31, 2005

Dear Mr. Johnson:

Attached are the Quarterly Financial Results and associated graphs for Arizona Public Service Company for the quarter ending December 31, 2005.

If you have any questions regarding this filing, please contact me at (602) 250-2060.

Sincerely,

Angela K Kraintz for JH Thompson

Justin H. Thompson
Manager
Regulation, Policy & Analysis

JHT/vld

Attachment

Cc: Brian Bozzo
Compliance and Enforcement

ARIZONA PUBLIC SERVICE COMPANY

2005 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2004 Yr End	Q1	Q2	Q3	Q4	2005 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	$230.8	101.8	$477.4	740.4	49.9	49.9
FINANCING: (a)						YTD
Long-Term Debt	478.1	164.0	0.0	247.8	0.0	411.8
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	478.1	164.0	0.0	247.8	0.0	411.8
Change in S-T Debt	0.0	0.0	0.0	0.0	0.0	0.0
Total	$478.1	$164.0	$0.0	$247.8	$0.0	$411.8
Repayments and Reacquistions (b)	($385.9)	($264.5)	($0.5)	($303.2)	$0.0	($568.2)
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	54.9%	53.4%	51.9%	46.0%	46.2%	46.2%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	54.9%	53.4%	51.9%	46.0%	46.2%	46.2%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	45.1%	46.6%	48.1%	54.0%	53.8%	53.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Adjusted Debt Ratio (c)	58.7%	57.7%	56.3%	50.5%	50.6%	50.6%
Non-Cash Income % Earnings (d) (e)	19.4%	17.5%	24.4%	37.3%	41.9%	41.9%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	45.2%	39.0%	20.0%	21.3%	36.9%	36.9%
TIMES EARNED COVERAGES:						
Before Tax	2.76	2.72	2.78	2.46	2.50	2.50
Before Tax excl. Non-Cash Inc. (d)	2.69	2.64	2.70	2.36	2.40	2.40
After Tax Incl. Preferred Div.	2.10	2.07	2.09	1.92	1.95	1.95
Return on Average Equity	9.0%	8.6%	8.9%	6.9%	6.6%	6.6%
Adjusted Return on Average Equity (e)	7.8%	7.7%	8.3%	6.6%	6.6%	6.6%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	8.3%	8.2%	8.7%	7.3%	7.0%	7.0%
Return on Avg. Total Capital	7.3%	7.0%	7.2%	6.3%	6.2%	6.2%

NOTES:

(a) Financing is shown net of issuance cost for period referenced.

(b) Includes premiums on reacquired debt and preferred stock.

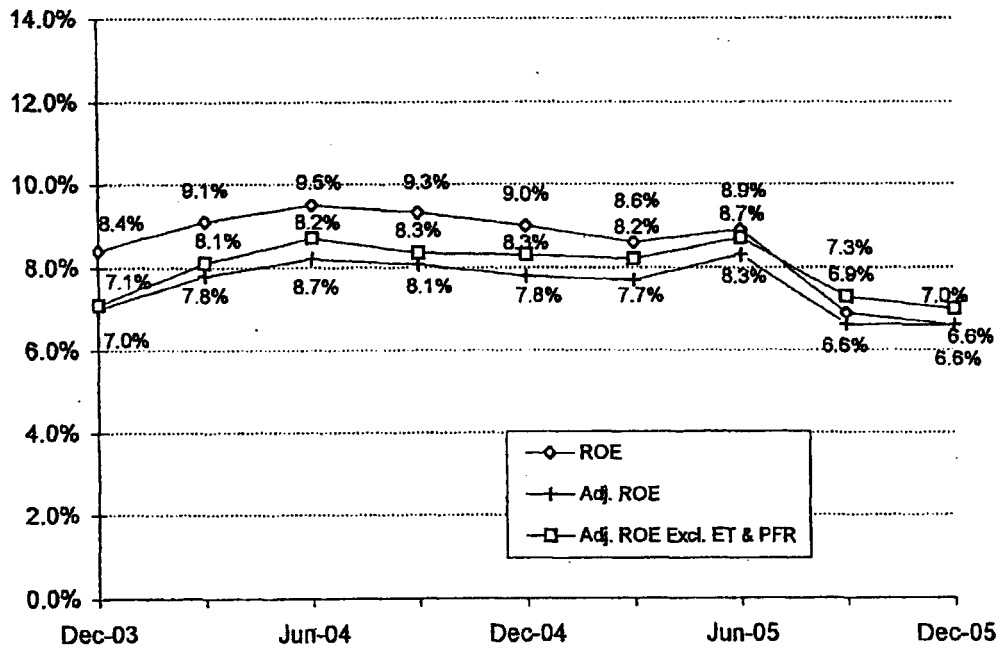
(c) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback and imputed debt on purchased power agreements.
Beginning December 2004 APS included purchased power agreements to the adjusted debt ratio.

(d) Non-cash income is defined as Capitalized Interest, AFUDC Equity and Deferred Fuel Costs beginning April 2005, using cumulative twelve month ended values.

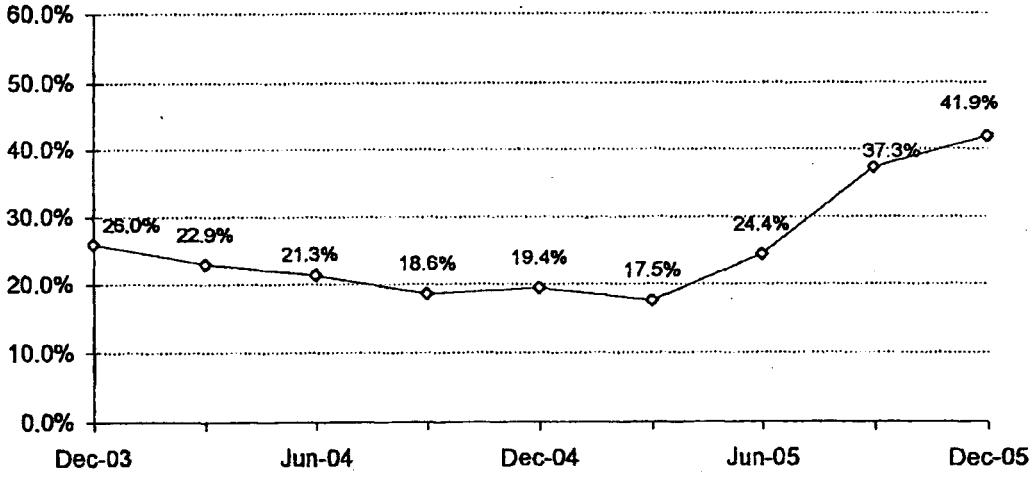
(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results and ending 11/05.

(f) Excludes Competitive Energy Trading and Purchases For Resale.

Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale*



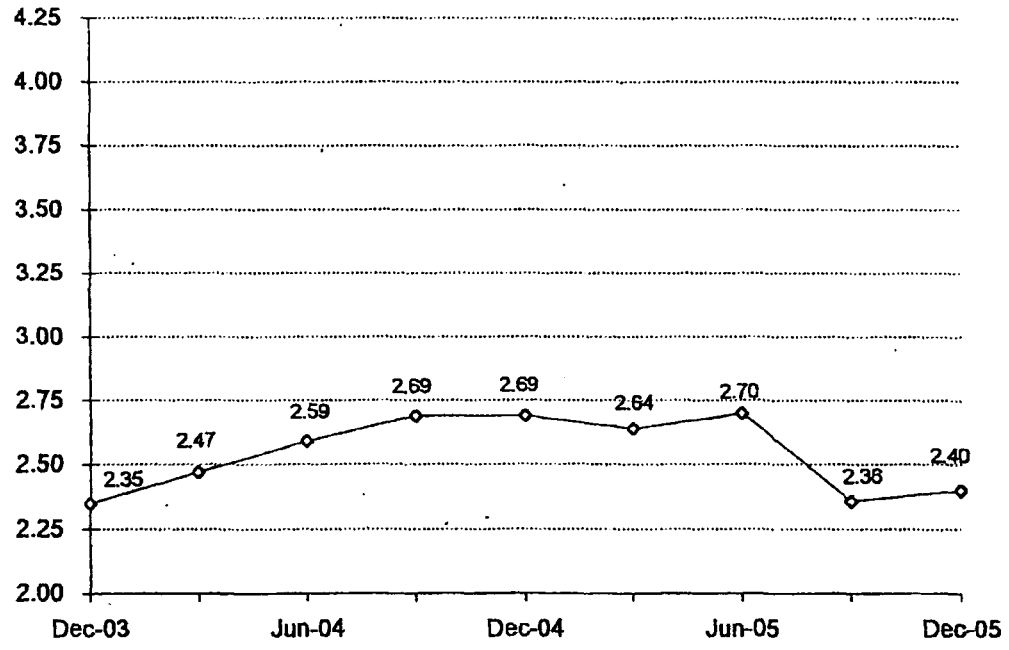
Non-Cash Income
as a % of Earnings *



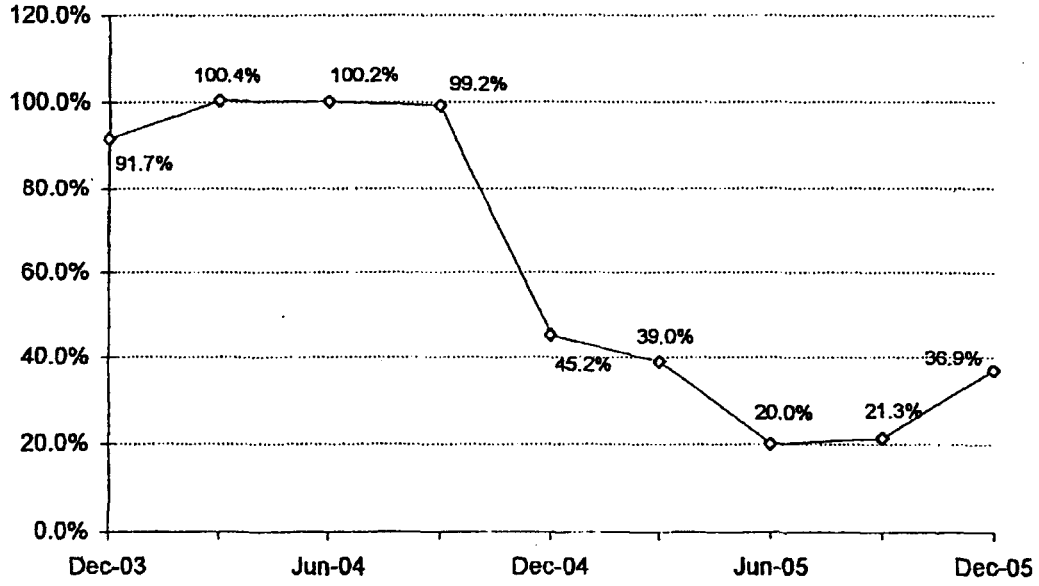
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



* See notes on Financial Results page for explanation of calculations.

APS

Justin H. Thompson
Manager
Regulation, Policy & Analysis

Tel 602/250-2060
Fax 602/250-3003
E -Mail: Justin.Thompson@aps.com
http://www.aps.com

Mail Station 9708
P.O. Box 53999
Phoenix, AZ 85072-3999

November 29, 2005

RECEIVED
NOV 29 2005
AZ Corporation Commission
Director of Utilities

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
THIRD QUARTER ENDING September 30, 2005

Dear Mr. Johnson:

Attached are the Quarterly Financial Results and associated graphs for Arizona Public Service Company for the quarter ending September 30, 2005.

If you have any questions regarding this filing, please contact me at (602) 250-2060.

Sincerely,

Justin H. Thompson
Manager
Regulation, Policy & Analysis

JHT/jd

Attachment

CC: Brian Bozzo
Compliance and Enforcement

ARIZONA PUBLIC SERVICE COMPANY

2005 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

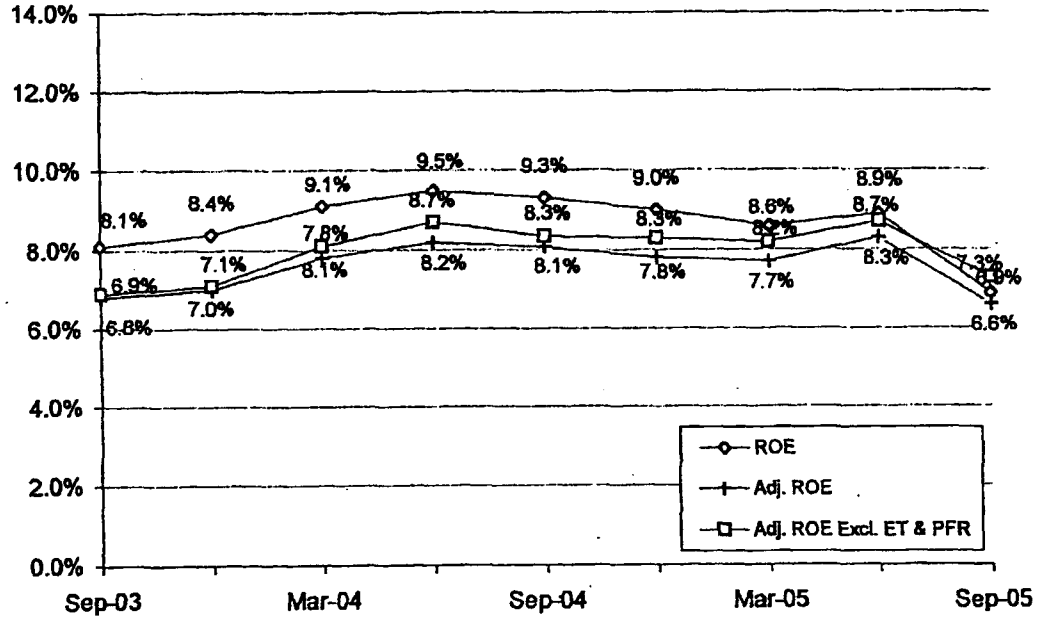
	2004 Yr End	Q1	Q2	Q3	Q4	2005 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	$230.8	101.8	$477.4	740.4	0.0	0.0
FINANCING: (a)						YTD
Long-Term Debt	478.1	164.0	0.0	247.8	0.0	411.8
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	478.1	164.0	0.0	247.8	0.0	411.8
Change in S-T Debt	0.0	0.0	0.0	0.0	0.0	0.0
Total	$478.1	$164.0	$0.0	$247.8	$0.0	$411.8
Repayments and Reacquistions (b)	($385.9)	($264.5)	($0.5)	($303.2)	$0.0	($568.2)
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	54.9%	53.4%	51.9%	46.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	54.9%	53.4%	51.9%	46.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	45.1%	46.6%	48.1%	54.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	0.0%	0.0%
Adjusted Debt Ratio (c)	58.7%	57.7%	56.3%	50.5%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	19.4%	17.5%	14.1%	14.6%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	45.2%	39.0%	20.0%	21.3%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.76	2.72	2.78	2.46	0.00	0.00
Before Tax excl. Non-Cash Inc. (d)	2.69	2.64	2.70	2.36	0.00	0.00
After Tax Incl. Preferred Div.	2.10	2.07	2.09	1.92	0.00	0.00
Return on Average Equity	9.0%	8.6%	8.9%	6.9%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.8%	7.7%	8.3%	6.6%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	8.3%	8.2%	8.7%	7.3%	0.0%	0.0%
Return on Avg. Total Capital	7.3%	7.0%	7.2%	6.3%	0.0%	0.0%

NOTES:

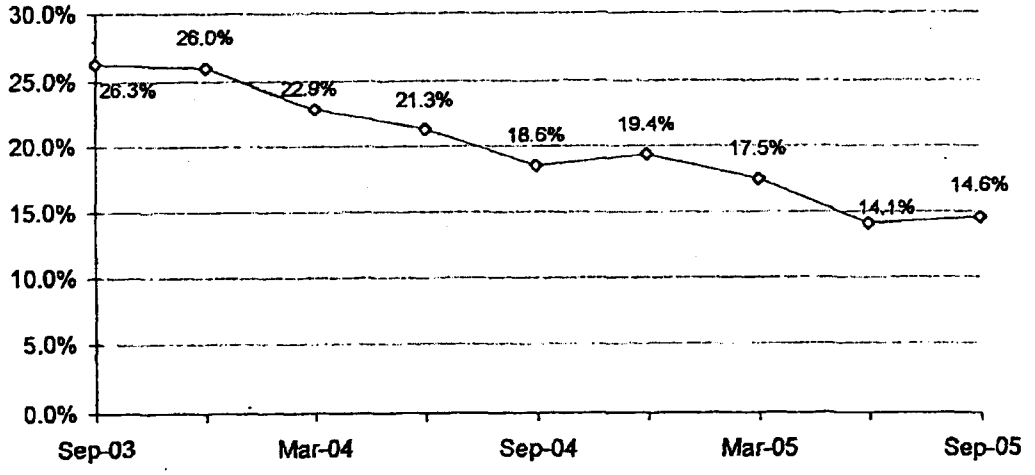
(a) Financing is shown net of issuance cost for period referenced.
(b) Includes premiums on reacquired debt and preferred stock.
(c) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback and imputed debt on purchased power agreements.
Beginning December 2004 APS included purchased power agreements to the adjusted debt ratio.
(d) Non-cash income is defined as Capitalized Interest and AFUDC Equity.
(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.
(f) Excludes Competitive Energy Trading and Purchases For Resale.

ARIZONA PUBLIC SERVICE COMPANY

Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale*



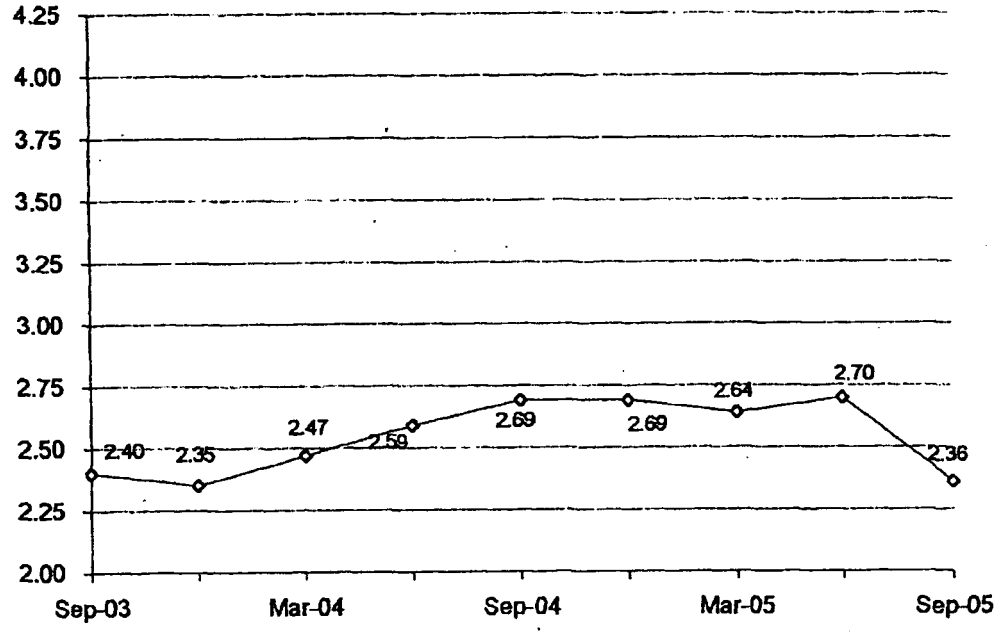
Non-Cash Income
as a % of Earnings *



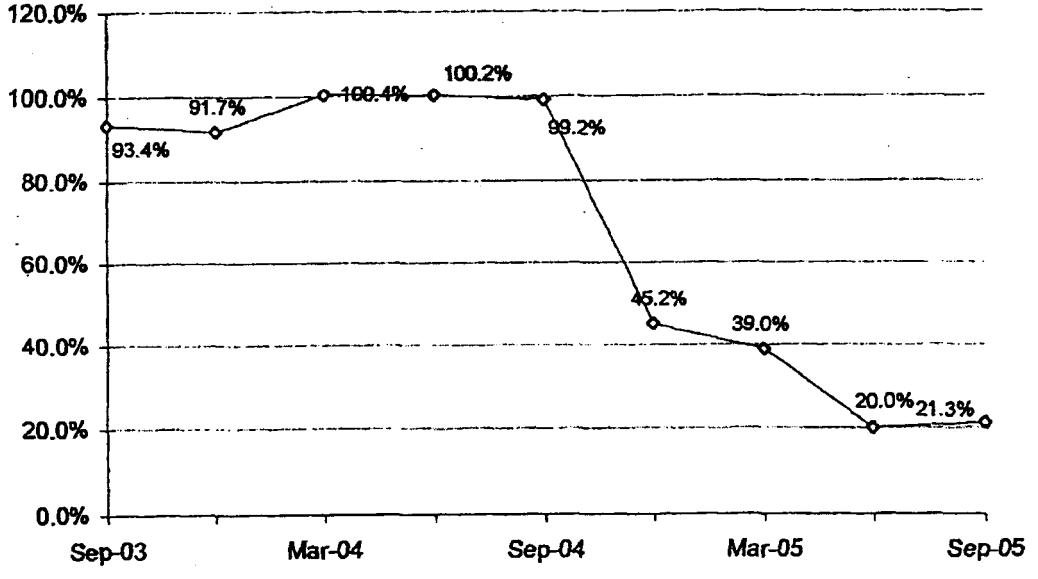
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



* See notes on Financial Results page for explanation of calculations.

Justin H. Thompson
Manager
Regulation, Policy & Analysis

Tel 602/250-2060
Fax 602/250-3003
E-Mail: Justin.Thompson@aps.com
http://www.aps.com

Mail Station 9708
P.O. Box 53999
Phoenix, AZ 85072-3999

August 31, 2005

AUG 31 2005

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
SECOND QUARTER ENDING June 30, 2005

Dear Mr. Johnson:

Attached are the Quarterly Financial Results and associated graphs for Arizona Public Service Company for the quarter ending June 30, 2005.

If you have any questions regarding this filing, please contact me at (602) 250-2060.

Sincerely,

Justin H. Thompson
Manager
Regulation, Policy & Analysis

JHT/jd

Attachment

CC: Brian Bozzo
Compliance and Enforcement

ARIZONA PUBLIC SERVICE COMPANY

2005 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2004 Yr End	Q1	Q2	Q3	Q4	2005 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	$230.8	101.8	$477.4	0.0	0.0	0.0
FINANCING: (a)						YTD
Long-Term Debt	478.1	164.0	0.0	0.0	0.0	164.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	478.1	164.0	0.0	0.0	0.0	164.0
Change in S-T Debt	0.0	0.0	0.0	0.0	0.0	0.0
Total	$478.1	$164.0	$0.0	$0.0	$0.0	$164.0
Repayments and Reacquisitions (b)	($385.9)	($264.5)	($0.5)	$0.0	$0.0	($265.0)
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	54.9%	53.4%	51.9%	0.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	54.9%	53.4%	51.9%	0.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	45.1%	46.6%	48.1%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	0.0%	0.0%	0.0%
Adjusted Debt Ratio (c)	58.7%	57.7%	56.3%	0.0%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	19.4%	17.5%	14.1%	0.0%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	45.2%	39.0%	20.0%	0.0%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.76	2.72	2.78	0.00	0.00	0.00
Before Tax excl. Non-Cash Inc. (d)	2.69	2.64	2.70	0.00	0.00	0.00
After Tax Incl. Preferred Div.	2.10	2.07	2.09	0.00	0.00	0.00
Return on Average Equity	9.0%	8.6%	8.9%	0.0%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.8%	7.7%	8.3%	0.0%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	8.3%	8.2%	8.7%	0.0%	0.0%	0.0%
Return on Avg. Total Capital	7.3%	7.0%	7.2%	0.0%	0.0%	0.0%

NOTES:

(a) Financing is shown net of issuance cost for period referenced.

(b) Includes premiums on reacquired debt and preferred stock.

(c) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback and imputed debt on purchased power agreements.
Beginning December 2004 APS included purchased power agreements to the adjusted debt ratio.

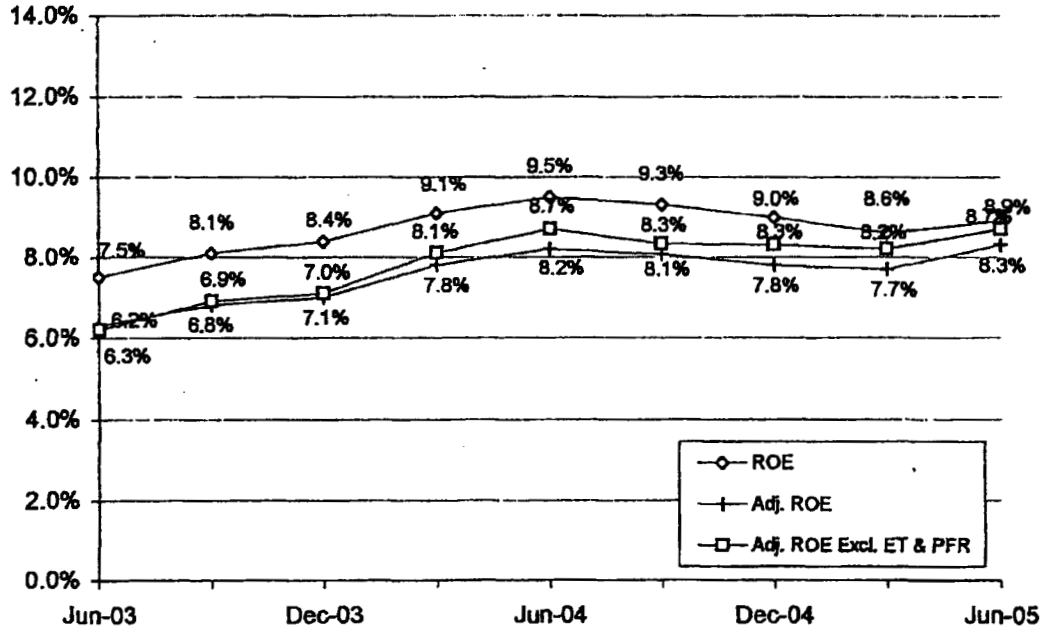
(d) Non-cash income is defined as Capitalized Interest and AFUDC Equity.

(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

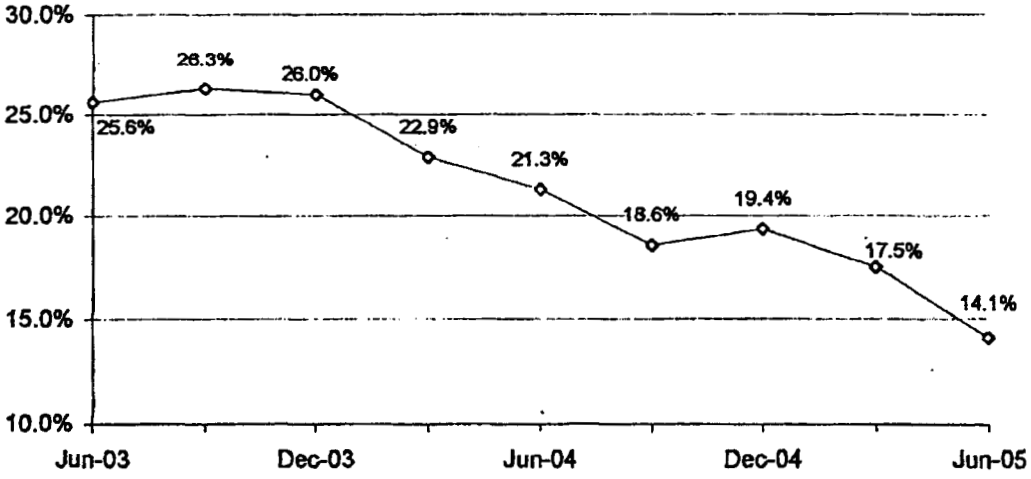
(f) Excludes Competitive Energy Trading and Purchases For Resale.

ARIZONA PUBLIC SERVICE COMPANY

**Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale***

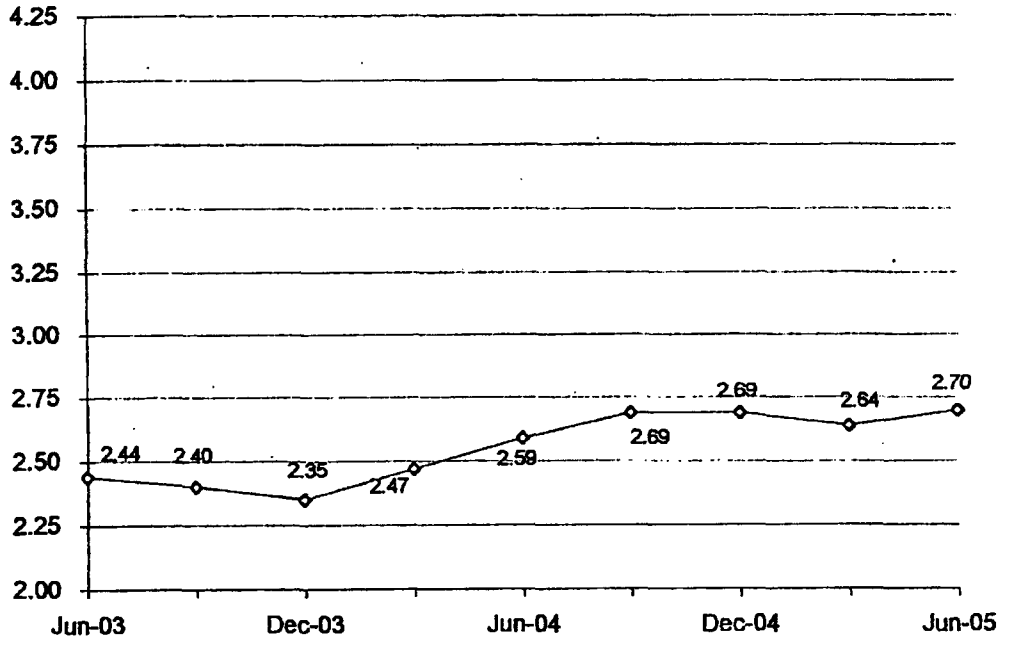


**Non-Cash Income
as a % of Earnings ***

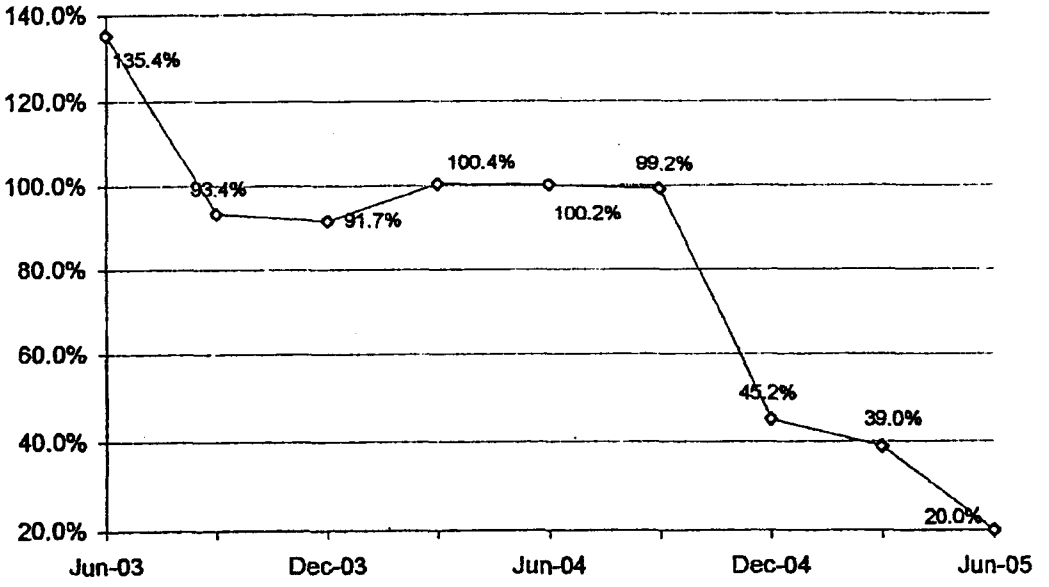


ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



Justin H. Thompson
Manager
Regulation, Policy & Analysis

Tel 602/250-2060
Fax 602/250-3003
E -Mail: Justin.Thompson@aps.com
http://www.aps.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

May 24, 2005

RECEIVED
MAY 24 2005
AZ Corporation Commission
Director Of Utilities

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
FIRST QUARTER ENDING MARCH 31, 2005

Dear Mr. Johnson:

Attached are the First Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending March 31, 2005.

If you have any questions regarding this filing, please contact me at (602) 250-2060.

Sincerely,

Justin H. Thompson
Manager
Regulation, Policy & Analysis

JHT/jd

Attachment

CC: Brian Bozzo
Compliance and Enforcement

ARIZONA PUBLIC SERVICE COMPANY

2005 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2004 Yr End	Q1	Q2	Q3	Q4	2005 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	230.8	101.8	0.0	0.0	0.0	0.0
FINANCING:						
Long-Term Debt	479.0	165.0	0.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	479.0	165.0	0.0	0.0	0.0	0.0
Change in S-T Debt	0.0	0.0	0.0	0.0	0.0	0.0
Total	$479.0	$165.0	$0.0	$0.0	$0.0	$0.0
Repayments and Reacquistions (a)	($385.9)	($264.5)	$0.0	$0.0	$0.0	$0.0
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	54.9%	53.4%	0.0%	0.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	54.9%	53.4%	0.0%	0.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	45.1%	46.6%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Adjusted Debt Ratio (b)	58.7%	57.7%	0.0%	0.0%	0.0%	0.0%
Non-Cash Income % Earnings (c) (d)	19.4%	17.5%	0.0%	0.0%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (c)	45.2%	39.0%	0.0%	0.0%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.76	2.72	0.00	0.00	0.00	0.00
Before Tax excl. Non-Cash Inc. (c)	2.69	2.64	0.00	0.00	0.00	0.00
After Tax Incl. Preferred Div.	2.10	2.07	0.00	0.00	0.00	0.00
Return on Average Equity	9.0%	8.6%	0.0%	0.0%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.8%	7.7%	0.0%	0.0%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (d) (e.)	8.3%	8.2%	0.0%	0.0%	0.0%	0.0%
Return on Avg. Total Capital	7.3%	7.0%	0.0%	0.0%	0.0%	0.0%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock.

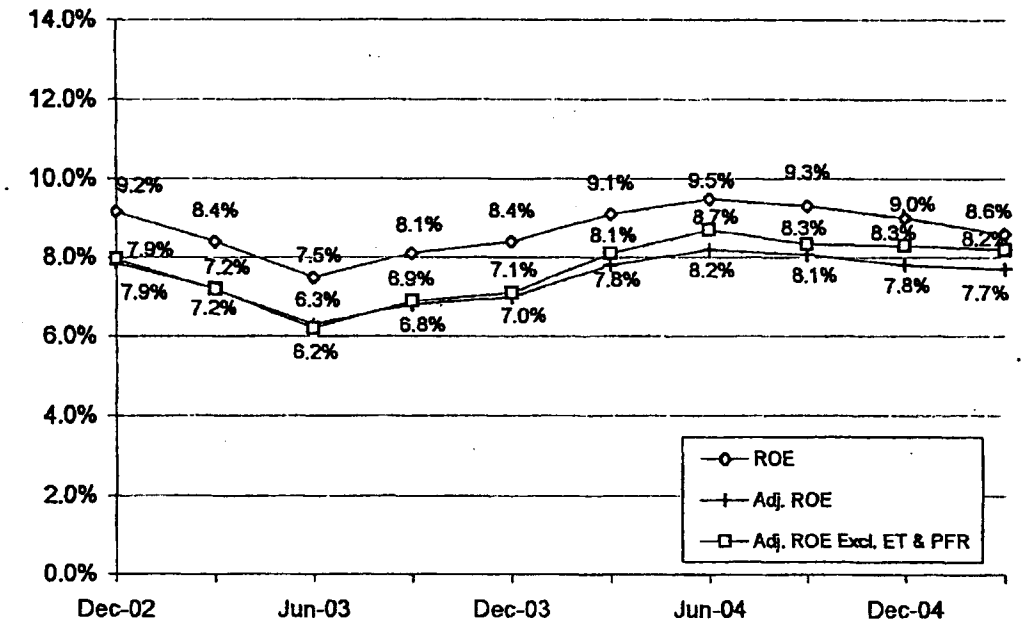
(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback and imputed debt on purchased power agreements.
Beginning December 2004 APS included purchased power agreements to the adjusted debt ratio.

(c) Non-cash income is defined as Capitalized Interest and AFUDC Equity.

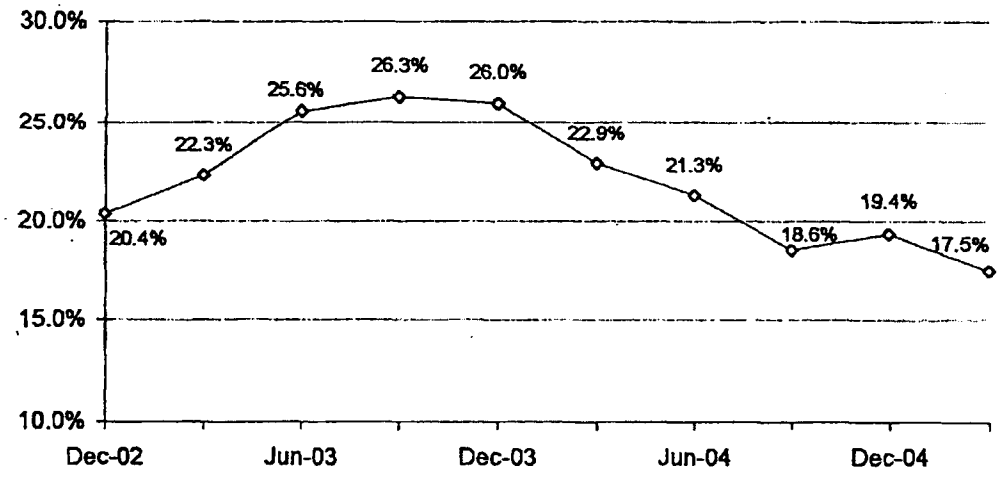
(d) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

(e) Excludes Competitive Energy Trading and Purchases For Resale.

**Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale**

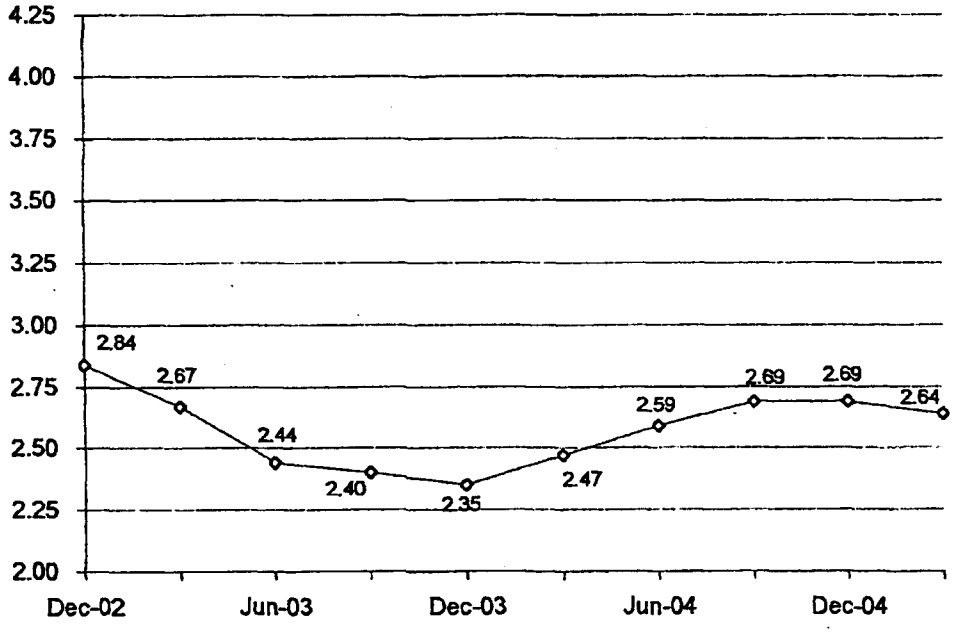


**Non-Cash Income
as a % of Earnings**

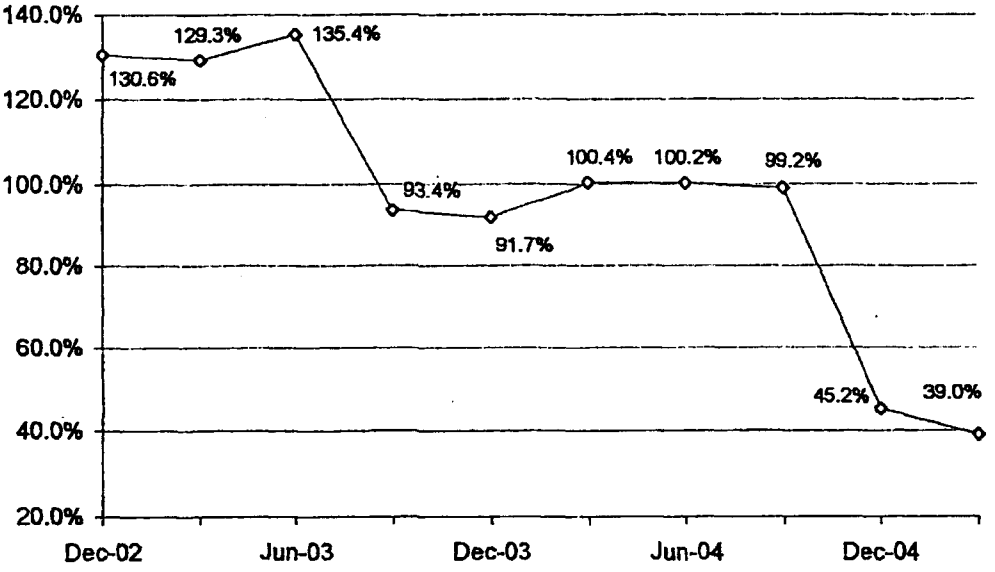


ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures



Justin H. Thompson
Manager
Regulation, Policy & Analysis

Tel 602/250-2060
Fax 602/250-3003
E-Mail: Justin.Thompson@aps.com
http://www.aps.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

March 28, 2005

RECEIVED

MAR 28 2005

AZ Corporation Commission
Director Of Utilities

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
FOURTH QUARTER ENDING DECEMBER 31, 2004

Dear Mr. Johnson:

Attached are the Fourth Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending December 31, 2004.

If you have any questions regarding this filing, please contact me at (602) 250-2060.

Sincerely,

Justin H. Thompson
Manager
Regulation, Policy & Analysis

JHT/jd

Attachment

CC: Brian Bozzo
Compliance and Enforcement

ARIZONA PUBLIC SERVICE COMPANY

2004 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2003 Yr End	Q1	Q2	Q3	Q4	2004 Yr End
Short-Term Debt	$0.0	$25.2	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	112.0	0.0	243.9	356.1	230.8	230.8
FINANCING:						
Long-Term Debt	500.0	179.0	300.0	0.0	0.0	479.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	500.0	179.0	300.0	0.0	0.0	479.0
Change in S-T Debt	0.0	25.2	(25.2)	0.0	0.0	0.0
Total	$500.0	$204.2	$274.8	$0.0	$0.0	$479.0
Repayments and Reacquistions (a)	$89.5	($384.6)	($0.6)	($0.3)	($0.4)	($385.9)
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	54.3%	52.0%	54.9%	54.2%	54.9%	54.9%
Short-Term Debt	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%
Total Debt	54.3%	52.5%	54.9%	54.2%	54.9%	54.9%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	45.7%	47.5%	45.1%	45.8%	45.1%	45.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Adjusted Debt Ratio (b)	57.7%	56.1%	58.0%	57.3%	58.7%	58.7%
Non-Cash Income % Earnings (c) (d)	26.0%	22.9%	21.3%	18.6%	19.4%	19.4%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (c)	91.7%	100.4%	100.2%	99.2%	45.2%	45.2%
TIMES EARNED COVERAGES:						
Before Tax	2.47	2.58	2.70	2.76	2.76	2.76
Before Tax excl. Non-Cash Inc. (c)	2.35	2.47	2.59	2.69	2.69	2.69
After Tax Incl. Preferred Div.	1.99	2.06	2.14	2.13	2.10	2.10
Return on Average Equity	8.4%	9.1%	9.5%	9.3%	9.0%	9.0%
Adjusted Return on Average Equity (d)	7.0%	7.8%	8.2%	8.1%	7.8%	7.8%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (d) (e)	7.1%	8.1%	8.7%	8.3%	8.3%	8.3%
Return on Avg. Total Capital	7.1%	7.5%	7.6%	7.4%	7.3%	7.3%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock.

(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback and imputed debt on purchased power agreements.
Beginning December 2004 APS included purchased power agreements to the adjusted debt ratio.

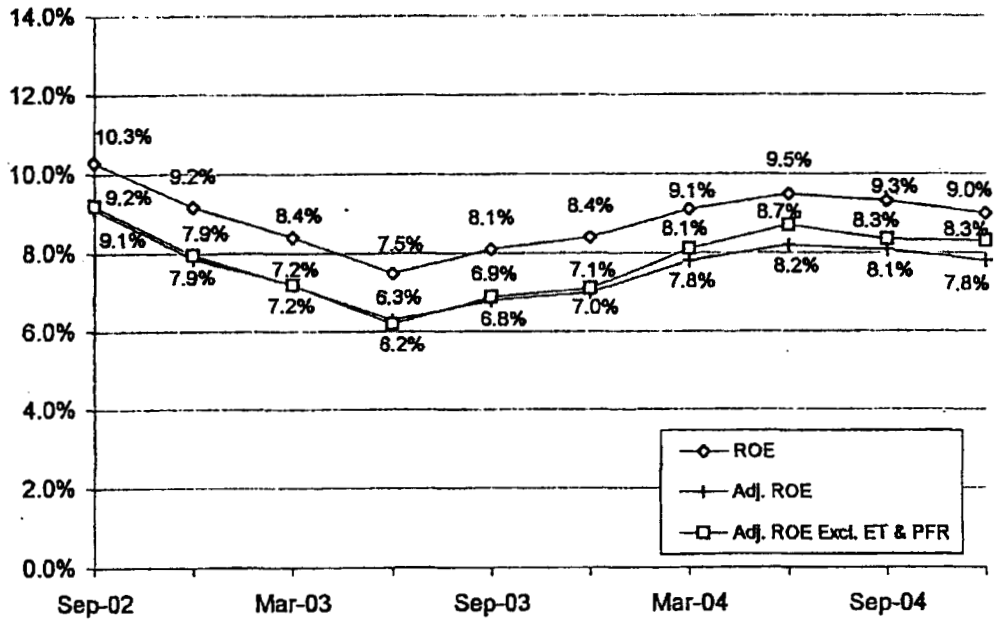
(c) Non-cash income is defined as Capitalized Interest and AFUDC Equity.

(d) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

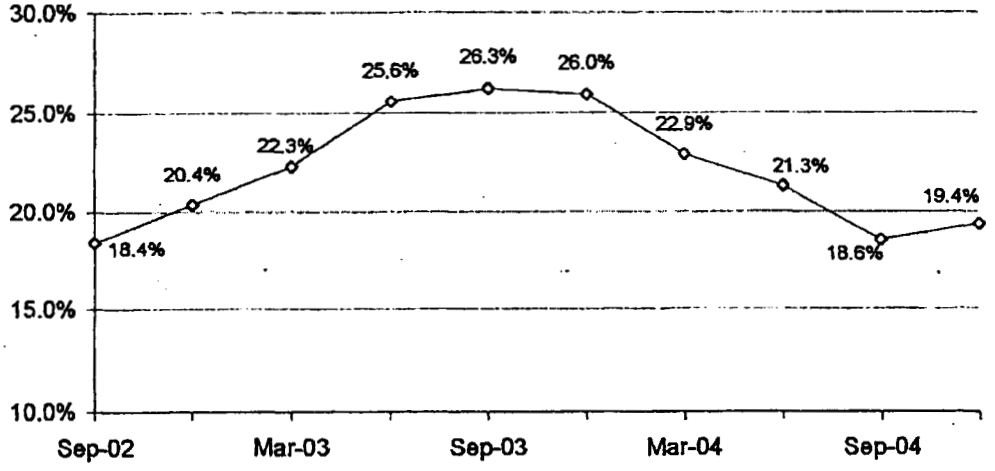
(e) Excludes Competitive Energy Trading and Purchases For Resale.

ARIZONA PUBLIC SERVICE COMPANY

Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale*

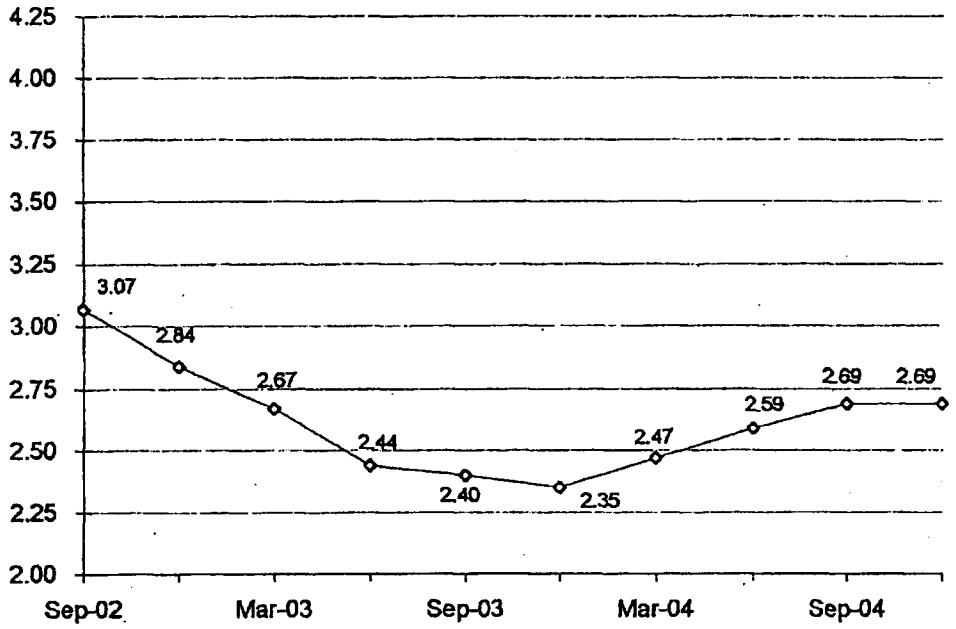


Non-Cash Income
as a % of Earnings *

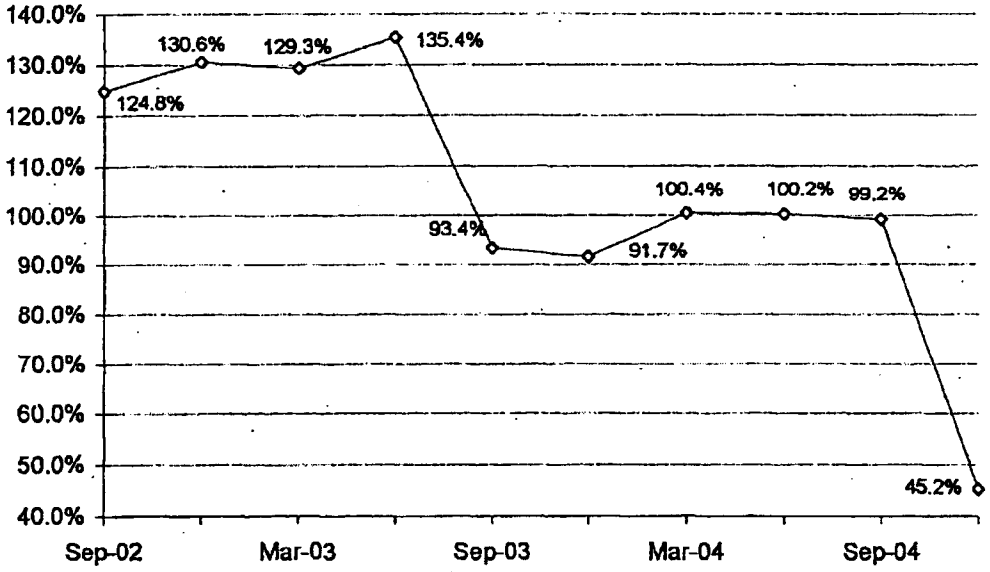


* See notes on Financial Results page for explanation of calculations.

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



* See notes on Financial Results page for explanation of calculations.

Jana Van Ness
Manager
Regulatory Affairs

Tel 602/250-2310
Fax 602/250-3003
E-Mail: Jana.VanNess@aps.com
http://www.aps.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

RECEIVED

NOV 3 0 2004

AZ Corporation Commission
Director Of Utilities

November 30, 2004

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
THIRD QUARTER ENDING SEPTEMBER 30, 2004

Dear Mr. Johnson:

Attached are the Third Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending September 30, 2004.

If you have any questions regarding this filing, please contact me at (602) 250-2310.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
Regulatory Affairs

JVN/srm

Attachment

CC: Brian Bozzo
Compliance and Enforcement

ARIZONA PUBLIC SERVICE COMPANY

2004 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2003 Yr End	Q1	Q2	Q3	Q4	2004 Yr End
Short-Term Debt	$0.0	$25.2	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	112.0	0.0	243.9	356.1	0.0	0.0
FINANCING:						
Long-Term Debt	500.0	179.0	300.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	500.0	179.0	300.0	0.0	0.0	0.0
Change in S-T Debt	0.0	25.2	(25.2)	0.0	0.0	0.0
Total	$500.0	$204.2	$274.8	$0.0	$0.0	$0.0
Repayments and Reacquistions (a)	$89.5	($384.6)	($0.6)	($0.3)	$0.0	$0.0
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	54.3%	52.0%	54.9%	54.2%	0.0%	0.0%
Short-Term Debt	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%
Total Debt	54.3%	52.5%	54.9%	54.2%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	45.7%	47.5%	45.1%	45.8%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	0.0%	0.0%
Adjusted Debt Ratio (b)	57.7%	56.1%	58.0%	57.3%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	26.0%	22.9%	21.3%	18.6%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	91.7%	100.4%	100.2%	99.2%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.47	2.58	2.70	2.76	0.00	0
Before Tax excl. Non-Cash Inc. (d)	2.35	2.47	2.59	2.69	0.00	0
After Tax Incl. Preferred Div.	1.99	2.06	2.14	2.13	0.00	0
Return on Average Equity	8.4%	9.1%	9.5%	9.3%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.0%	7.8%	8.2%	8.1%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.1%	8.1%	8.7%	8.3%	0.0%	0.0%
Return on Avg. Total Capital	7.1%	7.5%	7.6%	7.4%	0.0%	0.0%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock

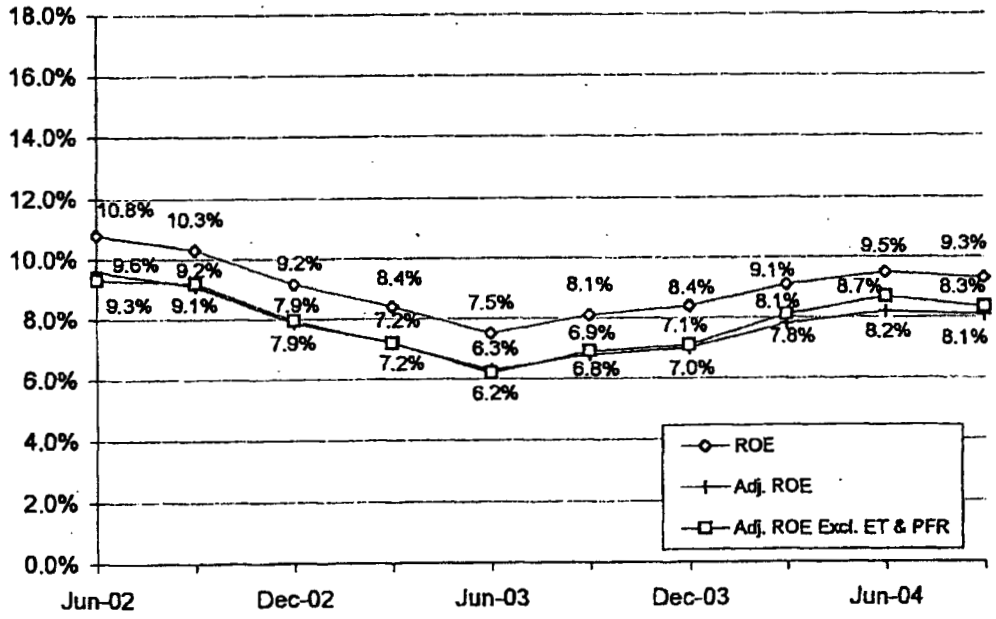
(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback

(d) Non-cash income is defined as Capitalized Interest and accelerated portion of ITC (beginning in 1/95).

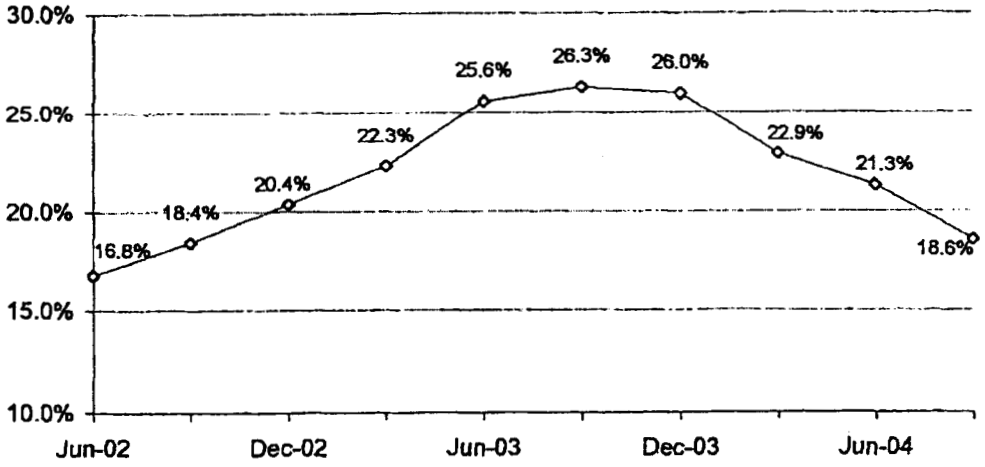
(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

(f) Excludes Competitive Energy Trading and Purchases For Resale

**Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale***



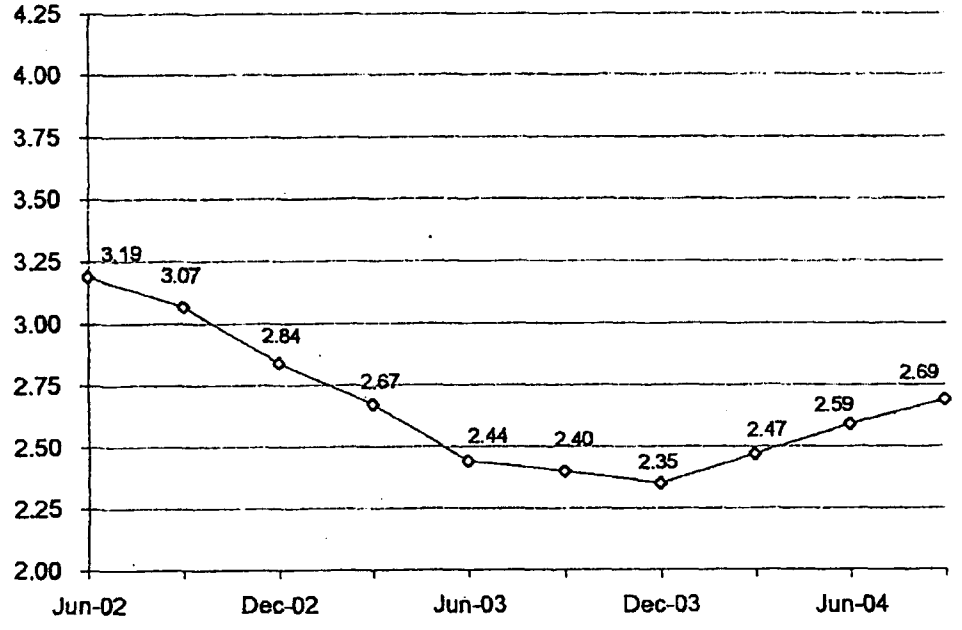
**Non-Cash Income
as a % of Earnings ***



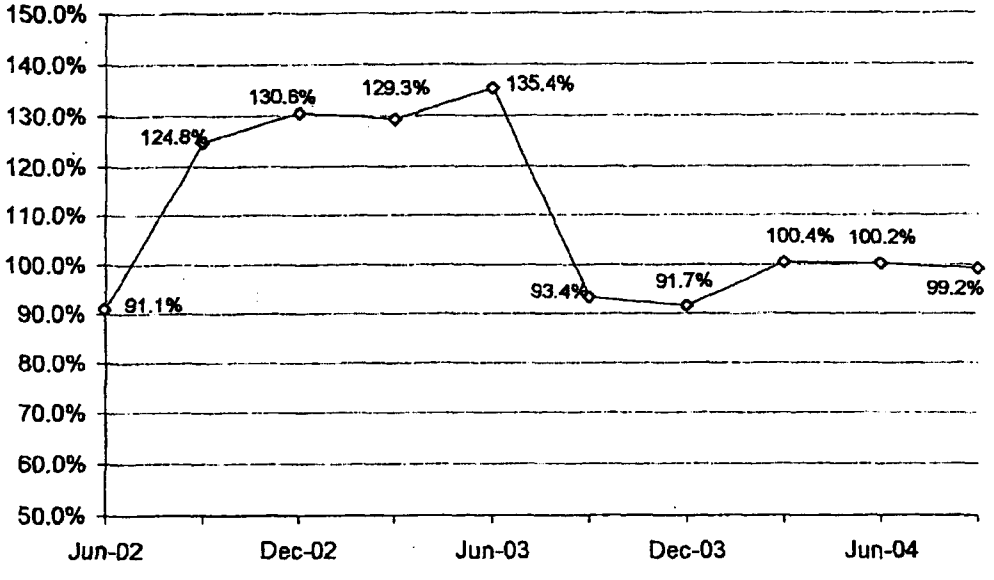
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



* See notes on Financial Results page for explanation of calculations.

Jana Van Ness
Manager
Regulatory Compliance

Tel 602/250-2310
Fax 602/250-3003
E-Mail: Jana.VanNess@aps.com
http://www.apsc.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

August 27, 2004

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

AUG 27 2004

RE: APS FINANCIAL REPORT
SECOND QUARTER ENDING JUNE 30, 2004

Dear Mr. Johnson:

Attached are the Second Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending June 30, 2004.

If you have any questions regarding this filing, please contact me at (602) 250-2310.

Sincerely,

Jana Van Ness/vld

Jana Van Ness
Manager
Regulatory Compliance

JVN/vld

Attachment

ARIZONA PUBLIC SERVICE COMPANY

2004 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2003 Yr End	Q1	Q2	Q3	Q4	2004 Yr End
Short-Term Debt	$0.0	$25.2	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	112.0	0.0	243.9	0.0	0.0	0.0
FINANCING:						
Long-Term Debt	500.0	179.0	300.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	500.0	179.0	300.0	0.0	0.0	0.0
Change in S-T Debt	0.0	25.2	(25.2)	0.0	0.0	0.0
Total	$500.0	$204.2	$274.8	$0.0	$0.0	$0.0
Repayments and Reacquistions (a)	$89.5	($384.6)	($0 6)	$0.0	$0.0	$0.0
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	54.3%	52.0%	54.9%	0.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%
Total Debt	54.3%	52.5%	54.9%	0.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	45.7%	47.5%	45.1%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	0.0%	0.0%	0.0%
Adjusted Debt Ratio (b)	57.7%	56.1%	58.0%	0.0%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	26.0%	22.9%	21 3%	0.0%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	91.7%	100.4%	100.2%	0.0%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.47	2.58	2.70	0.00	0.00	0
Before Tax excl. Non-Cash Inc. (d)	2.35	2.47	2.59	0.00	0.00	0
After Tax Incl. Preferred Div.	1.99	2.06	2.14	0.00	0.00	0
Return on Average Equity	8.4%	9.1%	9.5%	0.0%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.0%	7.8%	8.2%	0.0%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.1%	8.1%	8.7%	0.0%	0.0%	0.0%
Return on Avg. Total Capital	7.1%	7.5%	7.6%	0.0%	0.0%	0.0%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock

(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback

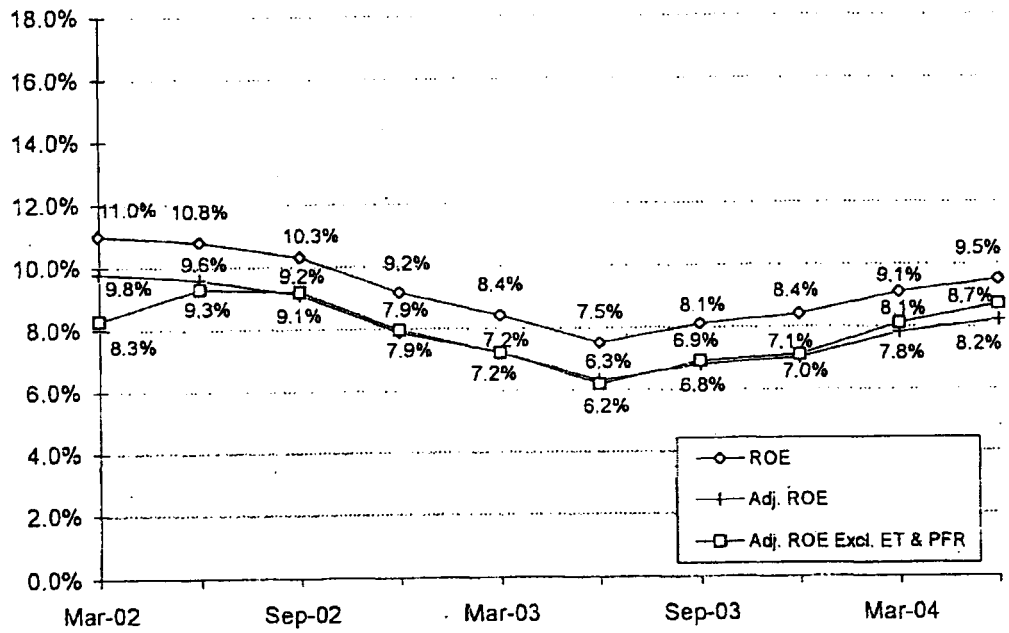
(d) Non-cash income is defined as Capitalized Interest and accelerated portion of ITC (beginning in 1/95).

(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

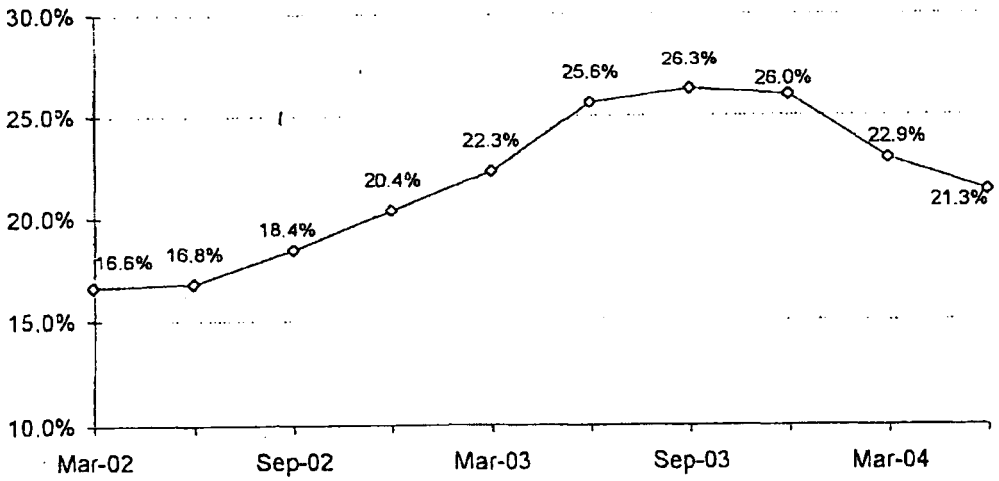
(f) Excludes Competitive Energy Trading and Purchases For Resale

ARIZONA PUBLIC SERVICE COMPANY

Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale*



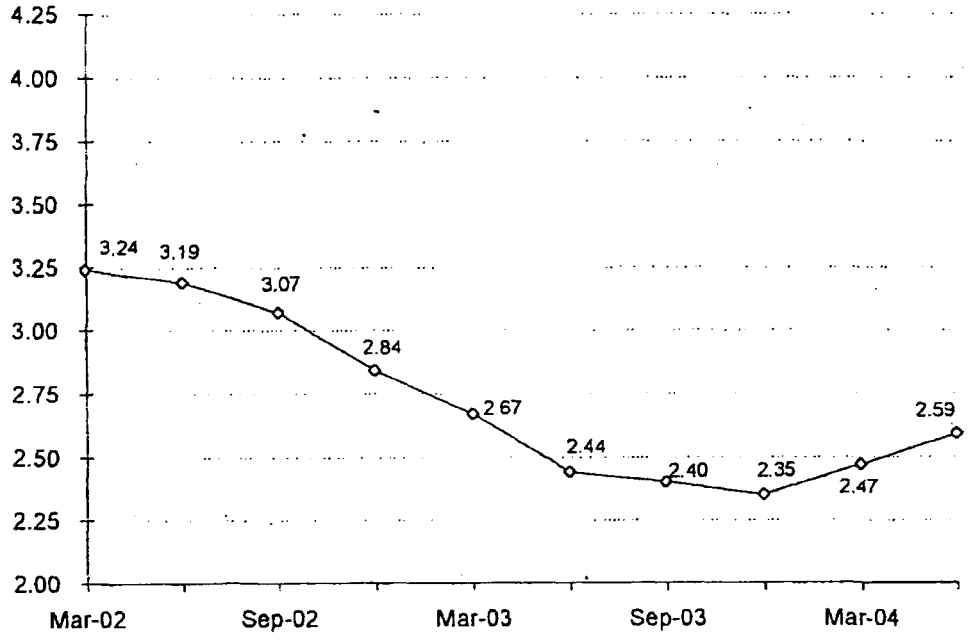
Non-Cash Income
as a % of Earnings *



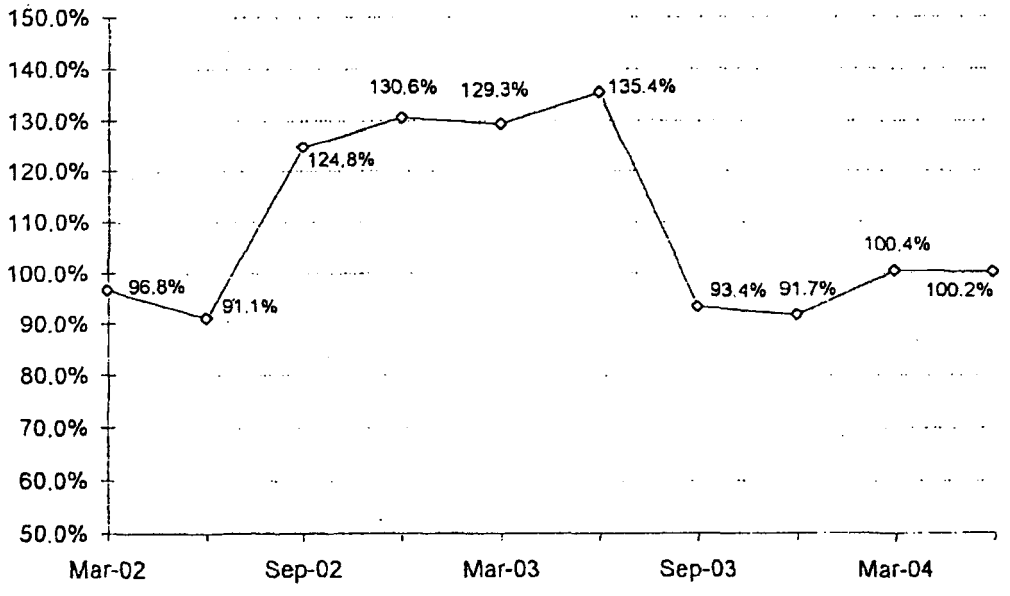
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



* See notes on Financial Results page for explanation of calculations

Jana Van Ness
Manager
Regulatory Compliance

Tel 602/250-2310
Fax 602/250-3003
E-Mail: Jana.VanNess@aps.com
http://www.apsc.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

May 28, 2004

MAY 28 2004

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
FIRST QUARTER ENDING MARCH 31, 2004

Dear Mr. Johnson:

Attached are the First Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending March 31, 2004.

If you have any questions regarding this filing, please contact me at (602) 250-2310.

Sincerely,

Jana Van Ness
Manager
Regulatory Compliance

JVN/srm

Attachment

ARIZONA PUBLIC SERVICE COMPANY

2004 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2003 Yr End	Q1	Q2	Q3	Q4	2004 Yr End
Short-Term Debt	$0.0	$25.2	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	112.0	0.0	0.0	0.0	0.0	0.0
FINANCING:						
Long-Term Debt	500.0	179.0	0.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	500.0	179.0	0.0	0.0	0.0	0.0
Change in S-T Debt	0.0	25.2	0.0	0.0	0.0	0.0
Total	$500.0	$204.2	$0.0	$0.0	$0.0	$0.0
Repayments and Reacquisitions (a)	$89.5	($384.6)	$0.0	$0.0	$0.0	$0.0
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	54.3%	52.0%	0.0%	0.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%
Total Debt	54.3%	52.5%	0.0%	0.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	45.7%	47.5%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Adjusted Debt Ratio (b)	57.7%	56.1%	0.0%	0.0%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	26.0%	22.9%	0.0%	0.0%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	91.7%	100.4%	0.0%	0.0%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.47	2.58	0.00	0.00	0.00	0
Before Tax excl. Non-Cash Inc. (d)	2.35	2.47	0.00	0.00	0.00	0
After Tax Incl. Preferred Div.	1.99	2.06	0.00	0.00	0.00	0
Return on Average Equity	8.4%	9.1%	0.0%	0.0%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.0%	7.8%	0.0%	0.0%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.1%	8.1%	0.0%	0.0%	0.0%	0.0%
Return on Avg. Total Capital	7.1%	7.5%	0.0%	0.0%	0.0%	0.0%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock

(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback

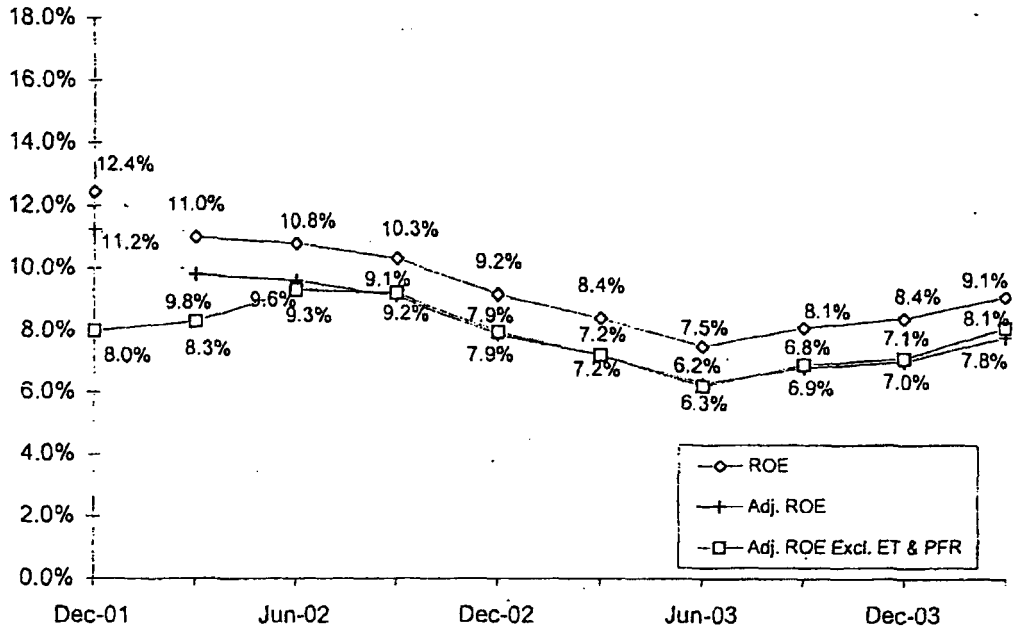
(d) Non-cash income is defined as Capitalized Interest and accelerated portion of ITC (beginning in 1/95).

(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

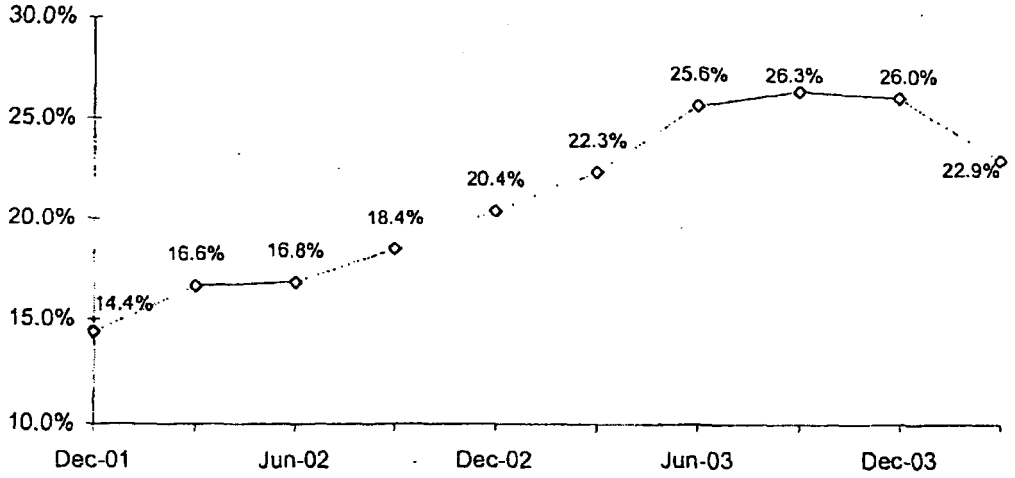
(f) Excludes Competitive Energy Trading and Purchases For Resale

ARIZONA PUBLIC SERVICE COMPANY

Return on Average Common Equity, Adjusted Return on Average Equity, and Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale*



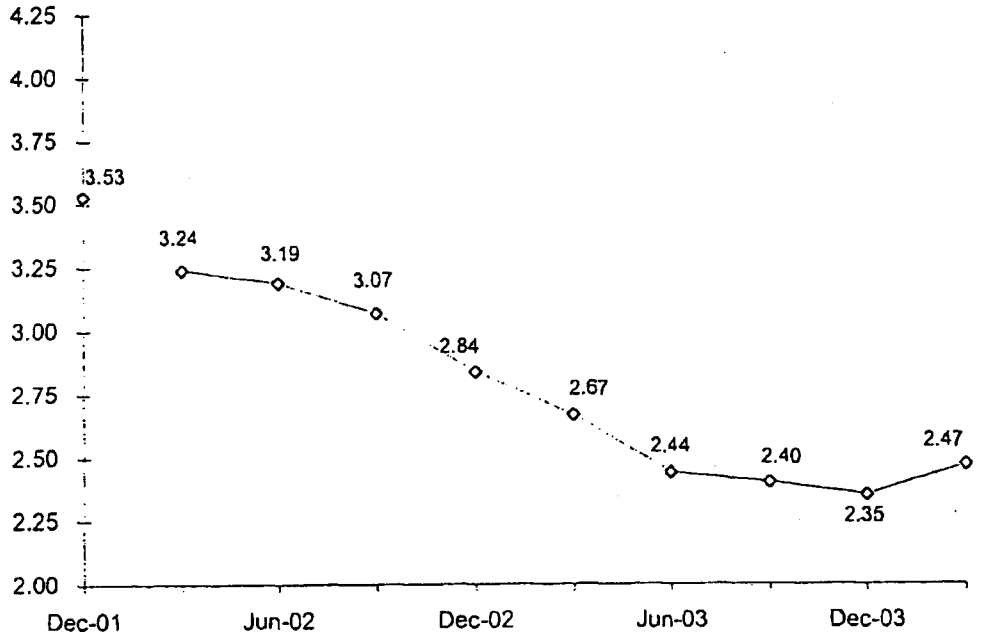
Non-Cash Income as a % of Earnings *



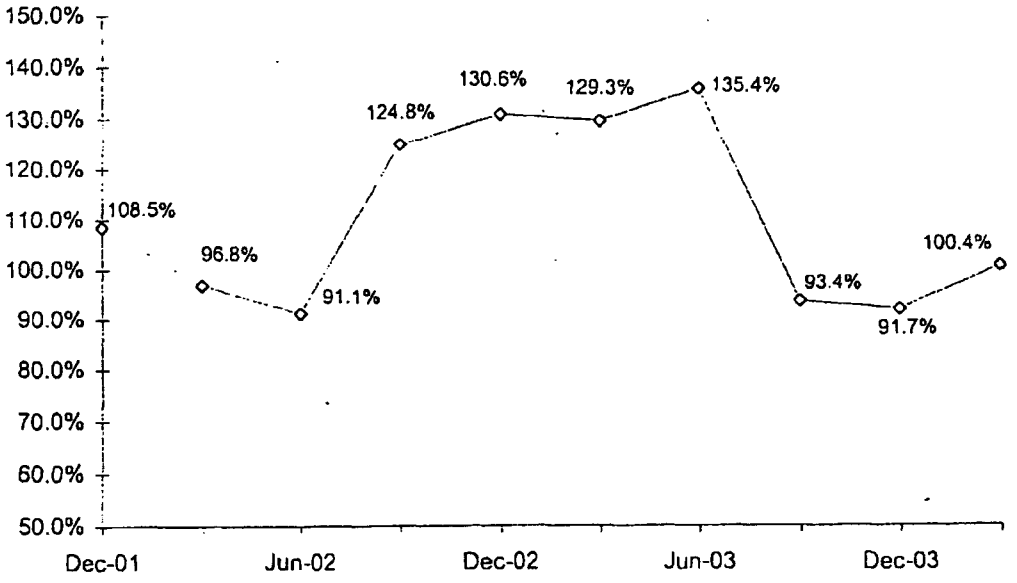
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



* See notes on Financial Results page for explanation of calculations.

Jana Van Ness
Manager
Regulatory Compliance

Tel 602/250-2310
Fax 602/250-3003
E-Mail: Jana.VanNess@aps.com
http://www.apsc.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

March 31, 2004

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RECEIVED
MAR 31 2004
AZ CORPORATION COMMISSIO
DIRECTOR OF UTILITIES

RE: APS FINANCIAL REPORT
FOURTH QUARTER ENDING DECEMBER 31, 2003

Dear Mr. Johnson:

Attached are the Fourth Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending December 31, 2003.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
Regulatory Compliance

JVN/srm

Attachment

ARIZONA PUBLIC SERVICE COMPANY

2003 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2002 Yr End	Q1	Q2	Q3	Q4	2003 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	42.5	31.8	63.3	161.2	112.0	112.0
FINANCING:						
Long-Term Debt	465.0	0.0	500.0	0.0	0.0	500.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	465.0	0.0	500.0	0.0	0.0	500.0
Change in S-T Debt	(171.2)	0.0	0.0	0.0	0.0	0.0
Total	$293.8	$0.0	$500.0	$0.0	$0.0	$500.0
Repayments and Reacquistions (a)	$337.1	$0.7	$33.7	$54.8	$0.3	$89.5
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	50.7%	50.9%	55.5%	54.3%	54.3%	54.3%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	50.7%	50.9%	55.5%	54.3%	54.3%	54.3%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	49.3%	49.1%	44.5%	45.7%	45.7%	45.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Adjusted Debt Ratio (b)	54.9%	55.1%	58.8%	57.6%	57.7%	57.7%
Non-Cash Income % Earnings (d) (e)	20.4%	22.3%	25.6%	26.3%	26.0%	26.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	130.6%	129.3%	135.4%	93.4%	91.7%	91.7%
TIMES EARNED COVERAGES:						
Before Tax	2.93	2.76	2.53	2.51	2.47	2.47
Before Tax excl. Non-Cash Inc. (d)	2.84	2.67	2.44	2.40	2.35	2.35
After Tax Incl. Preferred Div.	2.17	2.07	1.93	1.99	1.99	1.99
Return on Average Equity	9.2%	8.4%	7.5%	8.1%	8.4%	8.4%
Adjusted Return on Average Equity (e)	7.9%	7.2%	6.3%	6.8%	7.0%	7.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.9%	7.2%	6.2%	6.9%	7.1%	7.1%
Return on Avg. Total Capital	7.6%	7.3%	6.8%	7.1%	7.1%	7.1%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock

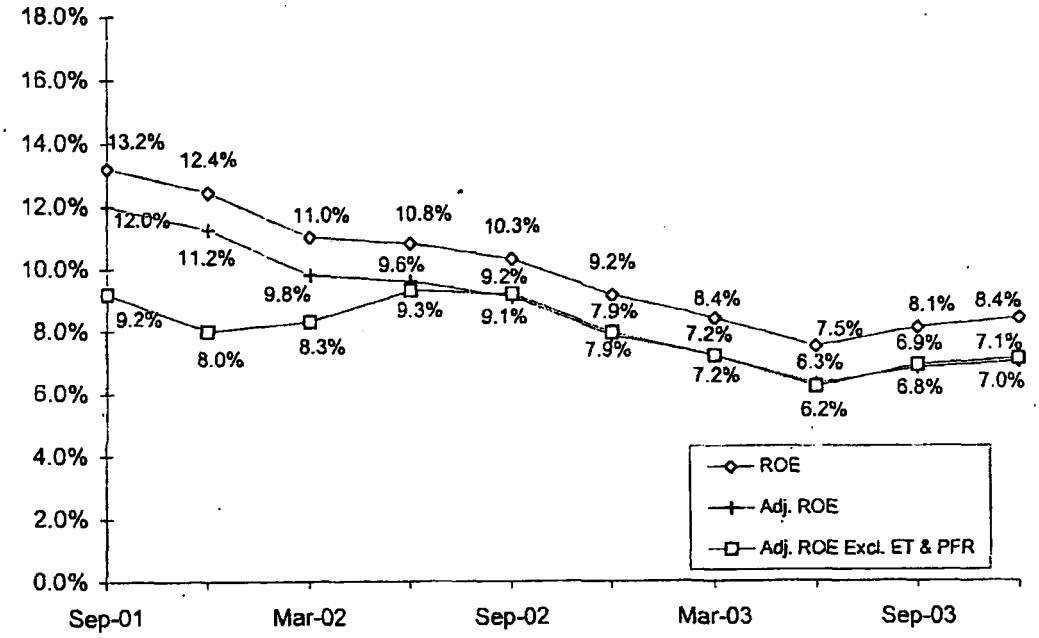
(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback

(d) Non-cash income is defined as Capitalized Interest and accelerated portion of ITC (beginning in 1/95).

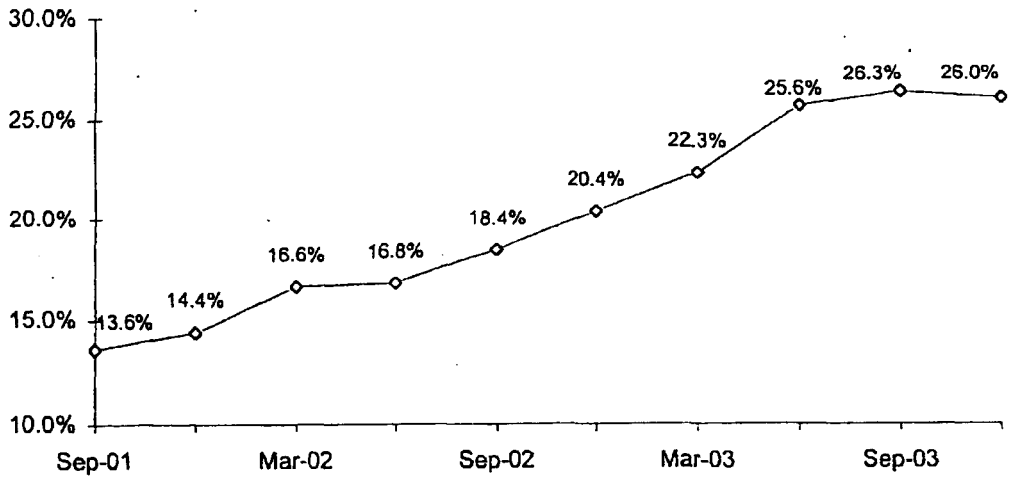
(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

(f) Excludes Competitive Energy Trading and Purchases For Resale

**Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale***



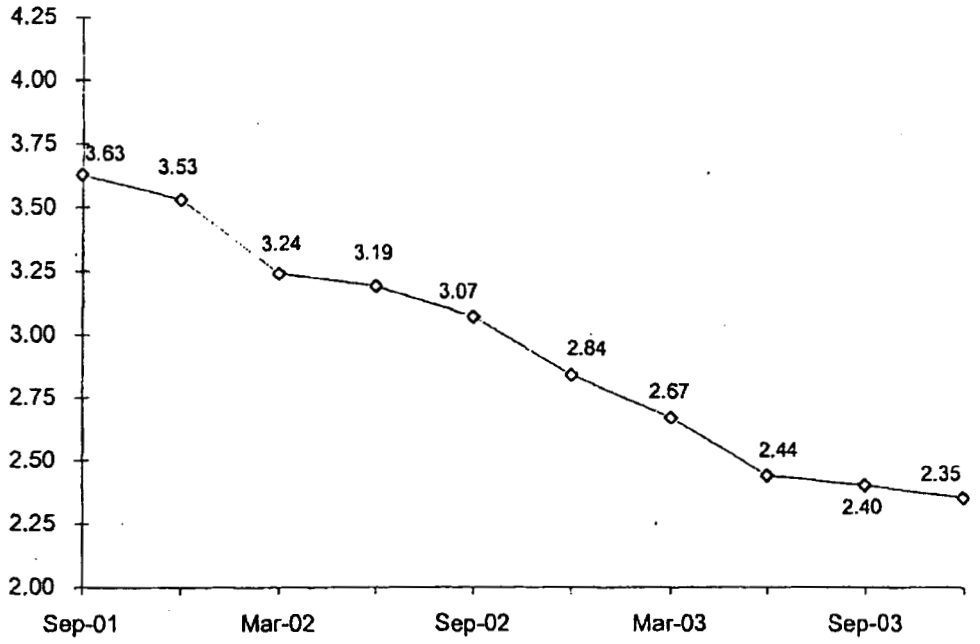
**Non-Cash Income
as a % of Earnings ***



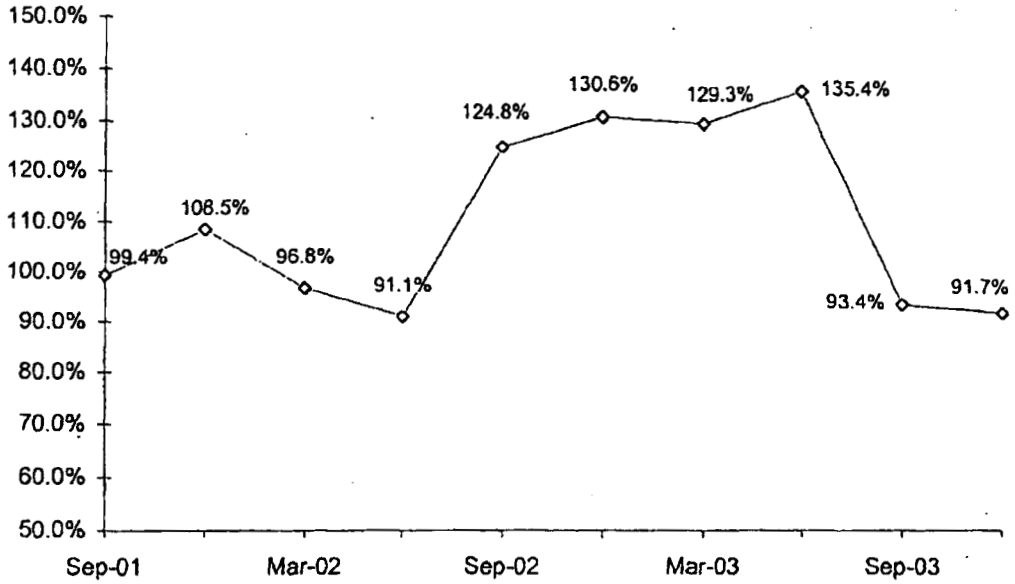
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes . Excluding Non-Cash Income *



Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



* See notes on Financial Results page for explanation of calculations.

APS

Jana Van Ness
Manager
Regulatory Compliance

Tel 602/250-2310
Fax 602/250-3003
E-Mail: Jana.VanNess@aps.com
http://www.apsc.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

November 26, 2003

RECEIVED
NOV 26 2003
AZ CORPORATION COMMISSION
DIRECTOR OF UTILITIES

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
SECOND QUARTER ENDING SEPTEMBER 30, 2003

Dear Mr. Johnson:

Attached are the Third Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending September 30, 2003.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
Regulatory Compliance

JVN/srm

Attachment

Cc: John Thornton
Chief of Accounting & Rates

ARIZONA PUBLIC SERVICE COMPANY

2003 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2002 Yr End	Q1	Q2	Q3	Q4	2003 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	42.5	31.8	63.3	161.2	0.0	0.0
FINANCING:						
Long-Term Debt	465.0	0.0	500.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	465.0	0.0	500.0	0.0	0.0	0.0
Change in S-T Debt	(171.2)	0.0	0.0	0.0	0.0	0.0
Total	$293.8	$0.0	$500.0	$0.0	$0.0	$0.0
Repayments and Reacquistions (a)	$337.1	$0.7	$33.7	$54.8	$0.0	$0.0
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	50.7%	50.9%	55.5%	54.3%	0.0%	0.0%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	50.7%	50.9%	55.5%	54.3%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	49.3%	49.1%	44.5%	45.7%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	0.0%	0.0%
Adjusted Debt Ratio (b)	54.9%	55.1%	58.8%	57.6%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	20.4%	22.3%	25.6%	26.3%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	130.6%	129.3%	135.4%	93.4%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.93	2.76	2.53	2.51	0.00	0
Before Tax excl. Non-Cash Inc. (d)	2.84	2.67	2.44	2.40	0.00	0
After Tax Incl. Preferred Div.	2.17	2.07	1.93	1.99	0.00	0
Return on Average Equity	9.2%	8.4%	7.5%	8.1%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.9%	7.2%	6.3%	6.8%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.9%	7.2%	6.2%	6.9%	0.0%	0.0%
Return on Avg. Total Capital	7.6%	7.3%	6.8%	7.1%	0.0%	0.0%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock

(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback

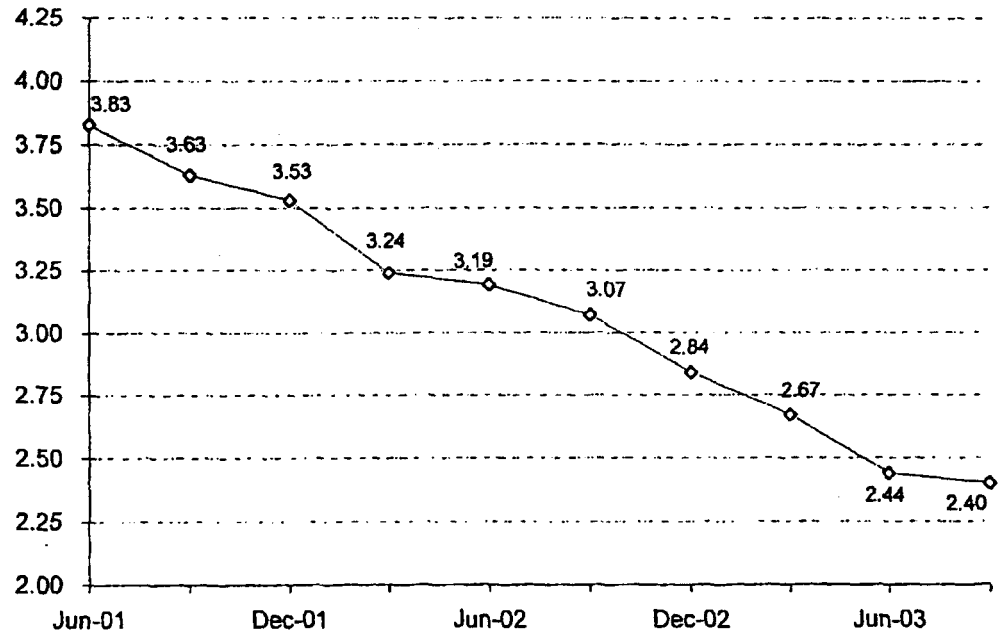
(d) Non-cash income is defined as Capitalized Interest and accelerated portion of ITC (beginning in 1/95).

(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

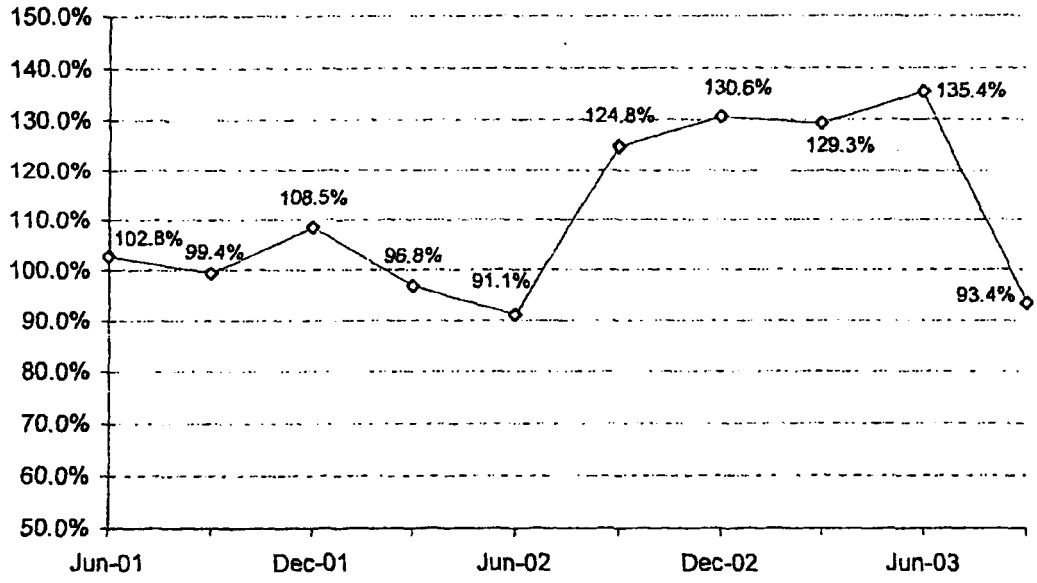
(f) Excludes Competitive Energy Trading and Purchases For Resale

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



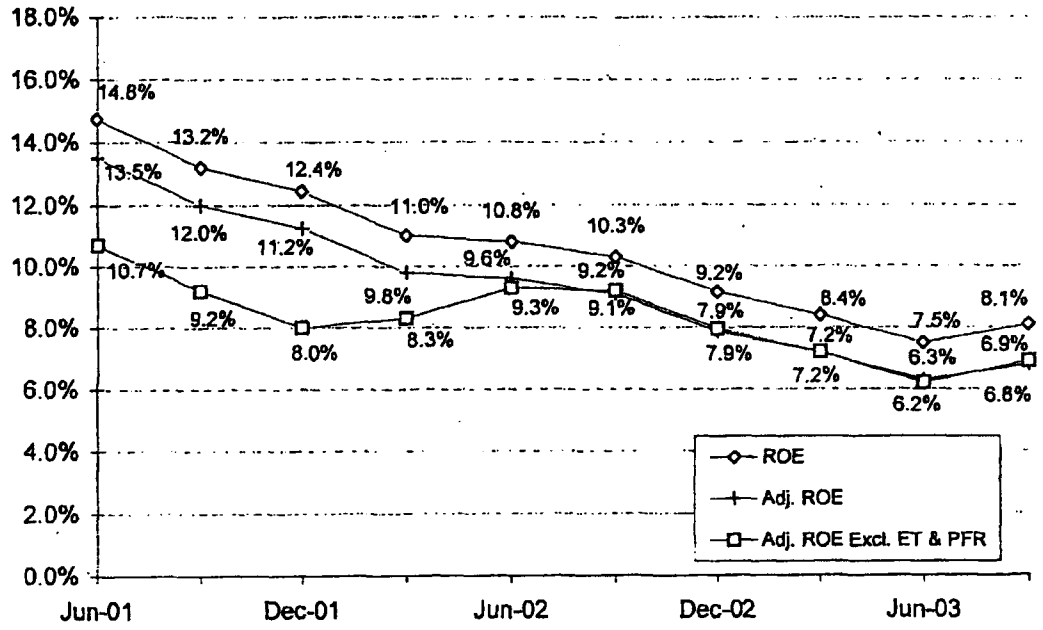
Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



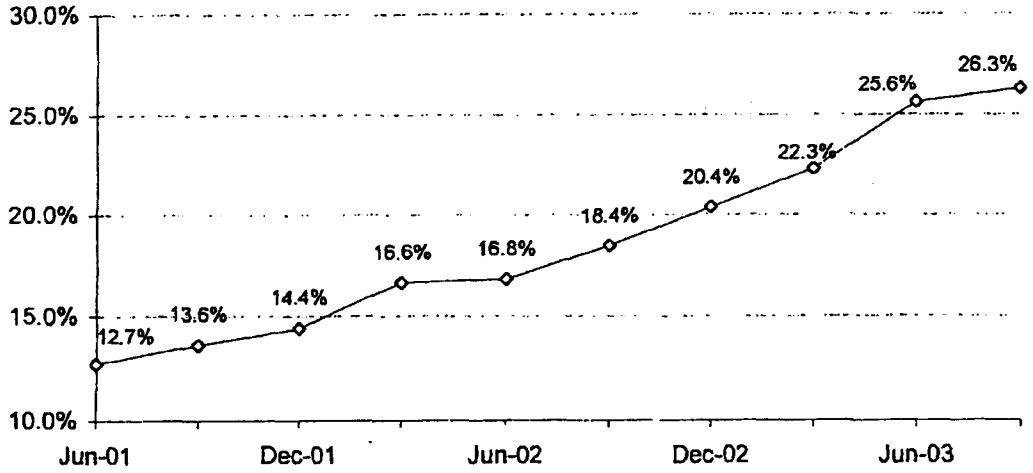
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

**Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale***



**Non-Cash Income
as a % of Earnings ***



* See notes on Financial Results page for explanation of calculations.

Jana Van Ness
Manager
Regulatory Compliance

Tel 602/250-2310
Fax 602/250-3003
E-Mail: Jana.VanNess@aps.com
http://www.apsc.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

August 29, 2003

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
SECOND QUARTER ENDING JUNE 30, 2003

Dear Mr. Johnson:

Attached are the Second Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending June 30, 2003.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness
Manager
Regulatory Compliance

JVN/srm

Attachment

Cc: John Thornton
Chief of Accounting & Rates

ARIZONA CORPORATION COMMISSION
RECEIVED
AUG 29 2003
Director of Utilities

ARIZONA PUBLIC SERVICE COMPANY

2003 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2002 Yr End	Q1	Q2	Q3	Q4	2003 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	42.5	31.8	63.3	0.0	0.0	0.0
FINANCING:						
Long-Term Debt	465.0	0.0	500.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	465.0	0.0	500.0	0.0	0.0	0.0
Change in S-T Debt	(171.2)	0.0	0.0	0.0	0.0	0.0
Total	$293.8	$0.0	$500.0	$0.0	$0.0	$0.0
Repayments and Reacquistions (a)	$337.1	$0.7	$33.7	$0.0	$0.0	$0.0
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	50.7%	50.9%	55.5%	0.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	50.7%	50.9%	55.5%	0.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	49.3%	49.1%	44.5%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	0.0%	0.0%	0.0%
Adjusted Debt Ratio (b)	54.9%	55.1%	58.8%	0.0%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	20.4%	22.3%	25.6%	0.0%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	130.6%	129.3%	135.4%	0.0%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.93	2.76	2.53	0.00	0.00	0
Before Tax excl. Non-Cash Inc. (d)	2.84	2.67	2.44	0.00	0.00	0
After Tax Incl. Preferred Div.	2.17	2.07	1.93	0.00	0.00	0
Return on Average Equity	9.2%	8.4%	7.5%	0.0%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.9%	7.2%	6.3%	0.0%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.9%	7.2%	6.2%	0.0%	0.0%	0.0%
Return on Avg. Total Capital	7.6%	7.3%	6.8%	0.0%	0.0%	0.0%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock

(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback

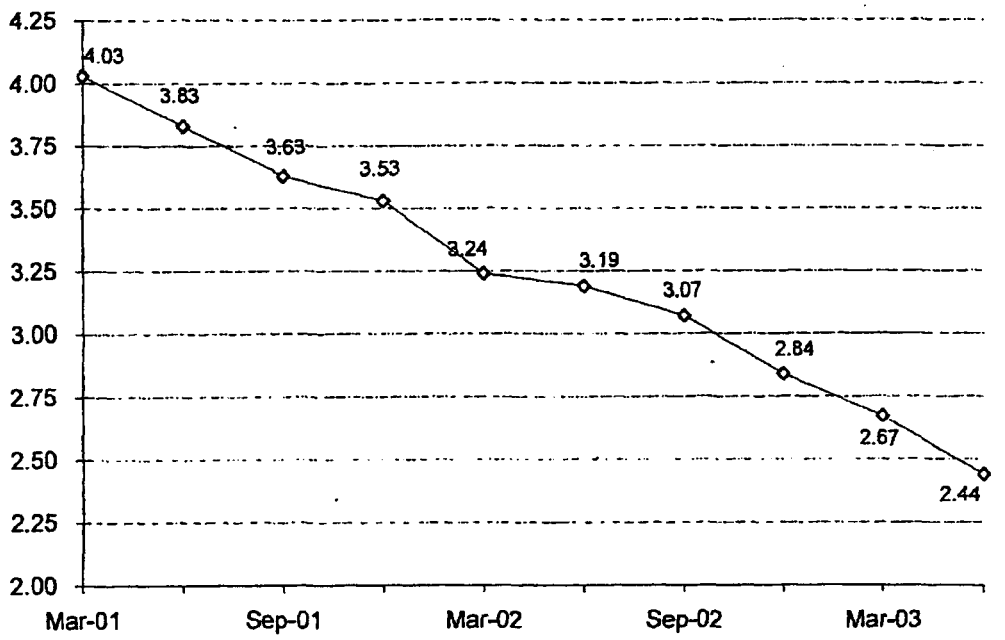
(d) Non-cash income is defined as Capitalized Interest and accelerated portion of ITC (beginning in 1/95).

(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

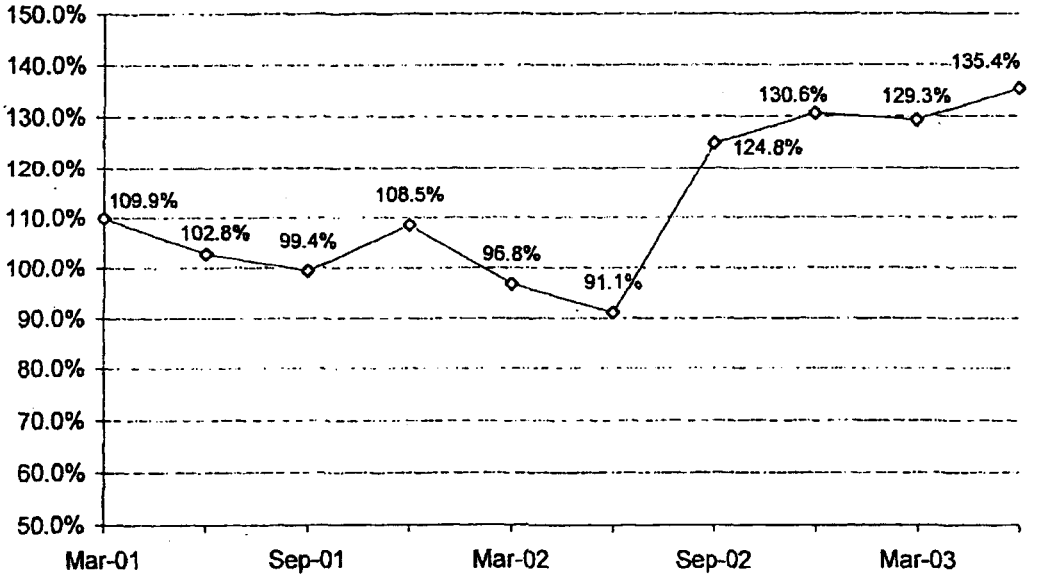
(f) Excludes Competitive Energy Trading and Purchases For Resale (revenues, energy costs, and operating expenses after income taxes).

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



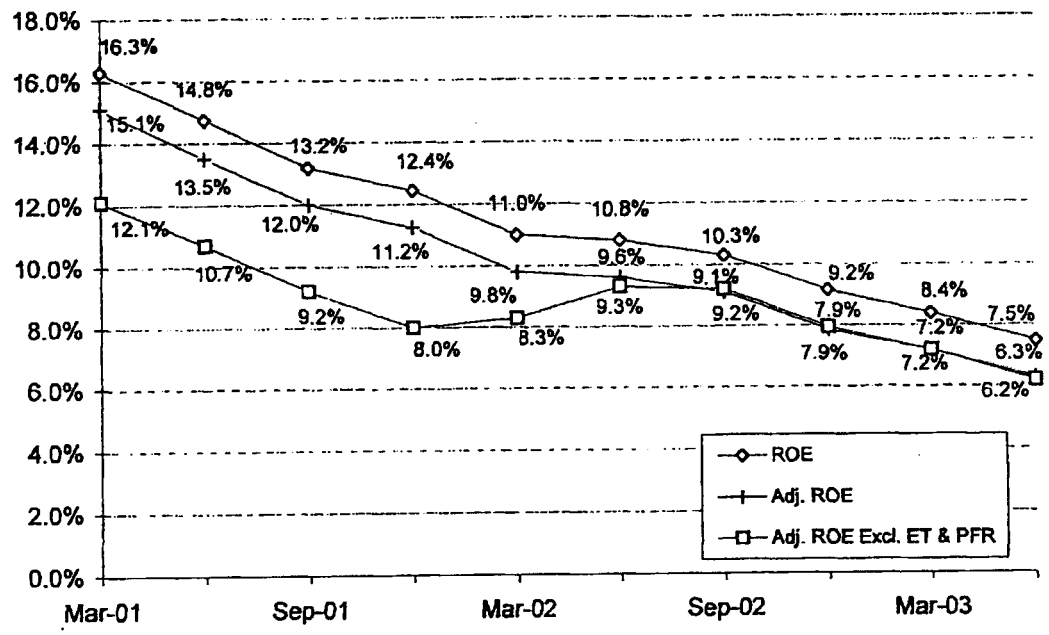
Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



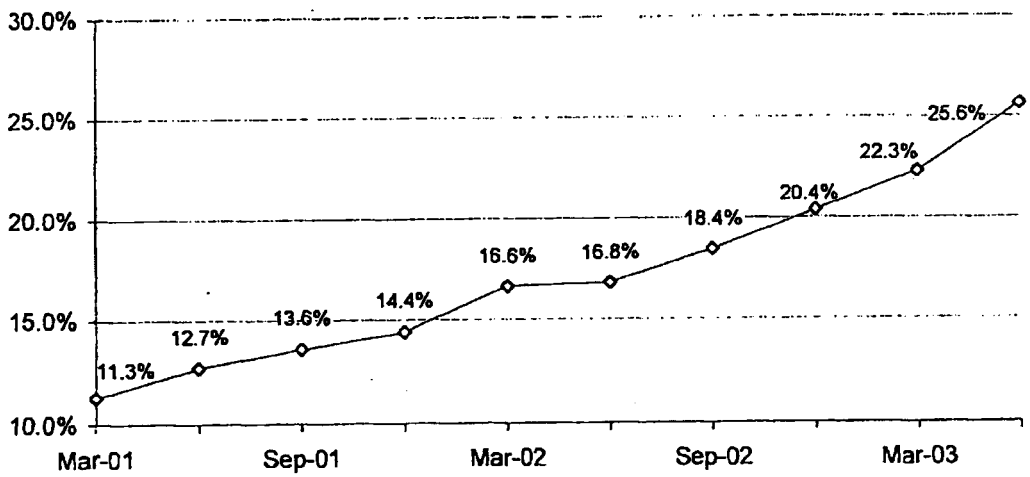
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

**Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale***



**Non-Cash Income
as a % of Earnings ***



* See notes on Financial Results page for explanation of calculations.

APS

Jana Van Ness
Manager
Regulatory Compliance

Tel 602/250-2310
Fax 602/250-3003
e-mail:jvanness@apsc.com
http://www.apsc.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

June 2, 2003

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

ARIZONA CORPORATION COMMISSION
RECEIVED
JUN - 2 2003
Director of Utilities

RE: APS FINANCIAL REPORT
FIRST QUARTER ENDING March 31, 2003

Dear Mr. Johnson:

Attached please find an update to the report for the First Quarter Financial Results for Arizona Public Service Company which was filed on Friday, May 30, 2003. The graphs that were filed were not complete, thus, a complete set of graphs is attached.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness
Manager
Regulatory Compliance

JVN/vld

Attachment

Cc: John Thornton
Chief of Accounting & Rates

ARIZONA PUBLIC SERVICE COMPANY

2003 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2002 Yr End	Q1	Q2	Q3	Q4	2003 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	42.5	31.8	0.0	0.0	0.0	0.0
FINANCING:						
Long-Term Debt	465.0	0.0	0.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	465.0	0.0	0.0	0.0	0.0	0.0
Change in S-T Debt	(171.2)	0.0	0.0	0.0	0.0	0.0
Total	$293.8	$0.0	$0.0	$0.0	$0.0	$0.0
Repayments and Reacquisitions (a)	$337.1	$0.7	$0.0	$0.0	$0.0	$0.0
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	50.7%	50.9%	0.0%	0.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	50.7%	50.9%	0.0%	0.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	49.3%	49.1%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Adjusted Debt Ratio (b)	54.9%	55.1%	0.0%	0.0%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	20.4%	22.3%	0.0%	0.0%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	130.6%	129.3%	0.0%	0.0%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.93	2.76	0.00	0.00	0.00	0
Before Tax excl. Non-Cash Inc. (d)	2.84	2.67	0.00	0.00	0.00	0
After Tax Incl. Preferred Div.	2.17	2.07	0.00	0.00	0.00	0
Return on Average Equity	9.2%	8.4%	0.0%	0.0%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.9%	7.2%	0.0%	0.0%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.9%	7.2%	0.0%	0.0%	0.0%	0.0%
Return on Avg. Total Capital	7.6%	7.3%	0.0%	0.0%	0.0%	0.0%

NOTES:

(a) Includes premiums on reacquired debt and preferred stock

(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback

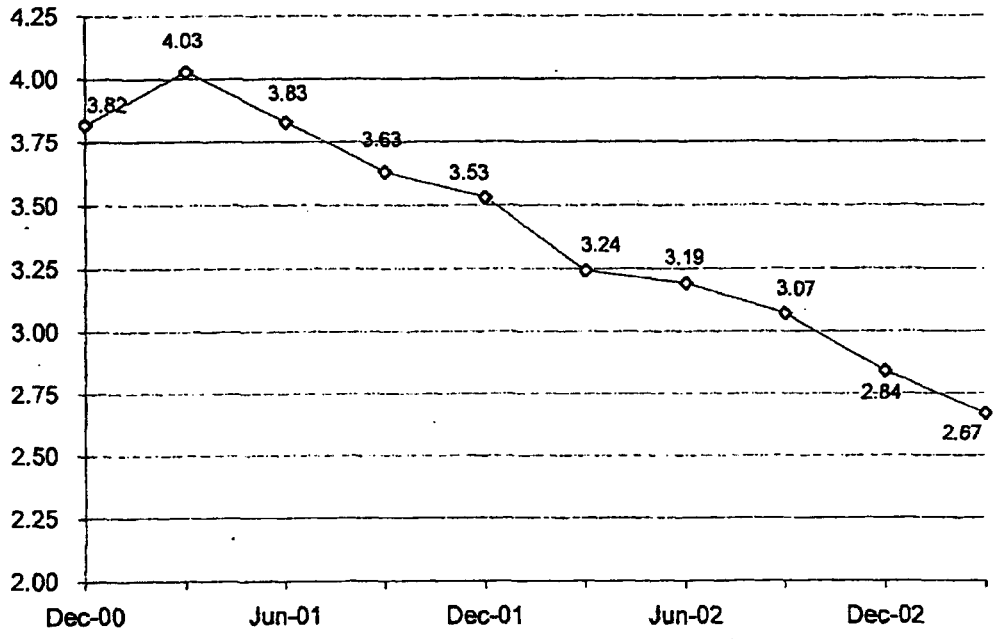
(d) Non-cash income is defined as Capitalized Interest and accelerated portion of ITC (beginning in 1/95).

(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

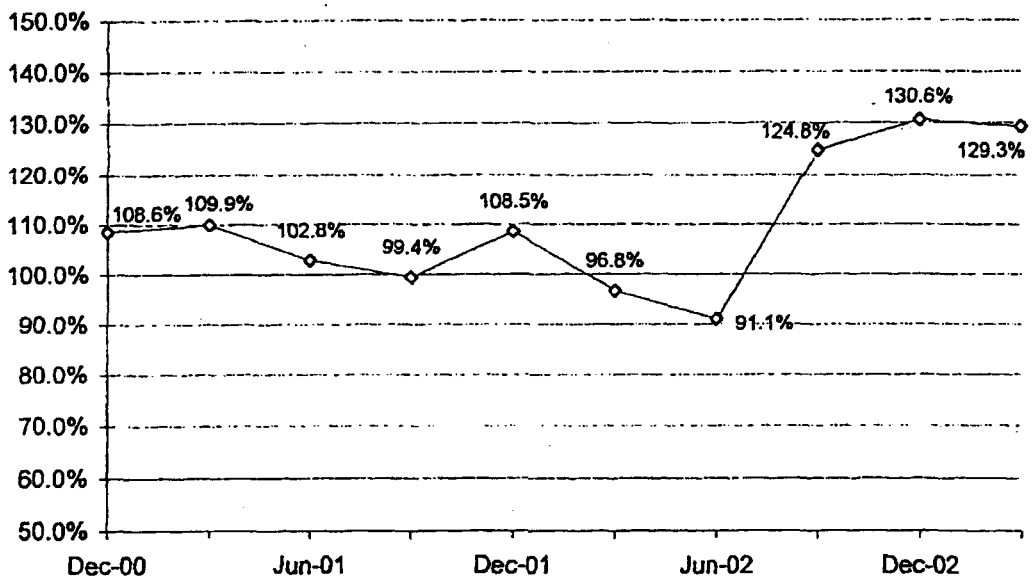
(f) Excludes Competitive Energy Trading and Purchases For Resale (revenues, energy costs, and operating expenses after income taxes).

ARIZONA PUBLIC SERVICE COMPANY

Fixed Charge Coverage Before Taxes Excluding Non-Cash Income *



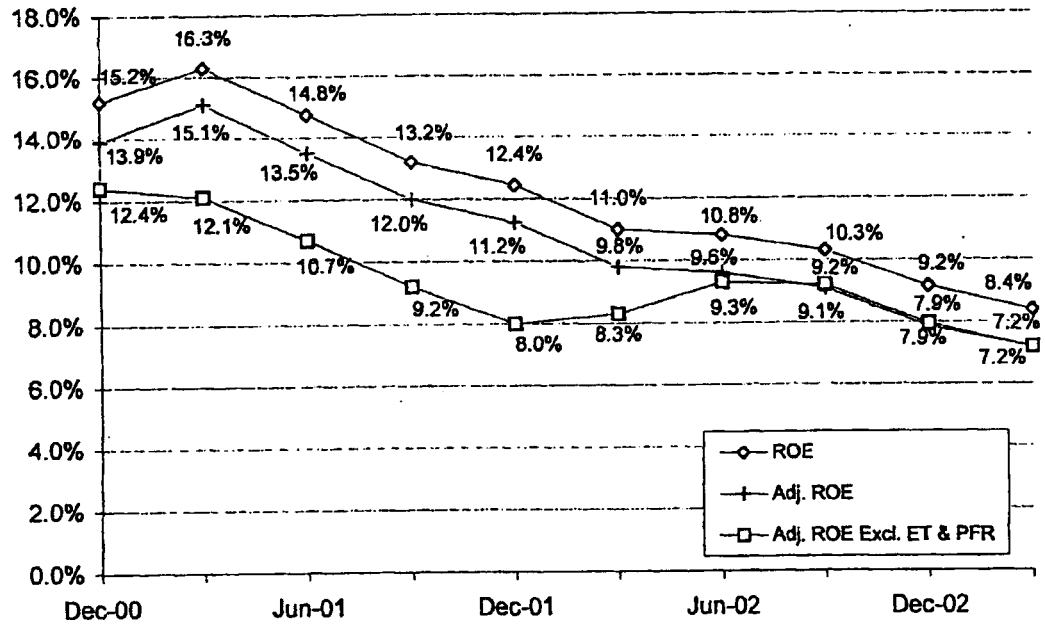
Net Cash Flow Excluding Non-Cash Income as a % of Capital Expenditures *



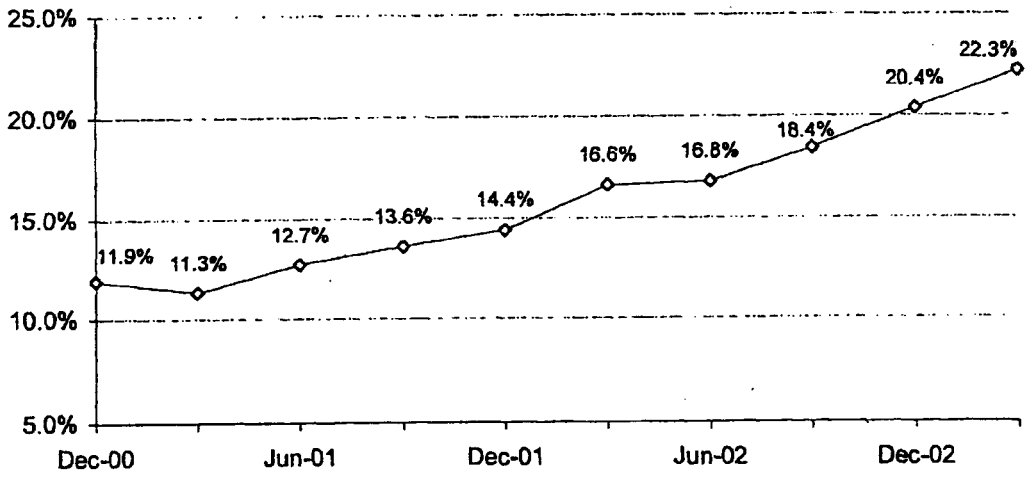
* See notes on Financial Results page for explanation of calculations.

ARIZONA PUBLIC SERVICE COMPANY

Return on Average Common Equity,
Adjusted Return on Average Equity, and
Adjusted Return on Avg. Equity Excl. - Comp. Energy Trading & Purch. For Resale*



Non-Cash Income
as a % of Earnings *



* See notes on Financial Results page for explanation of calculations.

APS

Jana Van Ness
Manager
Regulatory Compliance

Tel 602/250-2310
Fax 602/250-3003
e-mail:jvanness@apsc.com
http://www.apsc.com

Mail Station 9908
P.O. Box 53999
Phoenix, AZ 85072-3999

May 30, 2003

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: APS FINANCIAL REPORT
FIRST QUARTER ENDING March 31, 2003

Dear Mr. Johnson:

Attached is the First Quarter Financial Results and associated graphs for Arizona Public Service Company for the quarter ending March 31, 2003.

If you have any questions regarding this filing, please contact me at (602)250-2310.

Sincerely,

Jana Van Ness

Jana Van Ness
Manager
Regulatory Compliance

JVN/vld

Attachment

Cc: John Thornton
Chief of Accounting & Rates

ARIZONA CORPORATION
COMMISSION
RECEIVED
MAY 3 0 2003
Director of Utilities

ARIZONA PUBLIC SERVICE COMPANY

2003 ACTUAL FINANCIAL RESULTS
(DOLLARS IN MILLIONS)

	2002 Yr End	Q1	Q2	Q3	Q4	2003 Yr End
Short-Term Debt	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Cash & Cash Equivalents	42.5	31.8	0.0	0.0	0.0	0.0
FINANCING:						
Long-Term Debt	465.0	0.0	0.0	0.0	0.0	0.0
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	465.0	0.0	0.0	0.0	0.0	0.0
Change in S-T Debt	(171.2)	0.0	0.0	0.0	0.0	0.0
Total	$293.8	$0.0	$0.0	$0.0	$0.0	$0.0
Repayments and Reacquistions (a)	$337.1	$0.7	$0.0	$0.0	$0.0	$0.0
CAPITALIZATION RATIOS:						
Long-Term Debt (Including Current Maturities)	50.7%	50.9%	0.0%	0.0%	0.0%	0.0%
Short-Term Debt	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Debt	50.7%	50.9%	0.0%	0.0%	0.0%	0.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Common Equity	49.3%	49.1%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Adjusted Debt Ratio (b)	54.9%	55.1%	0.0%	0.0%	0.0%	0.0%
Non-Cash Income % Earnings (d) (e)	20.4%	22.3%	0.0%	0.0%	0.0%	0.0%
Net Cash Flow excl. Non-Cash Inc. % of Capital Expenditures (d)	130.6%	129.3%	0.0%	0.0%	0.0%	0.0%
TIMES EARNED COVERAGES:						
Before Tax	2.93	2.76	0.00	0.00	0.00	0
Before Tax excl. Non-Cash Inc. (d)	2.84	2.67	0.00	0.00	0.00	0
After Tax Incl. Preferred Div.	2.17	2.07	0.00	0.00	0.00	0
Return on Average Equity	9.2%	8.4%	0.0%	0.0%	0.0%	0.0%
Adjusted Return on Average Equity (e)	7.9%	7.2%	0.0%	0.0%	0.0%	0.0%
Adj. Return on Avg. Equity Excl E.T. & P.F.R. (e) (f)	7.9%	7.2%	0.0%	0.0%	0.0%	0.0%
Return on Avg. Total Capital	7.6%	7.3%	0.0%	0.0%	0.0%	0.0%

NOTES:

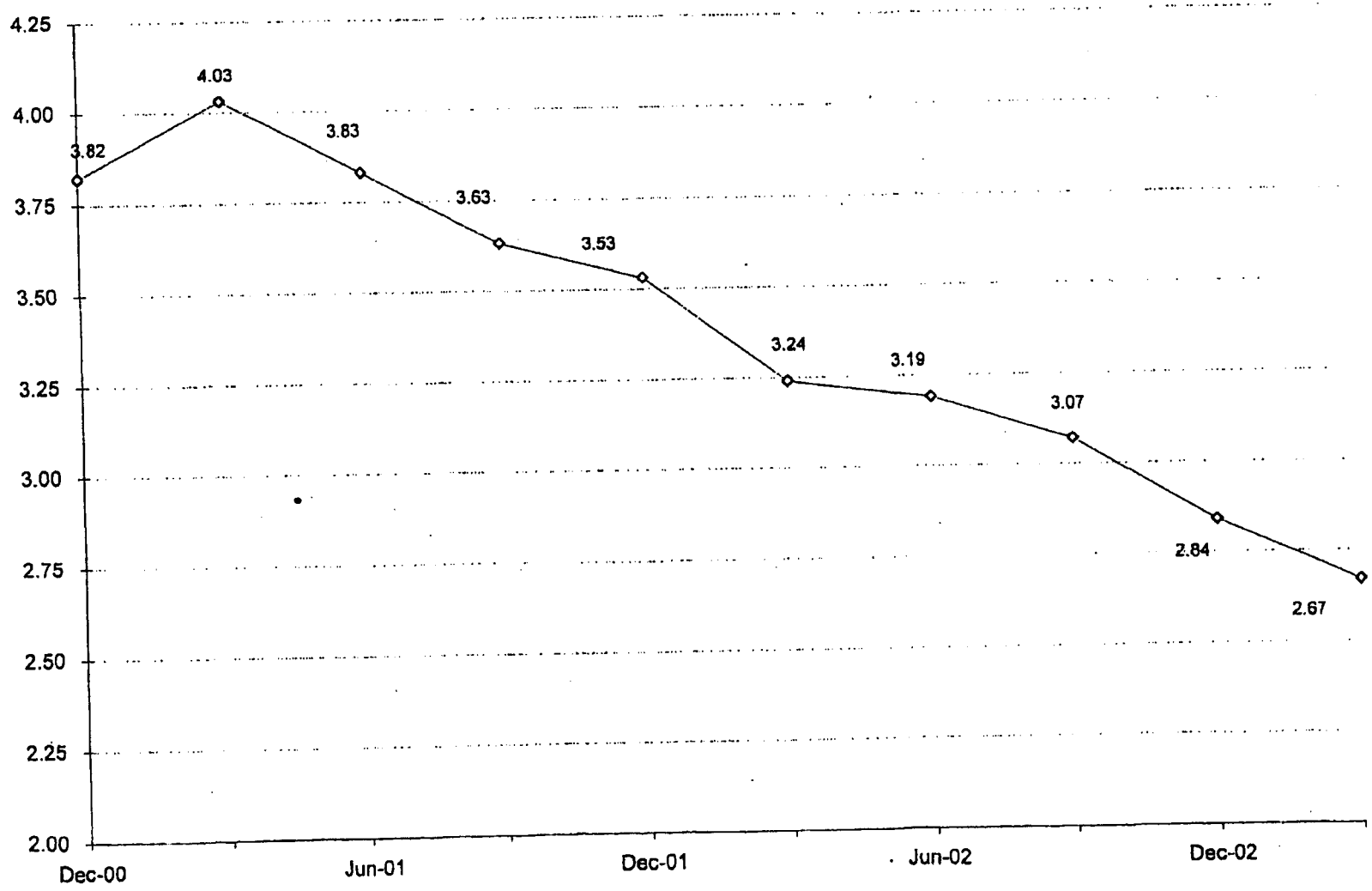
(a) Includes premiums on reacquired debt and preferred stock

(b) Adjusted Debt Ratio includes Palo Verde Unit #2 sale/leaseback

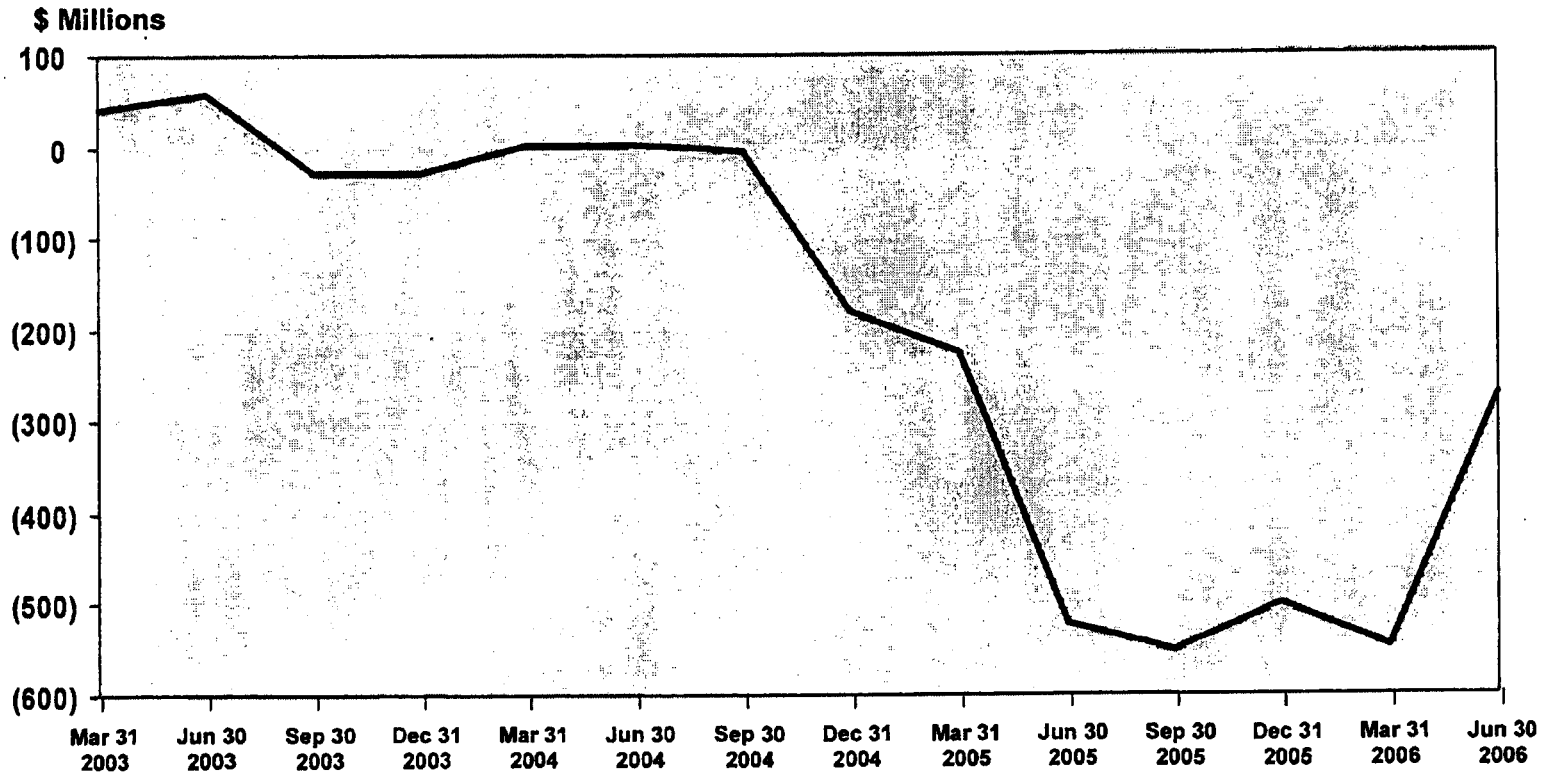
(d) Non-cash income is defined as Capitalized interest and accelerated portion of ITC (beginning in 1/95).

(e) Amortization of $183 million present value stranded revenue disallowance is included in adjustment starting with 9/99 financial results.

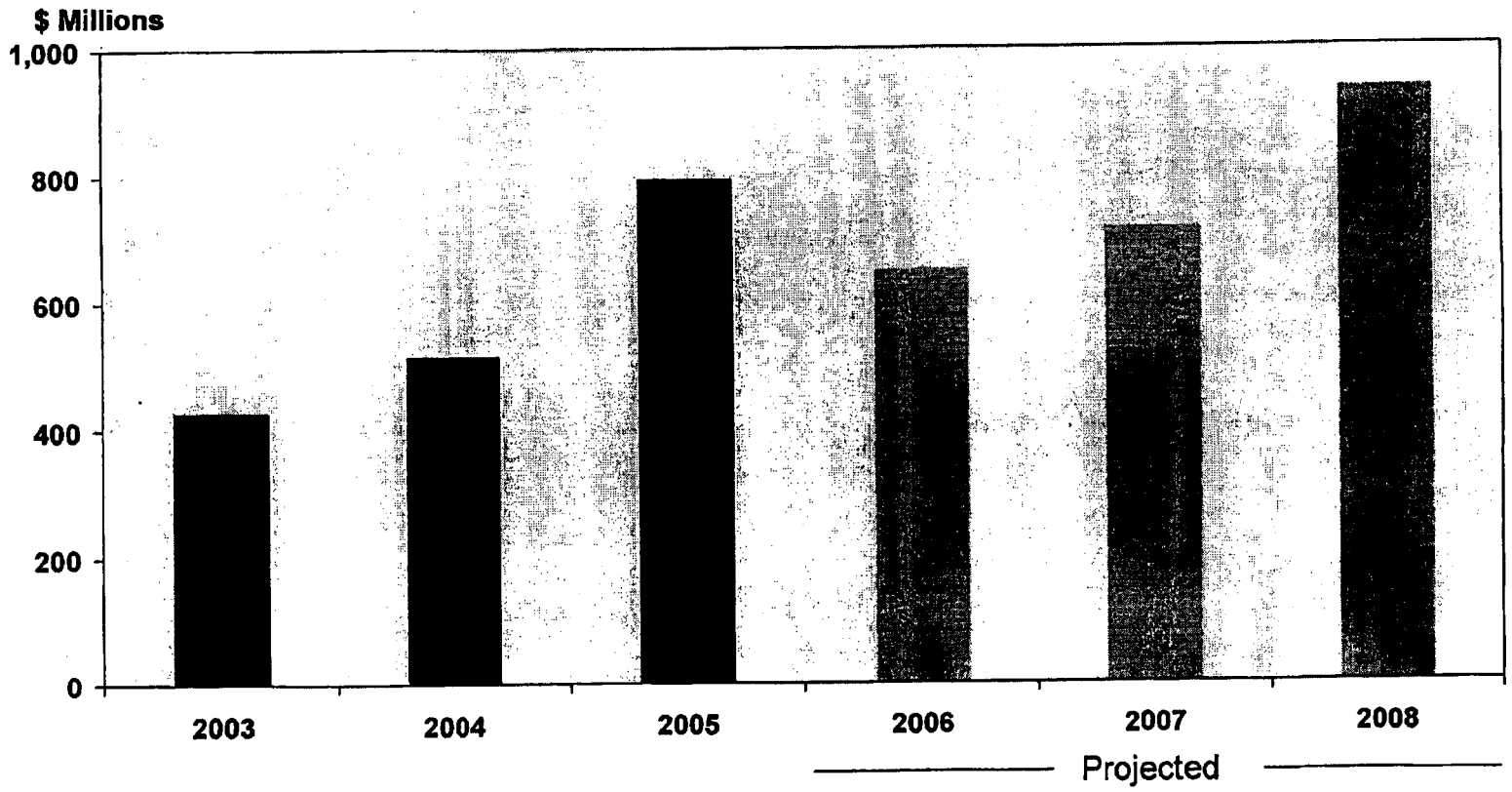
(f) Excludes Competitive Energy Trading and Purchases For Resale (revenues, energy costs, and operating expenses after income taxes).


4.25
4.00
3.75
3.50
3.25
3.00
2.75
2.50
2.25
2.00
3.82
4.03
3.83
3.63
3.53
3.24
3.19
3.07
2.84
2.67
Dec-00
Jun-01
Dec-01
Jun-02
Dec-02

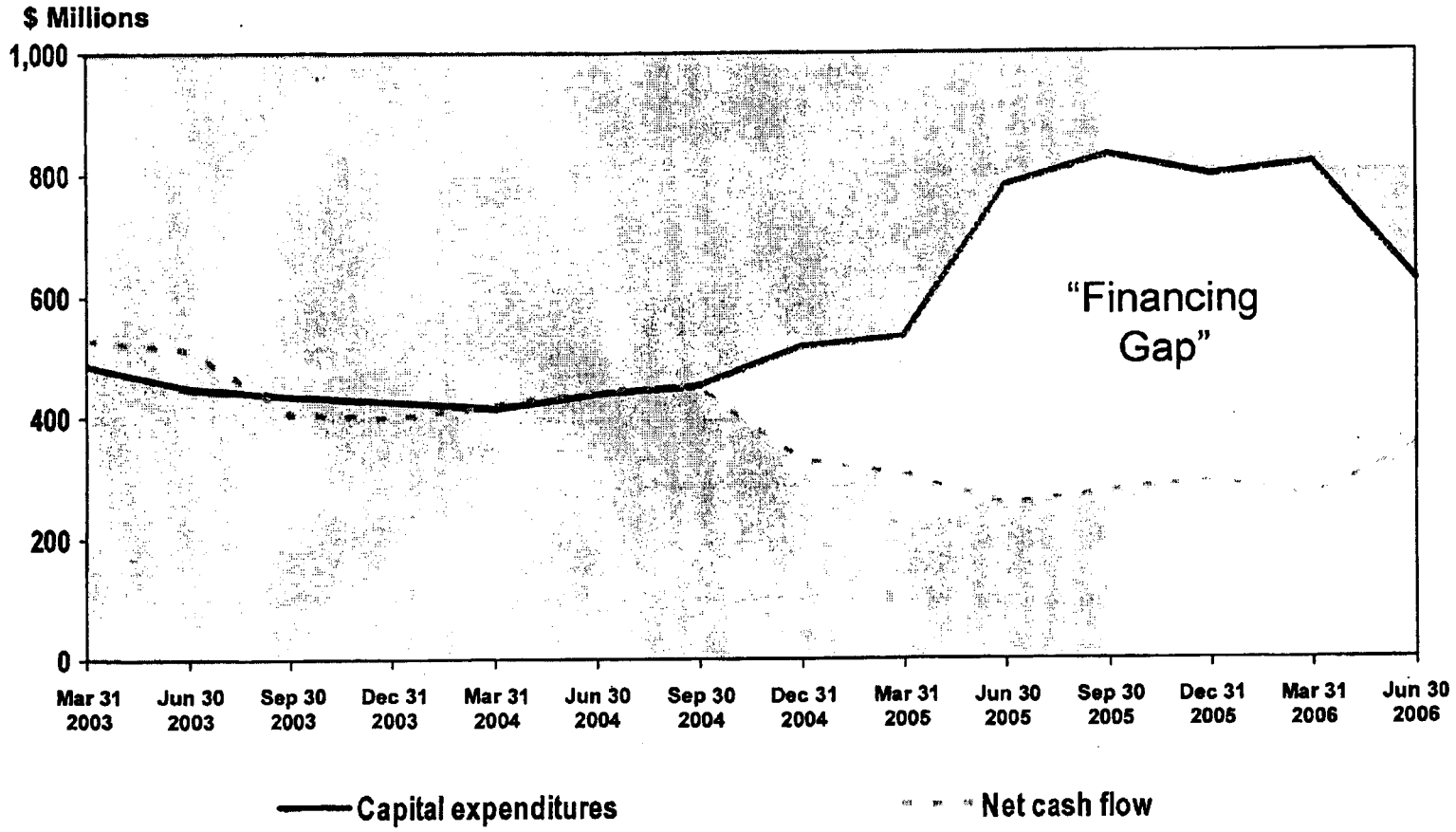
Arizona Public Service Company
Net Cash Flow after Capital Expenditures
Twelve-Month Periods Ended March 31, 2003 to June 30, 2006



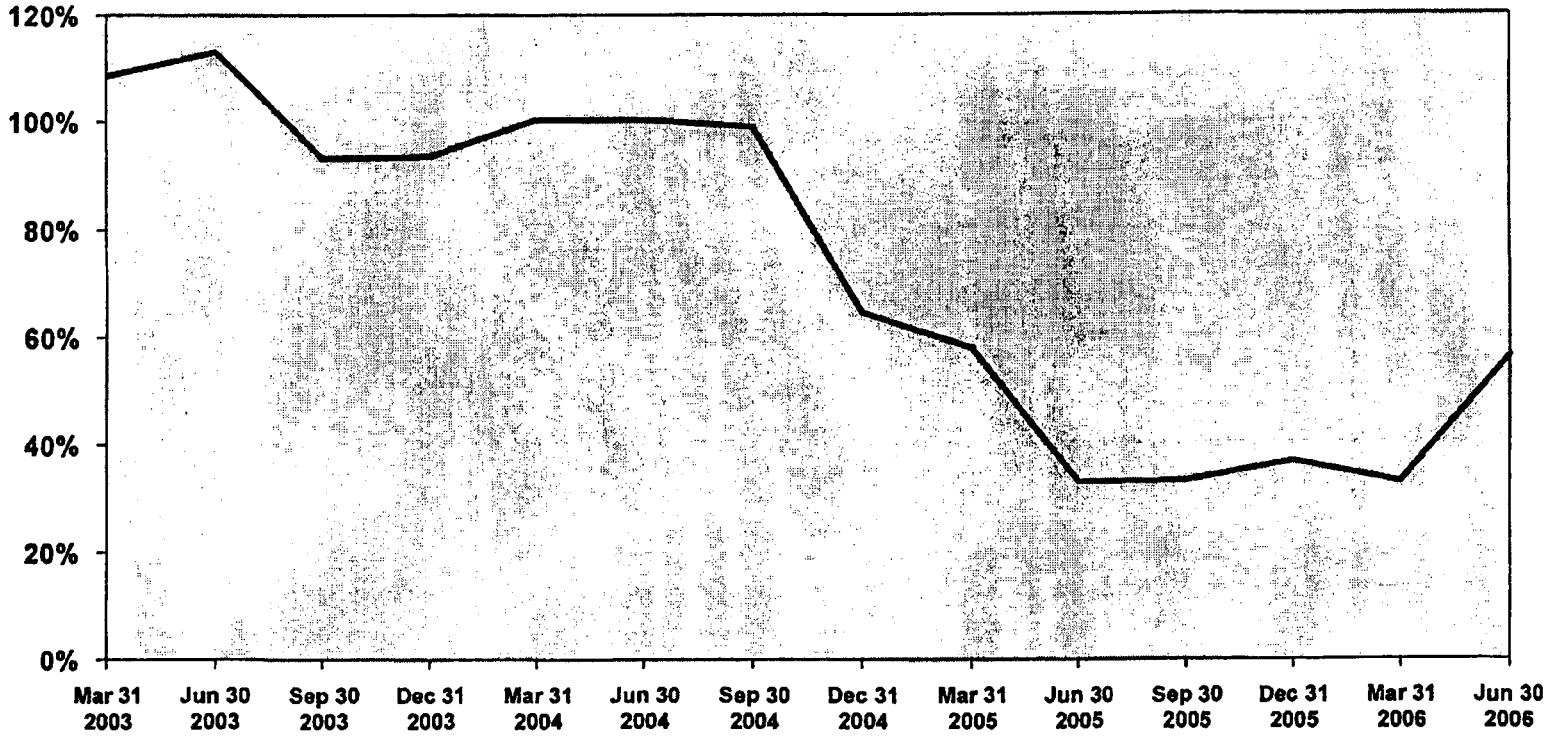
Arizona Public Service Company
Capital Expenditures
2003 - 2008



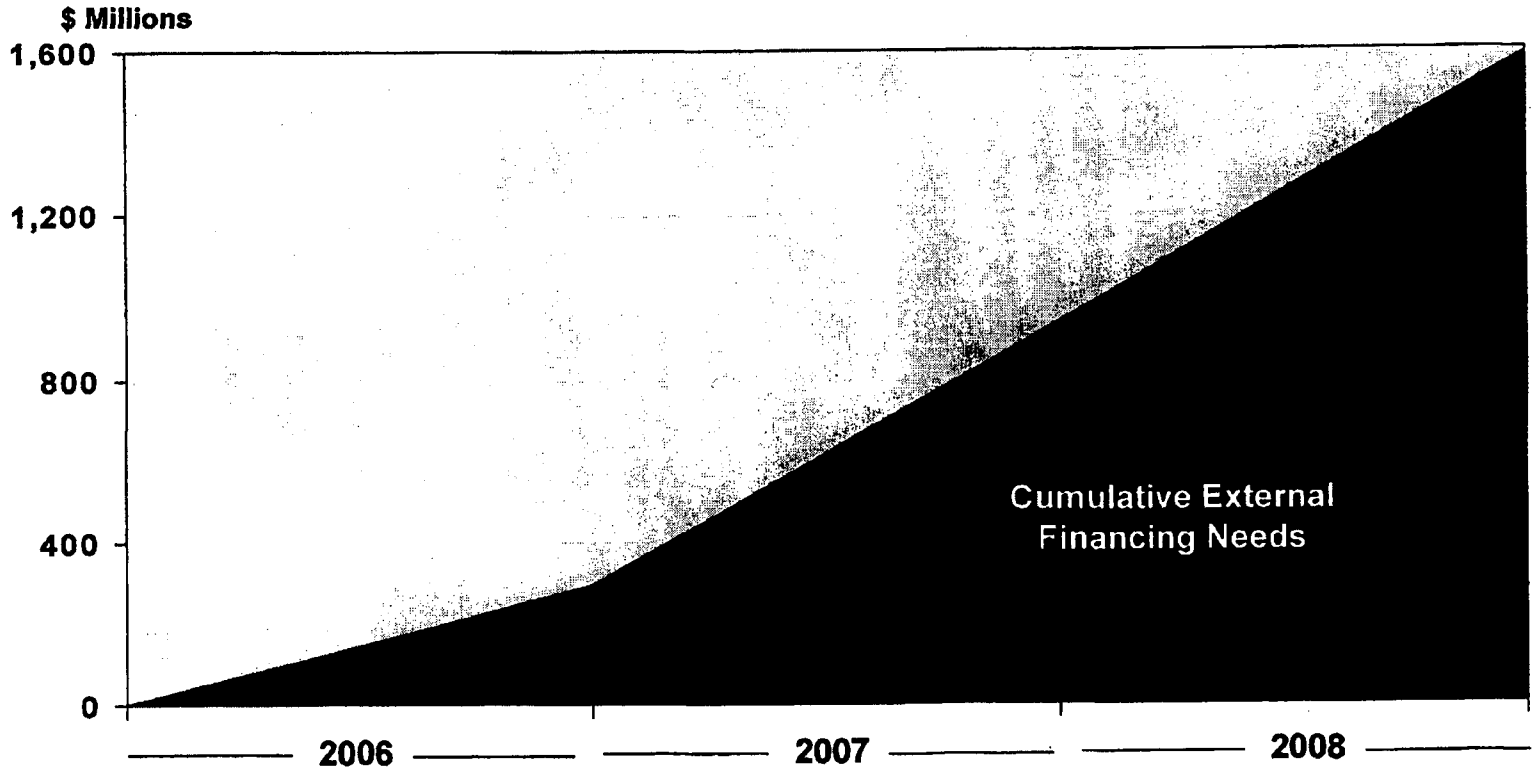
Arizona Public Service Company
Capital Expenditures vs. Net Cash Flow
Twelve-Month Periods Ended March 31, 2003 to June 30, 2006



Arizona Public Service Company
Net Cash Flow as Percent of Capital Expenditures
Twelve-Month Periods Ended March 31, 2003 to June 30, 2006



Arizona Public Service Company
Cumulative External Financing Needs Under Current Base Rate Levels
2006 - 2008



COMMISSIONERS
JEFF HATCH-MILLER - Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

BRIAN C. McNEIL
Executive Director

RECEIVED
ARIZONA CORPORATION COMMISSION
2006 JUL 21 A 8:56
AZ CORP COMMISSION
DOCUMENT CONTROL

June 21, 2006

Mr. Thomas Mumaw
Arizona Public Service
P.O. Box 53999
Phoenix, Arizona 85072-3999

Re: Arizona Public Service Company General Rate Case (Docket No. E-01345A-05-0816)

Dear Mr. Mumaw:

On July 19, 2006, Energy Central referenced a new report published by Standard & Poor's, entitled *U.S. Public Power Utilities' Self-Governance Bolsters Credit Quality*. This report explains the advantages public power utilities have over investor-owned utilities in terms of weathering significant increases in natural gas prices and purchased power costs, as well as preserving credit ratings and financial margins.

I request that a copy of this report be docketed in the APS General Rate Case and, if available electronically, forwarded to me and my colleagues. I believe this report could provide invaluable insight to aid the Commission in evaluating the importance of improving the financial metrics for APS.

As you know, APS is tasked with funding an enormous CAPEX budget of **$3.1 billion** over the next five years for generation, transmission and distribution projects. These improvements are presumed necessary to ensure the adequacy and reliability of electric service in addition to meeting estimated load growth of 4 percent per year. A portion of your company's CAPEX budget will be funded by the bond market. Your ratepayers stand to save money in long-term borrowing costs if your credit ratings hold or improve.

Based on the S&P report, please provide testimony on what measures the Commission could take in helping APS gradually improve its creditworthiness.

Thank you for your attention to this matter.

Sincerely,

Jeff Hatch-Miller
Chairman

CC: Commissioner William A. Mundell
Commissioner Marc Spitzer
Commissioner Mike Gleason
Commissioner Kristin Mayes
Parties to the Docket

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

U.S. Public Power Utilities' Self-Governance Bolsters Credit Quality

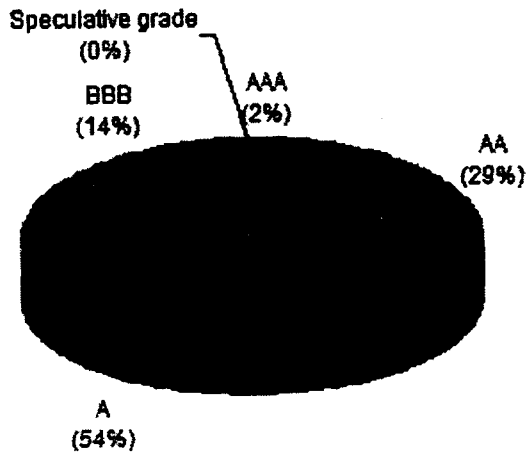
Publication date: 19-Jul-2006
Primary Credit Analyst: David Bodek, New York (1) 212-438-7969; mailto:david_bodek@standardandpoors.com

(**Editor's Note:** This article was adapted from a speech given at JPMorgan's 2006 Public Power and Gas Conference on May 11, 2006.)

Standard & Poor's Ratings Services has a favorable view of the U.S. public power sector. This is evident from a ratings distribution for public power utilities that very closely mirrors credit quality in the water and sewer sectors, even though public power utilities face greater operational and market challenges. In the public power and water and sewer utility sectors, 85% of the ratings are in the 'A' category or higher. Given the complex issues facing the power sector as compared with those facing water and sewer utilities, the similarities in the ratings distributions is really quite extraordinary.

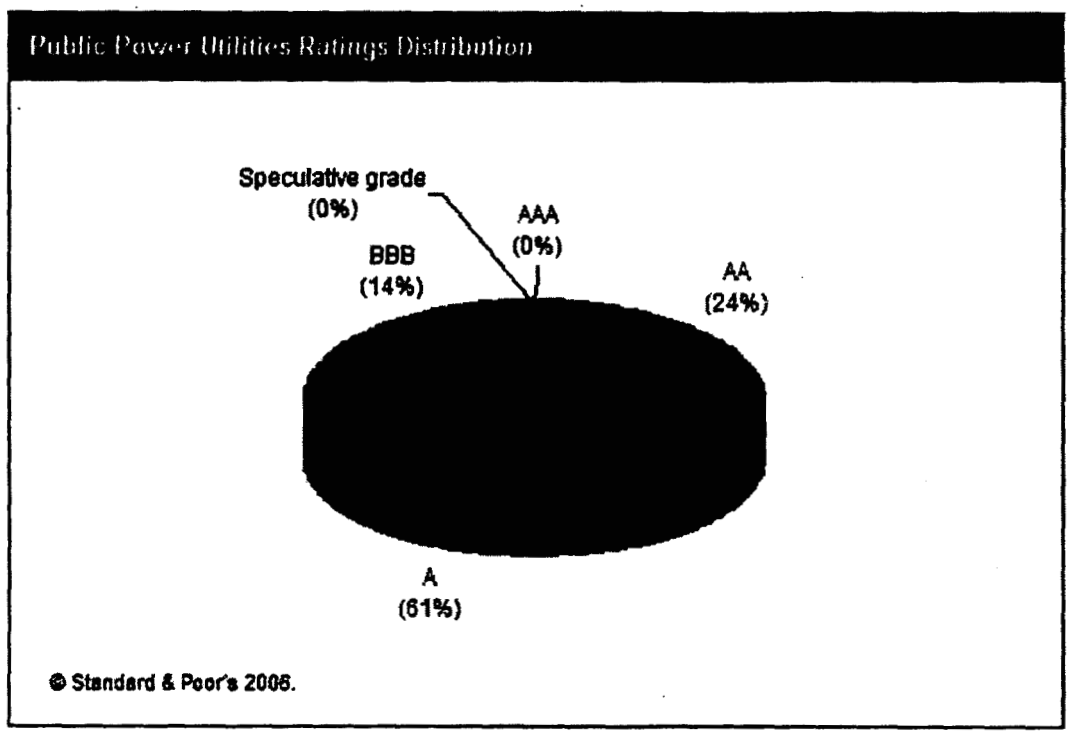
Chart 1

Municipal Water And Sewer Utilities Ratings Distribution



© Standard & Poor's 2006.

Chart 2



The similar ratings on utilities in these two sectors are based on several attributes that distinguish public power and other municipal utilities from investor-owned utilities. Like water and sewer utilities, the credit quality of public power utilities tends in the first instance to be defined by the interplay between autonomous rate setting authority and service area demographics. Autonomous rate setting is an important driver of credit quality because it provides public power utilities with the tools needed to respond quickly to changes in operating costs or capital needs. There are instances where public power utilities have chosen not to take advantage of these tools, which has had rating implications, but these tend to be limited cases. Examples in recent years included the electric utilities serving Lodi, Calif. and Jacksonville, Fla.

This rate setting authority continues to be one of the key factors that distinguishes the ratings on public power utilities from those on investor-owned electric utilities. The credit quality of investor-owned utilities generally suffers as a result of the regulatory lag and the potential for regulatory disallowances of costs.

Last year, the advantages of autonomous rate setting authority and the benefits of pass through mechanisms were in evidence as public power utilities successfully weathered dramatic increases in natural gas prices, preserving their financial margins and credit ratings. In fact, Illinois Municipal Energy Agency preserved a strong alignment of revenues and expenses during this period and was upgraded to reflect this and other positive developments.

In the rate adjustment arena, public power has also shown that slow and steady wins the race. Public utilities tend to implement palatable incremental rate adjustments to preserve financial performance and flexibility. Just compare investor-owned utilities in states like Illinois and Maryland where long-term rate freezes will soon expire and customers and legislators are fretting over prospects of steep rate increases.

That is not to say that public power is immune from these problems. Los Angeles' Department of Water and Power provides a case in point. There, rates were frozen about 10 years ago. The utility is now finding that it must jump through many hoops before it can implement a power cost adjustment mechanism and has needed to retain a third-party consultant to demonstrate to city council and community groups that rate adjustments are needed in response to higher costs.

Another important factor supporting strong credit quality among public power utilities is their narrow strategic focus and limited business scope compared with investor-owned utilities. By and large, public power utilities have not digressed from a business model under which management teams dedicate their efforts to providing reliable, reasonably priced electric service--no more, no less. This has meant that public power utilities have not placed capital at risk in the pursuit of elusive profits as many investor-owned utilities have done. In fact, the pursuit of earnings growth has proved to be the Achilles heel for the financial performance and credit quality of many companies in the investor-owned sector in recent years.

Much of what has been cited so far in support of public power's strengths can be said for water and sewer utilities. Yet, public power is different. Public power ratings are not solely premised on rate setting, a conservative business model, and demographics. Our public power ratings also incorporate operational issues that eclipse those facing water and sewer utilities.

Public power utilities face significant risks, including:

- Fuel price volatility,
- Wholesale electricity commodity price volatility,
- Fuel supply issues, including transportation issues that are plaguing many coal-dependent utilities,
- Transmission issues, and
- The need for management to understand and deploy complicated risk management tools.

These are only a few of the myriad issues facing public power. Even so, the addition of these elements of risk to our analysis has nevertheless yielded a strong collective credit profile for the public power sector.

As a result of the differences in the qualitative challenges facing the two sectors, there are fewer public power utilities rated 'AA' compared with water and sewer utilities, but the approximately five percentage point difference is small.

It is our view that public power has the potential to preserve its strong credit quality as is evidenced by the stable outlooks associated with 92% of our public power ratings. Just the same, ongoing rating stability is not something that will happen of its own accord. Public power utilities will continue to need to actively demonstrate the presence of the technical and political wherewithal to deal with significant challenges that lie ahead.

The principal challenges that we see on the horizon are tied to:

- Resource needs,
- Fuel supply,
- Environmental compliance including renewable portfolio standards and, as history has shown,
- Unforeseen challenges.

Resource needs are of particular significance to the power industry at this time. It has been many years since public power utilities have, as a group, embarked on significant baseload-generation additions. Now, numerous public power utilities across the country are responding to the need for additional baseload capacity to serve customers.

California's Sacramento Municipal Utility District recently added a 500 MW combined cycle gas turbine to

its fleet. South Carolina's Santee Cooper is in the process of adding two 580 MW coal-fired baseload units. Santee Cooper's board also approved a third coal unit. Beyond Santee Cooper, the Southeast is replete with evidence of baseload capacity additions. For example, the several utilities serving various Florida cities such as Gainesville, Jacksonville, Tallahassee, and others are all at various stages in their pursuit of baseload coal capacity additions. The American Heartland is also very much a part of this pursuit as is evidenced by public power investments in Prairie State Energy Campus, Council Bluffs Energy Center, Iatan Unit 2, and Nebraska City Unit 2.

As sizable projects proceed, the preservation of credit quality will hinge on a demonstration that those pursuing these projects can appropriately manage all of the associated risks, including:

- Construction risk;
- Uncertainty of future energy markets, including the ability to manage any surplus capacity that might result from capacity additions;
- Fuel risk, including price risk as well as sufficiency of supply and transportation; and
- Co-owner risk that may arise from partnering with companies in the independent power producer sector or even with co-owners of varying credit quality within the public power community as part of a joint powers authority.

It is our view that, with few exceptions, the public power community has repeatedly risen to the challenges presented by a very dynamic energy marketplace. The preponderance of stable outlooks reflects our expectations that public power utilities will continue to respond to the cited risks and changes in circumstances in a manner consistent with the preservation of credit quality. We expect the public power community to continue to use their financial flexibility and self governance as tools for preserving financial metrics. Consequently, we continue to have a very robust view of the public power sector's credit quality.

Analytic services provided by Standard & Poor's Ratings Services (Ratings Services) are the result of separate activities designed to preserve the independence and objectivity of ratings opinions. The credit ratings and observations contained herein are solely statements of opinion and not statements of fact or recommendations to purchase, hold, or sell any securities or make any other investment decisions. Accordingly, any user of the information contained herein should not rely on any credit rating or other opinion contained herein in making any investment decision. Ratings are based on information received by Ratings Services. Other divisions of Standard & Poor's may have information that is not available to Ratings Services. Standard & Poor's has established policies and procedures to maintain the confidentiality of non-public information received during the ratings process.

Ratings Services receives compensation for its ratings. Such compensation is normally paid either by the issuers of such securities or third parties participating in marketing the securities. While Standard & Poor's reserves the right to disseminate the rating, it receives no payment for doing so, except for subscriptions to its publications. Additional information about our ratings fees is available at www.standardandpoors.com/usratingsfees.

Copyright © 1994-2006 Standard & Poor's, a division of The McGraw-Hill Companies.
All Rights Reserved. Privacy Notice

The McGraw-Hill Companies

Moody's Investors Service

Global Credit Research
New Issue
16 JUN 2006

New Issue: Salt River Agriculture Impr.& Power Dist., AZ

MOODY'S ASSIGNS Aa1 TO SALT RIVER PROJECT'S $296 MILLION REVENUE BONDS; OUTLOOK STABLE

SALT RIVER PROJECT HAS $2.2 BILLION OF RATED DEBT OUTSTANDING

Electric Utilities
AZ

Moody's Rating

ISSUE	RATING
Salt River Project Electric System Revenue Bonds, 2006 Series A	Aa1

Sale Amount	$296,000,000
Expected Sale Date	06/27/06
Rating Description	Revenue Bonds

Moody's Outlook Stable

Opinion

NEW YORK, Jun 16, 2006 -- Moody's Investors Service has assigned the credit rating of Aa1 on the Salt River Project Agricultural Improvement and Power District's (SRP) $296 million of revenue bonds scheduled for pricing June 27, 2006. The outlook is stable. Bond proceeds will fund a portion of SRP's capital improvement program. Moody's is also affirming the Aa1 rating on SRPs outstanding $2.2 billion of revenue bonds. Moody's upgraded to Aa1 from Aa2 the revenue bond rating on June 12, 2006 and also affirmed the Aa2 credit rating on SRP's Lease Purchase Obligation bonds ($282,680,000) and the P-1 rating on its commercial paper notes($475,000,000).

Moody's considered the following factors in the rating upgrade: lessened deregulation risk; SRP's strong self-regulated governance including its timely rate setting process; SRP's historical and forecasted electricity pricing plan that incorporates objectives of strong debt service coverage margins and sound financial liquidity; a significant competitive rate advantage; a demonstrated well-defined and diversified power resource plan which allows for the management of risk exposures such as the shutdown of the Mohave Generating Station and debt ratios that continue to moderate.

LEGAL SECURITY: Bonds are secured by a pledge of and lien on the net revenues of the electric system.

INTEREST RATE DERIVATIVES: SRP has a $75 million fixed to floating rate swap. The SRP board has a defined oversight process and swap policy. SRP's rates are unregulated and increased interest costs could be included in SRP's rates.

STRENGTHS:

*Strong financial management which has consistently met targets of sound financial margins, strong liquidity given its risks and a below average and declining debt ratio

*Effective strategic planning which has historically met the challenges of demand growth in the Phoenix service area

*Unregulated rate setting and demonstrated record of timely rate increases to recover costs

*Average sales price is very competitive within the region

*Largely residential customer base with no dominant customers

CHALLENGES:

*Cost pressures related to ownership of nuclear generation including security, waste storage and decommissioning

*Potential future cost pressures related to SRP's coal-fired generation facilities and continued compliance with the federal clean air act

*Mohave Generating Station water supply and coal issues

*Additional gas units at Santan Generating Station have increased SRP's exposure to natural gas price risk

*Continued management of demand growth

MARKET POSITION/COMPETITIVE STRATEGY:

SOUND COST RECOVERY AUTHORITY HAS PROVIDED FOR STRONG DEBT SERVICE COVERAGE MARGINS

SRP serves more than one-half the population of the Phoenix-Mesa metropolitan statistical area, which continues to experience strong growth. The service area of SRP is established by agreement between SRP and Arizona Public Service Company (APS)(rated Baa2 by Moody's).

An important credit factor is the unregulated rate authority of the SRP board. Under state statute, the publicly elected SRP board has the authority to establish electric prices and the board has been supportive of management. SRP has established a multi-year pricing strategy that takes into account maintenance of sound financial objectives including strong debt service coverage margins and liquidity.

On October 3, 2005, the SRP board approved a 2.9% system average price increase to fund SRP's capital improvement program. The FY 2007-2012 financial plan includes additional price increases to meet rising fuel costs and to fund further capital items and to maintain board financial targets.

Despite the general rate increase, SRP's prices remain well below APS's retail rates. The total rate comparison for 2005 indicates SRP has more than a 20% competitive advantage and SRP's rates also compare favorably to most of the major investor-owned utilities serving the western United States.

FINANCIAL PERFORMANCE/FINANCIAL POSITION:

WELL MANAGED AND STABLE FINANCIAL PERFORMANCE BASED ON THE SOUND FINANCIAL PLAN INCLUDING RISK MANAGEMENT STRATEGY

SRP's historically favorable operating results reflect both the soundness of its rate policy and the focus on risk management. The dominance of the residential component of SRP's energy sales also lends stability to budget planning. SRP's sound financial polices reflected in SRP's six-year Financial Plan (2007-2012) established various core financial indicators and set financial performance parameters, which management treats as critical benchmarks for future success. The 2007 financial plan is largely unchanged from the 2006 plan.

Between FY 2002 and FY 2005, SRP maintained an average of $299 million in funds available for corporate purposes and an average total debt service coverage ratio of 2.39 times. Unaudited financial results for FY 2006 also reflect debt service coverage in the mid two times range. Average debt service coverage is projected to exceed three times between 2007 and 2012.

Since 1996, SRP's debt ratio has fallen significantly from the 70% range to just 52.8% in 2005, well below that of peer utilities. Moody's believes SRP's demonstrated focus on its financial plan gives a good insight into the future financial strengths the utility will exhibit.

SRP's average electricity sales price is projected to remain relatively stable through 2012. To date, SRP, has been able to maintain rate stability for retail customers due to the success of its approach to energy risk management, which limits exposure to risks inherent in the normal course of the energy business, including commodity price fluctuations, credit risk of counterparties and operational risks.

CAPITAL PLAN: SIZABLE BUT WELL MANAGED POWER SUPPLY PLAN HAS ENSURED SRP MEETS CHALLENGE OF DEMAND GROWTH

SRP's 2007-2012 Capital Improvement Plan amounts to $4.8 billion, of which $4.5 billion is planned for construction of new generation, transmission and distribution facilities. Of the total capital plan, about $1.1 billion (about the same level as prior year) will fund new generation projects including the addition of new steam generators at Palo Verde Nuclear Generating Station and the construction of Springerville 4

Generating Station. About 65% of the six-year plan is expected to be funded from internally generated funds with the balance funded from debt.

SRP has a well-managed and diverse mix of power resources that contribute to its overall competitive and reliable power supply program. There are no dominant resources or power purchase contracts. Sustained demand growth in the Phoenix service area has been a continuing challenge for SRP but the utility has performed well against key reliability measurements. Peak demand growth between 2006-2011 is projected to increase by 1,130 MWs to 7,010 MWs. SRP has targeted a planned reserve margin of 12% in each of the next five years to ensure adequate and reliable power supply.

SRP has proceeded with a least cost option power resource plan which includes several new generation projects to meet its future demand growth. In 2003, SRP acquired the 575 MW Desert Basin natural-gas fired combined-cycle generation plant. In April 2005, the first phase of the Santan Generating Station, a 550MW natural gas fired generation facility, became commercial. The second phase of the Santan project (275 MW) became operational in 2006. SRP has also entered into an agreement with Unisource Energy Development Company for the joint development of the 800 MW Springerville project whereby SRP will purchase 100 MW of capacity from the Springerville Unit 3 for 30 years beginning in 2006. In addition, SRP has received the right to construct Unit 4 of the Springerville project, giving it some planning flexibility.

The long term role of the Mohave Generating Station in SRP's power resource plans remains under continued evaluation due to water and coal supply issues. While the uncertainty about this low cost power resource is a concern, SRP management has taken steps to mitigate the impacts of such a closure. SRP has already replaced a portion of the energy it had previously received from Mohave and is now evaluating several options, such as the Springerville project, for replacing the capacity if Mohave is not reopened.

Outlook

Moody's has a stable credit outlook on SRP's revenue bonds given the utility's strong management of its operations and power supply requirements.

What Could Change the Rating-UP: SRP is the highest rated U.S. public power electric utility.

What Could Change the Rating-DOWN: The rating could be revised downward should SRP lose its competitive advantage or if its strong financial ratios weaken below the level expected at its current rating level.

KEY FACTS:

Peak Demand, 2005: 6,669 MW

Total Debt Service Coverage, 2005: 2.39 times

SRP Energy Sources, 2005:

Coal: 43.8%

Gas and Oil: 18.1%

Nuclear: 14.5%

Long-term purchases: 11.6%

Debt Ratio, 1999: 72.9%

2005: 52.8%

DEBT STATEMENT as of April 30, 2006:

Electric System Revenue Bonds $2,244,445,000

Lease Purchase Obligations 282,680,000

Commercial Paper Notes 475,000,000

ISSUER CONTACT:

Mark Bonsall, Associate General Manager 602-236-5702

Analysts

Dan Aschenbach
Analyst
Public Finance Group
Moody's Investors Service

Thomas Paolicelli
Backup Analyst
Public Finance Group
Moody's Investors Service

Patrick Ford
Senior Credit Officer
Public Finance Group
Moody's Investors Service

Contacts

Journalists: (212) 553-0376
Research Clients: (212) 553-1653

© Copyright 2006, Moody's Investors Service, Inc. and/or its licensors including Moody's Assurance Company, Inc. (together, "MOODY'S"). All rights reserved.

ALL INFORMATION CONTAINED HEREIN IS PROTECTED BY COPYRIGHT LAW AND NONE OF SUCH INFORMATION MAY BE COPIED OR OTHERWISE REPRODUCED, REPACKAGED, FURTHER TRANSMITTED, TRANSFERRED, DISSEMINATED, REDISTRIBUTED OR RESOLD, OR STORED FOR SUBSEQUENT USE FOR ANY SUCH PURPOSE, IN WHOLE OR IN PART, IN ANY FORM OR MANNER OR BY ANY MEANS WHATSOEVER, BY ANY PERSON WITHOUT MOODY'S PRIOR WRITTEN CONSENT. All information contained herein is obtained by MOODY'S from sources believed by it to be accurate and reliable. Because of the possibility of human or mechanical error as well as other factors, however, such information is provided "as is" without warranty of any kind and MOODY'S, in particular, makes no representation or warranty, express or implied, as to the accuracy, timeliness, completeness, merchantability or fitness for any particular purpose of any such information. Under no circumstances shall MOODY'S have any liability to any person or entity for (a) any loss or damage in whole or in part caused by, resulting from, or relating to, any error (negligent or otherwise) or other circumstance or contingency within or outside the control of MOODY'S or any of its directors, officers, employees or agents in connection with the procurement, collection, compilation, analysis, interpretation, communication, publication or delivery of any such information, or (b) any direct, indirect, special, consequential, compensatory or incidental damages whatsoever (including without limitation, lost profits), even if MOODY'S is advised in advance of the possibility of such damages, resulting from the use of or inability to use, any such information. The credit ratings and financial reporting analysis observations, if any, constituting part of the information contained herein are, and must be construed solely as, statements of opinion and not statements of fact or recommendations to purchase, sell or hold any securities. NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER. Each rating or other opinion must be weighed solely as one factor in any investment decision made by or on behalf of any user of the information contained herein, and each such user must accordingly make its own study and evaluation of each security and of each issuer and guarantor of, and each provider of credit support for, each security that it may consider purchasing, holding or selling.

MOODY'S hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MOODY'S have, prior to assignment of any rating, agreed to pay to MOODY'S for appraisal and rating services rendered by it fees ranging from $1,500 to $2,400,000. Moody's Corporation (MCO) and its wholly-owned credit rating agency subsidiary, Moody's Investors Service (MIS), also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually on Moody's website at www.moodys.com under the heading "Shareholder Relations - Corporate Governance - Director and Shareholder Affiliation Policy."

This credit rating opinion has been prepared without taking into account any of your objectives, financial situation or needs. You should, before acting on the opinion, consider the appropriateness of the opinion having regard to your own objectives, financial situation and needs.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2005

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission File Number	Registrants; State of Incorporation; Addresses; and Telephone Number	IRS Employer Identification No.
1-8962	PINNACLE WEST CAPITAL CORPORATION (An Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0512431
1-4473	ARIZONA PUBLIC SERVICE COMPANY (An Arizona corporation) 400 North Fifth Street, P.O. Box 53999 Phoenix, Arizona 85072-3999 (602) 250-1000	86-0011170

Securities registered pursuant to Section 12(b) of the Act:

	Title Of Each Class	Name Of Each Exchange On Which Registered
PINNACLE WEST CAPITAL CORPORATION	Common Stock, No Par Value	New York Stock Exchange Pacific Stock Exchange
ARIZONA PUBLIC SERVICE COMPANY	None	None

Securities registered pursuant to Section 12(g) of the Act:
None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

PINNACLE WEST CAPITAL CORPORATION Yes ☑ No ☐
ARIZONA PUBLIC SERVICE COMPANY Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

PINNACLE WEST CAPITAL CORPORATION Yes ☐ No ☑
ARIZONA PUBLIC SERVICE COMPANY Yes ☑ No ☐

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

PINNACLE WEST CAPITAL CORPORATION Yes ☑ No ☐
ARIZONA PUBLIC SERVICE COMPANY Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or in any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer" and "large accelerated filer" in Rule 12b-2 of the Exchange Act.

PINNACLE WEST CAPITAL CORPORATION
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐
ARIZONA PUBLIC SERVICE COMPANY
Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☑

Indicate by check mark whether each registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☑

State the aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of each registrant's most recently completed second fiscal quarter:

PINNACLE WEST CAPITAL CORPORATION $4,359,721,018 as of June 30, 2005
ARIZONA PUBLIC SERVICE COMPANY $0 as of June 30, 2005

The number of shares outstanding of each registrant's common stock as of March 7, 2006

PINNACLE WEST CAPITAL CORPORATION 99,166,990 shares
ARIZONA PUBLIC SERVICE COMPANY Common Stock, $2.50 par value, 71,264,947 shares. Pinnacle West Capital Corporation is the sole holder of Arizona Public Service Company's Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Pinnacle West Capital Corporation's definitive Proxy Statement relating to its Annual Meeting of Shareholders to be held on May 17, 2006 are incorporated by reference into Part III hereof.

Arizona Public Service Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format allowed under that General Instruction.

This combined Form 10-K is separately filed by Pinnacle West Capital Corporation and Arizona Public Service Company. Each registrant is filing on its own behalf all of the information contained in this Form 10-K that relates to such registrant and, where required, its subsidiaries. Except as stated in the preceding sentence, neither registrant is filing any information that does not relate to such registrant, and therefore makes no representation as to any such information.

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,	
	2005	2004	2005	2004
Discount rate-pension	5.66%	5.84%	5.84%	6.10%
Discount rate-other benefits	5.68%	5.92%	5.92%	6.10%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets	N/A	N/A	9.00%	9.00%
Initial health care cost trend rate	8.00%	8.00%	8.00%	8.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%	5.00%
Year ultimate health care trend rate is reached	2010	2009	2009	2008

In selecting the pretax expected long-term rate of return on plan assets we consider past performance and economic forecasts for the types of investments held by the plan. For the year 2006, we are assuming a 9% long-term rate of return on plan assets, which we believe is reasonable given our asset allocation in relation to historical and expected performance.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in the assumed initial and ultimate health care cost trend rates would have the following effects (dollars in millions):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$7	$(6)
Effect on service and interest cost components of net periodic other postretirement benefit costs	$11	$(9)
Effect on the accumulated other postretirement benefit obligation	$100	$(79)

Plan Assets

Pinnacle West's qualified pension plan asset allocation at December 31, 2005 and 2004 is as follows:

PINNACLE WEST CAPITAL CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Percentage of Plan Assets at December 31,		Target Asset Allocation
Asset Category:	2005	2004	
Equity securities	59%	60%	60%
Fixed income	26	27	30%
Other	15	13	10%
Total	100%	100%	

The Board of Directors has established an investment policy for the pension plan assets and has delegated oversight of the plan assets to an Investment Management Committee. The investment policy sets forth the objective of providing for future pension benefits by maximizing return consistent with acceptable levels of risk. The primary investment strategies are diversification of assets, stated asset allocation targets and ranges, prohibition of investments in Pinnacle West securities, and external management of plan assets.

Pinnacle West's other postretirement benefit plans' asset allocation at December 31, 2005 and 2004, is as follows:

	Percentage of Plan Assets at December 31,		Target Asset Allocation
Asset Category:	2005	2004	
Equity securities	69%	71%	70%
Fixed income	26	23	27%
Other	5	6	3%
Total	100%	100%	

The Investment Management Committee, described above, has also been delegated oversight of the plan assets for the other postretirement benefit plans. The investment policy for other postretirement benefit plans' assets is similar to that of the pension plan assets described above.

Contributions

The contribution to our pension plan in 2006 is estimated to be approximately $50 million. The contribution to our other postretirement benefit plans in 2006 is estimated to be approximately $29 million. APS' share is approximately 96% of both plans.

Estimated Future Benefit Payments

Benefit payments, which reflect estimated future employee service, for the next five years and the succeeding five years thereafter are estimated to be as follows (dollars in thousands):

	Allocation %	Long-term Expected Return %	Alpha	Active Return
U.S. Large Cap Stocks	42.0%	9.50%	1.00%	11%
U.S. Small & Mid Cap Stocks	6.0%	10.00%	1.00%	11%
International Stocks	12.0%	9.70%	1.00%	11%
Emerging Market Stocks	0.0%	12.50%	1.00%	14%
Private Equity	0.0%	14.30%	1.00%	15%
Total Equity	60.0%			11%
U.S. Fixed Income	24.0%	5.00%	1.00%	6%
International Fixed Income	6.0%	4.00%	1.00%	5%
Total Fixed Income	30.0%			6%
Real Estate	10.0%	7.40%	1.00%	8%
Total	100.0%			9%

PINNACLE WEST
CAPITAL CORPORATION
LAW DEPARTMENT

RECEIVED
2005 DEC 16 P 3:01
AZ CORP COMMISSION
DOCUMENT CONTROL

THOMAS L. MUMAW
Senior Attorney
(602) 250-2052
Direct Line

December 16, 2005

HAND-DELIVERED

Commissioner Kristin K. Mayes
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007-2996

RE: APS Rate Case; Docket No. E-01345A-05-0816

Dear Commissioner Mayes:

Arizona Public Service Company ("APS" or "Company") is responding to the matters raised in your letter of November 16, 2005.[1] I will begin by addressing your questions about the pension plan shortfall including how we find ourselves in this situation and why we are now seeking accelerated recovery of these costs from customers.

When it is said that a pension fund is "underfunded," it does not mean that it is currently running a deficit or that future pension benefits will not be paid. It does mean that the present value of future pension liabilities exceeds the present amount in the pension fund. Similarly, if a pension fund is "overfunded," APS cannot simply declare the excess to be "earnings" and use them for dividends or any purpose other than meeting future pension obligations. This understood, APS takes its responsibility with respect to its pension plan very seriously and understands how important the Company's pension plan is to the retirement security of approximately 12,000 current and former employees and their families – the vast majority of whom are Arizonans. Historically, this Commission has supported this goal, and to my knowledge, the inclusion of employee pension liabilities in cost of service for ratemaking

[1] APS wishes to clarify some possible confusion between the situation affecting employee benefits as a whole and the specific facts involving pension benefits. Your letter states: "According to APS testimony, the underfunded pension's deficit is due to escalating medical costs and reduced interest rates, which have negatively impacted the performance of the pension fund investments." The letter goes on to reference page 23 of the Direct Testimony of Ms. Laura Rockenberger. On that page, Ms. Rockenberger is referring to the pro forma adjustment for all employee benefits, whereas, page 24 of Ms. Rockenberger's testimony addresses the pro forma adjustment for accelerated recovery of the underfunded pension liability. The statements on page 23 of the testimony explaining the need for the pro forma adjustment for employee benefits combined in one sentence the explanations for both pension expense and for Other Post-retirement Employee Benefit ("OPEB") plans. However, OPEBs are primarily retiree medical benefits, which are significantly influenced by rising medical costs. In contrasts, escalating medical costs have no direct impact on pension expense.

purposes has never been an issue in APS rate proceedings, including the allowance requested for such liabilities in our last rate docket, which resulted in Decision No. 67744.

During the years 2000 through 2005, the Company contributed $228.5 million to the pension plan. In each of these years, the Company contributed more than the contribution required by the Employee Retirement Income Security Act of 1974 ("ERISA") and the Internal Revenue Code. Such excess contributions total $120.5 million.

Although APS did include pension costs in its last rate filing without objection from any party or the Commission, it did not seek accelerated funding of the underfunded amount in the Company's last rate case. At the time the last rate case was filed (June 2003), the substantial underfunded status was a relatively recent phenomena, and the Company, at that time, did not have the perspective to evaluate whether the underfunded status was a transitory or persistent situation. As can be seen in the following table, the underfunded percentage escalated rapidly over the years 2001 and 2002, and has since then remained relatively steady at about 30% underfunded:

	12/31/00	12/31/01	12/31/02	12/31/03	12/31/04	12/31/05
% Underfunded	3%	14%	32%	29%	28%	30%[2]

Pension funding status is based on the difference between the assets in the pension plan and the present value of future benefit payments that the assets are expected to fund. Funding status can change if either the plan assets or the pension liabilities change.

Consistent with ERISA's prudent diversification requirement, pension assets are allocated among six (6) diversified investment classes as follows:

Asset Class	Percentage
Domestic Large Cap Equities	42%
Domestic Small Cap Equities	6%
International Equities	12%
Domestic Fixed Income	24%
International Fixed Income	6%
Real Estate	10%

During the three years 2000 through 2002, Company pension plan investment returns were substantially below normal, long-term expected returns. Investment return for 2000 was a relatively flat +1%, while in 2001 and 2002, the plan posted net investment losses of −2.7% and −4.4%, respectively. The bear market from March 2000 to October 2002 was the worst downturn

[2] Estimated based on financial market conditions on 12/15/05

Pinnacle West Capital Corporation Law Department, 400 North Fifth Street, Station 8695, P. O. Box 53999 Phoenix, AZ 85072-3999
Phone: 602 250-3630, Fax: (602) 250-3335, E-mail: Thomas.Mumaw@pinnaclewest.com

in stock prices in 25 years. However, despite unfavorable market conditions, the performance of our pension plan has continued to compare very favorably versus the median return of 250 U.S. corporate pension plans ("Peer Group"), and the total return of the S&P 500 index, as shown in the following table:

	2000	2001	2002	2003	2004	Year to date 10/31/05
APS Plan	1.0%	-2.7%	-4.4%	23.3%	12.3%	3.6%
Peer Group[3]	0.3%	-3.8%	-9.3%	22.3%	11.6%	N/A
S&P 500	-9.1%	-11.9%	-22.1%	28.7%	10.9%	1.1%

Pension liabilities are calculated by making actuarial projections for the plan's future payments to participants, then discounting these amounts back to the present. The lower the discount rate, the higher the liabilities. The discount rate for determining funding status under generally accepted accounting principles is based on corporate bond yields as specified in FAS-87[4].

Standard & Poor's, in its July 18, 2005 report titled, ***S&P 500 2004 Pension Status Report***, stated: "In recent years, as interest rates fell to the lowest levels in 40 years, pension liability discount rates fell and liabilities surged. This was a major factor in the deterioration of corporate pension plans."

In conclusion, a number of factors have contributed to the current pension funding shortfall. Barring the accelerated recovery of the underfunded pension liability as proposed in APS' application, the pension funding situation is not expected to improve in the near future. And because pension costs have always been recognized as a legitimate cost of service for ratemaking purposes by this and every other regulatory commission of which I am aware (absent a showing of imprudence in the management of pension fund assets), it would be inappropriate to now suggest that shareholders fund without compensation this or any other cost of providing utility service to our customers.

I hope this letter has addressed the issues raised by your letter. As the discovery process unfolds in the pending rate proceeding, I believe that your Staff and other interested parties will gain additional insights into this matter, which as I have indicated in this letter, is a national phenomena.

---

[3] Median rate of return of approximately 250 U.S. corporate pension plans, Source: State Street Bank & Trust Co.

[4] Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions (Issued December 1985)

Pinnacle West Capital Corporation Law Department, 400 North Fifth Street, Station 8695, P. O. Box 53999 Phoenix, AZ 85072-3999
Phone: 602 250-3630, Fax: (602) 250-3335, E-mail: Thomas.Mumaw@pinnaclewest.com

Sincerely,

Thomas L. Mumaw

Cc: Docket Control
Parties of Record

APS • APS Energy Services • Pinnacle West Energy • SunCor • El Dorado
Pinnacle West Capital Corporation Law Department, 400 North Fifth Street, Station 8695, P. O. Box 53999 Phoenix, AZ 85072-3999
Phone: 602 250-3630, Fax: (602) 250-3335, E-mail: Thomas.Mumaw@pinnaclewest.com

Pension Costs and Contributions

Year	APS O&M Pension Expense	Consolidated Total Pension Cost (1)	Consolidated Cash Contributions	Consolidated Cash Contributions per Staff Witness Dittmer's Table C
2001				
2002				
2003				
2004				
2005				
Total				

(1) Mr. Dittmer refers to this as "Net Periodic Pension Cost" which is the accounting term representing total pension costs, both expensed and capitalized. All numbers are consolidated Pinnacle West, unless otherwise specified.

Accelerated Recovery of Underfunded Pension Liability
($000)

	APS Proposed Proforma Adjustment Utilizing PBO	Proforma Adjustment Utilizing ABO
Five Year Accelerated Recovery:		
Projected accumulated benefit obligation (ABO) at December 31, 2004		$ 1,138,500
Projected pension benefit obligation (PBO) at December 31, 2004	$ 1,371,600	
Value of pension assets at December 31, 2004	982,300	982,300
PNW[1] Consolidated underfunded pension balance	389,300	156,200
Percentage attributable to APS without participants	56%	56%
APS underfunded pension balance	218,475	87,659
Proposed recovery period (years)	5	5
Annual Accelerated Recovery Amount	**$ 43,695**	**$ 17,532**
Ten Year Subsequent Cost Reduction:		
Resulting APS pension regulatory liability at December 31, 2011	$ 218,475	$ 87,659
Proposed amortization period (years)	10	10
Annual rate decrease starting in 2012 from amortization of pension regulatory liability	**$ 21,848**	**$ 8,766**

[1] PNW is Pinnacle West Capital Corporation

LEHMAN BROTHERS
EQUITY RESEARCH

August 21, 2006

United States of America
Energy & Power
Power & Utilities

Daniel Ford, CFA
1.212.526.0836
daford@lehman.com

Pinnacle West Capital (PNW - US$ 44.08) 2-Equal weight

Change of Price Target

Staff Testimony as Expected

Investment Conclusion

- On 8/18, the ACC Staff and RUCO issued recommendations in the APS rate case. The recommendations mark the likely worst case in this proceeding. We view fair treatment by the ACC as essential to APS's investment grade rating and attraction to equity investors. We maintain our 2-EW rating but are raising our p-t to $45 from $41 based on a 10% discount to the utility 07 P/E multiple of 14.8x.

EPS (US$) (FY Dec)

	2005		2006			2007		% Change	
	Actual	Old	New	St. Est.	Old	New	St. Est.	2006	2007
1Q	0.27A	0.13A	0.13A	0.12A	N/A	N/A	0.37E	-52%	N/A
2Q	0.89A	1.03A	1.03A	1.03A	N/A	N/A	0.93E	16%	N/A
3Q	1.89A	N/A	N/A	1.58E	N/A	N/A	1.57E	N/A	N/A
4Q	0.24A	N/A	N/A	0.35E	N/A	N/A	0.46E	N/A	N/A
Year	3.29A	3.12E	3.12E	3.07E	3.40E	3.40E	3.32E	-5%	9%
P/E			14.1			13.0			

Summary

- Staff recommended $204 million (9.6%) rate increase based on a $4.401B rate-base, 54.5% equity and a 10.25% ROE. Significant operating disallowances render prospects for achieving the hypothetical allowed return remote in our opinion.
- RUCO recommended a $232.3 million (10.9%) rate increase. This included $4.463B of rate-base, 50% equity and a 9.25% ROE. Again, operating income disallowances of $120 million make hypothetical earnings difficult to achieve.
- Our EPS estimates are premised on a 10.5% ROE, 50% equity content and minimal expense disallowances. In spite of a 10% discount valuation based on our estimates, we believe that PNW shares will be under pressure for the next 6 months until certainty on this critical case nears.

Market Data

Market Cap (Mil.)	4390
Shares Outstanding (Mil.)	99.60
Float (%)	N/A
Dividend Yield	4.54
Convertible	No
52 Week Range	46.06 - 38.31

Financial Summary

Revenue FY06 (Mil.)	N/A
Five-Year EPS CAGR	9.0
Return on Equity	8.70
Current BVPS	32.27
Debt To Capital (%)	53.02

Stock Rating

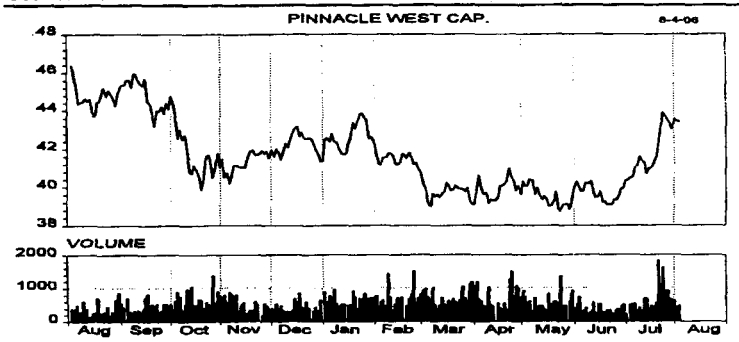
New:	2-Equal weight
Old:	2-Equal weight

Target Price

New:	US$ 45.00
Old:	US$ 41.00

Sector View: 3-Negative

Stock Overview



On August 18, the critical ACC Staff (Staff) and Residential Utility Consumers Office (RUCO) testimony was filed. As expected, the rate increases that these bodies supported were low. Should the final order reflect financial parameters approximating these filings, it would be difficult for Arizona Public Service (APS), the utility subsidiary of Pinnacle West Capital Corp. to maintain investment grade ratings or provide support for the current stock value in our view. While Arizona has historically been a very difficult jurisdiction for investors, we look for a final ACC order in 2Q of 2007 to significantly improve upon Friday's filings. We maintain our EPS estimates of $3.00 in 2006, $3.40 in 2007 and $3.60 in 2008. Our price target moves up to $45 vs $41 previously based on a 10% discount to the average utility 2007 P/E multiple of 14.8x which is higher than we last published.

GRC Testimony

Lehman Brothers does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the firm may have a conflict of interest that could affect the objectivity of this report.

Customers of Lehman Brothers in the United States can receive independent, third-party research on the company or companies covered in this report, at no cost to them, where such research is available. Customers can access this independent research at www.lehmanlive.com or can call 1-800-2LEHMAN to request a copy of this research.

Investors should consider this report as only a single factor in making their investment decision.

PLEASE SEE ANALYST(S) CERTIFICATION(S) ON PAGE 2 AND IMPORTANT DISCLOSURES BEGINNING ON PAGE 3

The key parameters of the Staff, RUCO, APS and our positions on the rate case are outlined in the table below. We also provide our estimate of the implied EPS implications for 2007E.

	APS	LEH	Staff	RUCO
Rate Increase	$453.9M	$374.1	$204M	$232.3M
% Rate Increase	21.4%	17.6%	9.6%	10.9%
Rate Base	$4.467B	$4.432B	$4.401B	$4.463B
Equity Ratio	54.5%	50.0%	54.5%	50%
ROE	11.5%	10.5%	10.25%	9.25%
Cost Adjustments	$0	$0	$126M	$27M
2007E	$3.88	$3.40	$2.80	$2.97

Source: Lehman Brothers estimates

Rebuttal testimony is due September 15, hearings are scheduled for October 10 and an ACC order is due in 2Q 07.

Palo Verde Recommendation

In a separate filing on 8/17, the staff recommended that the ACC disallow recovery of $17.4M of replacement power costs incurred during outages at the Palo Verde Nuclear Generating Station in 2005. The disallowance was designated to cover expenses incurred during outages that the staff deemed avoidable. The staff also recommended performance standards and penalties be implemented for the nuclear plant in the future. In February APS requested $45 million in Palo Verde costs.

Analyst Certification:

I, Daniel Ford, CFA, hereby certify (1) that the views expressed in this research Company Note accurately reflect my personal views about any or all of the subject securities or issuers referred to in this Company Note and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this Company Note.

Other Team Members:

Orrill, Gregg	1.212.526.0865	gorrill@lehman.com
Thomas, Scott	1.212.526.8273	sthomas@lehman.com
Straka, M. Beth	1.412.260.6071	mstraka@lehman.com
Brooks, Theodore	1.617.330.5895	tbrooks@lehman.com
Fowler, Ross	1.617.330.5893	rofowler@lehman.com

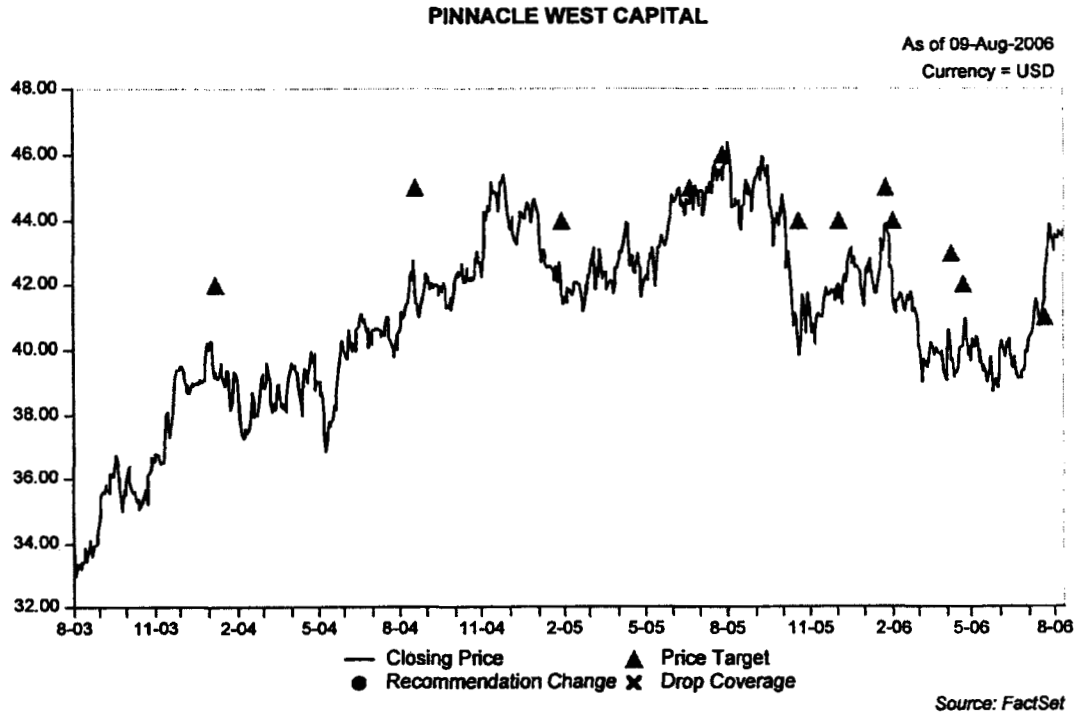
Company Description:

LEHMAN BROTHERS
EQUITY RESEARCH

Important Disclosures:

Pinnacle West Capital (PNW) **US$ 44.08 (17-Aug-2006)** **2-Equal weight / 3-Negative**

Rating and Price Target Chart:



Currency=US$

Date	Closing Price	Rating	Price Target
21-Jul-06	42.22		41.00
20-Apr-06	40.13		42.00
06-Apr-06	39.95		43.00
02-Feb-06	41.64		44.00
25-Jan-06	43.88		45.00
02-Dec-05	41.59		44.00
20-Oct-05	39.85		44.00

Date	Closing Price	Rating	Price Target
27-Jul-05	45.60		46.00
21-Jun-05	44.49		45.00
31-Jan-05	41.70		44.00
19-Aug-04	41.44		45.00
09-Jan-04	39.23		42.00

FOR EXPLANATIONS OF RATINGS REFER TO THE STOCK RATING KEYS LOCATED ON THE PAGE FOLLOWING THE LAST PRICE CHART.

Lehman Brothers Inc. and/or an affiliate has managed or co-managed within the past 12 months a 144A and/or public offering of securities for Pinnacle West Capital.
Lehman Brothers Inc. and/or an affiliate has received compensation for investment banking services from Pinnacle West Capital in the past 12 months.
Lehman Brothers Inc and/or an affiliate trade regularly in the shares of Pinnacle West Capital.
Lehman Brothers Inc. has received non-investment banking related compensation from Pinnacle West Capital within the last 12 months.
Pinnacle West Capital is or during the past 12 months has been an investment banking client of Lehman Brothers Inc. and/or an affiliate.
Pinnacle West Capital is or during the last 12 months has been a non-investment banking client (securities related services) of Lehman Brothers Inc.

Valuation Methodology: Our current price target of $45 is premised upon a 10% discount to the integrated utility average '07E P/E multiple of 14.8x our 2007E EPS of $3.40

Our prior price target of $41 is based upon a 10% discount to the integrated utility average '07E P/E multiple of 13.5x our 2007E EPS of $3.40.

Risks Which May Impede the Achievement of the Price Target: Key risks are commodity prices, refinancing and interest rate risk, credit risks, Arizona state and Federal regulation.

Important Disclosures Continued:
The analysts responsible for preparing this report have received compensation based upon various factors including the firm's total revenues, a portion of which is generated by investment banking activities

Company Name	Ticker	Price (17-Aug-2006)	Stock / Sector Rating
Pinnacle West Capital	PNW	US$ 44.08	2-Equal weight / 3-Negative

Sector Coverage Universe
Below is the list of companies that constitute the sector coverage universe against which the primary stock, Pinnacle West Capital, is rated:

AES Corp (AES)
Ameren Corp (AEE)
Aquila, Inc (ILA)
Consolidated Edison (ED)
Dominion Resources (D)
DTE Energy (DTE)
Duquesne Light Holdings (DQE)
Empire District Electric (EDE)
Exelon Corp (EXC)
FPL Group (FPL)
Hawaiian Electric Inds (HE)
Mirant Corp. (MIR)
Northeast Utilities (NU)
OGE Energy (OGE)
Pepco Holdings (POM)
Pinnacle West Capital (PNW)
Progress Energy (PGN)
Puget Energy (PSD)
Sempra Energy (SRE)
Southern Co (SO)
TXU Corp (TXU)
Wisconsin Energy (WEC)
Alliant Energy (LNT)
American Electric Power (AEP)
CMS Energy (CMS)
Constellation Energy (CEG)
DPL Inc (DPL)
Duke Energy (DUK)
Edison International (EIX)
Entergy Corp (ETR)
FirstEnergy Corp (FE)
Great Plains Energy (GXP)
ITC Holdings (ITC)
NiSource, Inc (NI)
NRG Energy (NRG)
Ormat Technologies (ORA)
PG&E Corp (PCG)
PPL Corporation (PPL)
Public Service Enterprise Gp (PEG)
Reliant Energy Inc. (RRI)
Sierra Pacific Resources (SRP)
TECO Energy (TE)
Westar Energy (WR)
Xcel Energy (XEL)

Guide to Lehman Brothers Equity Research Rating System:
Our coverage analysts use a relative rating system in which they rate stocks as 1-Overweight, 2-Equal weight or 3-Underweight (see definitions below) relative to other companies covered by the analyst or a team of analysts that are deemed to be in the same industry sector (the "sector coverage universe"). To see a list of the companies that comprise a particular sector coverage universe, please go to www.lehman.com/disclosures

In addition to the stock rating, we provide sector views which rate the outlook for the sector coverage universe as 1-Positive, 2-Neutral or 3-Negative (see definitions below). A rating system using terms such as buy, hold and sell is not the equivalent of our rating system. Investors should carefully read the entire research report including the definitions of all ratings and not infer its contents from ratings alone.

Stock Rating
1-Overweight - The stock is expected to outperform the unweighted expected total return of the sector coverage universe over a 12-month investment horizon.
2-Equal weight - The stock is expected to perform in line with the unweighted expected total return of the sector coverage universe over a 12- month investment horizon.
3-Underweight - The stock is expected to underperform the unweighted expected total return of the sector coverage universe over a 12-month investment horizon.
RS-Rating Suspended - The rating and target price have been suspended temporarily to comply with applicable regulations and/or firm policies in certain circumstances including when Lehman Brothers is acting in an advisory capacity in a merger or strategic transaction involving the company.

Sector View
1-Positive - sector coverage universe fundamentals/valuations are improving.
2-Neutral - sector coverage universe fundamentals/valuations are steady, neither improving nor deteriorating.
3-Negative - sector coverage universe fundamentals/valuations are deteriorating.

Distribution of Ratings:
Lehman Brothers Equity Research has 1848 companies under coverage.
44% have been assigned a 1-Overweight rating which, for purposes of mandatory regulatory disclosures, is classified as Buy rating, 34% of companies with this rating are investment banking clients of the Firm.
40% have been assigned a 2-Equal weight rating which, for purposes of mandatory regulatory disclosures, is classified as Hold rating, 5% of companies with this rating are investment banking clients of the Firm.

16% have been assigned a 3-Underweight rating which, for purposes of mandatory regulatory disclosures, is classified as Sell rating, 62% of companies with this rating are investment banking clients of the Firm.

This material has been prepared and/or issued by Lehman Brothers Inc., member SIPC, and/or one of its affiliates ("Lehman Brothers") and has been approved by Lehman Brothers International (Europe), authorized and regulated by the Financial Services Authority, in connection with its distribution in the European Economic Area. This material is distributed in Japan by Lehman Brothers Japan Inc., and in Hong Kong by Lehman Brothers Asia Limited. This material is distributed in Australia by Lehman Brothers Australia Pty Limited, and in Singapore by Lehman Brothers Inc., Singapore Branch ("LBIS"). Where this material is distributed by LBIS, please note that it is intended for general circulation only and the recommendations contained herein does not take into account the specific investment objectives, financial situation or particular needs of any particular person. An investor should consult his Lehman Brothers' representative regarding the suitability of the product and take into account his specific investment objectives, financial situation or particular needs before he makes a commitment to purchase the investment product. This material is distributed in Korea by Lehman Brothers International (Europe) Seoul Branch. This document is for information purposes only and it should not be regarded as an offer to sell or as a solicitation of an offer to buy the securities or other instruments mentioned in it. No part of this document may be reproduced in any manner without the written permission of Lehman Brothers. With the exception of disclosures relating to Lehman Brothers, this research report is based on current public information that Lehman Brothers considers reliable, but we make no representation that it is accurate or complete, and it should not be relied on as such. In the case of any disclosure to the effect that Lehman Brothers Inc. or its affiliates beneficially own 1% or more of any class of common equity securities of the subject company, the computation of beneficial ownership of securities is based upon the methodology used to compute ownership under Section 13(d) of the United States' Securities Exchange Act of 1934. In the case of any disclosure to the effect that Lehman Brothers Inc. and/or its affiliates hold a short position of at least 1% of the outstanding share capital of a particular company, such disclosure relates solely to the ordinary share capital of the company. Accordingly, while such calculation represents Lehman Brothers' holdings net of any long position in the ordinary share capital of the company, such calculation excludes any rights or obligations that Lehman Brothers may otherwise have, or which may accrue in the future, with respect to such ordinary share capital. Similarly such calculation does not include any shares held or owned by Lehman Brothers where such shares are held under a wider agreement or arrangement (be it with a client or a counterparty) concerning the shares of such company (e.g. prime broking and/or stock lending activity). Any such disclosure represents the position of Lehman Brothers as of the last business day of the calendar month preceding the date of this report.
This material is provided with the understanding that Lehman Brothers is not acting in a fiduciary capacity. Opinions expressed herein reflect the opinion of Lehman Brothers and are subject to change without notice. The products mentioned in this document may not be eligible for sale in some states or countries, and they may not be suitable for all types of investors. If an investor has any doubts about product suitability, he should consult his Lehman Brothers representative. The value of and the income produced by products may fluctuate, so that an investor may get back less than he invested. Value and income may be adversely affected by exchange rates, interest rates, or other factors. Past performance is not necessarily indicative of future results. If a product is income producing, part of the capital invested may be used to pay that income. © 2006 Lehman Brothers. All rights reserved. Additional information is available on request. Please contact a Lehman Brothers entity in your home jurisdiction.

Lehman Brothers policy for managing conflicts of interest in connection with investment research is available at www.lehman.com/researchconflictspolicy. Ratings, earnings per share forecasts and price targets contained in the Firm's equity research reports covering U.S. companies are available at www.lehman.com/disclosures.

Complete disclosure information on companies covered by Lehman Brothers Equity Research is available at www.lehman.com/disclosures.

REBUTTAL TESTIMONY OF

PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

TABLE OF CONTENTS

I. INTRODUCTION 1

II. SUMMARY OF REBUTTAL TESTIMONY 2

III. UPDATED BASE FUEL AND PURCHASED POWER PRO FORMA, INCLUDING OFF-SYSTEM SALES MARGINS 4

IV. STAFF AND INTERVENOR BASE FUEL, PURCHASED POWER, AND OFF-SYSTEM SALES MARGIN ADJUSTMENTS 5

A. Staff 5

B. AECC 8

V. OTHER STAFF AND INTERVENOR ADJUSTMENTS 9

A. DSM Lost Revenues 9

B. Treatment of Variable Operations & Maintenance Costs 12

VI. STAFF'S PSA RECOMMENDATIONS 13

A. Forecasted Fuel Prices 13

B. Implementation of Staff's PSA 14

VII. REPLACEMENT COSTS FOR PALO VERDE OUTAGES 19

VIII. STAFF'S FINAL AUDIT REPORT ON FUEL AND PURCHASED POWER PROCUREMENT 26

IX. CONCLUSION 27

ATTACHMENTS

Updated Base Fuel and Purchased Power Pro Forma	Attachment PME-1RB
Updated Off-System Sales Margins Pro Forma	Attachment PME-2RB
Forward Gas Prices for June 2006 – Aug. 2007 Delivery	Attachment PME-3RB
2005 Palo Verde Outage Costs: Corrections to Staff Recommended Disallowance	Attachment PME-4RB

REBUTTAL TESTIMONY OF
PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Peter M. Ewen. My business address is 400 N. 5th Street, Phoenix, Arizona, 85004. I am Manager of the Revenue and Fuel Analysis and Forecasts Department for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for preparing the Company's short-range and long-range forecasts of system peak demand and energy sales, and projecting the optimal dispatch of available resources to minimize the cost of meeting those energy requirements.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I filed direct testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal is to update the base fuel and purchased power cost included in the Company's request, reflecting more current market and resource conditions. I provide a more reasonable level of fuel costs compared to the base fuel rate recommended by the Arizona Corporation Commission Staff ("Staff"), and explain why the recommendations from Staff and from Arizonans for Electric Choice and Competition ("AECC") will understate likely fuel costs when the new base fuel rate becomes effective in 2007. I also present more appropriate

calculations of the 2005 Palo Verde Nuclear Generating Station ("PV" or "Palo Verde") unplanned outage costs discussed by Staff witness Jacobs. Additionally, I show that Staff has wrongly rejected the Company's revenue pro forma adjustment for the energy impacts stemming from the Company's committed expenditures on demand-side management ("DSM") programs through 2008, yet has retained those impacts in the derivation of the base fuel cost. I also disagree with both Staff and the Residential Utility Consumer Office ("RUCO") recommendations on the treatment of overhaul costs for certain of the Company's generating facilities. Staff's recommendation, in particular, deviates from past Commission practices in this area. Finally, I address certain of Staff's recommendations contained in the *Final Audit Report: APS Fuel and Purchased Power Procurement and Costs* ("Fuel Audit Report"), issued August 31, 2006.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In my rebuttal testimony, I address three key issues. Specifically, I:

1. Update the Company's base fuel, purchased power, and off-system sales pro forma to reflect the evolution of time and prices, which results in an additional $32 million[1] that the Company is seeking in this rate application bringing the Company's total fuel-related request to $331 million. I discuss why I do not agree with the base fuel adjustment proposals by Staff and AECC. I show why the Company's updated base fuel rate is a more correct

[1] This adjustment is set forth on Attachment CNF-2RB, page 8 of 16, which is attached to Chris Froggatt's Rebuttal Testimony.

and appropriate level than either of these proposals because it more accurately portrays the on-going level of costs facing the Company.

I also discuss why I do not agree with Staff and RUCO's proposed DSM lost revenue adjustments, as well as their respective treatment of overhaul costs at the Company's Sundance, Redhawk, and West Phoenix power plants.[2]

2. Provide the procedural details and missing elements associated with Staff's proposed changes to the operation of the Power Supply Adjustor ("PSA"), in the event those recommendations are adopted by the Commission. Staff was largely silent on several key aspects of how their proposed PSA would be implemented, so I describe some of the important steps that would have to be in place for such a proposal to work effectively. In any case, if the Commission were to adopt Staff's approach to the PSA and Staff's proposed base fuel rate, it is imperative that the Commission also establish the 2007 adjustor rate in this proceeding at the level I propose, and implement it concurrently with Staff's proposed base fuel rate.

3. Demonstrate that the financial disallowance recommended by Staff witness Jacobs overstates the actual costs of the PV outages charged to the PSA by $8.6 million, and does not reflect the impact of the superior performance at the Company's other low-cost baseload generating units.

---

[2] Throughout my testimony, I refer to the Redhawk and West Phoenix power plants as the "PWEC Units". The Commission authorized the transfer of these plants from Pinnacle West Energy Company ("PWEC") to APS in Decision No. 67744. Because this transfer did not occur until 10 months into the test year in this proceeding, the Company has offered a "PWEC Units" pro forma adjustment.

In addition, I address recommendations contained in Staff's Fuel Audit Report, specifically those regarding 1) written PSA policies and procedures, and 2) ways to incorporate 90/10 load forecasts in the future.

III. UPDATED BASE FUEL AND PURCHASED POWER PRO FORMA, INCLUDING OFF-SYSTEM SALES MARGINS

Q. HAVE YOU RECALCULATED THE COMPANY'S FUEL EXPENSES BASED ON MORE CURRENT FUEL AND PURCHASED POWER PRICES?

A. Yes. I have re-estimated fuel and purchased power expenses, including off-system sales margins,[3] using June 30, 2006 forward prices for natural gas and wholesale power for January through December 2007. These adjustments primarily reflect the process of bringing the information used in the calculation of the pro forma adjustment more current and of updating to 2007 calendar year levels, including the value of the Company's 2007 gas and power hedges. As APS witness Don Robinson indicates in his Rebuttal Testimony, the Company is withdrawing its proposal to retain 10% of actual hedge gains or losses each year. Accordingly, my fuel estimates reflect the credit of 100% of the hedge values in 2007. I have updated the Base Fuel and Purchased Power Expense pro forma (Attachment PME-1RB) and the Normalized Off-System Sales pro forma (Attachment PME-2RB) to reflect these changes.

Q. WAS THE UPDATE OF FORWARD PRICES AND HEDGES THE ONLY ADJUSTMENT YOU MADE TO THE ORIGINAL PRO FORMA?

A. No. I also adjusted the energy sales to reflect 2007 customer growth levels,

[3] Throughout the remainder of my testimony, the term "fuel expenses" may be used generically to refer to fuel and purchased power expenses, including off-system sales margins.

modified the resources available to meet load in 2007 based on known contract terminations (for example, with Salt River Project and Tucson Electric Power Company), new contracts (primarily the Reliability RFP contracts that begin in 2007), and increased coal and nuclear fuel prices to be in line with their 2007 contractual terms. Additional adjustments include the short-term capacity costs resulting from the adjusted 2007 load and resource balance, and the current view of the El Paso Natural Gas transportation contract costs.

Q. WHAT IS THE IMPACT OF YOUR UPDATED FUEL EXPENSE?

A. This update results in an increase in test year fuel expense of approximately $32 million, increasing the Company's originally filed fuel pro forma to $331 million. The base fuel rate consistent with this request is 3.3112 ¢/kWh.

IV. STAFF AND INTERVENOR BASE FUEL, PURCHASED POWER, AND OFF-SYSTEM SALES MARGIN ADJUSTMENTS

A. Staff

Q. WHAT IS STAFF'S PROPOSAL FOR TEST YEAR FUEL EXPENSE?

A. In his Direct Testimony, Staff witness Antonuk proposes a retail test year base fuel rate of 2.7975 ¢/kWh.

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No. I cannot agree with Staff's recommendation.

Q. IS STAFF'S CALCULATION OF COSTS INCORRECT?

A. Mathematically, it appears to be correct. However, conceptually it has two significant problems with its application. First, it has the obvious problem that it is backward looking and ignores known and measurable changes that are raising fuel costs during the time frame in which new rates are expected to take effect.

Mr. Antonuk admits as much when he indicated "we [Staff] do not consider 2007 circumstances irrelevant" and "we recommend the use of a forecasted year for setting the PSA rate in the future." (Antonuk Direct Testimony, page 33, lines 19, 22.) The following list catalogs the principal factors already known about 2007, which are included in the pro forma adjustment I described above:

- Different prices for natural gas and purchased power, the vast majority of which have already been locked in place through the Company's forward hedge contracts;
- Almost certain growth in customers and the corresponding increase in energy demand;
- Contractual changes in the Company's portfolio of long-term purchased power agreements, including resources acquired through the 2005 Reliability RFP and the 2005 Renewables RFP;
- Changes in the cost structure for natural gas transportation from the El Paso Pipeline;
- The contractual availability of the Sundance generating units;
- The DSM energy savings related to the Company's spending obligations resulting from the Company's previous rate case;[4]
- New requirements for short-term capacity agreements to meet the higher peak demand; and
- Increased costs for coal and nuclear fuel prices.

Q. WHAT IMPACT DOES IGNORING THESE KNOWN FACTORS HAVE ON FUEL COSTS?

---

[4] Docket No. E-01345A-03-0437.

A. In comparison to the estimated fuel costs for 2007, Staff's 2006 estimate is 0.5¢/kWh too low and leads to a revenue shortfall of almost $140 million on a normalized test year sales basis (3.3112¢/kWh – 2.7975¢/kWh x 26,759 GWh = $137.5 million). If not adjusted appropriately, this differential could amount to over $150 million in fuel deferrals in 2007. It is possible for this differential to become a non-issue if the Commission were to adopt a prospective PSA adjustor. I describe the important features that would be required for this type of prospective PSA adjustor later in my testimony.

Q. WHAT IS THE SECOND PROBLEM WITH STAFF'S CALCULATION OF TEST YEAR FUEL EXPENSE?

A. The second major problem with Staff's 2006 base fuel estimate is the reduction to the normalized fuel level of $3.7 million related to the transmission optimization transactions. The sales margins resulting from these transactions were credited to fuel expenses through the PSA mechanism when they occurred, so customers have already received the benefit from them. Just as importantly, however, the transactions Mr. Antonuk references are one-time, non-recurring transactions. Mr. Antonuk admits as much when he states that "we do not disagree with the forward-looking assumption that APS will not directly make such transactions and earn margins from them". (Antonuk Direct Testimony, page 29, lines 21-23.) Because customers have received the benefit of these transactions and since they are non-recurring activities, it is imperative that the Commission not include them in normalized off-system sales activity. All of these deviations from known and measurable costs result in a test year fuel expense that will preclude the Company from recovering its prudently incurred fuel costs in 2007 when rates from this case will go into effect.

B. AECC

Q. DO YOU AGREE WITH THE PROPOSED ADJUSTMENT TO FUEL EXPENSE RECOMMENDED BY AECC?

A. No, I do not. AECC witness Higgins has proposed that the base fuel rate be set at the level discussed in the Company's Emergency Case[5] earlier this year, which is some $99 million lower than what the Company and Staff believe is the correct price level. He bases that proposal on the conclusion that "February 28, 2006 prices . . . have generally held during the subsequent months . . .". (Higgins Direct Testimony, page 6, line 13-14.)

Q. IS THAT THE APPROPRIATE CONCLUSION TO DRAW?

A. No. Mr. Higgins apparently only looked at forward prices on two days – February 28, 2006 and June 30, 2006. He missed the fact that forward prices have continued to exhibit significant volatility, and the fact that by July 31, 2006 – almost three weeks prior to the filing of his testimony in this case – gas prices had increased by more than $1.00/mmbtu. Furthermore, Mr. Higgins indicated in response to an APS data request that he relied in part on market data provided to him by APS.[6] The market data he cited includes price quotes for natural gas at Henry Hub, the San Juan basin in northern New Mexico and the Permian basin in west Texas from May 1, 2006 to August 10, 2006. In that time span, prices exhibited volatility of over 20%. Henry Hub prices ranged from a high of $9.71/mmbtu on July 31 to a low of $7.95 on July 18. Attachment PME-3RB provides a graphical representation of the data provided to Mr. Higgins. I find it difficult to characterize price movements in natural gas of over $1.70/mmbtu in

---

[5] Docket No. E-01345A-06-0009.

[6] *See* Data Request and Response APS-AECC-2-1.

the span of several months, let alone a couple of weeks, as "hav[ing] generally held."

Mr. Higgins also neglected to consider changes in the Company's contractual commitments, including the Reliability RFP Contracts and the current hedge contracts, and the fact that energy demand will be significantly higher at the time that rates are expected to go into effect. Higher energy demand means an increased share of relatively higher cost gas generation and market purchases. It is both reasonable and appropriate to set the base fuel rate at a level that is consistent with fuel costs that are likely to be incurred at the time those rates become effective.

V. OTHER STAFF AND INTERVENOR ADJUSTMENTS

A. DSM Lost Revenues

Q. DO YOU BELIEVE IT IS APPROPRIATE TO EXCLUDE REVENUE IMPACTS RELATED TO THE COMPANY'S MANDATED DSM PROGRAMS FROM THE TEST YEAR?

A. No, I do not.

Q. IS SUCH AN ADJUSTMENT BEING PROPOSED BY STAFF AND RUCO?

A. Yes. Staff witness Anderson (in Schedule C-1) and RUCO witness Diaz Cortez (in pages 14 through 17 of her Direct Testimony) have both recommended excluding the Company's proposed revenue normalization for the anticipated energy reductions resulting from the Commission-mandated and Commission-approved DSM programs.

Q. WHAT IS YOUR UNDERSTANDING OF THEIR POSITIONS ON THE REVENUE-RELATED DSM PRO FORMA ADJUSTMENT?

A. Both Staff and RUCO state that such an adjustment violates the Settlement Agreement from the Company's previous rate case.[7] Staff additionally states that it duplicates the performance incentive clause that is included in the funding mechanism for the Company's DSM programs.

Q. DO YOU AGREE WITH THESE ANALYSES AND CONCLUSIONS REGARDING THIS ADJUSTMENT?

A. No. As I have explained before, it is appropriate to set rates based on conditions that will be present when the new rates go into effect. These DSM energy reductions are perfect examples of such conditions. In Decision No. 67744, the Commission ordered that the Company spend $48 million through 2007 on DSM programs. The Company filed a DSM Portfolio, including expenditure budgets and planned energy reduction achievements, for Commission review and approval, which has been granted. The Company is obligated to follow through on these programs, and the revenue pro forma adjustment simply normalizes for this known and measurable fact.

It appears that Staff and RUCO are confusing an adjustment to base rates in a general rate case for a known and measurable condition with a year-by-year net lost revenue approach. Per the Settlement Agreement, the Company is not proposing a year-by-year net lost revenue recovery mechanism, nor is it subtracting net lost revenues from its $48 million commitment. If APS cannot recover the lost revenues from DSM programs in general rate proceedings, it will never be able to recover its full cost of service – something that was neither

[7] The Settlement Agreement was adopted in Commission Decision No. 67744.

required by Decision No. 67744 nor is consistent with the concept of cost-of-service regulation.

Additionally, RUCO appears to equate the recovery of net lost revenue to a reduction in the Company's mandated DSM spending requirements. This is not the case. The Company will spend the amount of money it has been ordered by the Commission to spend on DSM programs ($16 million per year, $6 million recovered in base rates and $10 million recovered through the DSM adjustment mechanism).

Q. ARE THE ENERGY REDUCTIONS ASSOCIATED WITH THE DSM PRO FORMA ADJUSTMENT ALSO INCLUDED IN YOUR ESTIMATE OF BASE FUEL EXPENSES THAT YOU DESCRIBED EARLIER IN YOUR TESTIMONY?

A. Yes, they are.

Q. DID STAFF PROPOSE AN ADJUSTMENT TO BASE FUEL EXPENSES TO REMOVE THE EFFECT OF THESE ENERGY REDUCTIONS?

A. No, Staff did not. In my view, it is inappropriate to allow an adjustment to energy for the purpose of reducing average fuel expenses, but not allow that same adjustment to reduce revenue. Failure to make this adjustment seems particularly unusual because these amounts are derived from the very set of programs that were approved by the Commission.[8]

[8] The Commission approved the DSM programs in Decision No. 68064 (Consumer Products Program, issued August 17, 2005); Decision No. 68488 (Residential Programs, issued February 23, 2006); Decision No. 68647 (Low Income Programs) and Decision No. 68648 (Non-Residential Programs) – both of which were issued April 12, 2006.

B. Treatment of Variable Operations & Maintenance ("O&M") Costs.

Q. STAFF WITNESS DITTMER, AECC WITNESS HIGGINS, AND RUCO WITNESS SCHLISSEL HAVE EACH TAKEN A POSITION ON THE VARIABLE ROUTINE AND/OR OVERHAUL O&M EXPENSE FOR THE FORMER PWEC UNITS AND/OR THE SUNDANCE PLANT. DO YOU AGREE WITH THESE POSITIONS?

A. No. Staff has recommended that the overhaul O&M expense normalization for the Company's Sundance power plant be excluded, despite the fact that the Company has followed the same methodology for Sundance as it has for each and every other one of its generating facilities. This is the same methodology that has historically been accepted by the Commission. Mr. Dittmer is concerned that the adjustment for Sundance plant overhauls will potentially lead to an over-recovery of such costs. In fact, the converse is true. If we do not make this adjustment, the Company will almost certainly not recover its costs for Sundance. Mr. Dittmer offered no circumstances when such an adjustment was not accepted by the Commission. Mr. Dittmer's logic seems to be a classic case of selective and inconsistent treatment that, if adopted, would eliminate any chance the Company has in fully recovering its O&M expenses for Sundance.

Mr. Higgins's logic for ignoring the changes in variable O&M costs for the former PWEC plants is also curious. As I understand it, he is proposing that the Company revert back to the costs used in the previous rate case to establish the on-going costs for the PWEC plants. Mr. Higgins does not disagree with the concept that costs change over time (Higgins Direct Testimony, page 9, line 20), and he offers no support[9] that the costs of these plants have not changed in three

[9] In response to Data Request APS-AECC-2-2 , which sought supporting documents for the analysis that Mr. Higgins had done relating to increased O&M costs, Mr. Higgins had no documentation to provide.

years (2002 was the test year in the prior rate case). For these reasons, his proposal should be rejected.

Mr. Schlissel's proposed adjustment is inconsistent with Staff's consultants, who after an extensive and thorough audit, found that "O&M expenditure patterns [were] ... consistent with system operational requirements." Fuel Audit Report at 92. Moreover, Staff made no similar adjustment to O&M costs for the Company's natural gas units.

VI. STAFF'S PSA RECOMMENDATIONS

A. Forecasted Fuel Expense Levels

Q. DO YOU AGREE WITH STAFF WITNESS ANTONUK'S PROPOSAL TO UTILIZE 2007 ESTIMATED FUEL EXPENSE TO DETERMINE AN APPROPRIATE PSA ADJUSTOR?

A. I believe that setting the base fuel rate at the level I have described is far more important than utilizing a 2007 estimated fuel cost as the basis for a forward-looking PSA adjustor. However, if the Commission were to adopt a lower base fuel rate than the one I have proposed, I would support the concept of a prospectively-set PSA adjustor as a method for more closely aligning fuel expense recovery with fuel expense expenditures. This approach would have the benefit of keeping the Company's fuel expense deferrals (positive or negative) as low as possible.

Q. IS STAFF'S CALCULATION OF 2007 FUEL COSTS CONSISTENT WITH THE 2007 ESTIMATED COSTS YOU PRESENTED EARLIER IN YOUR TESTIMONY?

A. Yes, with one exception. The amount referenced by Mr. Antonuk in his direct testimony inadvertently excluded the capacity payments for the new Reliability

RFP contracts going into effect in June 2007. The fuel costs related to these contracts were included in the dispatch simulation model, but the capacity costs were omitted in the version initially provided to Staff. The corrected version has since been provided to Staff. Except for this change, the 2007 fuel estimates are identical.

For the purposes of setting a base fuel rate, it would also be important to annualize costs for events taking place mid-year. We would want to do this so that the base fuel rate could be most reflective of conditions that are known to be in effect for longer than just the current or upcoming year. In this respect, the Company would have also proposed that the changes in capacity costs resulting from the initiation of the Reliability RFP contracts in mid-2007 and the 2007 reduction in demand under the SRP Territorial and Contingent ("T&C") Agreement be annualized. As a practical matter, though, the annualization adjustments I describe do not result in a material change in the base fuel rate, and since Staff was not in favor of such an adjustment, the Company is not proposing it.

B. Implementation of Staff's PSA Proposal

Q. BASED ON YOUR UNDERSTANDING OF STAFF'S PROPOSAL FOR MODIFYING THE IMPLEMENTATION OF THE PSA, WHAT HAVE YOU CONCLUDED IS THE SINGLE MOST IMPORTANT ELEMENT THAT THIS COMMISSION SHOULD ADDRESS IN THIS PROCEEDING?

A. If the Commission chooses to adopt the Staff proposal in this case, without hesitation, I believe that the Commission should adopt the 2007 estimated fuel cost level as presented in this proceeding as the basis for a 2007 prospective PSA adjustor. I suggest this for the very simple reason that there is not sufficient time

to get a decision in this case which then prescribes a follow up (potentially lengthening) procedure to establish the new adjustor level and have the new adjustor in effect early in 2007.

Q. WHAT IS YOUR UNDERSTANDING OF STAFF'S PROPOSAL FOR MODIFYING THE OPERATION OF THE PSA?

A. As I understand the proposal, Mr. Antonuk would have the Company make a filing sometime in the fall of each year, which would provide the projected fuel costs for the following calendar year. The difference between the projected fuel costs and the projected recovery under base rates would serve as the basis for setting the PSA adjustor on a prospective basis. Mr. Antonuk's Direct Testimony did not provide specifics regarding the form of the filing; how much time the Commission Staff may take to review the filing; what the approval process would be; when the new approved adjustor level would take effect; and how the Company and the Commission would address deviations that occur throughout the adjustor year. He also remained silent on how such a process would work in the context of the current rate case, given that the evidentiary hearing in the current case is scheduled to commence in mid-October and is unlikely to produce a Recommended Opinion and Order until early next year. Finally, Mr. Antonuk does not address what Staff proposes to do with what he describes as "caps and collars," although it appears that he is opposed to them. (Antonuk Direct Testimony, page 6, lines 7-11.)

Q. HOW DO YOU PROPOSE THAT THE COMMISSION HANDLE THESE DETAILS?

A. For reasons I have articulated above, I believe that if the Commission wishes to adopt this general Staff approach, it should still adopt a base fuel rate of

3.3112¢/kWh and move to a prospective adjustor mechanism to take effect in 2008. This would allow the base fuel rate to be aligned as closely as possible to the fuel costs that the Company will be incurring the first year that rates are in effect and provide for an orderly transition to the new PSA structure suggested by Staff.

However, if the Commission chooses not to adopt such an approach in this proceeding and opts instead for the base fuel rate as proposed by Staff (without the $3.7 million increase to off-system margins proposed by Staff), then the Commission should use this rate case proceeding for setting the 2007 prospective costs. The revised 2007 fuel cost estimate would suffice for this purpose. In the instance where the Commission adopts Staff's proposed test year base fuel rate of 2.8111¢/kWh (corrected for the inappropriate off-system margin adjustment applied by Staff), the corresponding prospective adjustor for 2007 would be 0.5001¢/kWh.

Q. DO YOU FORESEE THE 90/10 SHARING MECHANISM APPLYING TO THIS ADJUSTOR?

A. No. The purpose of the prospective adjustor is to take into account costs that are already largely set and to adjust for a base fuel rate that is either too high or too low. In the situation where the base fuel rate is set lower than the Company's on-going fuel costs, the 10% sharing mechanism serves as nothing more than a penalty and an automatic disallowance of fuel costs. In the reverse situation, when on-going costs have fallen below the level of the base fuel rate, customers end up paying more than they otherwise would have to.

Q. YOU MENTIONED DEVIATIONS IN FUEL COSTS OVER AND ABOVE THE BASE RATE PLUS PROSPECTIVE ADJUSTOR LEVELS. WILL

THERE STILL BE A NEED FOR A RETROSPECTIVE ADJUSTOR LIKE THE ONE CURRENTLY IN PLACE?

A. Yes. In fact, the current PSA structure can remain largely intact with the exception of adding a provision for filing and approval of a prospective adjustor. The current structure would allow for any deviations as described above to be captured at year-end and flowed through in a separate adjustor rate in the following year. This is how the process works now, and it can also work this way with a prospectively-set adjustor. The primary difference between the current application and the one being proposed here is that once the prospective adjustor is set, the deviations in any year are likely to be minor. As we have seen in 2005 and 2006, deviations in actual fuel costs from the current base fuel rate of 2.0743¢/kWh <u>without a forward-looking adjustor</u> can be and have been quite large.

Q. WHEN WOULD THESE ADJUSTOR RATES BE IMPLEMENTED?

A. The current PSA structure calls for the retrospective or backward-looking adjustor to take effect with the first billing cycle in February of the following year. In the interests of simplifying the number of rate changes that customers might experience on their bills, we propose that both the prospective adjustor (beginning in 2008) and the retrospective adjustor be implemented at the same time, i.e., with the first billing cycle in February of each year.

Q. WHEN WOULD THE COMPANY FILE FOR THE PROSPECTIVE ADJUSTOR?

A. Under normal circumstances, the Company would file its forecast for the following year no later than September 30 of each year. I propose that Staff would then have 45 days to review the application and make its recommendation

to the Commission. This timing would allow the Commission sufficient time to review the Staff recommendation and issue a final decision by the end of the year, which would then allow the rate change to take effect in February as desired.

Under the current circumstances, to assure that the Company has sufficient recovery of fuel expenses in 2007, it is crucial that the Commission utilize this current rate case proceeding to set the prospective adjustor for 2007 and that the prospective adjustor go into effect with the new rates to be authorized by the Commission through this proceeding. Without such a process, there will be no opportunity for the Company to recover its fuel costs in a timely manner. As a practical matter, the process for setting a prospective adjustor cannot begin until after a final decision is reached in this case unless the prospective adjustor is established as a part of this case. The establishment of this prospective adjustor could wait until 2008 if the Commission adopts the Company's proposed base fuel rate.

The Company would continue to operate under the existing PSA structure in the meantime, which means that:

- The interim adjustor of 7 mills/kWh will be terminated at Dec. 31, 2006; and
- The Company will file the calculation of the retrospective Annual Adjustor in January 2007, which is currently anticipated to show a continuation of the Annual Adjustor at 4 mills/kWh. This will be the case regardless of what the Commission ultimately decides in this case.

Q. IS THERE A MORE DETAILED DESCRIPTION OF HOW THIS MECHANISM IS DESIGNED TO WORK?

A. Yes. Mr. David Rumolo is sponsoring a detailed Plan of Administration for the Company's interpretation of the Staff-proposed mechanism, as well as a detailed Plan of Administration that incorporates the Company-proposed PSA changes included in Mr. Robinson's Rebuttal Testimony.

VII. REPLACEMENT COSTS FOR PALO VERDE OUTAGES

Q. DO YOU PROPOSE ANY ADJUSTMENTS TO STAFF'S RECOMMENDED DISALLOWANCE OF REPLACEMENT POWER COSTS FOR PALO VERDE OUTAGES IN 2005?

A. Yes. Mr. Levine and other Company witnesses have provided Rebuttal Testimony in this proceeding that shows that the Palo Verde outages cited by Staff witness Jacobs were not at all imprudent and could not have been foreseen. However, if the Commission finds that any or all of these outages were imprudent, the disallowance of associated costs requires certain corrections and offsets. In particular, I have found that Dr. Jacobs has overstated the net replacement power costs by $8.6 million for the outages that occurred subsequent to the beginning of the Company's PSA mechanism in April 2005. I also note that the Company's coal plants reduced outage costs in 2005 by $10.0 million by performing above their normal levels, and I reiterate that the 2005 outages occurring prior to the start of the PSA – whether prudent or not – have already been expensed by the Company and are normalized out of the test period used for setting base rates. In summary, Staff's recommended disallowance of $17.4 million should be eliminated or, at the very least, reduced dramatically. The interest related to the ultimate disallowance, if any, must also be recalculated.

Q. DOES STAFF'S RECOMMENDATION OVERSTATE THE TRUE INCREMENTAL COST OF THE REPLACEMENT POWER FOR THE PALO VERDE OUTAGES HE FINDS FAULT WITH?

A. Yes. The $17.4 million disallowance cited by Staff witness Dr. Jacobs includes several overstatements, which amount to $8.6 million. They include the following:

Note: The analysis discussed below was contained in Report of GDS Associates, Inc. on Behalf of Utilities Division, Arizona Corporation Commission, ("GDS Report") issued August 17, 2006.[10]

- The impacts on off-system sales estimated by Dr. Jacobs are overstated by $1.8 million. Dr. Jacobs erroneously concludes that every megawatt-hour (MWh) of lost power results in a lost off-system sale, even though the Company was forced to purchase a large share of its replacement power from the market, and that on average the lost margins on each sale approximated the Company's average unit margin for the entire April-December 2005 time period. In fact, neither of these is the case. In contrast to the estimated 187,000 MWh of lost off-system sales calculated by Dr. Jacobs, it appears that the Company lost at most 9,000 MWh of sales during the Unit 1 outage from August 26th through August 28th and the Unit 2 and Unit 3 outages in mid-October. Having said that, it also is the case that the lost unit margins were approximately three times greater than the value used by Dr. Jacobs. I have estimated these amounts by running a simulation of the power system on the days of the outages at issue using actual load and market conditions. I then compare the results of this simulation to the actual results experienced by the Company for these same days. The result is a reduction in off-system sales margins from

[10] The GDS Report was filed in Docket No. E-01345A-05-0826, *In the Matter of the Inquiry into the Frequency of Unplanned Outages during 2005 at Palo Verde Nuclear Generating Station, the Causes of the Outages, the Procurement of Replacement Power and the Impact of the Outages on Arizona Public Service Company's Customers.*

what otherwise might have been achieved of $322,000. This reduced off-system sales result is $1.8 million lower than the $2.1 million amount recommended by Dr. Jacobs.

- The Unit 3 Refueling Water Tanks ("RWT") outage costs in October 2005 are overstated by $1.2 million. Dr. Jacobs appears to have repeated the outage costs incurred during the Unit 2 RWT outage for the Unit 3 outage during the same time period. GDS Report Attachment 15 shows a replacement power cost of $7.672 million for both the Unit 2 outage and the Unit 3 outage. However, this approach ignores the stratification of actual replacement power sources and costs from highest-cost resource to lowest-cost resource in the replacement power cost calculation methodology, and therefore ignores the ultimate assignment of higher cost resources to the Unit 2 outage than the Unit 3 outage. Per the correct method, the Unit 3 outage incurred only $6.475 million, not the $7.672 million claimed by Dr. Jacobs. APS provided Dr. Jacobs with the relevant information to make an accurate analysis in response to Data Request PB 1.7[11] The corrected value for the Unit 3 outage costs declines by $1.2 million. Following Dr. Jacobs's methodology of applying the 90/10 share to these costs, the decrease in costs becomes $1.1 million.

- The Unit 2 RWT outage costs in October 2005 are overstated by $5.6 million because the incremental outage duration related to the RWT question amounts to less than three days – as opposed to the nine days of outage used by Dr. Jacobs in his recommendation. As Mr. Levine describes in his Rebuttal Testimony, the fact that work was done on several other systems during the

[11] *Id.*

time period that Unit 2 was shut down avoided almost certain unplanned outages that would have occurred prior to Unit 2's scheduled refueling outage in April 2006. The most significant of these was the Reactor Coolant Pump ("RCP") oil seal replacements that, on average, require 6 days and 16 hours (160 hours in total) to complete from start to finish. Because Unit 2 was already shut down, the actual duration of the replacement work was limited to 90 hours between October 13 and October 16. During this time period, the replacement power cost (net of the avoided nuclear fuel expense) averaged $92.28/MWh and amounted to a total of $3.2 million. Using this same average cost for the full 160 hours of additional outage time that was avoided by performing the RCP oil seal work during the RWT investigation produces an avoided outage cost of $5.636 million. Following Dr. Jacobs's methodology of applying the 90/10 share to these costs, the decrease in costs becomes $5.1 million.

Another way of looking at these avoided outage costs is to estimate what the costs would have been if they had occurred at some point following the RWT-related outage. Replacement power costs, net of avoided nuclear fuel expense, averaged about $90/MWh in October 2005, $100/MWh in November 2005, and $70/MWh from December 2005 through March 2006. Applying these values to the energy lost from the RCP outage duration of 160 hours results in a range of potential outage replacement costs from $4.4 million to as much as $6.1 million. The calculation I have provided above falls in line with this range. Additionally, as Mr. Levine testifies, the main feedwater pump repair work and the heater steam drain repair would have been required at some point prior to Unit 2's next refueling outage. This work would not have required a complete

shut down of the unit, but it would have required a downpowering to partial power – 40% in the case of the main feedwater pump repair, and 10% for the heater steam drain repair. This work may or may not have been performed independently of the RCP oil seal work, but in the event that the work would have been performed incrementally to the RCP oil seal work, the upper end of the range of avoided costs would increase to $7.0 million. Mr. Levine also notes that a main generator bushing replacement was also performed at the same time as the RCP oil seal work and would have been timed to coincide with the RCP oil seal work if it had occurred at a later date than October 2005. The range of replacement power costs associated with this outage, calculated in the same manner as the outages above, is a low of $3.7 million to a high of $5.2 million. While the replacement power costs associated with this outage were not incremental to the RCP work, the range of cost estimates is evidence of the amount of prudent work performed during this period. It is clear that while the RWT question posed by the Nuclear Regulatory Commission was the initial cause of the October 2005 outage, the opportunity to perform necessary maintenance during that outage avoided future outage costs of a significant magnitude.

- The outage costs for Unit 1 from August 26 to August 28 are overstated by $98,000. Dr. Jacobs used the net replacement power cost calculation of $1.260 million initially provided by the Company in response to a data request, and this calculation did not appropriately account for the reactor power level when Unit 1 tripped off-line. The correct net replacement power cost is $1.162 million. This amount accounts for the fact that the reactor was at 1.8% power when Unit 1 tripped, and would have remained out of service for the first 6.5

hours of the outage even if it had not tripped off-line. While Unit 1 tripped off-line at 1824 on August 26th, the additional outage duration related to the trip started at 0100 on August 27th and continued until Unit 1 returned to service at 1646 on August 28th. At these levels, the corrected value for Unit 1 outage costs declines by $98,000. Following Dr. Jacobs's methodology of applying the 90/10 share to these costs, the decrease in costs becomes $88,000.

- Finally, Dr. Jacobs did not accurately apply the 90/10 sharing methodology in his calculated disallowance where the result was his recommendation that the Company expense $515,000 of replacement power costs a second time. In applying the 90/10 sharing requirement, Dr. Jacobs took the full net replacement power cost for any particular outage and reduced that amount by 10%. In actuality, the 90/10 sharing occurs only with respect to fuel costs in excess of the Company's fuel costs included in base rates. This means that the Company expenses 100% of the replacement power costs up to the level included in the Company's base rate and 10% of the amounts thereafter. For the outages cited by Dr. Jacobs as imprudent, the level of outage costs already expensed was $570,000 in base rates and $910,000 through the 90/10 sharing mechanism for a total of $1.480 million. Using my corrected values from above, Dr. Jacobs's method gives credit for only $965,000 of outage costs already expensed. The difference is $515,000, or 90% of the $570,000 included in base rates.

In summary, these corrections to Dr. Jacob's proposed disallowance significantly reduce that disallowance. Attachment PME-4RB shows each of these adjustments. Once these corrections are applied, the impact on interest will also have to be calculated.

Q. ARE THERE OTHER OFFSETTING FACTORS THAT DR. JACOBS IGNORES?

A. Yes. Most importantly, Dr. Jacobs neglected to reflect the mitigating effect on replacement power costs resulting from the superior performance of the Company's coal-fired generating plants. The Company's coal plants had a remarkable year of performance in 2005 and set an all-time high for capacity factor, which means that they produced more power in 2005 than in any previous year. These plants had 40% less unplanned outage time than the normalized amount included in the Company's base rates, and this "better than normal" performance reduced fuel costs by $10.0 million (at the relatively low market prices included in the Company's base fuel rate). The variable fuel costs for the coal plants are almost as low as those for Palo Verde. When considering the market costs for replacement power in 2005, it is clear that every MWh of higher-than-planned production by the coal plants served to offset almost a full MWh of lost production from Palo Verde. Customers have already received the benefit of these fuel expense savings through the PSA mechanism.

The following table summarizes the adjustment I have just described:

Corrections and Offsets to Staff Recommended Disallowance

Corrections to Staff Calculations:		
Unit 2 RWT	$ 5.1	Million
Off-System Sales Impact	1.8	Million
Unit 3 RWT Outage	1.1	Million
Unit 1 Reactor Trip	0.088	Million
Costs Already Expensed	0.515	Million
Total	$ 8.6	Million
Coal Plant Performance Offset	$10.0	Million
Total: Corrections & Offsets	**$18.6**	**Million**

VIII. STAFF'S FINAL AUDIT REPORT ON FUEL AND PURCHASED POWER PROCUREMENT

Q. IN ITS RECOMMENDATIONS IN THE FUEL AUDIT REPORT, STAFF HAS RECOMMENDED THAT THE COMPANY ANALYZE SYSTEM RESERVE CALCULATIONS USING BOTH A 50/50 AND 90/10 LOAD FORECAST, INCORPORATING THE CONSTRAINTS OF THE PHOENIX LOAD POCKET. WHAT IS YOUR RESPONSE TO THIS RECOMMENDATION?

A. The Company has prepared and analyzed the impacts of "90/10" load forecasts in the past as part of the Company's routine sensitivity analyses. While the risks of exceeding the 50/50 load forecast are fairly well understood in the Company, we will seek ways to incorporate these forecasts more formally.

Q. STAFF HAS ALSO MADE RECOMMENDATIONS IN THE FUEL AUDIT REPORT RELATED TO PSA PROCEDURES AND FILINGS. WHAT IS YOUR RESPONSE TO THESE RECOMMENDATIONS?

A. Staff has recommended that the Company develop a written procedure for the preparation of the monthly PSA filings, and add a supporting back-up schedule to add greater transparency between the confidential PSA filing and the non-confidential PSA filing. The Company has no objection to these recommendations, and has already developed both of the suggested documents.

Q. THE FUEL AUDIT REPORT ALSO RECOMMENDS THAT THE COMPANY CORRECT PSA REPORTING METHODS TO ASSURE MORE ACCURATE CLASSIFICATION AND REPORTING OF COAL, OIL AND GAS GENERATION INFORMATION. WHAT IS YOUR RESPONSE TO THIS RECOMMENDATION?

A. While I take issue with the notion that the prior method of reporting resulted in a mis-classification of costs, albeit of the most minor variety, the Company has no objection to this recommendation and has already revised the manner in which this information is reported.

IX. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. To preserve the Company's financial stability, it is critical that the Commission authorize rates that adequately cover the costs of energy *during the time that the rates are in effect.* Because rates that result from this case will not be in effect until 2007, it is necessary and proper to take into account know and measurable changes to the test year in setting base fuel rates. Therefore, the Commission should set the Company's base fuel rates at 3.3112¢/kWh for the reasons I have discussed. In the alternative, if the Commission decides to address the Company's fuel cost issues through the PSA, to assure timely recovery of fuel costs, it is essential that the Commission establish the 2007 adjustor rate in this proceeding at the level I have proposed, and implement it concurrently with the Staff's proposed base fuel rate. In regard to the costs of the unplanned Palo Verde outages, if the Commission finds, despite Company testimony to the contrary, that Company imprudence was the cause of the Palo Verde outages, the more appropriate calculations that I have presented should be the basis for any disallowance the Commission may consider.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

1887030.3

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **BASE FUEL AND PURCHASED POWER**
Adjustment to Test Year operations to include 2006 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption, and to remove Deferred Fuel related to the PSA.

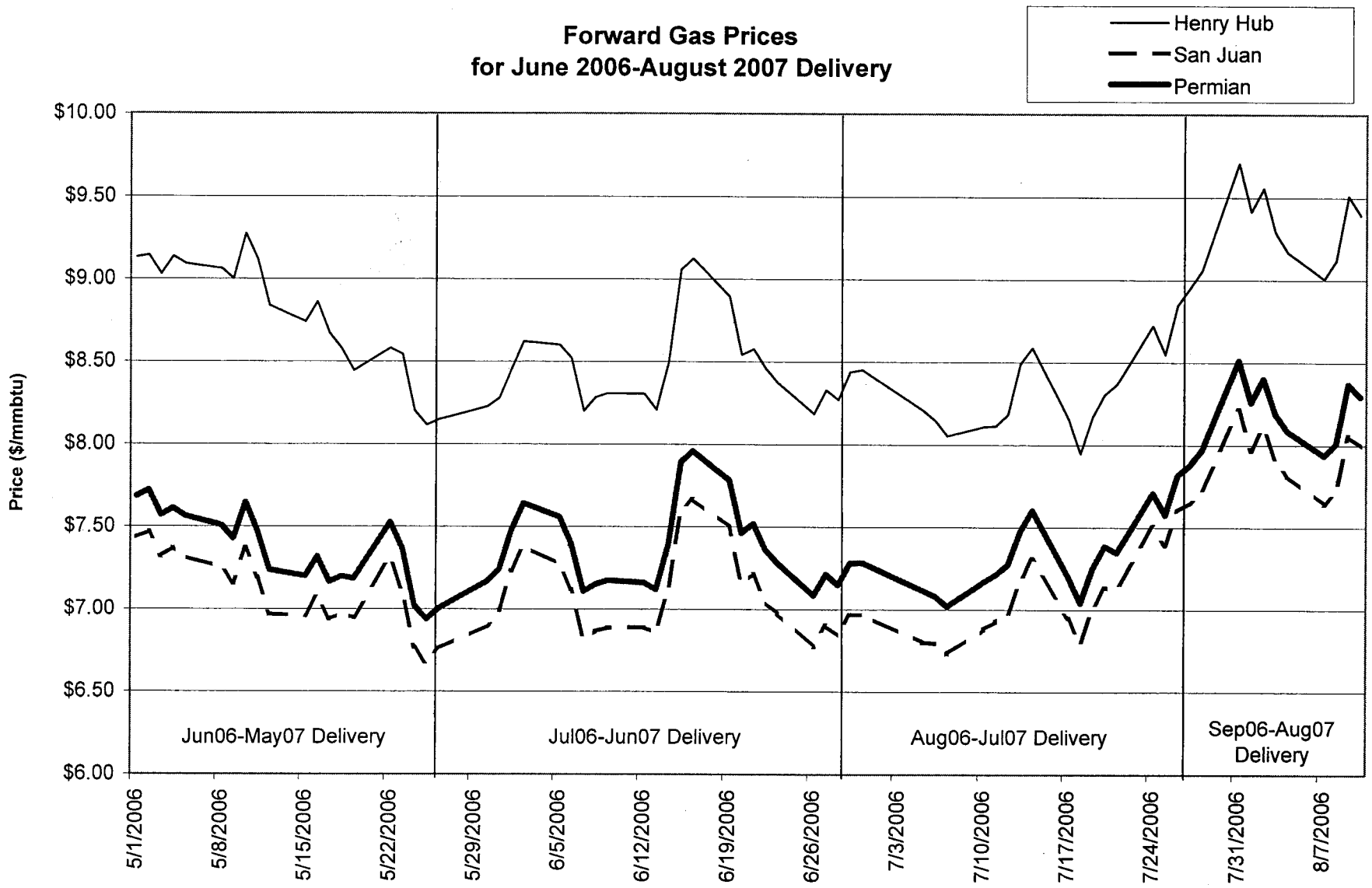
Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel and Purchased Power Expenses		
3.	Normalized 2006 Fuel and Purchased Power Costs (¢/kWh)	3.3994	
4.	Test Year Fuel and Purchased Power Costs (¢/kWh)	2.6983	
5.	Adjustment to Fuel and Purchased Power Costs (¢/kWh)	0.7011	
6.	Test Year Sales (MWh)	26,088,197	
7.	Pro Forma Adjustments to Test Year Billed Retail Sales (MWh)		
8.	To Adjust to Normal Weather	156,529	
9.	To Annualize to September 30, 2005 Customer Level	514,752	
10.	Adjusted Test Year Retail Sales (MWh)	26,759,478	
11.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 5 X Line 10)	187,611	
12.	Remove Test Year PSA Fuel Deferral		
13.	Retail PSA Fuel Deferral	139,768	
14.	Deferred Mark to Market on Native Load Hedge	(26,924)	
15.	Total Test Year PSA Fuel Deferral	112,844	
16.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 11+ Line 15)		$ 300,455
17.	**OPERATING INCOME (before income tax)**		**$ (300,455)**
18.	Income Tax at 39.05%		(117,328)
19.	**OPERATING INCOME AFTER TAX**		**$ (183,127)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: **NORMALIZE OFF-SYSTEM SALES**

Adjustment to Test Year operations to include off-system revenues consistent with the Base Fuel and Purchased Power pro forma adjustment.

Line No.	Description				Amount
1.	**REVENUES:**				
2.	Normalized Off-System Revenue	$	165,694		
3.	Test Year Off-System Revenue	$	74,619		
4.	Pro Forma Adjustment to Revenues			$	91,075
5.	**EXPENSES:**				
6.	Fuel and Purchased Power Expenses				
7.	Normalized Off-System Fuel and Purchased Power Expenses	$	141,695		
8.	Test Year Off-System Fuel and Purchased Power Expenses	$	75,344		
9.	Total Pro Forma Adjustment to Fuel and Purchased Power Expenses				66,351
10.	**OPERATING INCOME (before income tax)**			**$**	**24,724**
10.	**OPERATING INCOME (before income tax)**			**$**	**24,724**
11.	Income Tax at 39.05%				9,655
12.	**OPERATING INCOME AFTER TAX**			**$**	**15,069**



Data Source: AECC Response to APS AECC 2-1

ARIZONA PUBLIC SERVICE COMPANY
2005 PALO VERDE OUTAGE COSTS CORRECTED AND OFFSETS TO STAFF PROPOSED DISALLOWANCES
($000)

STAFF PROPOSED DISALLOWANCE

Unit	Description	Date	Net Replacement Cost	After 90/10 Sharing	Off-System Margin Impact	Total System Impact
1	Outage extension due to reactor trip	8/26 - 8/28	1,260	1,134	187	1,321
2	RWT inoperable	10/11 - 10/20	7,672	6,905	954	7,859
3	RWT inoperable	10/11 - 10/20	7,672	6,905	962	7,867
	Total		16,604	14,944	2,103	17,047

CORRECTED STAFF PROPOSED DISALLOWANCE

Unit	Description	Date	Net Replacement Cost	After 90/10 Sharing	Off-System Margin Impact	Total System Impact
1	Outage extension due to reactor trip	8/26 - 8/28	1,162	1,046	67	1,113
2	RWT inoperable	10/11 - 10/20	7,672	6,905	128	7,033
2	RCPs 1A and 2A oil seals replaced	10/13 - 10/16	(5,636)	(5,072)	(53)	(5,125)
	subtotal		2,036	1,833	75	1,908
3	RWT inoperable	10/11 - 10/20	6,475	5,828	128	5,956
	Total		9,673	8,707	269	8,976

CHANGE IN STAFF PROPOSED DISALLOWANCE DUE TO CORRECTIONS

Unit	Description	Date	Net Replacement Cost	After 90/10 Sharing	Off-System Margin Impact	Total System Impact
1	Outage extension due to reactor trip	8/26 - 8/28	(98)	(88)	(120)	(208)
2	RWT inoperable	10/11 - 10/20	(0)	-	(826)	(826)
2	RCPs 1A and 2A oil seals replaced	10/13 - 10/16	(5,636)	(5,072)	(53)	(5,125)
	subtotal		(5,636)	(5,072)	(879)	(5,951)
3	RWT inoperable	10/11 - 10/20	(1,197)	(1,077)	(834)	(1,911)
	Total		**(6,931)**	**(6,237)**	**(1,834)**	**(8,071)**

ARIZONA PUBLIC SERVICE COMPANY
2005 PALO VERDE OUTAGE COSTS
CORRECTED AND OFFSETS TO STAFF PROPOSED DISALLOWANCES
($000)

CORRECTED STAFF PROPOSED DISALLOWANCE

Unit	Description	Date	Net Replacement Cost	APS Shared Amount	After 90/10 Sharing	Off-System Margin Impact	Total System Impact
1	Outage extension due to reactor trip	8/26 - 8/28	1,162	116	1,046	67	1,113
2	RWT inoperable	10/11 - 10/20	7,672	767	6,905	128	7,033
2	RCPs 1A and 2A oil seals replaced	10/13 - 10/16	(5,636)	(564)	(5,072)	(53)	(5,125)
	subtotal		2,036	204	1,833	75	1,908
3	RWT inoperable	10/11 - 10/20	6,475	648	5,828	128	5,956
	Total		9,673	967	8,707	269	8,976

CORRECTED STAFF PROPOSED DISALLOWANCE WITH BASE RATE OFFSET

Unit	Description	Date	Net Replacement Cost	Base Rate Amount	Amount Above Base Rate	APS Shared Amount	Fuel Deferral Amount	Off-System Margin Impact	Total System Impact
1	Outage extension due to reactor trip	8/26 - 8/28	1,162	91	1,070	107	963	67	1,030
2	RWT inoperable	10/11 - 10/20	2,036	247	1,789	179	1,610	75	1,685
3	RWT inoperable	10/11 - 10/20	6,475	232	6,243	624	5,619	128	5,746
	Total		9,673	570	9,103	910	8,192	269	8,462

Total Change in Corrected Staff Proposed Disallowance Due to Base Rate Offset **(515)**

Total Change to Staff Proposed Disallowance (Page 1 + Page 2) **(8,585)**

REBUTTAL TESTIMONY OF DONALD G. ROBINSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

Table of Contents

I. INTRODUCTION 1

II. SUMMARY OF REBUTTAL TESTIMONY 1

III. THE POSITIONS OF THE PARTIES ON THE PSA AND THE COMPANY'S RESPONSE TO SUCH POSITIONS 4

IV. CONCLUSION 11

Comparison of PSA Positions ..... Attachment DGR-1RB

REBUTTAL TESTIMONY OF DONALD G. ROBINSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald G. Robinson. I am Vice President of Planning for Arizona Public Service Company ("APS" or "Company"). I have responsibility for Corporate Planning, Resource Acquisition, Resource Planning, Budgets, Forecasts, Energy Risk Management and New Business Ventures. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony addresses the proposals of Staff consultant Antonuk to modify the current Power Supply Adjustment ("PSA") rate mechanism for APS. I go on to address the continued need for some of the modifications to the PSA itself that I proposed in my Direct Testimony, even if the Staff recommendations relative to the PSA are adopted by the Commission. I also comment on the testimony of intervenors concerning the PSA.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. I must first note that there is universal agreement among the parties that a PSA should be retained. There is likewise unanimity that the current PSA structure should be modified to make it more flexible and do a better job of timely

recovering prudent fuel costs incurred to serve our customers. The extent of the needed modifications to the PSA is really the question that must be resolved by the Commission in this proceeding and is at the heart of the remaining disagreement among the parties relative to the PSA.

As we understand it, Staff would establish a base fuel cost based on "as-incurred" 2006 costs with normalizations for weather and power plant maintenance, but with no annualization adjustments for certain of the known and measurable changes occurring in 2006, let alone any in 2007. By Staff's own admission, this would set the base fuel rate well below the level of costs anticipated during the period the new base fuel rate would become effective. The resulting deferrals would be in the area of $150 million. To mitigate some of this tremendous run-up in 2007 PSA cost deferrals that would otherwise result from this conscious understatement of base fuel costs, a 2007 "prospective" PSA adjustor would be established (concurrently with the new base fuel rate or shortly thereafter) based on forecasted 2007 fuel costs. It is assumed by APS that the as-of-yet unrecovered amount of 2006 fuel costs would flow into the existing Annual PSA Adjustor effective February 1, 2007, which would now become a "retrospective" PSA adjustor to collect the difference between the forecasted fuel costs used to set the prospective PSA adjustor and actual fuel costs for the projected year – in this instance 2008. The following year, the 2008 prospective PSA adjustor would be established in some sort of proceeding in late 2007. The present "90/10" sharing mechanism, the four mill "cap" on what is now the Annual PSA Adjustor (both annual and cumulative), and what is described in my Direct Testimony as the Total Fuel Cost Cap would all seem to be replaced by

what Staff's consultant believes to be a more comprehensive regime of regulatory oversight of fuel costs.

The Staff proposal is a dramatic change to both the determination of base fuel costs and the current form of Annual PSA Adjustor. However, if implemented as a package and early in 2007, and with the application of any continued 90/10 sharing as described in my Rebuttal Testimony, the Staff proposal could be effective in reflecting changes in fuel costs on a more-timely basis than is presently the case. Nevertheless, APS still favors its original recommendations, and most specifically a properly updated and adjusted base fuel cost, in this case to the levels testified to in APS witness Ewen's Rebuttal Testimony.

APS believes its original proposals, with the exception of a change to the sharing of hedging gains and losses – a suggested change the Company is withdrawing, appear to have support, albeit to varying degrees, from all the parties filing testimony on the PSA and thus could be more easily implemented without significant changes to the already-approved PSA Plan of Administration. Moreover, if not implemented in a timely and comprehensive fashion, the Staff's proposal would result in a significant increase in PSA cost deferrals similar to what occurred after Decision No. 67744 was implemented (and for the same reason – an inadequate allowance for fuel costs in the base fuel rate) and the near automatic disallowance of prudently-incurred fuel costs during 2007. David Rumolo has attached a modified PSA Plan of Administration to his Rebuttal Testimony that would implement the Company's proposed changes to the PSA as discussed above with the exception of our originally suggested change in the allocation of hedging gains and losses.

Nevertheless, in the event the Commission accepts the Staff PSA proposal, APS has also submitted a Plan of Administration with the Rebuttal Testimony of David Rumolo that we believe would implement the Staff's recommendation. APS made, necessarily, a number of assumptions as to the details attendant to the Staff PSA proposal, which admittedly was more of a concept in Mr. Antonuk's testimony than a specific point by point proposal for modifying the present PSA structure. APS witness Ewen provides the calculation of the new Base Fuel Rate and the 2007 PSA Adjustor using our understanding of Staff's proposal with certain adjustments described in Mr. Ewen's Rebuttal Testimony.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. I first describe the positions of the various parties relative to the PSA. I then address the Company's areas of agreement, concerns and objections to those positions.

III. THE POSITIONS OF THE PARTIES ON THE PSA AND THE COMPANY'S RESPONSE TO SUCH POSITIONS

Q. PLEASE DESCRIBE THE VARIOUS PARTIES' POSITION ON THE PSA.

A. Staff's general PSA proposal is as described in my Summary. Staff also specifically rejected the Company's proposed change in the allocation of hedging gains and losses. Staff's position on the remaining APS proposed changes to the PSA is unclear, although Mr. Antonuk's position that "caps and collars" are unnecessary leads us to believe that Staff agrees that the Total Fuel Cost Cap and the cumulative four mill "cap" on the Annual PSA Adjustor should be removed. Likewise, it would be consistent with Mr. Antonuk's testimony that the annual four mill "cap" to the Annual PSA Adjustor be removed both for the prospective PSA adjustor and the retrospective PSA adjustor, as those concepts

are described in Mr. Ewen's Rebuttal Testimony. Staff is silent about the Company's specific proposals to "exempt" renewable energy and the demand component of purchased power agreements from the 90/10 sharing process, as well as our suggestion to remove the mandatory PSA surcharge application provision. Indeed, Staff's position on retention of this 90/10 sharing process as a general proposition is somewhat unclear, although discovery has led APS to conclude that at a minimum, Staff would not apply the 90/10 sharing to the difference between the Base Fuel Rate and the 2007 adjustor based on anticipated 2007 fuel costs. That is certainly a reasonable and fair position and indeed, it would be more appropriate to apply the 90/10 incentive only to the variation between the projected PSA annual adjuster and the actual fuel costs for the year in question than to all cost variations above or below base fuel costs.

RUCO has apparently accepted the APS proposal as filed with the exception of the change in the allocation of hedging gains and losses. As noted in my Summary, APS has now withdrawn that suggested change to the PSA. I must use the term "apparently" because RUCO also did not comment, one way or another, on the Company's suggestion to remove the requirement for a mandatory PSA surcharge filing when the Paragraph 19(d) Balancing Account was in excess of $100 million.

Arizonans for Electric Choice and Competition/Phelps Dodge Mining Corporation ("AECC/Phelps Dodge") likewise supported removal of the Total Fuel Cost Cap and the cumulative four mill "cap" on the Annual PSA Adjustor. It also adjusted the Base Fuel Rate to reflect lower fuel and purchased power prices since the time APS filed its Amended Application. AECC/Phelps Dodge

opposed APS' changes to the 90/10 sharing procedure. Like RUCO and Staff, AECC/Phelps Dodge did not address the mandatory PSA surcharge filing issue.

The only other parties that took a specific position on the PSA were the Arizona Utilities Investor Association ("AUIA") and Interwest Energy Alliance ("IEA"). The AUIA generally supported the Company's position although it was silent on some PSA issues. IEA proposed no structural changes to the PSA and did not comment on the Company's proposals but did advocate having all renewable PPA costs recovered through the PSA rather than the current practice of having at least a portion of those costs recovered through the EPS (RES). Attachment DGR-1RB compares the positions of the parties (excepting IEA) on each of the Company's original proposals regarding the PSA and shows any new proposals that have been presented.

Q. WHAT IS YOUR REACTION TO THESE PROPOSALS?

A. Let me start with RUCO. Because it appears that we are in agreement as to all the essentials relative to the PSA, our reaction is clearly positive. If APS is mistaken concerning RUCO's support for, or at least non-opposition to the deletion of the mandatory PSA surcharge application requirement or to our updated Base Fuel Rate, as discussed by Mr. Ewen, I presume RUCO would indicate as much in its Surrebuttal Testimony. APS will then address any presently non-apparent PSA issues with RUCO in our Rejoinder Testimony.

AECC/Phelps Dodge proposed a lower Base Fuel Rate than did APS but took no issue with how APS calculated that Base Fuel Rate. However, I want to echo the comments of Mr. Ewen, Steve Wheeler and Don Brandt that we need to set the

Base Fuel Rate right this time and not repeat what clearly turned out to be a mistake in the last APS general rate proceeding.

AECC/Phelps Dodge's opposition to the requested changes in the PSA to exempt renewable energy PPAs and the demand component of competitively-acquired PPAs does not directly contest the Company's underlying rationale for seeking these exemptions but rather suggests that if APS wished such a modification of the 90/10 sharing process, it should have done so in the last case. In responding, I will first reiterate the policy reasons behind our original request and then address the argument that APS should have requested these exemptions in the last rate proceeding.

There is no disagreement that as a general proposition, renewable PPAs will have higher per kWh prices than does purchased power from "conventional" resources. Likewise, this Commission has clearly supported and even required the acquisition by APS of renewable energy despite its higher cost. I believe it is inconsistent and counter-productive to the goals of promoting renewable energy to impose what is little more than a 10% penalty on the acquisition of new renewable energy.

With respect to the conventional resource PPAs, by competitively acquiring these resources from the market, APS has already done all it can to minimize the capacity cost of these incremental purchased power resources. Any attempt to further "incent" APS through 90/10 sharing is pointless. As with renewables, it is in effect a 10% penalty. In contrast, APS can influence the energy prices associated with these PPAs by prudent acquisition of fuel and economically-

justified dispatch of that energy. That is why APS only proposed to exempt the fixed demand charge component of these PPAs from the 90/10 sharing process.

At the time of the last rate proceeding, it was not evident to APS that both fixed capacity costs and renewable energy costs would be as prominent of components to the overall resource mix as is now clearly the case. The fact that APS, or for that matter other parties, did not make a proposal in some prior case has never foreclosed them from making it in a subsequent rate proceeding. For example, AECC/Phelps Dodge have suggested rate design modifications in this case that it also did not propose in the last case and which certainly did not appear in the final settlement of that case or in Decision No. 67744.

APS is not opposed in principle to having the cost of even EPS/RES-eligible renewables recovered through the PSA. APS would note that this would be a departure from current practice and would tend to obscure the higher cost of renewable resources from customers.

Q. WHAT ABOUT STAFF'S PROPOSAL?

A. As I discussed in my summary, there was little detail concerning the Staff's proposed modifications to the PSA other than a change to using projected costs to establish the Annual PSA Adjustor. Through discovery, APS has learned some additional information but must still "fill in the blanks" with some logical assumptions concerning the scope of the changes to the PSA necessary to implement the Staff proposal in a comprehensive fashion. With these assumptions, APS believes that Staff is suggesting:

> (1) a base fuel rate based on 2006 costs of $.027975 per kWh, which includes normalizations for maintenance and weather but not all annualizations of known and measurable changes during 2006 or for known and measurable changes during 2007;

(2) a 2007 Annual PSA Adjustor of $.005137 per kWh based on a forecast of 2007 sales and fuel costs ($.004099 in Mr. Antonuk's testimony, which Mr. Ewen has corrected in his Rebuttal Testimony);

(3) a second adjustor of approximately $.004 per kWh, implemented on February 1, 2007, to recover the unrecovered balance of 2006 fuel costs after expiration of the Interim PSA Adjustor approved by Decision No. 68685;[1]

(4) future annual PSA adjustors based on projected fuel costs and sales, which would be implemented February 1st of years after 2007 and concurrent with any adjustor necessary to reconcile the actual recovery of costs by the annual adjustor with the forecasted recovery of costs;

(5) under or over-collections of fuel costs by either the prospectively-set PSA adjustor or the February 1, 2007 Annual PSA Adjustor would flow into the Paragraph 19(d) Balancing Account and be subject to the existing PSA surcharge procedures (absent, however, the mandatory PSA surcharge application requirement discussed below and earlier in my Rebuttal Testimony)

(6) the 90/10 sharing provision would only apply to costs above or below the level of forecasted costs used to establish the 2007 and subsequent years' annual PSA adjustments;

(7) both the annual four mill limit on the PSA adjustor and the cumulative four mill limit would be eliminated;

(8) the Total Fuel Recovery Cap would be eliminated;

(9) the requirement that APS file a PSA surcharge application if the Paragraph 19(d) Balancing Account exceeded $100 million would be eliminated;

(10) the existing and pending PSA surcharges would be unaffected by the changes in the PSA, although Staff is proposing that approximately $27 million of the pending "Step 2" surcharge request be approved and implemented concurrent with a final order in this proceeding.

Obviously, the Base Fuel Rate created by the Staff proposal would greatly understate fuel costs during 2007. APS believes it is more appropriate to

use the Company's proposed base fuel rate of $.033112 as set forth in Mr. Ewen's Rebuttal Testimony. But if the Commission adopts the Staff's proposed base fuel rate, it is critical that the 2007 PSA Adjustor based on 2007 costs be implemented concurrently with the new Base Fuel Rate. It is similarly important that the 90/10 sharing provision be implemented as described above if the Staff proposal is not to result in an automatic disallowance of costs during 2007 and in future years. We further believe that modification of the 90/10 sharing provision in the manner envisioned above would address much of our concerns about the inclusion of renewable PPA costs and PPA demand costs in the calculation of the 90/10 sharing.

With the caveats described above, and assuming APS has correctly filled in the missing elements in the Staff PSA proposal, the Company finds Staff's PSA proposal, if implemented as a package, to be a constructive improvement over the current PSA structure. That is why APS has drafted a Plan of Administration for the Staff proposal and attempted to insert some needed detail into a general concept that, although different from that suggested by APS, would be capable of accomplishing many of the same goals.

As I indicated earlier, APS continues to favor its own PSA recommendations as requiring fewer changes to the existing PSA structure. Moreover, if Staff's proposal is adopted piecemeal, or if the Company is

---

[1] The net impact of the two PSA adjustors described above should recognize the expiration of the Interim PSA Adjustor of seven mills. Thus, these two adjustors would increase the PSA charges by approximately $.002137 per kWh, or just over two mills as compared to the Interim PSA Adjustor.

mistaken about the Staff position with regard to the application of the 90/10 sharing procedure, and especially if the 2007 PSA adjustor of roughly five mills is not implemented concurrent with the new Base Fuel Rate as part of this proceeding, APS is far less favorably disposed to the Staff proposal. Under these latter circumstances, what we are left with is essentially a woefully inadequate Base Fuel Rate and some vague suggestions for future reforms to the PSA. As can be seen by Mr. Brandt's analyses in his Rebuttal Testimony, the financial results for APS and the eventual costs to APS customers from such a situation would be unacceptable for a utility with the tremendous capital needs and service responsibilities of APS.

IV. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS has made a comprehensive proposal to update base fuel costs and implement certain changes to the PSA to make that mechanism more effective in its timely collection of prudent fuel costs and to eliminate some of the inequities in its current application. Staff has also made a general proposal with regard to the PSA that, with the additional provisions I have described in my Rebuttal Testimony, could be an acceptable alternative to the APS proposal.

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

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY

COMPARISON OF PSA POSITIONS IN DOCKET NO.E-01345A-05-0816

Line No.	Proposed PSA Changes (a)	APS Direct (b)	APS Rebuttal (c)	ACC Staff (d)	RUCO (e)	AECC (f)	AUIA (g)
1	Base Fuel Recovery Amount	$.031904 per kWh	$.033112 per kWh	$.027975 per kWh	Not Specifically Addressed but appears to accept APS original position	Reduced From APS' Direct to $.029100 per kWh	Not Addressed
2	Prospective Adjustor Based on 2007 (and subsequent future year costs)	Not Addressed	Support Staff's Proposal if own is not adopted	Use forecasted year for setting annual PSA adjustor	Not Addressed	Not Addressed	Not Addressed
3	4 mill Annual Cap for current Annual PSA Adjustor	Support	Support if Staff position not adopted	No cap for forecasted year adjustor	Support	Support	Support
4	Remove 4 Mill Cumulative Cap for PSA Adjustor	Support	Support	Support	Support	Support	Support
5	Total Fuel Cost Cap ($776 M)	No Cap	No Cap	No Cap	No Cap	No Cap	No Cap
6	Additional Sharing of Hedging Gains & Losses	Support	Withdraw	Oppose	Oppose	Oppose	Not Addressed
7	Eliminate 90/10 Cost Sharing Applied to Renewable Resources	Support	Support if 90/10 not applied to Staff position per APS testimony	Not Addressed[1]	Support	Don't Eliminate	Not Addressed
8	Eliminate 90/10 Cost Sharing Applied to Capacity Cost Portion of Purchase Power Contracts	Support	Support if 90/10 not applied to Staff position per APS testimony	Not Addressed[1]	Support	Oppose	Not Addressed
9	Eliminate $100 Million Mandatory PSA Surcharge Requirement	Support	Support	Not Addressed	Not Addressed	Not Addressed	Not Addressed

1. Staff position on retention of 90/10 sharing in general not clear. APS has interpreted Staff position as limiting 90/10 sharing to difference between PSA adjustor rate and actual costs for year.

REBUTTAL TESTIMONY OF STEVEN M. FETTER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

TABLE OF CONTENTS

I. Introduction 1

II. Summary 1

III. Credit Ratings 2

IV. Credit Rating Analysis of APS 9

V. Regulatory Lag 16

REBUTTAL TESTIMONY OF STEVEN M. FETTER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven M. Fetter, and my business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, Nevada 89014.

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

A. I am President of REGULATION UnFETTERED, an energy advisory firm I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London, as Group Head and Managing Director of the Global Power Group. Prior to my time at Fitch, I served as Chairman of the Michigan Public Service Commission.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. SUMMARY

Q. COULD YOU SUMMARIZE YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In this Rebuttal Testimony, I conclude that, if the Arizona Corporation Commission ("Commission") were to accept the positions put forward by either Commission Staff or RUCO in this proceeding, the financial condition of Arizona Public Service Company ("APS") would suffer significant deterioration, leading in all likelihood to a credit rating downgrade to below investment-grade level. Such negative rating actions would have a deleterious

effect on APS customers as access to capital would become more expensive, leading ultimately to higher rates.

In addition, I discuss the concept of regulatory lag, which undercuts the ability of a regulatory body to be timely in its decision-making, both as it relates to the Staff and RUCO recommendations and in response to Chairman Hatch-Miller's letter to this docket dated July 21, 2006. I explain how such delay in implementation of regulatory policy determinations can have a negative impact on both regulated utility companies as well as their customers.

III. CREDIT RATINGS

Q. WHAT CREDIT RATINGS DOES APS CURRENTLY HOLD?

A. APS' current Standard & Poor's ("S&P") ratings for senior unsecured debt are "BBB-", with a Stable ratings outlook. Moody's Investors Service ("Moody's") senior unsecured credit ratings for APS are "Baa2", with a Negative outlook.

These ratings designations for APS equate to lowest-quality investment-grade debt.

Q. PLEASE GENERALLY DESCRIBE THE CREDIT RATINGS PROCESS.

A. Credit ratings reflect a credit rating agency's independent judgment of the general creditworthiness of an obligor or the creditworthiness of a specific debt instrument. While credit ratings are important to both debt and equity investors for a variety of reasons, their most important purpose is to communicate to investors the credit strength of a company or the underlying credit quality of a particular debt security issued by that company. Credit rating determinations are made through a committee process involving individuals with knowledge of a company, its industry, and its regulatory environment. Rating designations of

both Fitch and S&P have "BBB-" as the lowest investment-grade rating and "BB+" as the highest non-investment-grade rating. Comparable rating designations of Moody's are "Baa3" and "Ba1", respectively. (I explain below the consequences of a utility's credit ratings falling below investment-grade.)

Corporate credit ratings analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income issuers. A credit rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. It also at times incorporates some consideration of ultimate recovery of investment in case of default or insolvency. Ratings can also be used by contractual counterparties such as fuel or power suppliers to gauge both the short-term and longer-term health and viability of a company, and they can directly impact the terms on which the counterparties are willing to do business.

Q. PLEASE DESCRIBE THE QUALITATIVE FACTORS USED BY THE RATING AGENCIES.

A. The most important qualitative factors include regulation, management and business strategy, and, for electric utilities, access to energy, gas and fuel supply with recovery of associated costs.

Q. CAN YOU SHARE YOUR THOUGHTS ON THE IMPORTANCE OF "REGULATION" WITHIN THE CREDIT RATINGS PROCESS?

A. Yes. Regulation is a key factor in assessing the credit profile of a utility because a state public utility commission determines rate levels (recoverable expenses including depreciation and operations and maintenance, fuel cost recovery, and return on investment) and the terms and conditions of service.

Since the announcement of California's restructuring plan in 1994, regulation has become an even more important variable as the nature of a utility's responsibilities in providing energy services to customers has undergone dramatic change. In some states, industry restructuring was the result of plans formulated by the state legislature. In other states, the regulators, rather than the legislators, have determined the nature and pace of restructuring.

Under restructuring plans, utilities have been directed to foster the development of competitive alternatives to the services they provide, materially scale down their operations for certain functions, often including divestiture of generation, while at the same time, retaining what is commonly referred to as the "provider of last resort" ("POLR") responsibility. As the POLR, a utility bears the ultimate responsibility to serve all of the customers in its service territory in the event of intermittent defaults or permanent failures by competitive suppliers to reliably discharge their responsibilities.

This situation affects utility investors' decisions because, before major energy investors will be willing to put forward substantial sums of money, they will want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a rapidly evolving industry. Investors also want assurance that regulators' decision-making will be fair, timely and will have a significant degree of predictability.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by the commissions. If a regulatory body were to encourage a company to make investments based upon an expectation of the opportunity to earn a reasonable return, and then did not apply regulatory

principles in a manner consistent with such expectations, investor interest in providing funds to such utility would decline, debt ratings would likely suffer, and the utility's cost of capital would increase.

Q. IN VIEW OF THESE UNPRECEDENTED EVENTS DURING THE PAST FIVE YEARS, DO THE ACTIONS OF UTILITY REGULATORS TODAY DRAW EVEN MORE ATTENTION FROM THE FINANCIAL COMMUNITY?

A. Yes, without a doubt. Regulation has always garnered the attention of Wall Street, but, years ago, seemingly only during the days leading up to a commission's rate case decision. This began to change around the time that Fitch hired me in 1993 to serve in the role of regulatory analyst and assess regulatory and political factors that could impact upon a utility's financial strength. When California announced its ultimately ill-fated restructuring plan in 1994, the entire financial community, especially Fitch and its rating agency competitors S&P and Moody's, took much greater notice of regulators and how they carried out their responsibilities, not only with regard to rate-setting, but even more importantly the manner in which they undertook to change the way the entire utility industry had operated for over 100 years.

S&P highlighted the continuing importance of regulation to the financial community in two recent reports. In a report entitled "New York Regulators' Consistency Supports Electric Utility Credit Quality," S&P offered general thoughts on the importance of regulation that apply within but also far beyond the borders of New York:

> Regulation defines the environment in which a utility operates and greatly influences a company's financial performance. A utility with a marginal financial profile can, at the same time, be considered highly creditworthy as a result of supportive regulation. Conversely, an unpredictable or antagonistic regulatory environment can

> undermine the financial position of utilities that are operationally very strong.
>
> To be viewed positively, regulatory treatment should be timely and allow consistent performance over time, given the importance of financial stability as a rating consideration. Also important is the transparency of regulatory policies...1

Earlier, S&P had discussed how changing circumstances within the utility industry have elevated the importance of regulatory policies:

> In recent years, [S&P's] emphasis on the decisions by state commissions has been less pronounced simply because so many jurisdictions have been working through multiyear restructuring transition periods. During this time, rates were frequently frozen, and companies and customers have been adjusting (albeit with limited success) to the opportunity that customers have to choose alternate power suppliers.
>
> But the confluence of the approaching end of these transition periods and the growing need in certain regions of the country for significant resource additions is quickly returning the regulatory arena to center stage. In assessing the regulatory environment in which a utility operates, [S&P's] analysis is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag that may prove detrimental if a utility needs rate relief.[2]

Q. NEXT, YOU MENTIONED MANAGEMENT AND BUSINESS STRATEGY AS ANOTHER IMPORTANT QUALITATIVE FACTOR. PLEASE DESCRIBE THAT FACTOR.

A. An assessment of quality and depth of management personnel is made and consideration is given as to how a company's strategic plans and risk profile fit

---

[1] S&P Research: "New York Regulators' Consistency Supports Electric Utility Credit Quality," August 15, 2005.

[2] S&P Research: "U.S. Utility Regulation Returns to Center Stage," April 14, 2005.

within its overall business and local regulatory environment, as well as how effective management is at implementing those plans. This includes consideration of management's ability to interact with regulators and executive and legislative branch officeholders in a way that allows the company to carry out its operations effectively and efficiently for the benefit of its key constituencies, including small and large customers and shareholders. Moreover, in view of the volatile environment within the utility sector at this time, an assessment is made of the utility's capability to respond to extraordinary occurrences, including events outside management's control.

Q. PLEASE DESCRIBE THE FINAL QUALITATIVE FACTOR THAT IS SO IMPORTANT TO ELECTRIC UTILITIES -- ACCESS TO ENERGY, GAS AND FUEL SUPPLY WITH RECOVERY OF ASSOCIATED COSTS?

A. Access to secure and reasonably-priced sources of energy and gas is a key factor for a utility. Equally important are the extent to which the utility recovers its costs of serving its core customers, the mechanisms for timely recovery, and the level of confidence that investors have that the state commissions will stand behind the established recovery methodology, even under potentially difficult circumstances, such as market volatility and increasing prices.

Q. COULD YOU PLEASE DESCRIBE THE QUANTITATIVE FACTORS USED BY THE RATING AGENCIES?

A. Financial performance continues to be a very important element in credit rating analysis. Credit rating agencies and fixed-income analysts utilize analytical ratios to understand the credit profile of a utility, with S&P publicly explaining the three financial measures that it views as most important in its analysis of utility companies: funds from operations ("FFO") / interest coverage; FFO / total debt; and total debt / total capital. I note that the rating agencies adjust

these key ratios to reflect imputed debt and interest-like fixed charges flowing from long-term contracts and certain other off-balance sheet obligations.

Building upon those key ratios, S&P has been the most explicit of the three major rating agencies in explaining how it views the interplay between quantitative and qualitative factors. As part of its utility credit rating process, S&P arrives at a "Business Profile" designation that it considers in concert with its "Utility Financial Targets." S&P's Utility Financial Targets, which encompass the quantitative ratios listed above, differ depending upon a utility's Business Profile rating. The weaker the Business Profile designation, the stronger the Financial Targets must be in order to obtain any given credit rating.

Q. WHAT DOES S&P'S BUSINESS PROFILE DESIGNATION REFLECT?

A. The Business Profile designation reflects S&P's assessment of qualitative factors such as regulation, markets, operations, competitiveness, and management. This designation is on a scale of '1' (meaning very strong) to '10' (meaning very weak). Designations of 1 and 2 indicate "Well Above Average" business position; 3 and 4 indicate "Above Average"; 5 and 6 indicate "Average"; 7 and 8 indicate "Below Average"; and 9 and 10 indicate "Well Below Average."

Q. GENERALLY, WHAT BUSINESS PROFILES APPLY TO UTILITIES?

A. Distribution and transmission companies usually have Business Profile ratings of '2' through '4.' Power generation and energy trading companies with significant commodity price risks usually have Business Profile ratings of '7' through '9.' Vertically-integrated utilities usually have Business Profile ratings in the middle of the scale, in the '4' to '6' range. APS' Business Profile is a "6", at the low end for a vertically-integrated utility.

Q. WHY IS S&P'S METHODOLOGY MEANINGFUL TO YOU?

A. I believe that S&P's methodology helps facilitate a general understanding of how a credit rating agency carries out the process of formulating a credit rating and the factors that go into such a determination.

Q. WHILE RETURN ON EQUITY ("ROE") IS NOT DIRECTLY RELATED TO BONDHOLDER REQUIREMENTS, CAN YOU SHARE YOUR THOUGHTS ON WHY THE LEVEL OF ROE AUTHORIZED BY REGULATORS IS OF CONSEQUENCE TO INVESTORS IN DEBT SECURITIES?

A. The existence of equity in a utility capital structure provides a company with the capacity to tolerate the normal ups and downs that come with operational business risks, while also providing a cushion to a company's lenders and bondholders (fixed-income investors). Fixed-income investors look to the earnings of shareholders as an additional margin available for the payment of interest and principal under adverse business circumstances.

IV. CREDIT RATING ANALYSIS OF APS

Q. YOU EARLIER REFERRED TO APS' CREDIT RATINGS AS EQUATING TO LOWEST-QUALITY INVESTMENT-GRADE DEBT. WHAT RATING CATEGORIES DO YOU MEAN WHEN YOU USE THIS DESCRIPTION?

A. I am referring to long-term credit ratings at the lower end of the "BBB" category. Within the "BBB" category, differentiations are made between "BBB+"/"BBB"/and "BBB-". "BBB-" is the lowest rating an issuer can be assigned without falling below investment grade into "junk bond" status. Moody's comparable rating scale uses "Baa1", "Baa2", and "Baa3", the lowest investment-grade rating.

Q. IN YOUR OPINION, DO RETAIL CUSTOMERS BENEFIT FROM HAVING UTILITY DEBT RATED ABOVE APS' CURRENT LEVEL OF LOW-QUALITY INVESTMENT-GRADE DEBT?

A. Yes. Let me first focus on mid-quality investment-grade debt at the "BBB+" level. The benefit to customers is that a utility with debt having at least a mid-quality investment-grade rating is able to raise debt capital when needed to fund infrastructure requirements necessary to meet growth in customer demand, and can refinance maturing debt on more reasonable terms than a lower credit quality utility. This is especially true when volatility in the energy/utility sector (like we have experienced during the past five years) has tightened up liquidity within the debt market. Moreover, the ability to access the debt market when needed is important because if a company needs to expand or upgrade its generation, transmission or distribution infrastructure to maintain system reliability or undertake construction projects for environmental compliance, debt funding is an advantageous source of capital as it is typically more economical than equity financing. As ratings trend down to the lowest-quality investment-grade level of "BBB-", APS' current level, the utility industry's continuing unsettled state neutralizes many of benefits I have described above.

Q. WHAT ARE SOME OF THE CONSEQUENCES OF A UTILITY'S CREDIT RATING FALLING BELOW INVESTMENT-GRADE QUALITY?

A. There would be a marked change in the investor profile for that utility. Major utility investors such as insurance companies and pension funds operate under legal restrictions that severely limit their ability to invest in below investment-grade debt instruments, or "junk bonds." Mutual funds could also be affected based upon what a particular fund has communicated to investors as to its investment profile. Moreover, a utility with a "junk bond" rating would likely have to post bond or put up cash as collateral in various contracts (such as for energy supply) or to meet certain regulatory commitments (such as Independent

System Operator agreements or environmental remediation requirements). This, of course, would come at a time when access to a utility's existing credit facilities likely would be limited by the financial institutions previously providing the assistance. Finally, a utility with below investment-grade status would be unable to access the commercial paper (short-term debt) market. Commercial paper is a key source of funding for utilities, most of which have revenues that vary substantially depending upon the time of year, and loss of access to that market can severely impair financial liquidity.

Q. PLEASE EXPLAIN THE STEPS YOU TOOK TO ASSESS THE POTENTIAL CREDIT RATING IMPACT FOR APS AS A RESULT OF THIS RATE PROCEEDING?

A. I requested from the Company three financial forecasts covering the period 2006 through 2008, assuming a May 1, 2007 effective date[3]: one using the financial information from the APS rebuttal filing as updated with new information; a second one utilizing financial information underlying the Commission Staff recommendation in this proceeding including Staff's projected PSA proposal under some favorable assumptions; and a third one doing the same thing with the RUCO recommendation.[4] (See DEB-1RB, DEB-2RB, and DEB-3RB attached to the testimony of APS witness Donald Brandt). I have utilized the S&P methodology and the forecast data in the analysis that follows, indicating the likely credit rating impacts under both the Commission Staff position and the RUCO case, compared against the likely result if the updated APS position were to be adopted by the Commission.

---

[3] Credit metrics for the three forecasts are provided in the testimony of APS witness Donald Brandt.

[4] As explained earlier, rating agencies often impute debt and interest to reflect certain off-balance sheet obligations including long-term leases. Accordingly, the Company has adjusted the three forecasts to account for

Q. PLEASE DESCRIBE THE RESULTS OF YOUR ANALYSIS.

A. Using the Commission Staff position even including a number of favorable assumptions concerning their proposal to revise the PSA calculation to allow projected fuel and purchased power costs, I found that APS' credit ratings would in all likelihood fall below investment-grade quality. While funds from operations (FFO) interest coverage weakens from 3.9x (times) to 3.4x by 2008, that measure remains at "BBB" investment-grade levels during the forecast period. However, the other two key S&P measures indicate a much more negative situation. FFO/Total Debt, which S&P has indicated is its most important ratio because it incorporates measures of both cash flow and debt, begins in 2006 at 17.6%, equating to a below-investment-grade rating in the "BB" category, and falls further during the subsequent two years to 15.1%, in the middle of the "BB" category. Total debt to total capital begins the forecast period at 54.6%, consistent with the investment-grade "BBB" category, but by the next year falls below investment-grade for the remainder of the forecast period. Forecasts under the Commission Staff case indicate that APS would likely not be able to maintain its investment-grade status once this proceeding has concluded. See, for example, S&P's recent statement:

> Of the staff's recommended increase, about 9.1% is related to base fuel and purchased power rates, but falls short by about $105 million of APS' requested increase for these costs. The remainder of the $141 million staff-recommended reduction is based on non-fuel items, with a large portion of the difference attributable to staff's suggestion that APS' authorized ROE be set at 10.25%, relative to the 11.5% that APS is seeking ... The stable outlook for PWCC and APS' rating is premised on the ACC continuing to provide sustained regulatory support that addresses permanent rate relief and manages

---

the credit rating agencies' imputation of debt and interest expense attributable to power purchase obligations and operating leases such as the Palo Verde Unit 2 Sale and Leaseback.

> the deferral balances downward over a reasonable time frame. A negative rating change or outlook could result if the size of the deferred balances materially increases...[5]

and similar sentiments from Moody's, which, acting upon its earlier warnings, downgraded the credit ratings of APS on April 27, 2006:

> The negative outlook ... reflects the potential for weaker performance if the Palo Verde nuclear facility does not return to normal operating performance by mid-summer as is expected, or if other significant pending regulatory proceedings for APS do not provide for relatively timely recovery of increased costs, particularly those for fuel and purchased power.[6]

The results under the RUCO case would cause an even more severe negative impact on APS' credit profile, thus also likely driving the Company into below investment-grade or "junk bond" status. The key FFO to total debt measure begins in 2006 at 17.6% in the "BB" below investment-grade category, and, by 2008, is just above the *bottom* of that already weak sub-investment category at 12.9% (with the "BB" category defined as 18% down to 12%). Total debt to total capital of 54.6% is at investment-grade level at the end of 2006, but worsens into below investment-grade status the next year (58.6%) and close to the *bottom* of the "BB" category in 2008 (60.9% with a bottom boundary of 62%). FFO interest coverage is within the "BBB" for the first two years of the forecast period (3.9x and 3.5x), but then drops in 2008 to the 3.0x dividing line between investment-grade and below investment-grade ratings. I believe that adoption of the RUCO case would, like the results from the Commission Staff case, quickly lead to below investment-grade determinations from the rating agencies.

---

[5] S&P Research Summary: "Arizona Public Service Co.," August 31, 2006.

Q. PLEASE SHARE THE RESULTS OF YOUR ANALYSIS OF THE UPDATED APS POSITION?

A. Under the modified APS case, both total debt to total capital and FFO interest coverage reside within the "BBB" investment-grade category for the entire forecast period, with the former varying between 3.9x and 4.0x (on a scale of 4.2x down to 3.0x) and the latter spanning 54.6% to 52.1% (with the "BBB" category defined as 48% to 58%). I note that APS' FFO to total debt measures of 17.6% in 2006, 19.2% in 2007 and 17.5% in 2008 skirt just below and just above the 18% investment-grade/non-investment-grade dividing during the forecast period.

Thus, while I believe that the three measures taken together will equate to investment-grade status for APS, the continuing weakness in the key FFO/total debt ratio indicates to me that the Company case will not lead to a significantly-stronger credit profile for APS than its current "BBB-" corporate rating level from S&P. I note S&P's comment from two weeks ago: "Given the regulatory challenges over the near term and the potential for continued operational challenges at Palo Verde, there is little opportunity for a positive rating action at this time."[7]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE CREDIT IMPLICATIONS OF YOUR ANALYSIS.

A. If the Commission were to adopt either the Commission Staff position or RUCO's case, APS' credit ratings would likely suffer a rating downgrade to below investment-grade level. I believe this would represent the first time in the

---

[6] Moody's Research: "Moody's Confirms Ratings of Pinnacle West (Baa3 Issuer Rating); Outlook Negative," May 8, 2006.

[7] S&P Research Summary: "Arizona Public Service Co.," August 31, 2006.

Company's 100-year plus history that it will have lost its investment-grade credit rating. If such a downgrade were to occur, APS' access to the already tightening capital markets would become more restricted, increasing its cost of capital and limiting its financial flexibility. The situation created by such a scenario would have a negative impact on both customers, in the form of higher capital costs translating into higher rates, and investors, through the loss in value of equity and debt holdings.

Q. IN GENERAL, WOULD A CREDIT RATING AGENCY ACT ON A COMPANY'S POTENTIAL DOWNGRADE IMMEDIATELY UPON ISSUANCE OF A REGULATORY ORDER THAT FORETELLS OF LIKELY DETERIORATION, OR WOULD IT WAIT UNTIL THE DETERIORATION IS EVIDENT IN THE COMPANY'S FINANCIAL STATEMENTS?

A. Credit ratings are based on prospective financials. As such, as soon as the final Commission order is issued, the credit rating agencies would analyze the likely financial impacts and provide the Company with an immediate opportunity to provide additional relevant information that should be considered. A rating change, if warranted, would follow shortly thereafter.

It is important to emphasize that in view of the volatility among utility credit ratings during the past five years, it is far easier for a utility's ratings to slip down due to a financial "ding" than for that same utility to regain its earlier status once the deficiency has been remedied. For that reason, I do not believe that any weakening of APS' credit profile now could, if the Commission changed its mind, be easily remedied in the Company's next rate proceeding. This would be especially so if the downward movement crossed APS into below investment-grade status. My advice to utility companies, investors and

regulators alike is that nothing should be taken for granted in the current utility investing environment.

Q. ASIDE FROM THE EFFECTS ON APS' FINANCIAL CONDITION AND CREDIT RATIOS, DO YOU FORESEE ANY OTHER POTENTIAL ADVERSE CREDIT IMPLICATIONS RESULTING FROM AN ADVERSE DETERMINATION BY THE COMMISSION FOR APS IN THIS PROCEEDING?

A. As I previously explained, an important element of the credit evaluation of electric utilities is an assessment of regulation. Currently, Arizona is viewed by the financial community as a difficult regulatory climate. For this reason, credit rating analysts will closely monitor this proceeding to see whether an improving trend becomes evident. However, if the Commission were to deny appropriate rate relief, the rating agencies would make an assessment of the reasons for the decision and determine whether they supported the maintaining of their current view. A decidedly negative assessment of Arizona regulation could have unfavorable credit rating implications, not only for APS, but potentially for all utilities subject to the rate making authority of the Commission.

V. <u>REGULATORY LAG</u>

Q. ARE YOU FAMILIAR WITH THE CONCEPT OF REGULATORY LAG?

A. Yes I am. The term is often used to describe delays occurring from the time a utility files for a rate increase (or commission staff or intervenor party files for a show cause seeking a decrease in rates) and the time that a regulatory body issues its decision and implements such rate change. While I accept that definition, when I served as chairman of the Michigan Public Service Commission, I viewed the term in a much broader context.

Q. HOW SO?

A. At the time that I was appointed to the Michigan PSC, the agency had a reputation for high-quality members and staff who shared an unfortunate inability to decide any types of cases on a timely basis. After I became chairman of the Michigan PSC three years later, I set as a goal the elimination of the agency's case backlog within two years. Michigan law provided a nine-month target for rate proceedings, but, upon missing that deadline, all that the commission had to do was inform the governor and legislative leaders that the target had been missed. The law did not provide for any sanctions.

Q. WHAT WERE THE RESULTS UNDER THAT STATUTE?

A. I am happy to say that the Michigan PSC was always timely in sending letters to those public officials informing them that we had missed the statutory target. Unfortunately, by the time I became chairman, the agency had a case backlog in excess of 50 matters, some that had been pending for years. I think my proudest accomplishment was in energizing my fellow commissioners and staff members to eliminate that backlog within six months, the first time the agency had enjoyed a clean slate in 23 years.

Q. DO YOU SEE APPLICABILITY OF YOUR EXPERIENCE HERE IN ARIZONA?

A. Yes, very much so. I would not presume to tell the Arizona Commission how it should organize its internal processes for maximum efficiency. I would not even presume to say that I have better ideas for reducing regulatory lag than APS or other companies regulated by the Commission. I encourage you to review and consider the ideas for reducing regulatory lag put forward by APS witnesses Steven Wheeler and Donald Brandt, as well as the thoughts of any other stakeholders who believe they know what can improve the process. The issue is

important not only to regulated utilities in a growing service territory or customers when rates deserve to go down, but also especially to financial community investors who spend everyday matching up risk and return. They must consider whether regulatory delay will be mitigated by rates under bond or some type of carrying charges in determining where to invest their funds. Under such circumstances, Arizona is competing with other jurisdictions all the time. Competitiveness in this context is measured by fair returns and timely processes.

Q. HAVE YOU SEEN SOME PROGRESS IN ARIZONA WITH REGARD TO THIS ISSUE?

A. Yes. The power supply adjustor was certainly a step in the right direction, including the Commission's continuing efforts to better align the amount and timing of recovery with the level of expenditures and when they were spent. On the other hand, APS general rate proceedings still take a very considerable amount of time, and reliance on a historical test period only exacerbates problems of regulatory lag. During my time as a regulator, I viewed that working toward more efficient processes was a never-ending task, one whose goal was to take one beneficial step and then seek to build upon it with another. And maybe it is because of where I came from, but I sincerely believe that, after stakeholders have had their opportunity to present views as to how to fix the process, the best knowledge base for formulating and implementing innovative and effective change still resides among those who are involved with the issues every day – those within the four walls of this Commission. I encourage you to take on that challenge.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

BEFORE THE

ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF

WILLIAM E. AVERA

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION **1**

II. SUMMARY **2**

III. REASONABLENESS OF RETURN **6**

IV. DAVID C. PARCELL **12**

A. DCF Analysis 13

B. Risk Premium Approach 21

C. Other Factors 29

V. STEPHEN G. HILL **31**

A. DCF Analysis 41

B. Risk Premium Approach 54

C. Other Methods 59

D. Capital Structure 64

VI. ATTRITION ADJUSTMENT **70**

Allowed ROE – Parcell & Hill Reference Groups ..... Attachment WEA-1RB

Multi-Stage DCF Model – Parcell Reference Group ..... Attachment WEA-2RB

Forward-looking CAPM Analysis ..... Attachment WEA-3RB

Historical CAPM Analysis ..... Attachment WEA-4RB

Multi-Stage DCF Model – Hill Reference Group ..... Attachment WEA-5RB

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. ARE YOU THE SAME WILLIAM E. AVERA THAT PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My purpose here is to respond to the testimony submitted by David C. Parcell, on behalf of the Staff of the Arizona Corporation Commission ("ACC" or "the Commission"), and Mr. Stephen G. Hill, on behalf of the Residential Utility Consumer Office ("RUCO"), concerning a fair rate of return on equity ("ROE") for Arizona Public Service Company ("APS" or "the Company"). I also address Mr. Hill's position concerning the reasonableness of APS' requested capital structure. In addition, I demonstrate the need for an attrition adjustment to the allowed return to give APS an opportunity to actually earn the ROE authorized by the Commission.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. After summarizing my conclusions in Section II, Section III of my Rebuttal Testimony examines the reasonableness of the ROE recommendations of Mr. Parcell and Mr. Hill against objective benchmarks. In particular, their

recommendations are shown to be inadequate to meet the economic standards under accepted regulatory policy. Next, Sections IV and V address the specific shortcomings of Mr. Parcell's and Mr. Hill's analyses and explain how their methods impart a downward bias to their recommendations. Finally, Section VI addresses the problem of attrition and evaluates the need for an attrition adjustment to ensure that the economic requirements for a fair rate of return will be met.

II. SUMMARY

Q. WHAT ARE YOUR CONCLUSIONS REGARDING STAFF'S AND RUCO'S ROE RECOMMENDATIONS?

A. Both Mr. Parcell and Mr. Hill purport to estimate the return investors require to put their money in APS. Each recognizes that investors have many potential options for their funds, and APS must compete for investment dollars. As documented in my Rebuttal Testimony, the 10.25% ROE recommendation of Mr. Parcell is significantly downward-biased and Mr. Hill's 9.25% cost of equity is completely out of touch with the requirements of actual investors in the capital markets. My rebuttal details the shortcomings that lead Mr. Parcell and Mr. Hill to underestimate investor requirements. Moreover, I document that application of quantitative methods identical to those recently used by the ACC Staff and adopted by this Commission imply an ROE of 11.20% for APS before consideration of flotation costs.

In addition, while Mr. Parcell accepts APS' requested capital structure, Mr. Hill would combine his low ROE with a capital structure with less equity than APS actually maintains. This phantom capital structure makes RUCO's position more extreme and amplifies the financial damage implied by Mr. Hill's recommendations. My Rebuttal Testimony demonstrates that Mr. Hill's rationale

for adjusting the capital structure is based on false premises and is inconsistent with industry practice and rating agency requirements.

But aside from the plethora of technical arguments, their recommendations do not withstand a simple reality check. These witnesses recommend returns lower than other utilities are currently authorized, a fact clearly documented in their own sources. As I also document in this testimony, both witnesses recommend that the ACC allow APS a return below the average that other commissions have been allowing utilities in recent months. Yet compared to other utilities, APS is facing unique risks and challenges such as a weakened credit standing, substantial funding needs, exposure to regulatory lag and increasing costs. Providing APS with the opportunity to earn a return that reflects these realities is an essential ingredient to strengthen the Company's financial position, which ultimately benefits customers by ensuring the Company's continued ability to meet customers' needs at lower long-run costs. The Staff and RUCO recommendations are out of line with investor requirements and regulatory practice and adopting them would send an alarming signal to the investment community at this critical juncture for APS. If investors lose confidence in the Company, customers and the economy of Arizona would be the ultimate losers.

Aside from their low return on equity recommendations, there is a more fundamental flaw in the testimonies of Mr. Parcell and Mr. Hill. Both witnesses agree that sound economics and the *Hope* and *Bluefield* cases require that the end result of return recommendations be tested against the standards of maintaining financial integrity, access to capital, and adequate compensation for risk. Even if the methods they use to test the end results were correct (and my rebuttal demonstrates that they are not), both witnesses wrongly assume that APS will

actually earn their allowed return recommendation. In fact, attrition will prevent APS from having an opportunity to actually earn the allowed ROE. Indeed, SFR Schedule F-1 of APS' January 31, 2006 filing ("Schedule F1") demonstrates that even if the Company were allowed my recommended 11.5%, and the new rates became effective on January 1, 2007, the earned return for 2007 would fall to 9.8%.

As explained in the Rebuttal Testimonies of Mr. Brandt and Mr. Wheeler and later in my rebuttal, the relentless forces of growth, new capital investment, inflation, and unrecovered costs, combined with regulatory lag, will drive APS' earned return well below the allowed ROE. Investors focus on what will actually be earned, not the promise of an allowed return that will be eroded by attrition. As a result, the financial indicators calculated by Mr. Parcell and Mr. Hill that assumed their recommended return is actually earned are exercises in financial fiction – they have no meaning in the real world from which capital must be raised. My Rebuttal Testimony proposes an attrition adjustment to the ROE of at least 170 basis points to give APS some opportunity to maintain its financial integrity, preserve the ability to attract capital, and offer investors a return commensurate with risk.

Q. WHAT DO TRENDS IN CAPITAL COSTS INDICATE WITH RESPECT TO YOUR RECOMMENDED 11.5% ROE FOR APS?

A. Since the time my Direct Testimony was prepared, capital costs have trended upwards. During the intervening period, the Federal Reserve Board ("Fed") continued its credit tightening campaign through a policy of measured increases to the target federal funds rate. Coupled with increasing concerns over inflation and other political and economic considerations, this has translated into higher long-

term capital costs. As shown in the table below, long-term bond yields have risen significantly from the levels referenced in my Direct Testimony:

	BBB Utility	20-Yr Govt.
July 2006	6.61%	5.25%
Avera Direct	5.80%	4.50%
Increase	0.81%	0.75%

While the cost of equity does not move in lockstep with changes in interest rates, the fact that long-term bond yields have increased significantly since my analyses were prepared indicates that my 11.5% recommended ROE is a conservative estimate of investors' current required rate of return.[1] Assuming that the cost of equity changes about one-half as much as the change in interest rates, a 75 basis point increase in bond yields implies an upward adjustment to the cost of equity on the order of approximately 33 basis points.[2] Coupled with the imperative of buttressing the Company's credit standing and meeting the economic requirements specified for a fair rate of return, this provides further confirmation that the 11.5% ROE requested by APS is the minimum cost of equity that could be found reasonable and should be adopted.

---

[1] Other factors also suggest that the cost of equity for my proxy group has increased. For example, the current beta values for my proxy companies shown on Attachment WEA-3RB result in a group average of 0.97, versus the 0.89 reflected in my CAPM analyses. Also, the cost of equity indicated by my DCF analyses has increased since my Direct Testimony was filed.

[2] The inverse relationship between equity risk premiums and interest rates was discussed in my Direct Testimony at 45-46.

III. REASONABLENESS OF RETURN

Q. DR. AVERA, IS IT POSSIBLE TO DISTILL THE MANY COMPLEXITIES ASSOCIATED WITH ESTIMATING INVESTORS' REQUIRED RATE OF RETURN INTO A SINGLE, THRESHOLD ISSUE?

A. While the details underlying a determination of the cost of equity are all near and dear to my heart, there is one fundamental requirement that any ROE recommendation must satisfy before it can be considered reasonable. Competition for capital is intense, and utilities such as APS must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of equivalent risk if they are to maintain their financial flexibility and ability to attract capital.

Beyond the specific quantitative analyses that I present in detail in subsequent sections demonstrating how Mr. Parcell and Mr. Hill underestimated the cost of equity, the bottom line is, "Do Mr. Parcell's and Mr. Hill's ROE recommendations meet the threshold test of reasonableness required by established regulatory and economic standards governing a fair rate of return on equity?" Based on the evidence discussed subsequently, the answer is clearly, "No."

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING APS' ACCESS TO CAPITAL?

A. Considering investors' heightened awareness of the risks associated with the electric power industry, supportive regulation remains crucial in preserving APS' access to capital. Moreover, considering the traumatic events that have transpired since the third quarter of 2000, investors' sensitivity to market and regulatory uncertainties has increased dramatically. Capital markets recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions.

For example, the decision of Standard & Poor's Corporation ("S&P") and Fitch Ratings ("Fitch") to downgrade Central Vermont from triple-B to below investment grade highlights the importance of constructive regulation. In explaining its rationale, S&P and Fitch cited an unfavorable rate order by the Vermont Public Service Board. S&P concluded that:

> The rate order represents an adverse shift in the company's regulatory environment, which heightens its business risk for the foreseeable future. ... It also limits the company's ability to generate adequate and stable cash flows over the foreseeable future. To be considered highly creditworthy, a utility with a marginal financial profile must operate in a regulatory environment that provides for financial stability.[3]

Business Wire reported to investors that Central Vermont "will now have to provide cash collateral for some power supply arrangements" and pay "increased financing costs for debt," with the end result being "higher customer costs."[4] As the investment advisory publication referenced by Mr. Hill made clear, "downgrades imply not only higher borrowing costs but also carry a negative psychological impediment toward new investment."[5]

Q. DO YOU AND MESSRS. PARCELL AND HILL ALL AGREE THAT A UTILITY'S ABILITY TO ATTRACT CAPITAL MUST BE CONSIDERED IN ESTABLISHING A FAIR RATE OF RETURN?

A. Yes. Mr. Parcell and Mr. Hill both recognized clearly the fundamental standards underlying a determination of a fair rate of return on equity. For example, Mr. Hill observed that investors should have "an opportunity to earn returns that are sufficient to attract capital and are comparable to returns investors would expect in

---

[3] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (Jun. 14, 2005).
[4] *Id.*
[5] A.G. Edwards, "Gas Utilities Quarterly Review," April 6, 2006 at 9.

the unregulated sector for assuming the same degree of risk."[6] Both Mr. Parcell (p. 6-7) and Mr. Hill (p. 4) acknowledged the Supreme Court's *Bluefield* and *Hope* decisions, which established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence that, if the utility is efficient and prudent on a prospective basis, it will have the opportunity to provide returns commensurate with those expected for other investments of comparable risk.

Q. WHAT BENCHMARKS ARE USEFUL IN EVALUATING THE ABILITY OF STAFF'S AND RUCO'S ROE RECOMMENDATIONS TO MEET THIS FUNDAMENTAL REGULATORY REQUIREMENT?

A. Reference to allowed rates of return for other utilities provides one useful guideline that can be used to assess the extent to which their respective 10.25% and 9.25% ROE recommendations are comparable and sufficient. The rates of return on common equity authorized electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates ("RRA") and published in its *Regulatory Focus* report. RRA reported average authorized ROEs of 10.69% and 10.57% for electric utilities for the second quarter and year-to-date 2006, respectively. APS must compete with other utilities for the large amounts of capital needed to fund growth and infrastructure improvements in Arizona. It is unreasonable to suppose that in the face of rising capital costs during 2006, investors would be attracted by the Staff and RUCO's recommendations for APS, which fall significantly below the allowed returns for other utilities.

As shown on Attachment WEA-1RB, with respect to the group of twelve utilities other than Pinnacle West that Mr. Hill concluded were most comparable to APS, data from the June 2006 *AUS Monthly Utility Report* (a source relied on by Mr. Hill

---

[6] Hill Direct at 4.

and Mr. Parcell)[7] indicated that these firms are presently authorized an average rate of return on equity of 10.89%, or 164 basis points more than Mr. Hill's ROE recommendation. Similarly, this source reported an average authorized ROE for the utilities in Mr. Parcell's comparable group (excluding Pinnacle West) of 10.91%, which exceeds his recommended ROE by 66 basis points.

Q. WHAT OTHER BAROMETERS INDICATE THAT INTERVENORS' ROE RECOMMENDATIONS ARE INSUFFICIENT TO ALLOW APS TO ATTRACT CAPITAL?

A. The comparable earnings standard recognizes that APS must compete for capital against firms in its own industry. Value Line reports that electric utilities as a whole are anticipated to earn a return of 11.5% from 2007 through 2011.[8] A return that is significantly below the 11.5% that Value Line expects for electric utilities generally would undermine confidence in the financial integrity of the firm and its ability to attract capital. Meanwhile, Mr. Hill expects the companies in his reference group to earn 10.35% on equity,[9] while myopically arguing that APS, which he claims is comparable in risk, could attract capital with a return of 9.25%.

Q. DO CUSTOMERS ALSO BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. While providing an ROE that is sufficient to maintain APS' ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to

---

[7] Hill Direct at Schedule 2, p. 4 and Schedule 3; Parcell Direct at Schedule 7.

[8] The Value Line Investment Survey (Sep. 1, 2006).

[9] Hill Direct at Schedule 10.

take whatever actions are required to ensure a reliable electric supply. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised. To continue to meet potential challenges successfully and economically, it is crucial that APS receive adequate support for its credit standing.

Q. WHAT ARE THE POTENTIAL CONSEQUENCES OF AUTHORIZING A RATE OF RETURN LESS THAN WHAT IS REQUIRED TO MEET THE FINANCIAL END-RESULT TEST?

A. Failing to provide investors with the opportunity to earn an adequate rate of return will only serve to hamper the Company's efforts to bolster its financial position, while impeding APS' ability to attract the capital needed to meet the economic and reliability needs of its service area. Given that the Company's financial parameters and bond ratings are already under pressure, and considering the significant risks faced by APS, the perception of a lack of regulatory support will almost certainly lead to ratings downgrades.

S&P recently confirmed this assessment, noting that "[t]he outcome in the case will largely determine whether APS' financial condition will improve from its currently weak position."[10] Similarly, Moody's concluded that the "key credit concern is the need for rate increases in a challenging regulatory environment in Arizona, which is expected to contribute to financial ratios that are weak for the rating category over the near term."[11] Setting an ROE that fails to provide investors with an opportunity to earn returns commensurate with companies of comparable risk

---

[10] Standard & Poor's Company, Bulletin: ACC Staff Recommendation Has No Immediate Effect On Arizona Public Service Co. Rtg," *RatingsDirect* (Aug. 22, 2006).

[11] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Global Credit Research* (May 9, 2006).

would weaken APS' financial integrity, violate the capital attraction standard, and send the wrong signal to investors at a time when access to capital markets is crucial for the Company.

Q. BASED ON YOUR REVIEW, WHAT DID YOU CONCLUDE WITH RESPECT TO THE REASONABLENESS OF STAFF AND RUCO'S RECOMMENDATIONS?

A. My review of authorized and earned rates of return conclusively demonstrates that the ROE recommendations of Mr. Parcell and Mr. Hill do not provide APS with the opportunity to earn a competitive rate of return on equity, commensurate with those that investors expect for other utilities. Moreover, the downward-biased ROEs of Staff and RUCO would further weaken APS' credit standing and ability to attract capital and almost certainly lead to ratings downgrades. Simply put, APS is facing large capital needs and has bond ratings at the lower extreme of the industry. If this Commission were to order a return at the lower end of the range of what other utilities are authorized and investors expect them to actually earn, why would investors supply capital to APS rather than other utilities? When investors factor in the likelihood that attrition will cause APS' actual returns to fall short of the allowed return, adopting Mr. Parcell's 10.25% return would not be sufficient to attract capital. Mr. Hill's 9.25% falls even further below any notion of reasonableness.

IV. DAVID C. PARCELL

Q. HOW DID MR. PARCELL ARRIVE AT HIS RECOMMENDED ROE OF 10.25% FOR APS?

A. Mr. Parcell's recommendation was based on the results of his application of the constant growth DCF model, CAPM, and comparable earnings approaches. His analyses focused primarily on a seven-company reference group, identified based

on Mr. Parcell's application of six separate selection criteria, as well as the ten companies in my proxy group. Mr. Parcell concluded that his DCF application implied a cost of equity in the range of 9% to 10%, his CAPM range was 10.5% to 10.75%, and he found a 10% cost of equity under his comparable earnings analysis. By focusing "on the upper portions of the respective model results," Mr. Parcell determined a cost of equity range of 9.5% to 10.75%, and recommended a point estimate of 10.25%.

Q. DO YOU AGREE WITH THE CRITERIA MR. PARCELL USED TO DEFINE HIS PROXY GROUP?

A. No. Mr. Parcell eliminated all utilities with less that 50% of operating revenues from regulated electric operations. But as discussed in greater detail subsequently in response to Mr. Hill, under the regulatory standards established by *Hope* and *Bluefield*, the issue in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream. Mr. Parcell presented no evidence that there is a connection between the subjective revenue test that he employed and the risk perceptions of actual investors in the capital markets. Moreover, because of organizational structure and reporting conventions, it is not always possible to accurately quantify revenues attributable to electric utility operations.

Finally, while Mr. Parcell included only firms that were rated triple-B by Moody's and S&P in his reference group, he applied his criteria using senior debt ratings, not the corporate, or issuer credit rating for the utility as a whole. Because equity investors are focused on the overall investment risks of the firm, and not those attributable to a specific debt issue, the appropriate indicia is the corporate credit rating.

A. DCF Analysis

Q. PLEASE DESCRIBE MR. PARCELL'S APPLICATION OF THE DCF MODEL.

A. For each of the firms in his reference group, Mr. Parcell calculated a dividend yield by dividing the company's current annualized dividend ("D_0"), increased by one-half the expected growth rate, by the average stock price for the three months ended July 2006. With respect to the growth component, Mr. Parcell averaged five proxies for investors' expectations that focused on historical and projected growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"), as well as the sustainable, or retention growth calculated as the product of the firm's retention ratio ("b") and its earned return on book equity ("r").

Combining this average growth rate with his adjusted spot dividend yield resulted in cost of equity estimates ranging from 7.5% to 8.8%, with the average being 8.1% and a median of 8.4%. Using the projected EPS growth rates published by First Call, Mr. Parcell also reported a high value of 10.0% for his reference group. Mr. Parcell concluded that "a range of 9 percent to 10 percent represents the current DCF cost of equity for APS,"[12] although only the high values produced by his analysis fall within this range.[13]

---

[12] Parcell Direct at 24.

[13] For my proxy group, Mr. Parcell reported average, median, and high DCF values of 8.8%, 8.8%, and 9.6%, respectively.

Q. DO YOU BELIEVE THAT MR. PARCELL'S APPLICATION OF THE DCF MODEL PRODUCES A REASONABLE ESTIMATE OF INVESTORS' EXPECTATIONS?

A. No. As I explained in my Direct Testimony, the short-term growth rates used to apply the DCF model may be colored by recent historical trends or lingering economic and industry uncertainties, as exemplified by declining payout ratios and Value Line's relatively pessimistic rankings for the entire utility sector. As a result, these DCF growth rates do not necessarily capture investors' long-term expectations for the industry, and the resulting cost of equity estimates will be downward-biased.

Consider Mr. Parcell's reliance on historical growth rates, for example. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for electric utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the electric utility industry. Moreover, to the extent historical trends for electric utilities are meaningful, they are also captured in the projected growth rates, such as those published by Value Line and IBES, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q. IS THIS DOWNWARD BIAS OF HISTORICAL GROWTH MEASURES EVIDENT IN MR. PARCELL'S DCF ANALYSIS?

A. Yes, it is. For example, consider the historical growth measures for the companies in Mr. Parcell's reference group displayed on his Schedule 8. As shown there, the

average 5-year historical growth rate for the seven companies in his comparable group was 0.8%, with many of the individual growth rates being negative or zero.[14] Combining a growth rate of 0.8% with Mr. Parcell's adjusted dividend yield for his group of 4.5% implies a DCF cost of equity of 5.3%. This implied cost of equity is equal to the average yield on 20-year Treasury bonds used as the risk-free rate in Mr. Parcell's CAPM analysis. Clearly, an investment in public utility common stocks is not risk free, and Mr. Parcell's historical growth measures provide no meaningful information regarding the expectations and requirements of investors.[15]

Q. IS THERE EVIDENCE THAT MR. PARCELL AGREES IN PRINCIPAL WITH THE NOTION THAT DCF GROWTH RATES AND COST OF EQUITY ESTIMATES MUST PASS FUNDAMENTAL TESTS OF REASONABLENESS?

A. Yes. Although not discussed explicitly in his testimony, Mr. Parcell apparently agrees with this premise. In arriving at his DCF results, Mr. Parcell eliminated the average historical growth rate for one firm in his reference group – Puget Energy – presumably because the value was negative, and therefore nonsensical. Unfortunately, Mr. Parcell did not apply this same test of economic reasonableness to the remainder of his DCF growth rates, many of which were also negative or too low to be considered indicative of investors' expectations. The result is a built in downward bias to Mr. Parcell's DCF conclusions.

Q. IS THERE ALSO A DOWNWARD BIAS INHERENT IN MR. PARCELL'S RETENTION, OR "B X R", GROWTH RATES?

A. Yes. Mr. Parcell based his calculation of the internal, "b x r" retention growth rate on data from Value Line, which reports end-of-period results. If the rate of return,

---

[14] Similarly, Mr. Parcell determined an average historical growth rate on Schedule 8 for the companies in my proxy group of 1.5%. Again, many of the individual growth measures were negative.

[15] Although not discussed in his testimony, Mr. Parcell eliminated

or "r" component of the "b x r" growth rate is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year. This downward bias, which has been recognized by regulators,[16] is illustrated in the table below.

Consider a hypothetical firm that begins the year with a net book value of common equity of $100. During the year the firm earns $15 and pays out $5 in dividends, with the ending net book value being $110. Using the year-end book value of $110 to calculate the rate of return produces an "r" of 13.6%. As the Federal Energy Regulatory Commission ("FERC") recognized, however, this year-end return "must be adjusted by the growth in common equity for the period to derive an average yearly return."[17] In the example below, this can be accomplished by using the average net book value over the year ($105) to compute the rate of return, which results in a value for "r" of 14.3%. Use of the average rate of return over the year is consistent with the theory of this approach to estimating investors' growth expectations, and as illustrated below, it can have a significant impact on the calculated retention growth rate:

---

[16] See, *e.g.*, *Southern California Edison Company,* Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070.
[17] *Id.*

Beginning Net Book Value		$100
Earnings		15
Dividends		5
Retained Earnings		10
Ending Net Book Value		$110
"b x r" Growth	End-of Year	Average
Earnings	$ 15	$ 15
Book Value	$110	$105
"r"	13.6%	14.3%
"b"	66.7%	66.7%
"b x r" Growth	**9.1%**	**9.5%**

Because Mr. Parcell did not adjust to account for this reality in his analysis, the "b x r" retention growth rates that he considered are downward-biased and the results of his DCF cost of equity analysis are understated.

Q. WAS THE METHOD MR. PARCELL USED TO CALCULATE THE RATE OF RETURN, OR "R" VALUE OF HIS RETENTION GROWTH RATE CONSISTENT WITH HIS OTHER ANALYSES?

A. No. In applying the CAPM method, Mr. Parcell recognized that average book values should be used to compute the return on equity over the year. On Schedule 9, Mr. Parcell computed an annual return on book equity for the S&P 500 by dividing EPS by the average of the book values for the beginning and end of each year.

Q. WHAT OTHER OMISSION CAUSES MR. PARCELL'S RETENTION GROWTH RATES TO BE UNDERSTATED?

A. In his analysis of projected retention growth rates, Mr. Parcell ignored the impact of new stock issuances on the sustainable growth of the firm. As discussed in my Direct Testimony, when a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of

existing shareholders leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically...[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[18]

In other words, the "sv" factor is an adjustment required by the DCF approach to ensure that the growth rate "g" is properly calculated for firms that plan to issue new common stock in the coming years. Mr. Hill also noted the importance of considering this source of growth when applying the DCF model using sustainable, or retention growth rates:

> Investor expectations regarding growth from external (sales of stock) must also be considered and examined.[19]

Because Mr. Parcell failed to consider the impact of expected new share issues in his analysis of projected retention growth, his DCF growth rates are again downward biased.

---

[18] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31 –32.

[19] Hill Direct at 39.

Q. HAS THE ACC STAFF PREVIOUSLY RECOGNIZED THAT THE IMPACT OF GROWTH FROM NEW COMMON STOCK MUST BE CONSIDERED WHEN IMPLEMENTING THE DCF MODEL?

A. Yes. For example, in his January 16, 2006 testimony in a proceeding involving Arizona American Water Company, Staff witness Dennis Rogers noted that growth attributable to the sale of common stock is consistent with the theory underlying the DCF model and included the "sv" factor in developing his cost of equity estimates.[20]

Q. DOES MR. PARCELL'S DIVIDEND YIELD CALCULATION COMPORT WITH DCF THEORY?

A. No, not strictly. As noted in my Direct Testimony, under constant growth DCF theory, the dividend yield component (D_1) is computed as the expected dividend over the coming year, divided by the current stock price.[21] Meanwhile, Mr. Parcell used a spot dividend yield, increased by one-half of the expected growth rate (*i.e.*, $D_0(1+ ½g)$). Because the constant growth form of the DCF model specifies that the correct dividend to use is the end-of-period value, not the mid-year value used by Mr. Parcell, his dividend yield and the resulting cost of equity estimates are understated. While the method used by Mr. Parcell to calculate the dividend yield is not novel, it does represent yet one other aspect of his DCF analysis that leads to downward-biased results.

---

[20] Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405 (January 16, 2006) at 20-23.

[21] This was recognized by ACC staff witness Dennis Rogers in his January 16, 2006 testimony in Docket No. W-01303A-05-0405 at 15.

Q. IN LIGHT OF THIS CONSISTENT DOWNWARD BIAS AND THE PROBLEMS ASSOCIATED WITH DCF RESULTS GENERALLY, WHAT DO YOU BELIEVE WOULD BE A MORE REASONABLE APPROACH?

A. Aside from the fact that many of the growth measures typically used to apply the DCF model do not capture investors' long-term expectations, the specific problems associated with Mr. Parcell's historical and retention growth rates ensure that his conclusions are understated and fall short of investors' required return. To the extent that the ACC gives any weight to Mr. Parcell's DCF results, I would recommend consideration of only the very top of his DCF range, or 10.0%.

Q. HAS THE ACC STAFF RECOGNIZED THAT THERE ARE ALTERNATIVES TO THE CONSTANT GROWTH FORM OF THE DCF MODEL?

A. Yes. Recognizing that the constant growth assumptions are not likely to be representative of real-world circumstances for utilities, the ACC Staff has also implemented a multi-stage form of the DCF model.[22] Recall that the constant growth form is a simplified version of the general DCF model:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

The general, or multi-state form of the DCF model can be used to estimate the cost of equity by substituting projections for a firm's future dividends (D_t) and price (P_t) for the variables in the equation, and imputing the cost of equity (K_e) by equating the future cash flows to the current price (P_0).

This approach was also recently applied by ACC Staff witness Dennis Rogers in his January 16, 2006 testimony in Docket No. W-01303A-05-0405 and adopted by

[22] See, *e.g.*, Direct Testimony of John S. Thorton, Docket No. W-03512A-03-0279 (October 15, 2003).

the ACC in its July 28, 2006 decision.[23] Based on projected dividends from Value Line and a terminal growth rate based on growth in Gross Domestic Product for the U.S. economy, Mr. Rogers applied the multi-stage DCF method as reflected on Schedule DRR-8 to his testimony.

Q. WHAT COST OF EQUITY IS PRODUCED FOR MR. PARCELL'S REFERENCE GROUP USING STAFF'S MULTI-STAGE DCF APPROACH?

A. Application of Staff's multi-stage DCF model to the firms in Mr. Parcell's group is presented on Attachment WEA-2RB. As shown there, this alternative to the constant growth form of the DCF model used by the ACC Staff results in an implied cost of equity for the firms in Mr. Parcell's reference group of 10.8%.

B. Risk Premium Approach

Q. PLEASE DESCRIBE MR. PARCELL'S APPLICATION OF THE CAPM.

A. Mr. Parcell applied the CAPM using a risk-free rate of 5.3%, based on the average yield on 20-year Treasury bonds for May-July 2006, a market risk premium of 5.8%, and the beta values published by Value Line. Mr. Parcell's market risk premium was based on historical data from two sources: 1) an examination of the earned rate of return on book equity for the S&P 500 versus 20-year Treasury bond yields for the period 1978-2004, and 2) the realized rates of return for common stocks and long-term government bonds published by Ibbotson Associates. Mr. Parcell concluded that his analysis of earned returns on equity for the S&P 500 implied an equity risk premium of 6.0%, and he calculated risk premiums of 6.5% and 4.9% based on the arithmetic and geometric mean returns from Ibbotson Associates, respectively.

---

[23] Decision No. 68858, *Arizona American Water Company*, Docket No. W-01303A-05-0405 (July 28, 2006).

Q. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH MR. PARCELL'S APPROACH TO APPLYING THE CAPM?

A. Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market. However, while Mr. Parcell noted that "the cost of capital is an economic and financial concept that refers to an ex-ante (before the fact) expected or required return,"[24] his application of the CAPM method was entirely premised on *historical* – not projected – rates of return. The primacy of current expectations was recognized by Ibbotson Associates:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[25]

By failing to look directly at the returns investors are currently requiring in the capital markets, as I did on Attachment WEA-6 to my Direct Testimony, Mr. Parcell's CAPM estimate significantly understates investors' required rate of return.

---

[24] Parcell Direct at 5.

[25] Ibbotson Associates, *Stocks, Bonds, Bills and Inflation, 2005 Yearbook, Valuation Edition* at 23.

Q. HAS THE ACC STAFF ALSO RECOGNIZED THE IMPORTANCE OF CONSIDERING CURRENT EXPECTATIONS WHEN ESTIMATING THE MARKET RISK PREMIUM?

A. Yes. In his January 2006 testimony, Staff witness Dennis Rogers developed an expected market risk premium for the market as a whole using essentially the same method that I presented on Attachment WEA-6 to my Direct Testimony. Staff first derived a DCF cost of equity estimate for the market as a whole by combining the projected dividend yields and growth rates for all dividend-paying stocks followed by Value Line. Based on this approach, Staff witness Rogers calculated an expected market risk premium of 7.57%.

Q. WHAT DOES STAFF'S FORWARD-LOOKING CAPM APPROACH IMPLY WITH RESPECT TO THE COST OF EQUITY FOR MR. PARCELL'S REFERENC GROUP?

A. As shown on Attachment WEA-3RB, the ACC Staff's forward-looking CAPM approach results in an average cost of equity for Mr. Parcell's reference group of 12.2%, or 12.8% for the firms in my proxy group. This same approach was adopted by the ACC in its July 28, 2006 decision in *Arizona American Water*.[26]

Q. WAS MR. PARCELL JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A. No. Both the arithmetic and geometric means are legitimate measures of average return; they just provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The

---

[26] Decision No. 68858, *Arizona American Water Company*, Docket No. W-01303A-05-0405 (July 28, 2006).

arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. Under the realized rate of return approach, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *Regulatory Finance: Utilities' Cost of Capital* had this to say:

> One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* When using historical risk premiums as a surrogate for the expected market risk premium, the relevant measure of the historical risk premium is the arithmetic average of annual risk premiums over a long period of time.[27]

Similarly, Ibbotson Associates concluded that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. ... The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[28]

One does not have to get deep into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The ACC is not setting a constant return

---

[27] Morin, Roger A., *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Reports (1994) at 275, (emphasis added).

[28] Ibbotson Associates, *Stocks, Bonds, Bills and Inflation, 2006 Yearbook, Valuation Edition* at 77.

that APS is guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, APS' yearly return will be volatile, depending on a variety of economic and industry factors, and investors do not expect to earn the same return each year.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO THE CONCLUSIONS OF MR. PARCELL'S CAPM ANALYSIS?

A. For a variable series, such as stock returns, the geometric average will always be less than the arithmetic average. Accordingly, Mr. Parcell's reference to geometric average rates of return provides yet another element of systemic downward bias.

Q. DO THE RISK PREMIUMS MR. PARCELL DERIVES FROM IBBOTSON ASSOCIATES' DATA COMPORT WITH THOSE REPORTED BY THIS ORGANIZATION?

A. No. As I noted in my Direct Testimony, Ibbotson Associates computes the equity risk premium by subtracting the arithmetic mean income return (not the total return) on long-term Treasury bonds from the arithmetic average return on common stocks. As Ibbotson Associates explained:

> Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.[29]

In other words, Ibbotson Associates concluded that using only the income component of the long-term government bond return provides a more reliable estimate of the expected risk premium because investors do not anticipate capital losses for a risk-free security. Mr. Parcell, however, calculated his equity risk premiums using the

---

[29] *Id.*

total return for Ibbotson Associates' long-term government bond series. As a result, his equity risk premiums fall far below what Ibbotson Associates reports and Mr. Parcell's CAPM cost of equity estimates are understated.

Q. IS YOUR ASSESSMENT OF THE CORRECT HISTORICAL RISK PREMIUM CONSISTENT WITH THE VIEWS OF THE ACC STAFF?

A. Yes. For example, in applying the CAPM to estimate the cost of equity, Staff witness Dennis Rogers used a 7.2% market risk premium based the difference between arithmetic mean returns for common stocks and government bond income returns. As Mr. Rogers stated:

> Ibbotson Associates calculated the historical risk premium by averaging the historical arithmetic differences between the S&P 500 and the intermediate-term government bond income returns. Staff's historical market risk premium estimate is 7.2 percent as shown in Schedule DRR-2.[30]

This is the exact same 7.2% historical market risk premium that I relied on in Attachment WEA-7 to my Direct Testimony.

Q. WHAT COST OF EQUITY IS PRODUCED BY THE HISTORICAL CAPM ANALYSIS ONCE THESE DEFICIENCIES ARE ADDRESSED?

A. Ibbotson Associates reports an arithmetic mean risk premium for the S&P 500 over the 1926-2005 time period of 7.1%.[31] As shown on Attachment WEA-4RB, when combined with Mr. Parcell's 5.3% risk free rate and the most recent beta values from Value Line, this results in CAPM cost of equity estimates of 11.8% for Mr. Parcell's reference group and 12.1% for the firms included in my proxy group.

---

[30] Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405 (January 16, 2006) at 30.

[31] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at Appendix C, Table C-1, p. 262.

Again, this exact approach was recently accepted by the ACC in a July 28, 2006 decision.[32]

Q. IS MR. PARCELL'S APPLICATION OF THE COMPARABLE EARNINGS APPROACH INTERNALLY CONSISTENT?

A. No. On the one hand, Mr. Parcell concludes that his comparable earnings analysis indicates that investors anticipate a return of approximately 13.5% from the firms in the S&P 500.[33] On the other hand, Mr. Parcell asserts that this approach implies that "the cost of equity for APS is no greater than 10%."[34] These findings simply are not compatible. Within the context of the CAPM model applied by Mr. Parcell, if investors expect a forward-looking return on the S&P 500 of 13.5%, and accepting his risk free rate of 5.3%, this implies an equity risk premium for the market as a whole of 8.2%. Multiplying this 8.2% risk premium by the average Value Line beta reported by Mr. Parcell for his reference group of 0.89 implies an equity risk premium for an electric utility of 7.3%. In turn, adding this 7.3% risk premium to Mr. Parcell's risk free rate of 5.3% implies a cost of equity for his electric utility group of 12.6%.

Similarly, while Mr. Parcell implies that an earned return of 10% or less is reasonable, Value Line reports that electric utilities as a whole are anticipated to earn a return of 11.5% from 2007 through 2011.[35] The comparable earnings standard recognizes that APS must compete for capital against firms in its own industry. A return that is significantly below the 11.5% that Value Line expects for

---

[32] Decision No. 68858, *Arizona American Water Company*, Docket No. W-01303A-05-0405 (July 28, 2006).

[33] Computed as the average of the 14.7% and 12.3% returns reported by Mr. Parcell for the 1992-2001 and 2000-2004 time periods, respectively.

[34] Parcell Direct at 31.

[35] The Value Line Investment Survey (Sep. 1, 2006).

electric utilities generally would undermine confidence in the financial integrity of the firm and its ability to attract capital.

Q. BASED ON THE METHODOLOGIES RECENTLY ADOPTED BY THE ACC STAFF AND APPROVED BY THE COMMISSION, WHAT COST OF EQUITY IS IMPLIED FOR MR. PARCELL'S REFERENCE GROUP?

A. As noted earlier, given the downward bias in Mr. Parcell's constant growth DCF results, the indicated cost of equity should be set at the very top of his range, or 10.0%. Meanwhile, application of the ACC Staff's multi-stage DCF model results in a cost of equity for Mr. Parcell's utility group of 10.8%. Taken together, these results imply an average DCF cost of equity of approximately 10.4%.

With respect to the CAPM, application of the ACC Staff's forward-looking risk premium approach produced an average cost of equity for Mr. Parcell's proxy group of 12.2%. Correcting the deficiencies in Mr. Parcell's historical CAPM analysis implied an indicated cost of equity of 11.8%. Combining these two values, consistent with the Staff methodology recently approved by the ACC, results in a CAPM cost of equity estimate of 12.0%. As shown below, Staff's approved methods imply an average cost of equity estimate for Mr. Parcell's reference group of 11.20%:

Method	Estimate
Average DCF Estimate	10.40%
Average CAPM Estimate	12.00%
Overall Average	**11.20%**

C. Other Factors

Q. DO YOU AGREE WITH MR. PARCELL (P. 37) THAT CONSIDERATION OF FLOTATION COSTS IS NOT WARRANTED IN THIS PROCEEDING?

A. No. Mr. Parcell's position is perplexing in light of his own research regarding the measurement and implementation of flotation cost adjustments.[36] In his 1993 paper, Mr. Parcell confirmed that "issuance costs have averaged 2 to 5 percent of the gross proceeds on new public stock sales," and noted that there are "a variety of mechanisms for the recovery of flotation costs."[37] While Mr. Parcell recognized that the issue of how best to account for issuance costs was not without controversy, he also documented the use of flotation cost adjustments by utility regulators.[38]

As discussed in detail in my Direct Testimony, apart from the impact of new equity issuances, a flotation cost adjustment to compensate for past equity issues is required to keep shareholders whole. The need to consider past flotation costs has been recognized in the financial literature, including sources that Mr. Parcell relied on in his testimony. Specifically, Ibbotson Associates concluded that:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[39]

---

[36] Parcell, D. C., "The Flotation Cost Adjustment To Utility Cost of Common Equity, Theory, Measurement, and Implementation" *National Society of Rate of Return Analysts*, Twenty-Fifth Financial Forum (Apr. 28, 1993).

[37] *Id.*

[38] *Id.*

[39] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at 35.

As I demonstrated by way of example in my Direct Testimony (pp. 59-61), unless an adjustment to account for the costs of past equity issuances is included, investors will be denied the opportunity to earn their required return.

Meanwhile, Mr. Parcell's suggestion that there is no evidence of Pinnacle West incurring any flotation costs is incorrect. Clearly, any time a company issues new common equity, there are costs associated with underwriting and floating the stock issue to the public. Consider the $250 million equity issuance made by Pinnacle West in 2005, for example, the proceeds of which all went to APS. This single stock sale resulted in underwriting fees and other flotation costs totaling over $8.5 million. Unless an adjustment to the ROE is made to recognize these costs and those associated with all other prior sales of common stock, investors will be denied the chance to earn their required return.

Q. WHAT ABOUT MR. PARCELL'S CONTENTION (P. 37) THAT A FLOTATION COST ALLOWANCE IS UNNECESSARY BECAUSE THE MARKET-TO-BOOK RATIO FOR ELECTRIC UTILITIES IS GREATER THAN 1.0?

A. Whether or not the market-to-book ratio is greater than, or less than, 1.0 says nothing about the need to recognize the impact of legitimate costs of issuing common stock when establishing a fair rate of return. Investors determine the price they are willing to pay for a share of common stock based on their assessment of expected cash flows and relative risks. While I don't dispute Mr. Parcell's observation that sales of stock at a price that exceeds book value will cause the book value per share of existing shareholders to grow,[40] this doesn't change the fact that investors must be granted an opportunity to earn their required rate of return on

[40] Indeed, this growth related to sales of new common stock forms the basis for the "sv" adjustment that Mr. Parcell ignored in calculating the retention growth rates used in his DCF analysis.

all invested capital, including that portion paid out as issuance expenses. As I demonstrated in the example in my Direct Testimony, this can only occur if an upward adjustment to the ROE is made to account for flotation costs.

Q. WHAT IS YOUR CONCLUSION REGARDING MR. PARCELL'S RECOMMENDED ROE?

A. As documented in my Rebuttal Testimony, Mr. Parcell's ROE recommendation is downward-biased, with revisions to his analyses consistent with recent ACC Staff testimony and Commission decisions implying a fair rate of return on equity for APS on the order of 11.20%, before consideration of flotation costs. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial to APS' access to capital. A return well in excess of Mr. Parcell's recommendation is required if APS is to have the opportunity to maintain its credit standing and financial flexibility.

V. STEPHEN G. HILL

Q. WHAT OVERALL RATE OF RETURN DID MR. HILL PROPOSE FOR APS?

A. Mr. Hill proposed an overall rate of return for APS of 7.33%. Along with the component costs of debt and preferred stock, Mr. Hill combined a rate of return on equity of 9.25% with a capital structure composed of 50.0% common equity and a total debt ratio of 50.0%, including long- and short-term debt.

Q. BRIEFLY DESCRIBE HOW MR. HILL ARRIVED AT HIS RECOMMENDED COST OF EQUITY FOR APS.

A. Following a general description of economic and capital market conditions, Mr. Hill applied the constant growth DCF model to a group of thirteen other electric utilities. He then used three other methods – the CAPM, earnings-price ratio, and

market-to-book ratio – to check his DCF results. Based on these analyses, Mr. Hill concluded that the cost of equity for the firms in his comparable group is in the range of 9.25% to 9.75%. Based on the contention that his recommended capital structure implies less financial risk than his comparable group, Mr. Hill recommended an ROE at the very bottom of his range, or 9.25%, for APS. Mr. Hill argued against any upward adjustment to the return on equity for flotation costs, concluding that it was "unnecessary."

Q. WHAT IS YOUR OVERALL ASSESSMENT OF MR. HILL'S ROE RECOMMENDATION?

A. Mr. Hill is in a difficult position. By his own admission, "returns in the single-digit range seem to be low."[41] But rather than considering the implications of this assessment, he sets about finding a hodgepodge of carefully selected references to obscure this unavoidable conclusion. In fact, Mr. Hill's recommended ROE is far beyond the pale and falls well short of investors' required return. The reason that Mr. Hill was compelled to observe that his single-digit cost of equity recommendation seems to be low, is that *it is low*. So low, in fact, that it falls completely outside a reasonable range and is entirely inconsistent with mainstream benchmarks. This conclusion is only buttressed by the need to consider the consequences for APS' already weakened credit standing and the Company's continued need to keep pace with strong service area growth while financing deferred power cost balances. It is plainly evident that Mr. Hill's recommendations would be disastrous for APS and, ultimately, for customers as well.

---

[41] Hill Direct at 7.

Q. DO THE RETURN ASSUMPTIONS UNDERLYING THE ACTUARIAL STUDIES OF PINNACLE WEST'S PENSION PLAN SUPPORT MR. HILL'S ROE RECOMMENDATION?

A. No. Incredibly, while Mr. Hill admits that his ROE recommendation appears low, he opines that investors' actual return expectations are even lower. The evidence Mr. Hill cites for his surprising finding is the return assumptions made in the administration of Pinnacle West's pension plan. Mr. Hill notes that Pinnacle West's 2005 Form 10-K Report indicated a 9.00% expected return on plan assets, which Mr. Hill stated were "comprised mostly of equity investments."[42] In fact, however, Pinnacle West reported on page 100 of this same report that the target asset allocation corresponding to this 9.00% return is comprised of only 60% equity securities. In fact, APS informed RUCO that the actual return it expects to earn on the equity component of its pension plan portfolio is approximately 11.0%.[43]

Q. CAN AN ASSUMED PENSION PLAN RETURN BE COMPARED DIRECTLY TO THE REQUIRED RETURN WE ARE TRYING TO ESTIMATE IN THIS CASE?

A. No. The return on pension plan assets is distinct from the ROE required by investors in the capital markets. This assumed return on plan assets was developed through simulations based on asset returns calculated over a 10-year time period, with the Towers Perrin document referenced by Mr. Hill specifically noting that their results "differ from those which would be calculated assuming independent annual returns."[44] Independent annual returns, which are analogous to arithmetic averages, are the appropriate benchmark for investors' expected rate of return.

---

[42] *Id.* at 5.
[43] Response to RUCO 3-10.
[44] APS10620.

Q. IS THERE ANY OTHER EVIDENCE THAT MR. HILL'S REFERENCE TO APS' PENSION PLAN'S ASSUMED 9.0% RETURN IS MEANINGLESS?

A. Yes. Mr. Hill noted that his 9.0% return benchmark "is for common stocks generally, not for utility stocks, which would have a lower equity return expectation due to their lower risk."[45] Mr. Hill's market return of 9.0% can be converted to a return for electric utilities using his own application of the CAPM model. Assuming Mr. Hill's risk free rate of 5.16% and his proxy group beta of 0.83, a 9.0% return on the stock market as a whole would imply an ROE for his electric utility group of 8.3%.[46] This result falls almost 100 basis points below the bottom end of Mr. Hill's own ROE range and outside the realm of reasonableness indicated by any objective benchmark. Far from confirming the reasonableness of Mr. Hill's recommendation, this outcome only confirms the fundamentally illogical nature of his conclusions.

Q. ARE THE SELECTED ACADEMIC STUDIES REFERENCED BY MR. HILL REPRESENTATIVE OF INVESTORS'EXPECTATIONS?

A. No. Mr. Hill claims that "recent economic research" suggests that the market risk premium has fallen sharply, justifying his single-digit cost of equity recommendation for APS."[47] First, many of Mr. Hill's selected studies do not examine the forward-looking expectations of today's investors to estimate the required market rate of return in current capital markets. Instead of directly considering requirements in today's capital markets, as I did in my Direct Testimony on Attachment WEA-6, Mr. Hill is implicitly asserting that events and expectations for the time periods covered by these particular studies are more

---

[45] Hill Direct at 8-13.

[46] 5.16% + 0.83(9.0% - 5.16%) = 8.3%.

[47] Hill Direct at 21.

representative of what is likely to occur going forward. This assertion runs counter to the assumptions underlying the use of the CAPM to estimate investors' required return, which as discussed earlier in response to Mr. Parcell, is a purely forward-looking model.

Moreover, even if historical studies were relevant in this context, there are other such studies of equity risk premiums published in academic journals that imply required rates of return considerably in excess of those selected by Mr. Hill. For example, a study reported in the *Financial Analysts' Journal* noted that the real risk premium for U.S. stocks averaged 6.9 percent over the period 1889 through 2000 and concluded that:

> Over the long term, the equity risk premium is likely to be similar to what is has been in the past and returns to investment in equity will continue to substantially dominate returns to investments in T-bills for investors with a long planning horizon.[48]

Combining this 6.9% real risk premium with a 3.0% inflation rate and Mr. Hill's 4.84% T-bill rate implies a current required rate of return on equity for the market as a whole of approximately 14.7% – far in excess of the single-digit returns cited by Mr. Hill.[49] Similarly, based on a study of *ex-ante* expected returns for a sample of S&P 500 firms over the 1983-1998 period, a 2003 article in *Financial Management* found an expected market risk premium of 7.2%,[50] identical to that used by the ACC Staff.

---

[48] Mehra, Ranjnish, "The Equity Premium: Why Is It a Puzzle?", *Financial Analysts' Journal* (January/February 2003).

[49] Mr. Hill's T-Bill rate is reported at Appendix D, p. iv to his Direct Testimony.

[50] Harris, R.S., Marston, F. C., Mishra, D. R., and O'Brian, T. J., "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," *Financial Management* (Autumn 2003) at Table I.

Q. DO THE RESULTS OF THE EQUITY RISK PREMIUM STUDIES REPORTED BY MR. HILL MAKE ECONOMIC SENSE?

A. No. In fact, five of the studies cited as support for Mr. Hill's conclusions implied market equity risk premiums ranging from 1.8% to 4.0% and averaging approximately 3.3%.[51] But multiplying a market equity risk premium of 3.3% by Mr. Hill's beta of 0.83 for his reference group, and combining the resulting 2.7% risk premium with his 5.16% risk-free rate, results in an indicated cost of equity of approximately 7.9%. By any objective measure, such results fall woefully short of required returns from an investment in common equity. Mr. Hill's interpretation of recent academic research has little relation to the expectations of actual investors and no value as a benchmark in evaluating the reasonableness of his recommendations.

Q. DOES THE IBBOTSON & CHEN ARTICLE CITED BY MR. HILL (P. 13) PROVIDE ANY SUPPORT FOR HIS POSITION THAT THE MARKET EQUITY RISK PREMIUM HAS FALLEN PRECIPITOUSLY?

A. No. Mr. Hill's conclusion differs markedly from the evidence in the article by Roger G. Ibbotson and Peng Chen that he cited.[52] Based on the results of their study, Ibbotson and Chen concluded that:

> Our forecast of the equity risk premium is only slightly lower than the pure historical return estimate. We estimate the expected long-term equity risk premium ... to be about 6 percentage points arithmetically... (p. 88)

---

[51] See, *e.g.*, Hill Direct at p. 8, ln. 11-12, p. 9, ln. 2, p. 11, ln. 17, p. 12, ln. 13, p. 12, ln. 20.

[52] Ibbotson, R., Chen P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

Apart from contradicting the findings of other studies selected by Mr. Hill, the 6.0% equity risk premium from Ibbotson and Chen disproves his contention that a single-digit cost of equity is reasonable.

Q. DOES MR. HILL OFFER A SIMPLE EXPLANATION AS TO WHY ALLOWED RETURNS ARE SO MUCH HIGHER THAN THE RESULTS OF HIS ANALYSES?

A. Yes. Mr. Hill asserts (p. 14) that regulatory commissions are ignorant as to this "new research" he cites in his testimony, and expresses his belief that allowed returns will decline as they develop an understanding of this information.

Q. BASED ON YOUR EXPERIENCE AS A REGULATORY STAFF MEMBER AND CONSULTANT, DOES THIS SEEM REASONABLE?

A. Far from it. The rate setting process is fractious and hard-fought, and the question of establishing a fair ROE is perhaps one of the most contentious issues among the various stakeholders. As a result, utilities, commission staff members, and intervenors typically devote considerable attention and resources in arguing their position before regulators. In my experience, authorized rates of return are decided based on careful consideration of extensive record evidence and staff members and commissioners have the resources and sophistication to assess the implications of current financial research and analyses. It is simply naïve of Mr. Hill to claim that authorized rates of return are somehow upward-biased because regulators have not been made aware of or understood the results of his selected crop of articles.

Q. DOES MR. HILL'S REFERENCE TO MARKET-TO-BOOK RATIOS FOR ELECTRIC UTILITIES DEMONSTRATE THE REASONABLENESS OF HIS 9.25% PERCENT RECOMMENDED COST OF EQUITY FOR APS?

A. No. In addition to other problems,[53] the argument that regulators should set a required rate of return to produce a market-to-book value of approximately 1.0 is fallacious. For example, *Regulatory Finance: Utilities Cost of Capital* noted that:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a M/B of 1.0, presumes that investors are masochistic. They commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is not a realistic or accurate view of regulation.[54]

Indeed, while Mr. Hill reports that investors' expect electric utilities to earn 10.35% percent on common equity, he suggests that regulators should allow them to earn 9.25%.[55] With market-to-book ratios above 1.0 times, Mr. Hill apparently believes that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall.

Within the paradigm of DCF theory, a drop in stock prices means negative growth, and if investors expect negative growth then this is the relevant "g" to substitute in the constant growth DCF model. In turn, a negative growth rate implies a DCF cost of equity for utilities less than their dividend yields. This, of course, is truly a nonsensical result, and a manifestation of Mr. Hill's confusion between DCF theory and practice.

---

[53] Market-to-book ratios are impacted by other external factors unrelated to utility operations. For example, current or anticipated diversification into non-regulated activities may cause the market price of a utility's stock to deviate significantly from its book value.

[54] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utility Reports* (1994) at 256.

[55] Hill Direct at 21.

Q. HAVE REGULATORS PREVIOUSLY RECOGNIZED THE FALLACY OF RELYING ON MARKET-TO-BOOK RATIOS IN EVALUATING COST OF EQUITY ESTIMATES?

A. Yes. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[56]

The Initial Decision found that there was no support in Commission precedent for the use of market-to-book ratios to evaluate market derived cost of equity estimates and concluded that such arguments were to be treated as "academic rhetoric" unworthy of serious consideration.

Q. DOES THE FACT THAT BOND YIELDS ARE "LOW RELATIVE TO THE INTEREST RATE LEVELS THAT EXISTED IN THE MID-1980S"[57] IMPLY THAT MR. HILL'S RECOMMENDED 9.25% ROE IS REASONABLE?

A. No. While interest rates represent one logical reference point, the impact of fluctuating capital market conditions on the cost of equity is not readily determined. In fact, there is substantial evidence that equity risk premiums tend to move inversely with interest rates. In other words, when interest rates rise, equity risk premiums narrow, and when interest rates fall, equity risk premiums are greater. This inverse relationship has been recognized in the financial literature and by regulators.

Moreover, contrary to Mr. Hills assertion that "long-term capital costs have not increased to a substantial extent,"[58] as documented earlier, triple-B utility bond

---

[56] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).

[57] Hill Direct at 16.

yields have increased approximately 80 basis points from the levels in my Direct Testimony. As I explained there, capital market participants generally anticipate that long-term interest rates will continue to rise. For example, the most recent forecast of GlobalInsight, a widely referenced forecasting service, calls for double-A public utility bond yields to average 6.92% over the next five years,[59] versus 6.13% in July 2006.[60] Meanwhile, the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy, anticipates that the double-A public utility bond yield will average of 7.18% for the period 2007-2011.[61]

Q. DOES THE SINGLE INVESTMENT ANALYST REPORT CITED BY MR. HILL SUPPORT HIS ALLEGATION THAT INVESTORS' RETURN EXPECTATIONS FOR UTILITIES ARE ESPECIALLY LOW?

A. No. On page 7 of his testimony, Mr. Hill resorts to a selected cite from A. G. Edwards in an attempt to support his position. But the 8.1% return figure cited in this report is simply another example of a mechanical application of the constant growth DCF model. It is not uncommon for stock research reports to include a perfunctory application of the DCF or CAPM models, but these results hardly represent an in-depth analysis of investors' expectations or their required rates of return. The fact that this 8.1% figure falls some 115 basis points below even Mr. Hill's anemic ROE recommendation amply demonstrates that this provides no insight as to a fair return on equity for APS. Indeed, A.G. Edwards noted that the median ROE authorized for the gas industry in 2005 was 10.6% and, in contrast to

---

[58] *Id.* at 15.

[59] GlobalInsight, "The U.S. Economy: The 30-Year Focus" (First-Quarter 2006) at Table 34. This is the only series of projections for public utility bond yields reported by GlobalInsight.

[60] Moody's Investors Service, *Credit Perspectives* (Aug. 21, 2006) at 56.

[61] Energy Information Administration, "Annual Energy Outlook 2006" (Jan. 2006) at Table 19. This is the only series of projections for public utility bond yields reported by EIA.

APS, the report concluded that "gas utilities have typically been able to earn near or above their authorized return."[62]

A. DCF Analysis

Q. DID MR. HILL PROPERLY APPLY THE CONSTANT GROWTH DCF MODEL?

A. No. Mr. Hill began his DCF analysis by correctly stating:

> 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.[63]

Nevertheless, his application of the DCF model to his proxy group of utilities departed from this fundamental proposition because of his strict reliance on the mathematical DCF theory instead of the realities of investors' actual expectations in financial markets. The use of DCF models to estimate the cost of equity is essentially an attempt to replicate the market pricing mechanism that led to the observed stock price, with investors' required rate of return simply being inferred. In contrast, Mr. Hill applied the DCF model based on a strict interpretation of the academic theory underlying its derivation.

---

[62] A.G. Edwards, "Gas Utilities Quarterly Review," April 6, 2006 at 6.

[63] Hill Direct at 34.

Q. WHAT IS WRONG WITH ADHERING STRICTLY TO THE THEORY UNDERLYING THE CONSTANT GROWTH DCF MODEL?

A. Enumerated in my Direct Testimony,[64] many unrealistic assumptions are required to derive the constant growth form of the DCF model, with Mr. Hill noting some of these infirmities in his testimony:

> 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.[65]

Because the assumptions underlying the constant growth DCF model are never met in practice, the constant growth DCF model can, at best, only be considered an abstraction of reality. As such, the DCF model <u>cannot</u> universally produce correct measures of the cost of equity; rather, it can only serve as a potential guide to investors' required rate of return. Mr. Hill granted this limitation of the DCF model in his testimony:

> As with all mathematical models of real-world phenomena, the DCF theory does not exactly "track" reality.[66]

Therefore, the only inputs (i.e., cash flows) that matter in implementing the DCF model are those that <u>investors used</u> to value the utility's stock. Any application of the DCF model that does not focus exclusively on investors' actual expectations is a misuse of the DCF model to estimate the cost of equity.

---

[64] Avera Direct at 31-32.
[65] Hill Direct at 34.
[66] *Id.*

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW MR. HILL DISREGARDS THIS PRINCIPLE?

A. Yes. Consider Mr. Hill's discussion of his hypothetical firm in Appendix B to his testimony. He stated that certain actual growth rates can be "unreliable" within DCF theory, and concluded that the proper growth rate to use with the DCF model is the theoretical "sustainable growth rate". But Mr. Hill's contention is wrong. The only correct growth rate to be used in the DCF model is the long-term growth rate investors actually incorporated into the observed stock price, irrespective of whether Mr. Hill considers it "ridiculous" or inconsistent with "the underlying fundamentals of growth in the DCF model."[67]

The fact is Mr. Hill confused the theory of the DCF model with its application. Professor Myron J. Gordon's complete mathematical DCF model is tautological. In other words, the constant growth DCF model is true by virtue of the strict assumptions made to derive it, and given these assumptions, any number of propositions can be "demonstrated" (*e.g.*, Appendix B, p. v). But to the extent that these assumptions are not met in practice and the DCF model does not "track reality", the theoretical DCF model will not conform to the real world. In turn, cost of equity estimates that are based solely on mathematical identities instead of investors' actual long-term growth expectations will not accurately measure their required rate of return. In a 2005 case decided by the New Hampshire Public Service Commission, regulators specifically concluded that Mr. Hill's DCF growth analysis "does not in our view reflect true market conditions."[68]

---

[67] Hill Direct at Appendix B, p. iv.

[68] Order No. 24,473, *New Hampshire Public Utilities Commission* (June 8, 2005).

Q. ARE THERE OTHER PROBLEMS ASSOCIATED WITH THE GROWTH RATES UNDERLYING MR. HILL'S DCF RESULTS?

A. Yes. The sustainable, "br x sv" growth rates that formed the sole basis for Mr. Hill's DCF cost of equity estimates require an explicit assumption regarding the return on book equity ("r") that the utilities will earn in the future. But whereas Mr. Hill concludes that the DCF cost of equity for his reference group is 9.44%, the expected ROEs used by Mr. Hill to calculate his sustainable growth rates averaged 10.7% over the 2006-2011 period. In other words, Mr. Hill's analysis assumes that the companies in his group will earn a return significantly higher than the ROE he believes that regulators should adopt. For a regulated firm with earnings tied to the authorized return on book equity, this mismatch makes no sense.

Additionally, Mr. Hill's sustainable growth calculations fail to account for the fact that the returns on equity published by Value Line are based on end-of-period book equity rather than on average book equity. As discussed earlier in response to Mr. Parcell, this will understate actual returns because of growth in common equity over the year and results in a built-in downward bias in the resulting cost of equity estimates.

Q. DO THE RESULTS OF ALTERNATIVE METHODS SUPPORT MR. HILL'S DCF FINDINGS IN THIS CASE?

A. No. Even without incorporating expectations for higher interest rates, as noted in my Direct Testimony, application of the risk premium approach based on allowed rates of return for electric utilities resulted in a current cost of equity of 10.7%,[69] while applying the CAPM based on forward-looking expectations that are more

---

[69] Avera Direct at 47.

consistent with the underlying theory of this approach produced an estimated cost of equity of 12.5%.[70]

Q. WHAT OTHER EVIDENCE INDICATES THAT MR. HILL'S DCF RESULT IS BIASED DOWNWARD?

A. As noted earlier, reference to allowed rates of return for other utilities also provides further confirmation that Mr. Hill's DCF result, and his ultimate ROE recommendation, fall significantly short of a reasonable rate of return. The rates of return on common equity authorized for electric and gas utilities averaged 10.57% and 10.60% for the first half of 2006, respectively.[71] This provides further confirmation that Mr. Hill's DCF results, which formed the basis of his recommendations, are far below the returns required by actual investors.

Q. IS MR. HILL ACCURATE TO SUGGEST (P. 51) THAT THE RESULTS OF THE CONSTANT GROWTH DCF MODEL ARE ONLY BEING QUESTIONED BY "UTILITY-SPONSORED" RATE OF RETURN WITNESSES?

A. No. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is a blunt tool that should never be used exclusively, and regulators have customarily considered the results of alternative approaches in determining allowed returns. It has become increasingly evident to rate of return witnesses, regardless of whether they represent commission staffs, intervenors, or utilities, that conventional applications of the constant growth DCF model do not always provide accurate estimates of investors' required rates of return.

---

[70] *Id.* at 51.

[71] Regulatory Research Associates, "Major Rate Case Decisions – January-June 2006," *Regulatory Focus* (July 6, 2006).

Accordingly, increased reliance is being placed on other methods to estimate the cost of equity, including alternative forms of the DCF model (e.g., multi-stage DCF models) and risk premium methods. The need to consider alternative methods is especially important where the results of one approach deviate significantly from cost of equity estimates produced by other applications, with risk premium methods suggesting a cost of equity far in excess of DCF values.

Q. HAS THE FALLIBILITY OF THE CONSTANT GROWTH DCF MODEL BEEN RECOGNIZED BY REGULATORS?

A. Yes. For example, the Public Utility Commission of Texas ("PUCT"), which I can assure you is not "utility-sponsored", made the following Findings of Fact in a case involving El Paso Electric Company:

> 109. Under present market and utility industry conditions, the constant discounted cash flow model does not provide reliable results.[72]

Mr. Hill refers to a dated article from Public Utility Reports (p. 52) in support of his claim that state regulators continue to rely on the DCF approach. But the DCF techniques that regulators are currently relying on may not be the constant growth methods advocated by Mr. Hill. In Florida, one of the states that Mr. Hill cites as continuing to rely on "standard" DCF techniques, the FPSC concluded in an April 29, 1998 decision that:

> Upon consideration, we find that the multi-stage DCF model employed by AT&T/MCI witness Cornell is superior to the single-stage DCF model used by BellSouth witness Billingsley for estimating the cost of capital of BellSouth. Witness Cornell testifies that the form of the DCF model he uses is well supported in the financial community. (p. 22)

---

[72] Final Order, Docket No. 9945, *Public Utility Commission of Texas.*

State regulators in Pennsylvania, Iowa, and Alaska have also recognized the pitfalls associated with constant growth DCF results. The Pennsylvania Public Utility Commission concluded in a 1998 order that "the sole use of the DCF method can result in an understatement of the common equity cost rates."[73] Similarly, the Iowa Utilities Board concluded that "the DCF model may understate the return on equity in some circumstances,"[74] while regulators in Alaska specifically noted the importance of considering multiple approaches:

> We agree ... that investors are aware of all the various traditional cost of common equity models discussed in the financial literature. Absent good reason for believing that investors weight the results of one method more heavily than another in their assessment of an appropriate return, it is reasonable to hold that investors ascribe weight to them all.[75]

The Federal Communications Commission ("FCC") has also recognized the need for pragmatism when evaluating a fair return on equity, citing the need for an "accommodating and flexible position" that is not restricted to a single methodology.[76] More recently, in a 2003 decision establishing a fair rate of return for local service network elements, the FCC's Wireline Competition Bureau specifically considered and rejected the use of the DCF model, concluding that "the CAPM is the better mechanism for estimating the cost of equity in this proceeding."[77] With respect to the constant growth DCF approach advocated by

---

[73] *United Water Pennsylvania,* Case No. R-00973947.

[74] *U.S. West Communications, Inc.*, 152 PUR 4th (June 17, 1994) at 459.

[75] *Trans Alaska Pipeline System*, Docket Nos. P-97-4 and P-97-7, Order Nos. 151 and 110 (Nov. 27, 2002) at 144-145.

[76] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

[77] *Memorandum Opinion and Order*, CC Docket Nos. 00-218, 00-251, DA 03-2738 (Aug. 29, 2003) (*Virginia Arbitration Order*). at P. 71.

Mr. Hill, the Wireline Competition Bureau expressed serious doubts about this model's ability to accurately reflect investors' expectations in today's capital markets. Considering the deviation between Mr. Hill's results and other, objective benchmarks, considerable caution is warranted when evaluating the usefulness of DCF cost of equity estimates.

Q. YOU NOTED EARLIER THAT THE ACC STAFF HAS ALSO APPLIED A MULTI-STAGE FORM OF THE DCF MODEL. WHAT COST OF EQUITY IS INDICATED FOR MR. HILL'S UTILITY GROUP USING THIS APPROACH?

A. As shown on Attachment WEA-15RB the ACC staff's multi-stage DCF model that was adopted by the Commission results in an average cost of equity for Mr. Hill's reference group of 10.7%. This provides yet another indication that Mr. Hill's application of the DCF model produces illogical results.

Q. DO YOU AGREE WITH MR. HILL'S ASSERTIONS THAT CERTAIN COMPANIES SHOULD BE EXCLUDED FROM YOUR PROXY GROUP?

A. No. While Mr. Hill argued that certain companies should be dropped based on subjective arguments concerning the impact of non-regulated operations, he failed to demonstrate any link between his subjective musings and the investment risks perceived by investors. Moreover, there are significant errors and inconsistencies associated with his approach that justify rejecting Mr. Hill's proxy group altogether.

As discussed in my Direct Testimony (p. 33), a comparison of bond ratings indicates that investment risks for the firms in my proxy group of western utilities are relatively homogeneous. There are important factors distinguishing western utilities from those located in other regions and the Supreme Court has recognized

the relevance of geographical location.[78] My Direct Testimony demonstrated that investors are likely to regard my proxy group as facing similar market conditions and having comparable risks and prospects.

Q. DID MR. HILL DEMONSTRATE A NEXUS BETWEEN THE SUBJECTIVE CRITERIA HE USED TO DEFINE HIS PROXY GROUP AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A. No. Mr. Hill claimed that utilities with less than 70% of operating revenues from regulated electric operations or companies that had divested generation assets should be eliminated when determining a proxy group. But under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream or ownership of generating assets. As Mr. Hill correctly recognized:

> 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 [utilities] are to be given an opportunity to earn returns that are sufficient to attract capital and are <u>comparable to returns investors would expect in the unregulated sector</u> for assuming the same degree of risk.[79]

Mr. Hill presented no evidence that there is a connection between the subjective criteria that he employed and the views of actual investors in the capital markets.

Q. WHAT OBJECTIVE EVIDENCE CONFIRMS THE CONCLUSION THAT MR. HILL'S SUBJECTIVE CRITERIA ARE NOT SYNONYMOUS WITH COMPARABLE RISK IN THE MINDS OF INVESTORS?

A. Bond ratings are perhaps the most objective guide to utilities' overall investment risks and they are widely cited in the investment community and referenced by

---

[78] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).

[79] Hill Direct at 8 (emphasis added).

investors. While the bond rating agencies are primarily focused on the risk of default associated with the firm's debt securities, bond ratings and the risks of common stock are closely related. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Concrete evidence supporting the relationship between bond ratings and the quality of a security is abundant. ... The strong association between bond ratings and equity risk premiums is well documented in a study by Brigham and Shome (1982).[80]

Indeed, Mr. Hill also relied on bond ratings as one criteria in developing his comparable group.

As Mr. Hill noted, the companies he selected had a bond rating "between "A-" to 'BBB-'."[81] Meanwhile, a review of Mr. Hill's Schedule 3, which presents the basis of his sample group selection, indicates that, of the 19 firms excluded by Mr. Hill based on his electric revenue and generating asset tests, 10 had bond ratings within his permissible range. Of the remaining nine, all had bond ratings *above* Mr. Hill's required range, indicating *less* – not more – investment risk. Considering that credit ratings provide the most widely referenced benchmark for investment risks, a comparison of this objective risk indicator demonstrates that the risks of the companies eliminated under the subjective criteria proposed by Mr. Hill are either identical to, or less risky, than the companies included in his sample group.

---

[80] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utility Reports* (1994) at 81.
[81] Hill Direct at 36.

Q. WHAT DO YOU CONCLUDE FROM THIS REVIEW OF CREDIT RATINGS?

A. Contrary to the allegations of Mr. Hill, comparisons of objective, published indicators that incorporate consideration of a broad spectrum of risks confirm that there is no link between the subjective tests he applied to define his proxy groups and the risk perceptions of investors.

Q. APART FROM BOND RATINGS, WHAT OTHER EVIDENCE INDICATES THAT MR. HILL'S CONCLUSIONS ARE BASELESS?

A. While Mr. Hill asserts that my proxy group is tainted by "additional unregulated company risk,"[82] this conclusion is contradicted by the very same risk benchmarks referenced in his testimony. As discussed subsequently, Mr. Hill cited S&P's *business profile* rank as an indicator of relative business risk. The average *business profile* rank for the firms in my proxy group is "6", which is identical to the rank for APS reported by Mr. Hill (p. 28). Again, this objective indicator cited by Mr. Hill confirms my conclusion that the risks of the companies in my proxy group are comparable to those of APS.

Q. WHAT ERRORS AND INCONSISTENCIES ARE ASSOCIATED WITH THE PROXY GROUP PROPOSED BY MR. HILL?

A. First, Mr. Hill screened all electric and combination electric and gas utilities followed by Value Line, with five of his reference utilities being engaged in both electric and gas utility operations.[83] Nevertheless, Mr. Hill based his revenue test solely on <u>electric</u> revenues and ignored the impact of other regulated activities, such as gas utility operations. Considering that Mr. Hill presented no explanation or evidence to suggest that the risks and required returns for other rate regulated

---

[82] *Id.* at 54.

[83] *Id.* at Schedule 3.

operations are significantly different than for electric utilities, his failure to include the impact of other utility operations in implementing his revenue test is misleading.

For example, consider Avista Corporation ("Avista"), which Mr. Hill excluded from his reference group based solely on his revenue test.[84] Avista reported in its 2005 Form-10K report (Note 29) that it has three operating segments, with its Avista Utilities segment making up "total regulated utility operations."[85] Avista reported that operating revenues from its regulated utility segment totaled approximately $1.16 billion, or 83% of total operating revenues of $1.40 billion. Similarly, Puget Energy, Inc. informed investors that it "operates in one business segment referred to as the regulated utility segment," with revenues from utility operations making up virtually 100% of total revenues in 2005.[86]

Q. ARE THERE OTHER PROBLEMS ASSOCIATED WITH THE CRITERIA PROPOSED BY MR. HILL?

A. Yes. Due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as total revenues, between utility and non-utility sources. Consider the example of Dominion Resources, Inc. ("Dominion"), which Mr. Hill excluded from his sample group based on his contention that only 30% of Dominion's revenues were from electric utility sources. However, this 30% figure used to apply Mr. Hill's electric revenue criteria is unrelated to the actual percentage of regulated revenues for Dominion, which classifies its operations into four primary segments – Dominion

---

[84] See Hill Direct at Schedule 3.

[85] Avista Corporation, Form 10-K Report (2005) at 110.

[86] Puget Energy, Inc., Form 10-K Report (2005) at Note 22.

Delivery, Dominion Energy, Dominion Generation and Dominion Exploration & Production.

Dominion Delivery includes regulated electric and gas distribution and customer service business, as well as nonregulated retail energy marketing operations. Similarly, Dominion Energy includes tariff-based electric transmission, natural gas pipeline, and natural gas storage businesses subject to varying degrees of rate regulation. Meanwhile, Dominion Generation includes the generation operations for both the electric utility and merchant power generation operations. As a result, even ignoring the fact that there is no clear link between the source of a utility's revenues and investors' risk perceptions, it is not possible to accurately apply Mr. Hill's criteria.

Q. WHAT OTHER INCONSISTENCIES ARE REFLECTED IN MR. HILL'S REFERENCE GROUP?

A. While Mr. Hill purports to include only those utilities with credit ratings between "A-"and "BBB-", three of the companies included in his reference group are actually rated below investment grade. As noted earlier, S&P downgraded its corporate credit rating for Central Vermont from "BBB-" to "BB+" in June 2005.[87] Similarly, in a recent review of utility credit ratings, S&P noted that DPL, Inc., another of Mr. Hill's proxy firms, is currently rated below investment grade at "BB+".[88] Finally, Unisource Energy, Inc. ("Unisource") reported that Moody's Investors Service ("Moody's) has assigned it a rating of "Ba2".[89] While S&P does not publish ratings for Unisource, it has assigned a corporate credit rating of "BB"

---

[87] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (June 14, 2005).

[88] Standard & Poor's Corporation, "Issuer Ranking: U.S. Utility And Power Companies, Strongest to Weakest," *RatingsDirect* (Aug. 4, 2006).

[89] http://ir.uns.com/ratings.cfm (retrieved Sep. 7, 2006).

to Unisource's principal subsidiary, Tucson Electric Power.[90] Given the financial and operating challenges that typically lead to below-investment grade, or "junk" bond ratings, such firms hardly exemplify the "steady-state" required by Mr. Hill's theoretical DCF application.

Finally, while Mr. Hill indicated on his Schedule 3 that he excluded companies involved in a pending merger, Green Mountain Power Corporation announced on June 22, 2006 that it has entered into an agreement to be acquired by Northern New England Energy Corporation.[91] Accordingly, apart from the problems inherent in Mr. Hill's revenue test, there are other inconsistencies in Mr. Hill's application of his proxy group criteria.

B. Risk Premium Approach

Q. IS MR. HILL'S APPLICATION OF THE CAPM CONSISTENT WITH THE ASSUMPTIONS UNDERLYING THIS METHOD?

A. No. As explained in response to Mr. Parcell earlier, the CAPM is a forward-looking model that must be applied using data that reflects the expectations of actual investors in the market. However, while Mr. Hill noted that "[c]ost of capital analysis is a decidedly forward-looking, or *ex-ante*, concept,"[92] like Mr. Parcell, his application of the CAPM method was entirely premised on *historical* – not projected – rates of return. As I noted earlier and wish to re-emphasize, by failing to look directly at the returns investors are currently requiring in the capital

---

[90] *Id.*

[91] "Green Mountain Power Corporation to be Acquired by Northern New England Energy Corporation, a subsidiary of Gas Metro Limited Partnership," *News Release* (June 22, 2006).

[92] Hill Direct at Appendix D, p. ii.

markets, as I did on Attachment WEA-6 to my Direct Testimony, Mr. Hill's CAPM estimate significantly understates investors' required rate of return.

Q. WAS MR. HILL JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE CAPM?

A. No. As discussed earlier in response to Mr. Parcell, under the realized rate of return approach, the arithmetic mean risk premium provides the best estimate of what investors might expect in future periods. Because the geometric average is lower than the arithmetic average, his reference to geometric average rates of return ensures that his cost of equity estimates will be significantly understated. Professor Jeremy Siegel, who Mr. Hill cited at page 11 of his testimony, found a differential of 2.0% between the geometric and arithmetic mean,[93] which is also consistent with the findings of Ibbotson Associates.[94]

Q. DOES MR. HILL'S CAPM ANALYSIS ACCURATELY REFLECT THE RISK PREMIUM DATA REPORTED BY IBBOTSON ASSOCIATES?

A. No. Like Mr. Parcell, while Mr. Hill claims to premise his analysis on data from Ibbotson Associates, he chooses to ignore the market risk premium reported directly from this source. As noted earlier, Ibbotson Associates reports that the long-horizon equity risk premium based on realized returns between 1926 and 2005 is 7.1%, versus the 6.5% and 4.9% figures used by Mr. Hill.[95] Again, this 7.1% risk premium is consistent with the 7.2% market risk premium from Ibbotson Associates adopted by the ACC Staff and used on Attachment WEA-7 to my Direct Testimony, only updated for an additional year of information.

---

[93] Siegel, Jeremy J., "Perspectives on the Equity Risk Premium," *Financial Analysts Journal*, Vol. 61, No. 6, (Nov./Dec. 2005) at 69.

[94] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, 2006 Yearbook*, at 31.

[95] Hill Direct at Schedule 8.

Q. DO MR. HILL'S APPLICATIONS OF THE CAPM PROVIDE A MEANINGFUL GUIDE TO INVESTORS' REQUIRED RATE OF RETURN FOR APS?

A. No. Mr. Hill's CAPM results are biased downward for a number of important reasons. As indicated above, his analysis ignored investors' current expectations and focused entirely on historical data. In addition, Mr. Hill's reliance on geometric mean returns is inconsistent with using the CAPM to estimate the cost of equity and produced understated results. Finally, although Mr. Hill referenced data from Ibbotson Associates, his CAPM analysis did not incorporate the market risk premium reported by this source.

Q. DO YOU AGREE WITH MR. HILL THAT IT IS NOT APPROPRIATE TO CONSIDER EXPECTED INCREASES IN CAPITAL COSTS WHEN ESTABLISHING THE ALLOWED ROE FOR APS?

A. No. While Mr. Hill grants that yields "are likely to move slightly higher," he argues that any expectation of higher rates should be ignored when estimating investors' required return "because current interest rates best represent investors' current expectations for the future."[96] But consideration of interest rate forecasts does not presume that financial markets are wrong; rather, it recognizes that investors' required returns can and do shift over time with changes in capital market conditions. In fact, it is this very realization, and the general expectation that long-term capital costs will move higher, that warrants consideration of widely referenced forecasts of future bond yields. Indeed, as I noted earlier, bond yields have increased significantly since the analyses contained in my Direct Testimony were prepared.

---

[96] *Id.* at 18 and 59-60.

As discussed in greater detail subsequently, utilities such as APS must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments if they are to maintain their financial flexibility and ability to attract capital. Expected capital market conditions during the time when rates established in this proceeding will be in effect are certainly one very valid barometer in ensuring that this fundamental economic and regulatory test is met.

Q. HAS YOUR OPINION CONCERNING THE USEFULNESS OF RISK PREMIUM METHODS CHANGED OVER TIME, AS CLAIMED BY MR. HILL?

A. No. On pages 60-61 of his testimony, Mr. Hill quotes from an affidavit I filed before the Federal Communications Commission ("FCC").[97] Then, as now, my position is that there is no infallible quantitative method to estimate the cost of equity. All of the available tools, including DCF and risk premium methods, must be used carefully and with common sense.

Because of the unobservable nature of cost of equity and the complexities of capital markets, I have consistently taken the position that no one quantitative method of estimating the cost of equity should be accepted without testing the reasonableness of the results against other methods. Indeed, Mr. Hill's use of multiple methods suggests that he agrees with this fundamental principle, although, as discussed earlier, he failed to follow it to any significant degree.

In Docket No. 84-800, the FCC proposed to use a risk premium formula to adjust the prescribed rate of return. My testimony in that case was that no <u>single</u> risk premium application should be relied upon in isolation. It was not that risk

---

[97] *In the Matter of Authorized Rates of Return for the Interstate Services of AT&T Communications and Exchange Telephone Carriers*, CC Docket No. 84-800.

premium methods are useless, as Mr. Hill insinuates by quoting me out of context, but that each method of estimating equity risk premium suffers from some infirmity that limits its suitability for the type of "automatic pilot" rate of return determination that was being considered by the FCC.

Q. IS THERE ANYTHING WRONG WITH THE EQUITY RISK PREMIUM IN YOUR FORWARD-LOOKING CAPM ANALYSIS (ATTACHMENT WEA-6)?

A. No. As explained in my Direct Testimony, I estimated the current equity risk premium by first applying the DCF model to estimate investors' current required rate of return for the firms in the S&P 500 and then subtracting the yield on government bonds. Mr. Hill (p. 65-66) contends that this CAPM analysis is flawed because of an alleged upward bias in the market risk premium. In fact, however, the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. For example, in "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts" [*Journal of Applied Finance*, Vol. 11 No. 1, 2001], Robert S. Harris and Felicia C. Marston employed the DCF model and earnings growth projections from IBES – just as I did in Attachment WEA-6 to my Direct Testimony. Moreover, as noted earlier, the approach I used in Attachment WEA-6 is directly analogous to that relied on by the ACC Staff and recently adopted by the Commission.[98]

Mr. Hill's complaints about my forward-looking CAPM approach seem to hinge on the fact that this method produces an equity risk premium for the S&P 500 that is considerably higher than the unrealistic benchmarks he cites. But as I explained earlier, the benchmarks cited by Mr. Hill fail even the most rudimentary tests of

---

[98] Decision No. 68858, *Arizona American Water Company*, Docket No. W-01303A-05-0405 (July 28, 2006).

economic logic. Estimating investors' required rate of return by reference to current, forward-looking data, as I have done, is entirely consistent with the theory underlying the CAPM methodology, which is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of required rates of return, the CAPM is best-applied using data that reflects the expectations of actual investors in the market. Rather than look backwards to risk premiums based on historical data, as Mr. Hill advocates, my analysis appropriately focused on the expectations of actual investors in today's capital markets.

C. Other Methods

Q IS THERE ANY SUBSTANCE TO MR. HILL'S MODIFIED EARNINGS-PRICE RATIO ("MEPR") ANALYSIS?

A. None whatsoever. First, it is worth noting that, as far as I am aware, Mr. Hill is alone in referencing the earnings/price ratio approach and this method has rarely, if ever, been used to establish the cost of equity in regulatory proceedings. Second, while Mr. Hill's statement that the earnings-price ratio understates the cost of equity when the utility's market-to-book ratio is greater than one is generally correct,[99] this simply confirms that the earnings/price ratio provides no guidance as to investors' actual required return.

Moreover, there is absolutely no theoretical justification for Mr. Hill's <u>averaging</u> the earnings-price ratio with a rate of return on book equity, either current or expected, as he did in his Schedule 10. This combination of apples and oranges is meaningless and provides no guide as to the expectations of actual investors. Nor

[99] Hill Direct at Appendix D, p. ix.

is such an averaging justified today, notwithstanding that the FERC may have utilized the expected rate of return on book value over twenty years ago as a check of reasonableness in establishing an upper bound to investors' required rate of return. Given the fact that Mr. Hill's MEPR analysis is fatally flawed and provides no information regarding the cost of equity for APS, it should be completely rejected by the ACC.

Q. DOES MR. HILL'S MARKET-TO-BOOK RATIO ("MTB") ANALYSIS PROVIDE ANY NEW OR ADDITIONAL INFORMATION AS TO THE RATE OF RETURN REQUIRED BY INVESTORS FROM HIS PROXY GROUP OF UTILITIES?

A. Absolutely none. As Mr. Hill acknowledged:

> This method is derived algebraically from the DCF model and, therefore, cannot be considered a strictly independent check of that method.[100]

That Mr. Hill's MTB analysis is nothing more than a restatement of his previous DCF analysis is also evident from his exhibits. In particular, there is little difference between Mr. Hill's average cost of equity of 9.44% using his DCF method[101] and the 9.31% using his MTB method based on Value Line's projections.[102] This similarity is not because the results of two different methods are converging, but because the DCF and MTB methods are essentially the same, only packaged slightly differently. And just as Mr. Hill's DCF analysis is fundamentally flawed because it is tied to tautological DCF theory rather than investors' actual expectations, so too is his MTB analysis since it is derived from the very same theoretical model and uses virtually identical inputs.

---

[100] *Id.* at Appendix D, p. x.
[101] *Id.* at Schedule 7.
[102] *Id.* at Schedule 11.

Q. PLEASE COMMENT ON THE TABLE DISPLAYED ON PAGE 42 OF MR. HILL'S TESTIMONY.

A. While at first blush this table might suggest that Mr. Hill performed four different analyses that all indicated a cost of equity for his sample group falling within a fairly narrow range, this is not the case. As discussed earlier, Mr. Hill's CAPM analyses are flawed because they include geometric mean risk premiums, do not reflect the most recent market risk premium reported by his own source, and ignore investors' current expectations. Moreover, Mr. Hill's DCF and MTB analyses are, for all intents and purposes, one and the same and his MEPR analysis is meaningless, since he averaged "apples and oranges" to arrive at the values shown.

Q. DID MR. HILL INCLUDE AN ADJUSTMENT TO RECOGNIZE COMMON STOCK FLOTATION COSTS IN HIS RECOMMENDED FAIR RATE OF RETURN ON EQUITY?

A. No. Mr. Hill asserted (pp. 47-49) that an adjustment for flotation costs was unnecessary because:

- Electric utility common stocks are selling above book value;
- Issuance expenses are not out-of-pocket expenses;
- Because the amount of underwriter's fees is disclosed, investors have already accounted for issuance costs in their expectations;
- His DCF growth rate included an upward adjustment to recognize expectations of stock sales above book value; and,
- "Research" has shown that an adjustment for issuance expenses is unnecessary.

Q. DO THESE FIVE ASSERTIONS JUSTIFY MR. HILL'S DECISION TO IGNORE FLOTATION COSTS IN DETERMINING HIS RECOMMENDED RATE OF RETURN FOR APS?

A. No. While Mr. Hill's first observation about market-to-book ratios may be factually correct, it says nothing about whether or not a flotation cost adjustment is

warranted for APS. The fact that market prices are above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. In fact, even if APS is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issues of common stock.

Mr. Hill's second argument that flotation costs "are not out-of-pocket expenses" is simply wrong. Indeed, Mr. Parcell's review of flotation cost adjustments specifically noted that [i]ssuance costs are the *out-of-pocket* costs directly associated with the public offering of new shares."[103] Mr. Hill apparently believes that if investors in past common stock issues had paid the full issuance price directly to APS and APS had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Mr. Hill's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

Next, Mr. Hill argues that flotation costs have somehow already been accounted for in the price investors are willing to pay for new common stock. *Regulatory Finance: Utilities' Cost of Capital* noted that this double-counting argument is fallacious, concluding that:

> The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on

---

[103] Parcell, D. C., "The Flotation Cost Adjustment To Utility Cost of Common Equity, Theory, Measurement, and Implementation" *National Society of Rate of Return Analysts*, Twenty-Fifth Financial Forum (Apr. 28, 1993) at 3 (emphasis added).

> its reduced rate base in order to produce a return equity to that required by shareholders.[104]

With respect to his contention that his DCF growth rate included an upward adjustment to recognize future sales of common stock above book value, the growth investors might expect resulting from sales of new stock above book value is a completely different issue than past or future flotation costs paid to third parties. While this "sv" growth component is properly considered in establishing investors' expectations when applying the DCF model, it in no way compensates for the impact of stock issuance costs.

Finally, contrary to Mr. Hill's assertions, the necessity of an adjustment for past flotation costs has been recognized in the literature. For example, in an article entitled "Common Equity Flotation Costs and Rate Making" published in *Public Utilities Fortnightly* (May 2, 1985), E.F. Brigham, D.A. Aberwald, and L.C. Gapenski demonstrate that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings. Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the

---

[104] Morin, Roger A., *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Reports (1994) at 174.

> initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[105]

Finally, as noted earlier in response to Mr. Parcell, Ibbotson Associates, a source referenced repeatedly by Mr. Hill, noted that a flotation adjustment is properly considered in establishing the ROE for regulated utilities.

D. Capital Structure

Q. WHAT WAS THE CRUX OF MR. HILL'S ARGUMENT FOR A LOWER COMMON EQUITY RATIO?

A. Mr. Hill's recommendation to rejected APS' requested capital structure was based primarily on his contention that 1) APS' requested capital structure is different than its historical capitalization, 2) differences in business risk justify a lower equity ratio for APS, and 3) APS' requested capitalization is not consistent with industry benchmarks.

Q. DO MR. HILL'S ARGUMENTS CONCERNING APS' HISTORICAL CAPITAL STRUCTURE HAVE ANY MERIT?

A. No. First, it is worth noting that APS' requested equity ratio is not inconsistent with the capitalization maintained by the Company in the past. As shown on Mr. Hill's Schedule 2, APS maintained an average equity ratio over the five quarters reflected in his table of 51.46%. More importantly, however, Mr. Hill's observations regarding APS' capital structure in 2003 and 2004 simply are irrelevant in this proceeding. Historical ratios do not provide a basis to determine a reasonable capitalization for APS going forward, especially considering what is

---

[105] *Id.* at 175.

required to maintain the Company's financial integrity in the face of weakened credit ratings and the challenges of raising the capital necessary to support its enormous investment requirements.

Mr. Hill's observation (p. 24) that APS "maintained investment-grade bond ratings" in the past is cold comfort considering Moody's recent decision to downgrade APS and Pinnacle West, in part due to "deterioration in key financial metrics."[106] Moody's went on to conclude that, because of regulatory uncertainties, "Moody's would look for APS to have financial metrics that are somewhat stronger than comparably rated utility operating companies."[107] Similarly, S&P recently observed that a key financial ratio for APS fell below the benchmarks established for a triple-B rating in 2005 and noted that "[a] negative rating change or outlook could result if leverage and cash flow metrics come under additional pressure."[108]

Q. SHOULD MR. HILLS ASSERTIONS CONCERNING THE RELATIVE RISKS OF APS AND PINNACLE WEST BE CONSIDERED IN EVALUATING A REASONABLE CAPITAL STRUCTURE IN THIS PROCEEDING?

A. No. First, the issue at hand is the determination of a capitalization and ROE that will meet the regulatory requirements of allowing investors an opportunity to earn a fair return while preserving APS' financial integrity and ability to access the capital markets on reasonable terms. As supported in my Direct Testimony, the testimony of APS' witnesses, and the testimony of Mr. Parcell, the Company's

---

[106] Moody's Investors Service, "Moody's Downgrades Pinnacle West (Issuer Rating to Baa3) and Arizona Public Service (Sr. Uns. To

[107] Moody's Investors Service, "Credit Opinion: Arizona Public Serivce Company," *Global Credit Research* (May 9, 2006).

[108] Standard & Poor's Corporation, "Bulletin: ACC Staff Recommendation Has No Immediate Effect On Arizona Public Service Co. Rtg," *RatingsDirect* (Aug. 22, 2006).

requested capitalization is reasonable and consistent with these objectives and with industry benchmarks and investors' expectations.

Aside from the fact that the relative business risk of Pinnacle West is nothing more than a "red herring," Mr. Hill has presented no evidence to support his assertion that "Pinnacle West has higher business risk than APS."[109] In fact, the key measure of business risk – S&P's *business profile* ranking – cited by Mr. Hill contradicts his conclusion. While Mr. Hill noted that "S&P currently assigns APS a business profile score of 6,"[110] he failed to report that S&P has also assigned Pinnacle West *the exact same* ranking.[111] In other words, according to Mr. Hill's own benchmark, the business risks of Pinnacle West and APS are identical. Similarly, S&P's credit ratings, which consider both relative and business risks, are identical for Pinnacle West and APS. Mr. Hill's comparison between APS and "the highest risk, energy trading companies" is nothing more than a straw man and his arguments concerning relative risk and cross-subsidization should be ignored in their entirety.

Q. DO THE INDUSTRY CAPITALIZATION RATIOS THAT MR. HILL DERIVED REPRESENT A MEANINGFUL BENCHMARK FOR APS IN THIS CASE?

A. No. While APS's capital structure consists solely of long-term debt and common equity, Mr. Hill argued (p. 31) that short-term debt should be considered when comparing the Company with other electric utilities. Mr. Hill is wrong.

---

[109] Hill Direct at 28.

[110] *Id.*

[111] Standard & Poor's Corporation, "Issuer Ranking: U.S. Utility And Power Companies, Strongest To Weakest," *RatingsDirect* (Aug. 4, 2006).

Q. WHY IS IT WRONG TO CONSIDER SHORT-TERM DEBT IN ESTABLISHING A CAPITAL STRUCTURE FOR APS, AS MR. HILL ADVOCATES?

A. Aside from the fact that Mr. Hill documents the absence of short-term debt in the Company's capitalization,[112] the facilities that APS employs to provide electric utility service are long-lived assets. In order to match the nature of APS' investment in plant and equipment, the capital structure should consist of permanent capital – long-term debt and common equity. Short-term debt is generally not viewed as part of the permanent capital used to finance investment in plant and equipment and is properly excluded in calculating the overall rate of return. Indeed, short-term debt is typically used to meet seasonal working capital needs, and may also be used to finance capital improvements until a sufficient balance has accumulated to economically issue common stock or long-term debt.

Q. DOES THE SIMPLE FACT THAT A UTILITY MAY HAVE SHORT-TERM DEBT OUTSTANDING AT A POINT IN TIME MEAN THAT IT SHOULD BE INCLUDED WHEN EVALUATING THE CAPITAL STRUCTURE?

A. No. For most utilities, short-term debt balances fluctuate depending on seasonal or other operating or financial requirements and the amount outstanding can vary considerably over time. Moreover, financing policies and practices vary widely among utilities. While isolated utilities may rely fairly heavily on short-term debt as a source of financing, others have little or no short-term debt outstanding, consistent with APS' requested capital structure.

For example, consider Xcel Energy, which Mr. Hill claimed "has approximately $1.5 billion in short-term debt." In contrast, Xcel Energy reported in its June 30, 2006 Form 10-Q report that short-term debt balances totaled only $138 million, or

---

[112] Hill Direct at Schedule 2, p. 1.

a decline of over 90% from Mr. Hill's benchmark. This evidences that short-term debt is not used as a permanent source of financing for electric utilities and should not be regarded as part of the capital structure for regulatory purposes.

Q. WHAT OTHER SPECIFIC PROBLEMS ARE ASSOCIATED WITH THE INDUSTRY BENCHMARKS MR. HILL USED TO EVALUATE APS' CAPITAL STRUCTURE?

A. The industry common equity ratios that Mr. Hill cites as benchmarks are distorted and inconsistent with the premise of the capitalization he derived for APS. For example, Hawaiian Electric Industries' ("HEI") June 30, 2006 Form 10-Q Report reflected the following capital structure balances:

Component	$ (Mil)	Percent
Short-term Borrowings	$ 296.5	11.5%
Long-term Debt	1,033.1	40.2%
Preferred Stock	34.3	1.4%
Common Equity	1,205.1	46.9%
Total	$2,569.0	100.0%

But in contrast to the 46.9% equity ratio reflected above, Mr. Hill reported an equity ratio of 37% for HEI.[113] The only possible explanation for the vastly lower equity ratio relied on by Mr. Hill is that it considered short-term deposit liabilities associated with HEI's unregulated banking subsidiaries. Of course, this directly contradicts Mr. Hill's position that the impact of non-regulated activities should not be considered when establishing the ROE for APS.

Meanwhile, the average capital structure ratios presented by Mr. Hill are also distorted because they include downward-biased equity ratios associated with

[113] *Id.* at Schedule 2, p. 4.

speculative grade companies. For example, consider the equity ratios in the table below:

Company	Equity Ratio
Allegheny Energy	31%
CMS Energy	22%
Sierra Pacific Resources	32%
TECO Energy	29%
Unisource Energy	32%

S&P has assigned a corporate credit rating of "B" to Sierra Pacific Resources, with the remaining companies being rated double-B. With respect to CMS Energy, for example, S&P observed that an impairment charge related to a cogeneration venture had caused the company to fail coverage tests specified by its first mortgage bonds and led to a drastic decline in common equity:

> The action reflects the charge's negative impact on the balance sheet, because it cuts common equity about 14% and considerably boosts leverage just as CMS needs to continue improving its overall financial profile to levels more commensurate with current ratings [114]

The financial ratios of utilities with "junk" ratings simply have no place in an evaluation of an appropriate capital structure and fair rate of return for APS. By including capital structure ratios for utilities under financial stress, Mr. Hill perpetuates the downward bias that characterizes his conclusions.

Q. WHAT DID YOU CONCLUDE REGARDING THE REASONABLENESS OF APS'S REQUESTED EQUITY RATIO?

A. Considering APS' ongoing efforts to improve its financial standing, and the need to support the Company's financial flexibility, there is no justification for Mr. Hill's recommendation to depart from APS' proposed capital structure. The decision of

---

[114] "S&P puts CMS Energy, Consumers Energy on CreditWatch, negative," *Platts Commodity News* (Nov. 1, 2005).

S&P and Fitch to downgrade Central Vermont from triple-B to below investment grade highlights the importance of maintaining sufficient common equity to preserve the utility's creditworthiness, even during times of stress. Despite a common equity ratio that exceeds 60%, S&P and Fitch determined that Central Vermont's financial position was inadequate to support an investment grade rating in the face of an unfavorable regulatory order.[115]

APS' proposed capital structure is just one reflection of the Company's ongoing efforts to enhance its credit standing and maintain access to capital on reasonable terms in order to ensure its ability to meet its obligations to customers. The reasonableness of the Company's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, APS' relative risks and circumstances, the need to support continued system investment, and the imperative of maintaining continuous access to capital, even during times of adverse industry and market conditions. As the experience of Central Vermont illustrates, even a healthy equity cushion may not be sufficient to support a utility's credit ratings when investors perceive a lack of regulatory support.

VI. ATTRITION ADJUSTMENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section discusses the necessity of an attrition adjustment to meet the end result standards of *Hope* and *Bluefield.* There is one area of complete agreement between Mr. Parcell, Mr. Hill, and me – the allowed return should meet the end result test of being sufficient to maintain APS' financial integrity, preserve the

[115] "S&P Downgrades CVPS Corporate Credit Rating," *Business Wire* (June 14, 2005); "Fitch Ratings Downgrades CVPS," *Business Wire* (June 20, 2005).

Company's ability to attract capital, and provide investors with sufficient compensation for risk. While we disagree on what level of return investors' require given current market conditions, we seem united on the proposition that APS should have an opportunity to earn that market-based return. The economic reality, based on past experience and future projections, is that APS will in all likelihood suffer attrition so that actual returns will fall systematically short of the allowed return built into the rate order. In other words, allowed return will not translate into an opportunity for investors to earn that same return.

The amalgamated effect of growth, massive capital investment needs, and unrecovered costs combines with regulatory lag to prevent APS from having a realistic opportunity to earn whatever return is ultimately allowed by this Commission. In their Rebuttal Testimony, Mr. Brandt and Mr. Wheeler discuss attrition from the perspective of the Company's experience and projections. In this section, I examine the causes of attrition, the regulatory mechanisms to deal with attrition, and an adjustment to the allowed return to mitigate the impact of attrition from the perspective of a financial analyst and former regulator. Unless attrition is addressed, fine-tuning the determination of the market required return is a largely futile exercise. Investors and rating agencies look past the "sticker price" of the allowed return to end result of what the utility can reasonably be expected to earn.

Q. WHAT CAUSES ATTRITION?

A. Attrition is the deterioration of actual return below the allowed return that occurs when the relationships between revenues, costs, and rate base used to establish rates (e.g., using a historical test year) have changed by the time rates go into effect. For example, if external factors are driving costs to increase more than revenues, then the rate of return will fall short of the allowed return even if the

utility is operating efficiently. Similarly, when growth in the utility's investment outstrips the rate base used in the test year, the earned rate of return will fall below the allowed return through no fault of the utility's management. These imbalances are exacerbated as the regulatory lag increases between the time when the data used to establish rates is measured and the date when the rates go into effect.

Q. WHAT IS YOUR PERSONAL EXPERIENCE WITH ATTRITION?

A. I began studying regulatory finance and consulting with commissions in the early 1970's. Attrition was a recognized issue that could thwart a utility's ability to earn its allowed ROE, depending on the facts and circumstances of the particular utility. As fuel prices and inflation started to increase, attrition became a more pressing problem in many parts of the country. When I joined the staff of the Public Utility Commission of Texas ("PUCT") in 1977, the electric utilities operating in Texas were suffering from significant attrition that was threatening the ability of our jurisdictional companies to raise capital. There were a number of tools available to deal with attrition. The pass-through of all fuel and purchased power costs helped to attenuate attrition. Known and measurable changes to investment and costs could be factored into the historical test year so that there was less of a mismatch between expected cost and investment level and those used to set rates. We also processed rate cases as quickly as possible to reduce regulatory lag. To assure that the utilities had an opportunity to earn the return recommended by the PUCT staff, we would routinely project the utility's earnings after rates went into effect. If we found a deterioration in the return on equity and other financial indicators, the PUCT staff would recommend including construction work in progress ("CWIP") in rate base. If the inclusion of CWIP was insufficient to bring projected financial indicators to the levels necessary to maintain the utility's financial integrity, ability

to attract capital, while providing a return commensurate with risk, my staff would recommend an additional attrition allowance to insure that the *Hope* and *Bluefield* end result tests were met.

Throughout my career as a consultant and teacher, attrition has remained an issue that arises in particular circumstances of growth, rapidly expanding utility investment, rising costs, inflation, and regulatory lag. The problem has been less of an industry-wide problem as the levels of growth, new investment, and inflation for most utilities has moderated from that experience in the 1970's and 1980's. Yet attrition can still arise in particular circumstances, such as those faced now by APS. For example, in addressing the need to increase investment in the interstate transmission infrastructure, FERC has recognized that changes in ratemaking methods are necessary to attract capital to transmission companies and regional transmission organizations. Included in the policies adopted by FERC are methods designed to alleviate investors' concerns regarding the possible impact of attrition, such as pass-through of costs and provisions to include new investments in rates on a prospective basis.

Q WHY IS IT NECESSARY TO DEAL WITH ATTRITION?

A. Investors are concerned with what they can expect in the future, not what they might expect in theory if a historical test year were to repeat itself. To be fair to investors and to benefit customers, a regulated utility must have an <u>opportunity to actually earn</u> a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk. In other words, it is the end result in the future that determines whether or not the *Hope* and *Bluefield* standards embraced by Mr. Parcell, Mr. Hill, and me are met. Yet, Mr. Parcell and Mr. Hill examined a hypothetical end result in the theoretical world where the test year is repeated in the

future. Such a test is not relevant to the investors and rating agencies that will determine the ability of APS to attract the capital so necessary to assure continued reliable and economical electric service in Arizona.

Q. HAS THE INVESTMENT COMMUNITY RECOGNIZED THE RISKS ASSOCIATED WITH ATTRITION AND LAG IN ITS EVALUATION OF APS?

A. Yes. Earlier this year, S&P noted that the slow pace of regulatory adjustments in Arizona acts as a drag on utility finances, especially considering the pressures of high growth.[116] With respect to APS specifically, S&P reiterated that cash flows are "highly predicated on the outcome and timing of APS' pending rate case," and concluded that regulatory lag could result in depressed financial metrics and, ultimately, lower credit ratings.[117] Similarly, Moody's noted the weakness attributable to "below average assurance of timely recovery of costs and investments," observing that "APS' 2003 rate case was not concluded until April 2005," and "[a] fuel surcharge mechanism requested as part of the 2003 rate case was not implemented until February 2006."[118] Both rating agencies have clearly recognized the difficulties faced by APS in recovering necessary costs on a timely basis.

Q. WHAT ARE THE WAYS TO DEAL WITH ATTRITION?

A. For many utilities, the widespread adoption of pass-through clauses for fuel, purchased power, and other costs that were rising rapidly in the late 1970's and early 1980's helped to offset the impact of attrition. The use of future test years

---

[116] Standard & Poor's Corporation, "Credit Factors for U.S. Natural Gas Distributors," *RatingsDirect* (Feb. 28, 2006).

[117] Standard & Poor's Corporation, "Research Update: Arizona Public Service's $400 Million Bonds Rated BBB-," *RatingsDirect* (July 31, 2006).

[118] Moody's Investors Service, "Credit Opinion: Arizona Public Service Company," *Global Credit Research* (May 9, 2006).

and other forward-looking mechanisms is also useful in ameliorating the impact of attrition, as is inclusion of CWIP in rate base, particularly where financing an expensive generating plant addition is undermining a utility's financial indicators. Many jurisdictions have developed methods to attenuate regulatory lag, such as allowing interim rates, putting rates into effect subject to refund, as well as accelerating the administrative process to allow faster rate decisions. As a result of these measures, combined with the fall-off of inflation, growth, and new construction across the electric utility industry, attrition ceased to be a major regulatory issue by the mid-1980s.

Q. WHY DOES APS FACE ATTRITION NOW?

A. The unique circumstances of APS have led to an attrition problem just as severe as I observed for electric utilities in the turbulent decades of the 1970's and 1980's. APS is experiencing significant growth in customers and has to finance a huge capital investment program. Regulatory lag is also prevalent in Arizona. While the Commission's past constructive actions have been helpful in preventing APS' credit ratings from falling below investment grade pending the outcome of this case, attrition remains a major concern of the investment community. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. S&P noted that:

> When examining the quality of regulation, Standard & Poor's factors in what level of support the utility might get in times of distress, when its needs are most acute.[119]

---

[119] Standard & Poor's Corporation, "Regulation and Credit Quality in the U.S. Utility Sector," *RatingsDirect* (Jan. 30, 2003).

S&P went on to note the importance of financial flexibility, especially considering the capital markets' ability to constrict access to capital when investors' confidence is compromised.

Q. CAN AN ADJUSTMENT TO ALLOWED RETURN ON EQUITY BE USED TO OFFSET ATTRITION?

A. Yes. The allowed return can be set with a margin over the cost of capital so that when rates go into effect the utility has an opportunity to actually earn its cost of capital. That end result would maintain the utility's financial integrity, ability to attract capital and offer investors fair compensation for the risk they bear. Ibbotson Associates, a source used by Mr. Parcell, Mr. Hill, and me noted that adjustments to the allowed return may be appropriate, including the potential that "regulatory conditions may require that the allowed rate of return be different from the cost of capital."[120] In this case, adding an increment to the cost of equity is the most logical way to offset the effect of attrition and ensure that APS has the opportunity to actually earn the cost of equity capital. Schedule F1 (p. 116) of APS' January 31, 2006 filing projects a return on equity of 9.8% in 2007 <u>if the full rate request is granted.</u> As documented by Mr. Brandt, this calculation assumes that new rates become effective on January 1, 2007. I understand that the current schedule for this case may result in new rates that are not in effect until May 2007. But even under a scenario where new rates are effective at the beginning of 2007 and the Company's full rate full rate request is granted, the projected earned return will fall 170 basis points below the allowed return. Thus, 170 basis points is the minimum attrition adjustment to the cost of equity in order to achieve a fair rate of return that would meet the *Hope* and *Bluefield* standards. Moreover, Mr. Brandt

---

[120] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, 2006 Yearbook, Valuation Edition* at 35.

calculates that the return on equity will fall further in 2008, confirming the absolute minimum attrition adjustment indicated by Schedule F1 of 170 basis points. Given the likely timing of rate relief and the dynamics faced by APS, there is every reason to believe that attrition would overcome the minimum adjustment and APS would still not earn its cost of capital. Further, as demonstrated by Mr. Brandt, if the Staff or RUCO's proposals are accepted, a much higher adjustment is required to meet financial integrity, capital attraction, and investor compensation standards.

The Supreme Court recently reaffirmed that the end result test must be applied to the actual returns that investors expect if they put their money at risk to finance utilities.[121] This end result can only be achieved for APS if the allowed return is sufficient to offset the impact of attrition. Thus, whatever the Commission ultimately determines to be investors' required return, the only way to achieve that end result is to make an attrition adjustment sufficient to give APS an opportunity to actually earn that ROE in the future.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

---

[121] *Verizon Communications, et al v. Federal Communications Commission, et al*, 535 U.S. 467 (2002). While I cannot comment of the legal significance of this case, I found the economic wisdom of looking to the reasonable expectations of actual investors compelling. I understand that as a fair value state, Arizona law may have requirements beyond the *Hope* and *Bluefield* end-result tests. But economic logic and common sense confirm that a utility cannot attract capital on reasonable terms if investors expect future returns to fall short of those offered by comparable investments.

ALLOWED ROE

PARCELL & HILL GROUPS

	Allowed ROE
Parcell Proxy Group	
Cleco Corp.	12.25%
DTE Energy	11.00%
Energy East	10.77%
Hawaiian Electric	10.82%
Pinnacle West	--
PNM Resources	10.33%
Puget Energy	10.30%
Average	**10.91%**
Hill Proxy Group	
Central Vermont PS	10.00%
FirstEnergy Corp.	9.75%
Green Mountain Pwr	10.50%
Progress Energy	12.42%
Ameren Corp.	10.92%
Cleco Corp.	12.25%
DPL, Inc.	11.00%
Empire District	11.00%
Entergy Corp.	10.97%
Hawaiian Electric	10.82%
PNM Resources	10.33%
Pinnacle West	--
Unisource Energy	10.67%
Average	**10.89%**

Source: *AUS Monthly Utility Report* (June 2006). Provided in response to APS/STAFF/WEA 3.10.

MULTI-STAGE DCF MODEL

PARCELL REFERENCE GROUP

Company	(a) Recent Price	(a) 2006 Div.	(a) 2007 Div.	(a) 2009-11 Div.	(b) Annual Change	(c) Terminal Growth	Annual Cash Flows Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	End Yr 5	(d) Implied Cost of Equity
Cleco Corp.	$22.00	$ 0.90	$ 0.90	$ 1.00	$ 0.03	6.8%	$0.45	$0.90	$0.93	$0.97	$1.00	$29.10	10.5%
DTE Energy	$39.93	$ 2.06	$ 2.06	$ 2.10	$ 0.01	6.8%	$1.03	$2.06	$2.07	$2.09	$2.10	$52.18	11.1%
Energy East	$22.55	$ 1.18	$ 1.24	$ 1.40	$ 0.05	6.8%	$0.59	$1.24	$1.29	$1.35	$1.40	$29.73	11.8%
Hawaiian Electric	$28.10	$ 1.24	$ 1.24	$ 1.24	$ -	6.8%	$0.62	$1.24	$1.24	$1.24	$1.24	$36.83	10.4%
Pinnacle West Capit	$43.44	$ 2.03	$ 2.13	$ 2.43	$ 0.10	6.8%	$1.02	$2.13	$2.23	$2.33	$2.43	$57.45	11.3%
PNM Resources Gro	$27.13	$ 0.86	$ 0.92	$ 1.10	$ 0.06	6.8%	$0.43	$0.92	$0.98	$1.04	$1.10	$36.20	10.0%
Puget Energy, Inc.	$22.40	$ 1.00	$ 1.00	$ 1.10	$ 0.03	6.8%	$0.50	$1.00	$1.03	$1.07	$1.10	$29.55	10.8%
Average													10.8%

(a) The Value Line Investment Survey (June 2, June 30, & Aug. 11, 2006).
(b) Annual change in dividend between 2007 and 2009-11.
(c) Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405, at Schedule DRR-8.
(d) Discount rate that equates the present value of cash flows in years 1-5 with Recent Price.

	(a)	(b)	(c)	(d)
Parcell Reference Group	**Risk-free Rate**	**Beta**	**Risk Premium**	**Cost of Equity**
Cleco Corp.	5.3%	1.25	7.57%	14.8%
DTE Energy	5.3%	0.75	7.57%	11.0%
Energy East	5.3%	0.90	7.57%	12.1%
Hawaiian Electric	5.3%	0.70	7.57%	10.6%
Pinnacle West	5.3%	1.00	7.57%	12.9%
PNM Resources	5.3%	1.00	7.57%	12.9%
Puget Energy	5.3%	0.80	7.57%	11.4%
Average				**12.2%**
Avera Reference Group				
Black Hills Corp.	5.3%	1.10	7.57%	13.6%
Edison International	5.3%	1.10	7.57%	13.6%
Hawaiian Electric	5.3%	0.70	7.57%	10.6%
IDACORP, Inc.	5.3%	1.00	7.57%	12.9%
MDU Resources Grou	5.3%	1.00	7.57%	12.9%
PNM Resources Grou	5.3%	1.00	7.57%	12.9%
Pinnacle West Capital	5.3%	1.00	7.57%	12.9%
Puget Energy, Inc.	5.3%	0.80	7.57%	11.4%
Sempra Energy	5.3%	1.05	7.57%	13.2%
Xcel Energy	5.3%	0.90	7.57%	12.1%
Average				**12.8%**

(a) Parcell Direct at Schedule 10.
(b) The Value Line Investment Survey, *Summary & Index* (Aug. 25, 2006).
(c) Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405 at 31.
(d) (a) + (b) x (c).

	(a)	(b)	(c)	(d)
Parcell Reference Group	**Risk-free Rate**	**Beta**	**Risk Premium**	**Cost of Equity**
Cleco Corp.	5.3%	1.25	7.1%	14.2%
DTE Energy	5.3%	0.75	7.1%	10.6%
Energy East	5.3%	0.90	7.1%	11.7%
Hawaiian Electric	5.3%	0.70	7.1%	10.3%
Pinnacle West	5.3%	1.00	7.1%	12.4%
PNM Resources	5.3%	1.00	7.1%	12.4%
Puget Energy	5.3%	0.80	7.1%	11.0%
Average				**11.8%**
Avera Reference Group				
Black Hills Corp.	5.3%	1.10	7.1%	13.1%
Edison International	5.3%	1.10	7.1%	13.1%
Hawaiian Electric	5.3%	0.70	7.1%	10.3%
IDACORP, Inc.	5.3%	1.00	7.1%	12.4%
MDU Resources Grou	5.3%	1.00	7.1%	12.4%
PNM Resources Grou	5.3%	1.00	7.1%	12.4%
Pinnacle West Capital	5.3%	1.00	7.1%	12.4%
Puget Energy, Inc.	5.3%	0.80	7.1%	11.0%
Sempra Energy	5.3%	1.05	7.1%	12.8%
Xcel Energy	5.3%	0.90	7.1%	11.7%
Average				**12.1%**

(a) Parcell Direct at Schedule 10.

(b) The Value Line Investment Survey, *Summary & Index* (Aug. 25, 2006).

(c) Arithmetic mean risk premium on Large Company Stocks from 1926-2005 reported by Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at Appendix C, Table C-

(d) (a) + (b) x (c).

MULTI-STAGE DCF MODEL

HILL REFERENCE GROUP

Company	(a) Recent Price	(a) 2006 Div.	(a) 2007 Div.	(a) 2009-11 Div.	(b) Annual Change	(c) Terminal Growth	Annual Cash Flows Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	End Yr 5	(d) Implied Cost of Equity
Central Vermont PS	$17.25	$ 0.92	$ 0.92	$ 0.92	$ -	6.8%	$0.46	$0.92	$0.92	$0.92	$0.92	$22.48	11.2%
FirstEnergy Corp.	$52.02	$ 1.82	$ 1.94	$ 2.30	$ 0.12	6.8%	$0.91	$1.94	$2.06	$2.18	$2.30	$69.31	10.3%
Green Mountain Pw	$28.93	$ 1.12	$ 1.24	$ 1.54	$ 0.10	6.8%	$0.56	$1.24	$1.34	$1.44	$1.54	$38.66	11.1%
Progress Energy	$40.96	$ 2.44	$ 2.50	$ 2.62	$ 0.04	6.8%	$1.22	$2.50	$2.54	$2.58	$2.62	$53.41	12.0%
Ameren Corp.	$50.29	$ 2.54	$ 2.54	$ 2.54	$ -	6.8%	$1.27	$2.54	$2.54	$2.54	$2.54	$65.65	10.9%
Cleco Corp.	$22.00	$ 0.90	$ 0.90	$ 1.00	$ 0.03	6.8%	$0.45	$0.90	$0.93	$0.97	$1.00	$29.10	10.5%
DPL, Inc.	$26.46	$ 1.00	$ 1.04	$ 1.16	$ 0.04	6.8%	$0.50	$1.04	$1.08	$1.12	$1.16	$35.07	10.3%
Empire District	$20.40	$ 1.28	$ 1.28	$ 1.28	$ -	6.8%	$0.64	$1.28	$1.28	$1.28	$1.28	$26.43	12.0%
Entergy Corp.	$70.24	$ 2.16	$ 2.32	$ 2.80	$ 0.16	6.8%	$1.08	$2.32	$2.48	$2.64	$2.80	$93.82	10.0%
Hawaiian Electric	$28.10	$ 1.24	$ 1.24	$ 1.24	$ -	6.8%	$0.62	$1.24	$1.24	$1.24	$1.24	$36.83	10.4%
PNM Resources Gro	$27.13	$ 0.86	$ 0.92	$ 1.10	$ 0.06	6.8%	$0.43	$0.92	$0.98	$1.04	$1.10	$36.20	10.0%
Pinnacle West Capit	$43.44	$ 2.03	$ 2.13	$ 2.43	$ 0.10	6.8%	$1.02	$2.13	$2.23	$2.33	$2.43	$57.45	11.3%
Unisource Energy	$33.72	$ 0.84	$ 0.92	$ 1.16	$ 0.08	6.8%	$0.42	$0.92	$1.00	$1.08	$1.16	$45.21	9.5%
Average													10.7%

(a) The Value Line Investment Survey (June 2, June 30, & Aug. 11, 2006).
(b) Annual change in dividend between 2007 and 2009-11.
(c) Direct Testimony of Dennis Rogers, Docket No. W-01303A-05-0405, at Schedule DRR-8.
(d) Discount rate that equates the present value of cash flows in years 1-5 with Recent Price.

REBUTTAL TESTIMONY OF LAURA L. ROCKENBERGER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-816

September 15, 2006

Table of Contents

I. INTRODUCTION 1

II. SUMMARY OF REBUTTAL TESTIMONY 1

III. ALLOWANCE FOR WORKING CAPITAL 8

IV. PRO FORMA ADJUSTMENTS TO BOTH RATE BASE & OPERATING INCOME 11

A. Palo Verde Unit 1 Steam Generators 11

B. Bark Beetle Remediation 12

V. TOTAL RATE BASE ADJUSTMENTS 15

VI. RECONSTRUCTION COST NEW STUDY 15

VII. ADDITIONAL PRO FORMA ADJUSTMENTS TO OPERATING INCOME 16

A. PWEC and Sundance Units 16

B. Nuclear Plant Decommissioning 16

C. Spent Fuel Storage 17

D. Depreciation and Amortization 17

E. Property Taxes 20

F. Payroll 21

G. Underfunded Pension Liability 23

H. Advertising 23

I. Lobbying 24

J. Other Administrative and General ("A&G") Adjustments 25

VIII. LIBERTY CONSULTING GROUP FUEL AUDIT 26

IX. OFFSETS TO FINANCIAL IMPACTS OF PARTIES' RECOMMENDATIONS 28

A. Plant-in-Service 28
X. COMMISSION ACTION REQUESTED 29
XI. CONCLUSION 30
XII. ATTACHMENTS
Allowance for Working Capital (SFR B-5) ..... Attachment LLR-1-1RB
Palo Verde Unit 1 Steam Generators ..... Attachment LLR-2-1RB
Bark Beetle Regulatory Asset ..... Attachment LLR-2-2RB
Allowance for Working Capital ..... Attachment LLR-2-3RB
Adjustments to Rate Base (SFR B-1) ..... Attachment LLR-3-1RB
Adjustments to Original Cost Rate Base (SFR B-2) ..... Attachment LLR-3-2RB
Adjustments to RCND (SFR B-3) ..... Attachment LLR-3-3RB
Palo Verde Unit 1 Steam Generators Depreciation ..... Attachment LLR-4-1RB
Bark Beetle [Operating Income] ..... Attachment LLR-4-2RB
Spent Fuel Storage ..... Attachment LLR-4-3RB
Property Taxes ..... Attachment LLR-4-4RB
Pension Expense ..... Attachment LLR-4-5RB
Post Retirement Medical Benefits ..... Attachment LLR-4-6RB
Advertising ..... Attachment LLR-4-7RB
Administrative and General ..... Attachment LLR-4-8RB
Revenue Requirement for Additional Plant-in-Service Attachment LLR-5-1RB

REBUTTAL TESTIMONY OF LAURA L. ROCKENBERGER ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (Docket No. E-01345A-05-816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Laura L. Rockenberger. My business address is 400 North Fifth Street, Phoenix, Arizona, 85004. I am the Manager of Operations Accounting for Arizona Public Service Company ("APS" or "Company").

Q. *DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?*

A. Yes. I filed direct testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

Most importantly, my Rebuttal Testimony addresses the critical need of the Company to maintain an appropriate level of cash working capital and refutes both the Staff and Residential Consumer Utility Office ("RUCO") recommended reductions in cash working capital that will further handicap the Company's ability to have cash available to operate and maintain its electric system on a daily basis. The Company opposes Staff recommendations that cash working capital be reduced by $59,600,000 by removing "non-cash items" and including interest expense in the Cash Working Capital calculation. RUCO also recommends that depreciation expense, as a "non-cash item," be excluded from and interest expense be included in the cash working capital calculation. Certain income statement expenses have been casually referred to as "non-cash" items; but, the stark reality

is that these items provide cash resources that the Company desperately needs to maintain operations while funding expansive growth in its service territory. The fundamental regulatory concept that we must remain focused on is that the current period depreciation expense, and other non-cash expenses, reduce rate base before the cash is collected from the customers. Because there is a gap in time from the rate base reduction (when the Company stops earning a return on the assets which are "consumed" in operations and allocated to expense) and the cash collection from the customers, it makes sense to bridge that "gap" in time by including those expenses in the cash working capital calculation. APS witness Balluff will provide further elaboration on the technical merits of including these non-cash items and excluding interest expense in the cash working capital calculation. Finally, the Company does not oppose $5,019,000 in cash working capital reductions recommended by Staff which are based on adjustments to the cash working capital calculation.

My Rebuttal Testimony also discusses the rate base and operating income adjustments advocated by Staff, RUCO and Arizonans for Electric Choice and Competition ("AECC"). These adjustments fall into these categories: recommendations we do not oppose; those we can support in part; and, those we completely oppose. These adjustments are summarized below. All the rate case and operating income adjustments summarized are stated as total company numbers. The jurisdictional portion of the adjustments are summarized in Attachments LLR-3-1RB through LLR-3-3RB.

Adjustments to Both Rate Base and Operating Income

A. Palo Verde Unit 1 Steam Generators

The Company does not oppose RUCO's recommendation to record the $36,684,000 retirement of the old steam generators and low pressure turbines which has no impact on rate base. Accordingly, the Company does not oppose the related $262,000 adjustment to reduce operating income for depreciation expense related to a portion of the old low pressure turbine equipment retired, but does oppose the recommended $404,000 adjustment for depreciation on the old steam generators which was included in the Company's calculation.

B. Bark Beetle Remediation

The Company has deferred bark beetle remediation costs in compliance with Decision No. 67744, and opposes both (1) Staff recommendations to remove 2005 expenses from January 1, 2005 through March 31, 2005, and (2) RUCO's recommendation to remove projected costs from the end of the Test Year through December 31, 2006. These recommendations would decrease the allowable deferred bark beetle remediation costs and related annual amortization expense. The Company is not opposed to certain adjustments to include the impacts of deferred income taxes in rate base and correct the original pro forma for the actual costs at September 30, 2005. The Company is also proposing to update the projected costs through December 31, 2006. This will increase the total deferred bark beetle remediation costs by $333,000 to $11,622,000. The net pro forma adjustment will reduce rate base by $1,755,000 and increase amortization expense by $110,000.

Additional Pro Forma Adjustments to Operating Income

A. PWEC Units[1] and Sundance Units

[1] "PWEC Units" refers to the generation plants that were transferred to APS in the prior rate case, as discussed in my Direct Testimony.

Mr. Ewen discusses the PWEC Units' and Sundance Units O&M in his Rebuttal Testimony.

The Company is opposed to Mr. Higgins' recommended adjustment to reduce the PWEC Units' A&G by $11,618,000 based on the concept that A&G recovery should be limited to historical levels. It should be noted, however, that the Company is not opposed to $5,098,000 in out-of-period adjustments related to PWEC A&G which I address in "J. Other Administrative and General Adjustments".

B. Decommissioning

The Company is opposed to RUCO's recommended $765,000 reduction in operating expenses related to decommissioning. RUCO included the decommissioning costs, but did not take into consideration that funding into the decommissioning trusts also provides for post-shutdown spent nuclear fuel storage costs which was properly recorded as $765,000 in fuel expense and funded into the decommissioning trusts.

C. Spent Nuclear Fuel Storage

The Company is not opposed to Staff's recommendation to reduce operating income by $264,000 for ongoing spent nuclear fuel storage expenses.

D. Depreciation and Amortization

The Company is opposed to RUCO's recommended $6,991,000 reduction in amortization expense, as RUCO provided an historical average rate which understates normalized amortization expense in a period of time when assets balances are increasing significantly and, thus, amortization expense is increasing.

E. Property Taxes

The Company is not opposed to Staff's recommended $1,708,000 reduction in property taxes related to the 2007 phase-in of new generation plant costs. Accordingly, the Company is opposed to RUCO's adjustment to reduce the property taxes by $5,977,000 based on the temporary suspension of the County Education Tax Rate, because RUCO did not take into consideration all known and measurable factors impacting the assessed value which would impact the pro forma adjustment.

F. Payroll

The Company is opposed to both Staff and RUCO recommendations to disallow stock-based incentive compensation and to have an overall 20% reduction in incentive compensation. Mr. Wheeler discusses this further in his Rebuttal Testimony. The Company is also opposed to RUCO's recommendation that Supplemental Excess Benefit Retirement Plan ("SEBRP") expense be disallowed. Mr. Brandt discusses this further in his Rebuttal Testimony.

Staff has proposed an $8,155,000 increase in pension costs and a $2,038,000 increase in post retirement medical costs based on estimated 2006 expenses. The Company agrees that the Test Year expenses should be based on 2006 cost levels and has now received final 2006 actuarial calculations, which increase Test Year pension expense by $2,249,000 and decrease post retirement medical costs by $3,191,000. The Company is proposing adjustments based on these final 2006 actuarial calculations.

G. Underfunded Pension Liability

The Company opposes Staff, RUCO and AECC recommendation to deny the Company's request to accelerate the recovery of its underfunded pension liability over a five-year period beginning in 2007. Mr. Brandt discusses the necessity for the Company to accelerate this funding in his Rebuttal Testimony.

H. Advertising

The Company is not opposed to the $437,000 reduction in advertising costs recommended by Staff, $66,000 of the $566,000 reduction recommended by RUCO, and the $4,625.00 reduction recommended by Mr. Rigsby. The Company is opposed to RUCO's recommendation to remove $400,000 of meals expense from operating expenses as these costs are incurred to provide company lunches for employees that are working during their personal lunch time. The Company is proposing a pro forma adjustment to reduce operating expenses by $508,000.

I. Lobbying

The Company is opposed to adjustments to remove lobbying costs from the Test Year, as Mr. Wheeler discusses in his Rebuttal Testimony.

J. Other Administrative and General Adjustments

The Company is not opposed to Staff and RUCO recommended adjustments to reduce A&G by $8,520,000 for out-of-period costs and legal fees. This amount includes $5,098,000 in PWEC Units out-of-period adjustments.

Liberty Consulting Group Fuel Audit

My Rebuttal Testimony also responds to one recommendation which was addressed by Staff's consultant, Liberty Consulting Group, in its *Final Audit Report: APS Fuel and Purchased Power Procurement and Costs* ("Fuel Audit

Report"), which was issued August 31, 2006. This recommendation addresses an accounting practice for allocating refunds on fuel transportation costs to fuel expense and inventory. The Fuel Audit Report noted that the recommended accounting adjustment is only a short-term timing issue regarding the flow of fuel expense through the Power Supply Adjustor ("PSA").

Finally, my Rebuttal Testimony includes the calculation of estimated Plant-in-Service at December 31, 2006, as discussed in Mr. Wheeler's Rebuttal Testimony. The estimated Plant-in-Service is $11,369,665,000. The increase in Plant-in-Service from the Test Year to December 31, 2006 is estimated to be $572,058,000, which has a related revenue requirement of $13,480,000.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I will discuss the adjustment to the cash working capital ("CWC") included in the Allowance for Working Capital, as set forth in Attachment LLR-1-1RB. Then, I will discuss the items that have a pro forma adjustment to Original Cost Rate Base, as set forth in Attachments LLR-2-1RB through LLR-2-3RB and any corresponding pro forma adjustments to operating income. After the discussion of these items, which adjust the rate base, I will present the Summary of Original Cost and RCND Rate Base Elements, Adjustments to B-2 and Adjustments to B-3 in Attachments LLR-3-1RB through LLR-3-3RB. I will then discuss the remaining operating income pro forma adjustments. These pro forma adjustments, as set forth in Attachments LLR-4-1RB through LLR-4-8RB, reflect total Company amounts prior to any jurisdictional allocation. Then I will discuss one of the recommendations in the Fuel Audit Report that is related to fuel accounting practices. Finally, I will discuss the estimated Plant-in-Service at December 31, 2006 as set forth in Attachment LLR-5-1RB.

III. ALLOWANCE FOR WORKING CAPITAL

Q. HAVE YOU REVIEWED STAFF AND RUCO TESTIMONY AND EXHIBITS RELATING TO WORKING CAPITAL?

A. Yes. Both Staff witness Mr. Dittmer and RUCO witness Ms. Diaz Cortez discuss working capital issues in their testimony. Both make significant adjustments to the Company's lead lag study in the area of cash working capital ("CWC"), as identified in Staff Schedule B-4 and RUCO Schedule MDC-5.

Q. PLEASE IDENTIFY STAFF'S RECOMMENDED ADJUSTMENTS TO CWC.

A. As is shown in Mr. Dittmer's Direct Testimony on page 32, Staff's recommended CWC adjustments are as follows:

APS CWC Recommendation	$(29.3) million
Staff CWC Adjustments:	
Remove Non-Cash Items	(43.7) million
Recognize Interest Expense	(15.9) million
Total Non-Cash and Interest Expense	(59.6) million
Revise Palo Verde Lease Payment Lag	(7.1) million
Adjust Level of Purchased Power Expense	2.6 million
Re-weight Revenue Lag	(0.5) million
Total Other CWC Adjustments	(5.0) million
Total Staff CWC Adjustments:	$(64.6) million
Staff's Recommended CWC:	$(93.9) million

Q. PLEASE IDENTIFY RUCO'S RECOMMENDED ADJUSTMENTS TO CWC.

A. Ms. Diaz Cortez also recommends that depreciation expense be excluded and interest expense be included in the CWC calculation. Although Ms. Diaz Cortez also substituted RUCO's recommended expense levels for the Company in its

CWC calculation, she states in her testimony on page 12 that her entire proposed adjustment "is primarily attributable to the depreciation and interest expense factors and decreases cash working capital by $78.2 million."

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. I agree with Staff's recommendations for adjustments to Palo Verde lease payment lags, levels of purchased power expense, and to its re-weighting of revenue lags in CWC. However, I strongly disagree with both Staff and RUCO's recommendation to eliminate so called "non-cash" items from CWC. I also strongly disagree with their recommendation to include interest expense in the CWC calculations. APS witness Balluff discusses the appropriateness of inclusion of "non-cash" items, as well as the exclusion of interest expense in the CWC calculations, in his Rebuttal Testimony.

Q. TAKING INTO CONSIDERATION THE RECOMMENDATIONS THAT YOU DO NOT OPPOSE, CAN YOU SUMMARIZE THE COMPANY'S REVISED CASH WORKING CAPITAL REQUEST?

A. Yes. The Company does not oppose the recommended adjustments to the Palo Verde lease payment lags, levels of purchased power expense, and to its re-weighting of revenue lags. These total changes result in a revised cash working capital request of ($34,158,000), which is a reduction of $5,019,000 from the January Filing in SFR Schedule B-5, line 1. *See* Attachment LLR-1-1RB.

Q. PLEASE EXPLAIN WHY CASH WORKING CAPITAL IS A CRITICAL SOURCE OF FUNDS TO THE COMPANY.

A. The Company must operate and maintain its electric system on a daily basis. As Mr. Wheeler discussed in his Direct Testimony, APS is experiencing dramatic growth in its service territory. Mr. Brandt discusses in his Rebuttal Testimony that

the Company anticipates spending in excess of an average of $900 million per year, from 2007 through 2009, for capital investments to serve its rapidly growing customer base and maintain high service reliability. Cash working capital is a critical source of funds.

The arbitrary reduction of rate base to the tune of about $44 million, due to a perception by Staff and RUCO that such depreciation expense is not a "cash" item, effectively reduces APS' cash flow during a time in which the Company is experiencing unprecedented growth and must be able to generate sufficient cash to continue construction and provide reliable service to its rapidly increasing customer base.

Q. PLEASE EXPLAIN THE FUNDAMENTAL CONCEPT THAT PROVIDES FOR INCLUDING NON-CASH ITEMS IN THE CASH WORKING CAPITAL CALCULATION.

A. The fundamental regulatory concept that we must remain focused on is that the current period depreciation expense, and other non-cash expenses, reduce rate base before the cash is collected from the customers. Because there is a gap in time from the rate base reduction (when the Company stops earning a return on the assets which are "consumed" in operations and allocated to expense) and the cash collection from the customers, it makes sense to bridge that "gap" in time by including those expenses in the cash working capital calculation.

Q. IS APS' REQUEST TO INCLUDE THESE OTHER REVENUE ITEMS IN THE LEAD LAG STUDY UNPRECEDENTED OR OUT-OF-LINE WITH OTHER COMMISSIONS' TREATMENT OF THESE SAME EXPENSES?

A. No. Mr. Balluff discusses the fact that other state commissions have recognized the appropriateness of reflecting these non-cash items somewhere in a utility's rate

base. For APS, it has been eighteen years since these issues were litigated, so it is time for the Commission to revisit the analysis of how cash working capital is determined for rate making purposes.

IV. PRO FORMA ADJUSTMENTS TO BOTH RATE BASE & OPERATING INCOME

A. Palo Verde Unit 1 Steam Generators

Q. RUCO IDENTIFIED THAT THE COMPANY'S RATE BASE PRO FORMA, WHICH REFLECTED THE REPLACEMENT OF STEAM GENERATORS FOR PALO VERDE UNIT 1, FAILED TO INCLUDE A PROVISION FOR THE RETIREMENT OF THE ORIGINAL UNIT 1 STEAM GENERATORS AND PROPOSED A RATE BASE ADJUSTMENT TO REFLECT THAT RETIREMENT. DO YOU AGREE WITH RUCO'S PROPOSED ADJUSTMENT?

A. Yes. As a result, the Company is proposing a rate base pro forma to reflect the retirement of the original steam generators, including the low pressure turbine rotors. The pro forma will decrease plant assets by $36,684,000 and decrease accumulated depreciation by $36,684,000. This pro forma has no effect on rate base, but does have an impact on depreciation expense. *See* Attachment LLR-2-1RB.

Q. PLEASE EXPLAIN THE IMPACT OF THIS PRO FORMA ON DEPRECIATION EXPENSE.

A. The Test Year depreciation expense was adjusted to reflect the increase in the level of plant-in-service resulting from the addition of the replacement steam generators, net of the retirement of the original steam generators. The Company's depreciation expense adjustment was properly calculated for the replacement of the steam generators, but did not include the retirement of the low pressure turbine rotors in the calculation.

Q. RUCO PROPOSED A $666,000 ADJUSTMENT TO REDUCE DEPRECIATION EXPENSE TO REFLECT THE RETIREMENT OF THE ORIGINAL STEAM GENERATORS AND THE ADDITION OF THE REPLACEMENT STEAM GENERATORS, INCLUDING THE LOW PRESSURE TURBINES. DO YOU AGREE WITH RUCO'S ADJUSTMENT?

A. The Company agrees with a portion of the adjustment. The $666,000 adjustment includes reductions in depreciation expense of $404,000 related to the steam generators and $262,000 related to the low pressure turbine rotors. The Company agrees with the $262,000 adjustment for the low pressure turbine rotors proposed by Mr. Rigsby, which is included in Attachment LLR-4-1RB. However, the $404,000 depreciation adjustment for the retirement of the original steam generators was included in the Company's Test Year pro forma adjustment, therefore, Mr. Rigsby's adjustment would double count depreciation expense reduction for the original steam generators. *See* LLR_WP17, page 2 of 12.

B. Bark Beetle Remediation

Q. HAVE YOU REVIEWED STAFF AND RUCO TESTIMONY AND EXHIBITS RELATING TO BARK BEETLE REMEDIATION?

A. Yes. Mr. Dittmer and Mr. Rigsby each addressed bark beetle remediation in their Direct Testimony. They each concluded that Decision No. 67744 provided for the deferral of bark beetle remediation costs and subsequent amortization of such costs; and, furthermore, each accepted the three-year amortization period proposed by the Company. Additionally, Mr. Dittmer and Mr. Rigsby each propose certain pro forma adjustments, which I shall now address.

Q. MR. DITTMER RECOMMENDED THAT THE COSTS DEFERRED FOR THE PERIOD OF JANUARY 1, 2005 THROUGH MARCH 31, 2005 BE REMOVED FROM THE DEFERRED COSTS AND CORRESPONDINGLY, THAT THE ANNUAL AMORTIZATION

EXPENSE BE REDUCED. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Mr. Dittmer believes that the effective date to commence deferral of bark beetle remediation costs should be April 1, 2005, the effective date of Decision No. 67744. However, the language of that Decision, which states, "APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the test *year* [emphasis added] levels of tree and bush control", indicates that a full year of cost recovery was intended. Therefore, the Company actually began deferring costs incurred effective January 1, 2005. The Company believes that the August 2004 Settlement intended and Decision No. 67744, effective April 1, 2005, authorized that deferrals would include the entire calendar year in which the deferral became effective. Thus, effective January 1, 2005, the Company began deferring costs to ensure that the allowable deferred costs were properly calculated for 2005.

Q. MR. DITTMER ALSO RECOMMENDS ADJUSTMENTS TO CORRECT THE COMPANY'S ORIGINAL PRO FORMA ADJUSTMENT. DO YOU AGREE WITH THIS RECOMMENDATION?

A. The Company agrees that the rate base should include accumulated deferred income taxes associated with APS' pre-tax pro forma rate base adjustment and that the actual bark beetle deferral balance used in the Company's original pro forma adjustment was incorrect. These corrections have been made and the projected cost deferral through December 31, 2006 has been updated and slightly increased. Taking these items into consideration, the Company is proposing a pro forma adjustment to reduce the rate base by $1,755,000. *See* Attachment LLR-2-2RB. This includes an adjustment to reduce the rate base by $2,793,000 for accumulated deferred income taxes related to rate base adjustments, partially offset by a

$1,038,000 rate base increase comprised of a $705,000 addition to rate base to correct the calculation for the actual September 30, 2005, deferred bark beetle remediation costs in the Company's original pro forma in the January filing, as discussed in Mr. Bischoff's testimony, and a $333,000 addition to rate base to increase the projected bark beetle remediation cost deferral through December 31, 2006.

Q. IS THERE A CORRESPONDING OPERATING INCOME PRO FORMA TO ADJUST THE ANNUAL AMORTIZATION EXPENSE?

A. Yes. A pro forma adjustment to increase the operating costs by $110,000 from $1,438,000 to $1,548,000 to reflect the increased bark beetle amortization cost is included as Attachment LLR-4-2RB.

Q. MR. RIGSBY PROPOSES A PRO FORMA ADJUSTMENT TO REMOVE ESTIMATED BARK BEETLE REMEDIATION COSTS INCLUDED IN THE COMPANY'S DEFERRAL CALCULATION. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Estimating costs for the period of time from September 30, 2005 (the end of the Test Year) through January 1, 2007 (when rates are expected to be in place), is a reasonable period of time to project the costs for ongoing remediation activities and also meets the standard of known and measurable costs. Our current financial projections, based on actual costs at July 31, 2006, and including transportation costs related to remediation activities, indicate that the Company will have about $11,622,000 in deferred costs at December 31, 2006, about $333,000 more than the amounts estimated in our January Filing. It is appropriate under the matching principal to use estimated costs to ensure that the rates in effect in 2007 provide (at a minimum) for the amortization of the actual costs incurred by year-end 2006. Thus, APS does not accept Mr. Rigsby's proposed adjustments to reduce the rate

base for costs incurred subsequent to the Test Year, and the corresponding adjustment to reduce operating expenses for the annual amortization expense.

V. TOTAL RATE BASE ADJUSTMENTS

Q. PLEASE SUMMARIZE THE ADJUSTED TEST YEAR ORIGINAL COST RATE BASE PROPOSED BY APS.

A. For the Test Year ending September 30, 2005, APS is proposing a total Company OCRB adjustment of $10,660,000 to decrease the OCRB from $5,327,833,000 in the January Filing to $5,317,173,000. The jurisdictional allocation of the OCRB is $4,456,937,000, which is sponsored by Mr. David Rumolo. These adjustments are summarized in Adjustments to Schedule B-2, which is included as Attachment LLR-3-2RB.

VI. RECONSTRUCTION COST NEW STUDY

Q. HAVE YOU DEVELOPED REVISED RCND CALCULATIONS FOR VARIOUS RATE BASE ADJUSTMENTS PROPOSED OR ACCEPTED BY THE COMPANY?

A. Yes. In my Direct Testimony, I sponsored the Company's Reconstruction Cost New ("RCN") and Reconstruction Cost New Less Depreciation ("RCND") study. In Attachments LLR-3-1RB through LLR-3-3RB, I present the Original Cost and RCND Rate Base Elements, Adjustments to B-2 and Adjustments to B-3.

Q. IS THE METHODOLOGY BY WHICH YOU CALCULATED THE RCN AND RCND AMOUNTS THE SAME AS PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes. The calculations of the RCN and RCND amounts follow the same methods that I discussed at pages 28-33 of my Direct Testimony.

VII. ADDITIONAL PRO FORMA ADJUSTMENTS TO OPERATING INCOME

A. PWEC and Sundance Units

Q. MR. HIGGINS AND MR. SCHLISSEL RECOMMENDED REDUCTIONS TO THE PWEC UNITS AND SUNDANCE UNITS O&M COSTS INCLUDED IN OPERATING EXPENSES. WHAT IS THE COMPANY'S RESPONSE TO THESE RECOMMENDATIONS?

A. Mr. Ewen responds to these recommended pro forma adjustments in his Rebuttal Testimony.

Q. MR. HIGGINS (AECC) RECOMMENDED THAT THE PWEC UNITS' ADMINISTRATIVE AND GENERAL ("A&G") COSTS BE LIMITED TO THOSE EXPENSES ATTRIBUTED TO THE PWEC UNITS DURING THE COMPANY'S PRIOR RATE CASE. DO YOU AGREE WITH THIS APPROACH?

A. No, I do not agree with Mr. Higgins' pro forma adjustment to arbitrarily reduce PWEC A&G by $11,618,000 based on the argument that some prior year costs should be a consideration for reduction in costs in this rate case. Decision No. 67744 specifically ordered APS to rate base the units at December 31, 2004, at $700,000,000. The order to rate base the generating units did not include any requirements for or limitations on operating expenses. Additionally, it should be noted that the Company has proposed a reduction in operating expenses of $5,098,000 for PWEC Units A&G out-of-period adjustments, which effectively reduces Mr. Higgins' recommended adjustment of $11,618,000 to $6,520,000. These A&G adjustments are discussed later in my testimony and included as Attachment LLR-4-8RB.

B. Nuclear Plant Decommissioning

Q. RUCO PROPOSED A $765,000 REDUCTION IN OPERATING EXPENSES FOR DECOMMISSIONING. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. During the Test Year, the Company funded $16,093,000 into the decommissioning trusts. Since the decommissioning trusts are funded for both plant decommissioning costs and post-shutdown spent nuclear fuel storage costs, the Test Year operating expenses include $15,328,000 in depreciation expense for decommissioning funding and $765,000 in fuel expense for post-shutdown spent nuclear fuel storage funding. RUCO's proposed adjustment did not include the $765,000 in nuclear fuel expense for funding the post-shutdown spent nuclear fuel storage costs.

C. Spent Fuel Storage

Q. STAFF HAS PROPOSED AN ADJUSTMENT TO SPENT NUCLEAR FUEL STORAGE EXPENSE. DO YOU AGREE WITH THIS RECOMMENDATION?

A. Yes. A pro forma adjustment of $264,000 is included in SFR Schedule C-2 to reduce the ongoing spent nuclear fuel storage expense. *See* Attachment LLR-4-3RB.

D. Depreciation and Amortization

Q. HAVE ANY OF THE PARTIES' TAKEN THE POSTION THAT THE COMPANY'S DEPRECIATION RATES PROPOSED IN THIS CASE ARE DIFFERENT THAN THOSE AUTHORIZED IN COMMISSION DECISION NO. 67744?

A. No. In fact, Staff witness Smith acknowledged that the depreciation rates proposed by APS were developed in a manner that is consistent to the depreciation rates that the Commission approved in Decision No. 67744 and recommended that those rates be adopted.

Q. HAVE YOU REVIEWED THE TESTIMONY PROVIDED BY RUCO REGARDING AMORTIZATION EXPENSE?

A. Yes. Ms. Diaz Cortez objected to the Company pro forma increasing amortization expense by $10,002,000 without the Company performing a study of the general and intangible assets. Ms. Diaz Cortez proposed an operating expense reduction of $6,991,000 based on her analysis.

Q. WHAT ANALYSIS DID MS. DIAZ CORTEZ PERFORM TO CALCULATE HER ADJUSTMENT TO AMORTIZATION EXPENSE?

A. The composite rate appears to have been calculated by taking amortization expense for the twelve months ended September 30, 2005, and dividing that amount by the original cost plant balance at September 30, 2005. That composite rate multiplied by the increase in the original cost plant balances during the Test Year, increased amortization expense by $3,011,000. The pro forma adjustment proposed by RUCO reduces the increase in amortization expense to that level.

Q. WHAT OBSERVATIONS DID YOU MAKE REGARDING THE METHODOLOGY USED BY MS. DIAZ CORTEZ IN HER PRO FORMA ADJUSTMENT CALCULATION?

A. Her calculation methodology does not have sufficient analysis or detail to properly normalize amortization expense. The method is a high level general estimating process that may be appropriate to use when the assets all have similar estimated useful lives. However, because the Company's intangible assets have a wide range of estimated useful lives, and because each asset is individually amortized, the calculation cannot properly normalize amortization expense.

Q. PLEASE EXPLAIN THE METHODOLOGY USED IN PREPARING THE COMPANY PRO FORMA ADJUSTMENT FOR AMORTIZATION EXPENSE.

A. The pro forma adjustment proposed by the Company used a more precise method to calculate amortization expense. The calculation was based on the actual

individual asset costs and lives at September 30, 2005, multiplied by the actual amortization rates for each individual asset. By using the actual assets at September 30, 2005, the calculation would exclude recent retirements and include recent additions for a full year calculation of amortization expense. Fully amortized assets were properly excluded from the calculation. The amortization rates in effect today were approved by the Commission in Decision No. 67744. The pro forma adjustment is the difference between the normalized annual amortization expense and the actual test year amortization expense. This calculation method was consistently used by the Company in the last rate case filing and has not been objected to by any party in that case or by Staff in this case.

Q. HAVE YOU PERFORMED ANY ADDITIONAL REVIEWS OF AMORTIZATION EXPENSE SINCE THE END OF THE TEST YEAR?

A. Yes. For the period of time from the end of the Test Year, September 30, 2005 through June 30, 2006, the General and Intangible Assets have increased from $371 million to $387 million. At June 30, 2006, the annualized level of amortization expense is $45.3 million which exceeds the normalized pro forma adjustment proposed by the Company in its January Filing by $6.6 million.

Q. IS THE COMPANY REQUESTING ANY CHANGES TO ITS EXISTING AMORTIZATION RATES?

A. No. As I discussed in my Direct Testimony, APS is not requesting any change to the amortization rates authorized in Decision No. 67744. These rates are set forth on Attachment LLR-2-11.

Q. IS THE COMPANY REQUESTING ANY NEW AMORTIZATION RATES?

A. Yes. APS is requesting two new rates which I discussed in my Direct Testimony. No parties have objected to these rates. These rates are also set forth on Attachment LLR-2-11.

E. Property Taxes

Q. DID YOU REVIEW THE STAFF AND RUCO TESTIMONY FOR PROPERTY TAXES?

A. Yes. Mr. Dittmer proposed an adjustment to reduce property taxes by $1,708,000 to eliminate the APS proposed inclusion of the 2007 statutory phase-in of increased property taxes associated with the PWEC Units. Additionally, Mr. Rigsby proposed an adjustment to reduce property taxes by $5,977,000 to reflect the temporary suspension of the County Education Tax Rate provided by H.B. 2876.

Q. CAN APS ACCEPT STAFF'S PROPERTY TAX RECOMMENDATION FOR THE TEST YEAR?

A. Yes. A $1,708,000 pro forma adjustment is included in SFR Schedule C-2 to reduce operating expenses for property taxes. *See* Attachment LLR-4-4RB.

Q. DO YOU AGREE WITH THE ADJUSTMENTS THAT RUCO PROPOSED?

A. No. The adjustment proposed by Mr. Rigsby only took into consideration the impact of the temporary suspension of the County Education Tax Rate for 2006. The suspension of the County Education Tax Rate will reduce property taxes in 2006, 2007 and 2008. There are other significant issues that will also impact property taxes that Mr. Rigsby did not take into consideration. The Arizona Department of Revenue has approved the 2007 assessed value, which is based on APS plant balances at December 31, 2005, and has recently approved the

Company's request to reduce the 2007 assessed value for the PWEC Units regulatory disallowance reflected in Company records that was discussed in my Direct Testimony. The assessed value of the property, and thus the calculation of the impact on the property taxes for the suspension of the County Education Tax Rate, should appropriately consider these known and measurable net increases in the 2007 assessed value. The Company is now opposed to this pro forma adjustment because these net increases in assessed valuation, which are known and measurable, were not factored into the analysis performed by Mr. Rigsby. If all of these factors were considered at the time Mr. Rigsby proposed his adjustment, Mr. Rigsby's adjustment would fall to $2.4 million, rather than $6 million. In addition, the $2.4 million reduction would also encompass Staff's proposed adjustment for the 2007 generation phase-in costs, which we have not opposed. They are not additive.

F. Payroll

Q. BOTH STAFF AND RUCO HAVE PROPOSED CHANGES TO INCENTIVE COMPENSATION. WHAT IS YOUR RESPONSE TO THESE PROPOSED CHANGES?

A. In his Rebuttal Testimony, Mr. Wheeler explains why the Company disagrees with both Staff's proposal to disallow stock-based incentive compensation and RUCO's proposal that the Commission order an overall 20% reduction in incentive pay for all employees.

Q. WHAT IS THE COMPANY'S RESPONSE TO RUCO'S RECOMMENDATION THAT THE SUPPLEMENTAL EXCESS BENEFIT RETIREMENT PLAN ("SEBRP") COSTS BE DISALLOWED?

A. The Company disagrees with RUCO's position on SEBRP. Mr. Brandt explains the Company's position in his Rebuttal Testimony.

Q. HAVE YOU REVIEWED THE STAFF TESTIMONY ON PENSION EXPENSE?

A. Yes. Mr. Dittmer recommended increasing operating expenses by $8,155,000 for pension expense. His analysis was based on the level of estimated pension expense that the Company was recording in 2006, in excess of the pension expense recorded in the Test Year. In his testimony, Mr. Dittmer also noted that this estimate will need to be adjusted to actual costs in 2006 when the actual costs are known.

Q. HAS THE COMPANY RECENTLY RECEIVED ACTUARIAL INFORMATION THAT PROVIDES THE ACTUAL 2006 PENSION EXPENSE?

A. Yes. The Company has received updated actuarial information for 2006, although the final report has not yet been issued. The actuarially calculated number is higher than last year and indicates that the Test Year expense should be increased by $2,249,000. A pro forma adjustment of $2,249,000 is included to increase pension expense based on the updated actuarial information. *See* Attachment LLR-4-5RB.

Q. HAVE YOU REVIEWED THE STAFF TESTIMONY FOR POST RETIREMENT MEDICAL BENEFITS?

A. Yes. Similar to pension expense, Mr. Dittmer recommended an increase in operating expenses of $2,038,000, which is based on the actuarial estimates that the Company is relying on to record 2006 post retirement benefit costs in excess of the level of costs recorded in the Test Year. Mr. Dittmer also noted that his estimate will need to be adjusted to actual costs when the final information is available.

Q. DID THE ACTUARIAL INFORMATION RECENTLY RECEIVED BY THE COMPANY INCLUDE THE ACTUAL 2006 POST RETIREMENT MEDICAL BENEFITS?

A. Yes. The updated actuarial information indicates that the Test Year expense should be decreased by $3,191,000. A pro forma adjustment of $3,191,000 is included to decrease post retirement medical benefits expense based on the updated actuarial information. *See* Attachment LLR-4-6RB.

G. Underfunded Pension Liability

Q. STAFF, RUCO AND AECC HAVE ALL RECOMMENDED THAT THE COMMISSION DENY THE COMPANY'S REQUEST TO ACCELERATE THE RECOVERY OF ITS UNDERFUNDED PENSION LIABILITY OVER A FIVE-YEAR PERIOD BEGINNING IN 2007. WHAT IS THE COMPANY'S RESPONSE TO THESE RECOMMENDATIONS?

A. Mr. Brandt explains why the Company opposes these recommendations in his Rebuttal Testimony.

H. Advertising

Q. STAFF PROPOSED PRO FORMA ADJUSTMENTS FOR ADVERTISING COSTS. PLEASE DISCUSS THESE ADJUSTMENTS.

A. In his testimony, Mr. Dittmer identified marketing and sponsorship costs totaling $437,000, which the Company has agreed to exclude from operating expenses.

Q. RUCO ALSO PROPOSED PRO FORMA ADJUSTMENTS FOR ADVERTISING COSTS. PLEASE DISCUSS THESE ADJUSTMENTS.

A. Ms. Diaz Cortez proposed adjustments totaling $566,000 for sponsorships and other expenses that she deemed were not needed to provide electric service. Mr. Rigsby proposed an adjustment for $4,625.00 to remove promotional advertising that he believes is similar to branding advertising.

Q. **DO YOU AGREE WITH THE ADJUSTMENTS PROPOSED BY MS. DIAZ CORTEZ?**

A. I agree with $66,000 of the proposed $566,000 adjustment. The $100,000 Dodge Theatre expense was included in the operating adjustment for advertising costs that Staff has proposed and the Company has already accepted. Ms. Diaz Cortez has also proposed a $400,000 adjustment to reduce operating expenses for business lunches. Business lunches are provided by the Company when employees are expected to continue to work during their personal lunch break. We believe these are legitimate business expenses that provide the Company the benefit of additional productive non-interrupted, non-paid work time from our employees. For these reasons, the Company does not agree with Ms. Diaz Cortez's recommendation to reduce operating expenses for these lunches.

Q. **WHAT ADVERTISING COSTS PRO FORMA ADJUSTMENT IS THE COMPANY PROPOSING?**

A. The Company is not opposed to Mr. Dittmer's $437,000 adjustment, $66,000 of Ms. Diaz Cortez's adjustment and Mr. Rigsby's $4,625.00 adjustment. An operating income adjustment of $508,000 is proposed to remove these costs from the Test Year Operations. *See* Attachment LLR–4-7RB.

I. Lobbying

Q. **DO YOU AGREE WITH THE STAFF POSITION THAT LOBBYING EXPENSES SHOULD BE RECORDED IN ACCOUNT NO. 426.4?**

A. We agree that lobbying expenses should be recorded in Account No. 426.4. FERC's instructions for Account 426.4 state:

> *This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the*

possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations. [Emphasis added.]

Q. DO THE FERC INSTRUCTIONS PROVIDE ANY ADDITIONAL GUIDANCE ON CHARGING PRACTICES FOR ACCOUNT NO. 426.4?

A. The FERC Instruction states that "the classification of expenses as non-operating and their inclusion in these accounts is for accounting purposes. It does not preclude Commission consideration of proof to the contrary for ratemaking or other purposes."

Q. FERC ACKNOWLEDGES THAT LOBBYING COSTS CHARGED TO FERC ACCOUNT 426.4 MAY BE CONSIDERED FOR RATE MAKING PURPOSES. DOES THE COMPANY BELIEVE THAT LOBBYING COSTS INCLUDED IN TEST YEAR OPERATING EXPENSES BENEFIT THE RATEPAYER?

A. Yes. Mr. Wheeler discusses the benefits of lobbying costs to the ratepayers and the appropriate inclusion of lobbying costs in operating expenses for ratemaking purposes in his Rebuttal Testimony.

J. Other Administrative and General Adjustments

Q. STAFF AND RUCO TESTIMONY PROPOSED PRO FORMA ADJUSTMENTS FOR OUT-OF-PERIOD EXPENSES INCLUDED IN THE TEST YEAR. PLEASE DISCUSS THESE ADJUSTMENTS.

A. Staff testimony by Mr. Dittmer identified $8,419,000 in out-of-period adjustments related to depreciation and rent expense. The $8,419,000 includes $5,098,000 in out-of-period adjustments for the PWEC Units. Ms. Diaz Cortez also identified

these depreciation and rent out-of-period costs, which are included in the amounts identified by Mr. Dittmer. Additionally, Mr. Dittmer identified $101,000 in legal costs related to the sale of the Silverhawk generating plant, which he recommended be removed from operating expenses. The Company does not oppose these pro forma adjustments totaling $8,520,000, which reduce operating expenses for out-of-period and legal administrative and general expenses. *See* Attachment LLR-4-8RB.

VIII. LIBERTY CONSULTING GROUP FUEL AUDIT

Q. THE STAFF'S FUEL AUDIT REPORT CONTAINS A CONCLUSION AND A RECOMMENDATION REGARDING ACCOUNTING FOR SUPPLEMENTAL FUEL CHARGES AND REFUNDS. PLEASE IDENTIFY THIS CONCLUSION AND RECOMMENDATION.

A. The Fuel Audit Report "Conclusion" section on page 140 states, "A review of APS handling of supplemental fuel charges and refunds have been accounted for in the PSA [Power Supply Adjustor] when applicable; the accounting methods are not consistent for purposes of recording refunds, but the inconsistency has not had a material impact on the PSA". The related "Recommendation" section on page 13 states that APS should, "Closely review and monitor adjustments to fuel costs to assure that supplemental charges and refunds appropriately consider the impact on inventory values and fuel expenses for financial reporting purposes."

Q. WHAT ARE THE ACCOUNTING TRANSACTIONS REFERENCED IN THESE SECTIONS OF THE FUEL AUDIT REPORT?

A. Staff's consultant reviewed three transactions related to railroad transportation charges for coal delivery. These charges included a refund settlement and retroactive rate reductions that were negotiated as part of a long term agreement. The Fuel Audit Report noted that two of the three transactions properly allocated

costs to both fuel expense and inventory based on the period of time that the adjustment related to. The third and final adjustment was charged to fuel expense. The Fuel Audit Report asserts that a portion of the adjustment related to the period of September 2005 thru December 2005 should have been allocated to inventory.

Q. DO YOU AGREE?

A. In retrospect, yes. The final settlement was signed on January 10, 2006, and was related to the period of September 2005 through December 2005. When the entry was made for the January 2005 financial statements, the assumption was that the actual inventory turn approximated the targeted inventory turn of 25 days, or would be close enough to reasonably record the entire amount as fuel expense for the month of January. Actually the inventory turn was about 45-60 days and the refund attributed to the month of December would have been more accurately allocated to inventory and not expensed in January. The refund attributed to December would flow through the inventory charged to fuel expense, and, thus, the PSA in February 2006.

Q. HOW DID THIS IMPACT THE PSA?

A. As noted by Staff's consultant, the only impact would be the amount of time it would have taken the costs to flow through the PSA. In this case, the costs would have flowed through the PSA in the following month. The Fuel Audit Report specifically states that this did not materially impact the PSA.

Q. WERE THESE TRANSACTIONS MONITORED AND REVIEWED AT THE TIME THE ENTRIES WERE RECORDED FOR FINANCIAL REPORTING PURPOSES?

A. Yes. This transaction was reviewed and approved at the time it was made.

Consideration was given to recording a portion of the entry to inventory and a judgment call was made at the time not to do so. As noted above, the amounts that should have been allocated to inventory were not material and did properly flow through the PSA account within 30 days.

IX. OFFSETS TO FINANCIAL IMPACTS OF PARTIES' RECOMMENDATIONS

A. Plant-In-Service

Q. HAVE YOU CALCULATED THE VALUE FOR THE ADDITIONAL PLANT-IN-SERVICE DISCUSSED IN MR. WHEELER'S REBUTTAL TESTIMONY?

A. Yes. The additional Plant-in-Service is $572,058,000.

Q. HOW DID YOU CALCULATE THE VALUE OF THE ADDITIONAL PLANT-IN-SERVICE?

A. The additional Plant-in-Service of $572,058,000 consists of both actual transfers to Plant-in-Service subsequent to September 30, 2005, and projected transfers to Plant-in-Service through December 31, 2006. This includes $395,634,000 in actual additions to Plant, net of actual retirements, for the period of October 1, 2005, through July 31, 2006. This also includes $176,424,000 of projected additions to Plant, net of estimated retirements, for the period of August 1, 2006, through December 31, 2006.

Q. HOW DID YOU DETERMINE THE INCREMENTAL RATE OF RETURN THAT APPLIES TO THE ADDITIONAL PLANT-IN-SERVICE?

A The incremental rate of return calculated to be 3.0% which is the difference between the 11.5% requested return on equity and the 8.5% projected return on equity at December 31, 2006.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT FOR THE ADDITIONAL PLANT-IN-SERVICE?

A. The calculated revenue requirement at an 11.5% return on equity for the additional plant-in-service is $13,480,000. *See* Attachment LLR-5-1RB.

Q. IF YOU UPDATE PLANT THROUGH YEAR-END 2006, DON'T YOU HAVE TO UPDATE OTHER COSTS AND REVENUES?

A. No. The 2006 return on equity of 8.5% already reflects the net impact of these other rate-making elements. By calculating only the incremental revenue requirements for this plant, we have implicitly synchronized the adjustment with related costs and revenues. If anything, this is conservative because, as can be seen by Mr. Brandt's Rebuttal Testimony, the Company's return on equity continues to decline in 2007 and 2008.

X. COMMISSION ACTION REQUESTED

Q. DOES THE COMPANY BELIEVE THAT THE COMMISSION NEEDS TO TAKE ANY FURTHER ACTION REGARDING THE APPROVAL OF DEPRECIATION RATES?

A. For purposes of clarity and transparency, we are requesting that the Commission formally authorize and approve, as it has in prior cases, the depreciation rates developed by Dr. White and included in his Direct Testimony as Attachments REW-1 and REW-2.

Q. IS THE COMPANY REQUESTING THAT THE COMMISSION TAKE ANY FURTHER ACTIONS REGARDING AMORTIZATION RATES?

A. Yes. As I stated in my Direct Testimony, the Company is not requesting any changes to the amortization rates authorized in Decision No. 67744. The Company is requesting that the Commission formally authorize the continued use

of the amortization rates that are currently in effect and approve two new amortization rates. The two *new* rates provide for the amortization of leased vehicles that are purchased by the Company at the end of the lease term. The Company is requesting a 50% amortization rate for vehicles with a Gross Vehicle Weight ("GVW") under 26,000 pounds and a 20% amortization rate for vehicles with a GVW greater than 26,000 pounds. The rates reflect what we believe will be the estimated useful lives for such vehicles. No party has objected to these rates. We are requesting that the Commission include Attachment LLR-2-11, the Amortization Rate Summary, as part of its final order.

Q. PLEASE SUMMARIZE THE COMMISSION ACTION THAT THE COMPANY REQUESTED IN YOUR DIRECT TESTIMONY RELATED TO DECOMMISSIONING AND SPENT FUEL STORAGE EXPENSE.

A. In my Direct Testimony, the Company requested that the Commission's Decision in this docket specifically provide for approval of the annual level of decommissioning funding and Spent Fuel Storage costs, as set forth in Attachment LLR-3, as well as the amortization of the Spent Fuel Cost regulatory asset included in Attachment LLR-2-2. Attachment LLR-3 should be attached to any Commission Decision accepting these amounts.

XI. CONCLUSION

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF ALLOWANCE FOR WORKING CAPITAL
Revised Schedule B-5
TEST YEAR ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION	REVISED REBUTTAL AMOUNT	AS FILED AMOUNT	INC/(DEC)	
1	WORKING CAPITAL - OPERATIONS	(34,157,681)	(29,138,598)	(5,019,083)	
2	MATERIALS & SUPPLIES[1]	106,426,822	106,426,822	0	A
3	FUEL - COAL AND OIL	25,452,192	25,452,192	0	B
4	FUEL - NUCLEAR, NET	59,888,780	59,888,780	0	C
5	PREPAYMENTS	5,517,425	5,517,425	0	
6	ALLOWANCE FOR WORKING CAPITAL	163,127,538	168,146,621	(5,019,083)	

Note [1]: Materials and Supplies include FERC 154 & 156

A + B + C =	191,767,794	191,767,794	0

SUMMARY OF ACCEPTED CHANGES

REVENUE LAG	(427,493)
PURCHASED POWER	2,691,284
PV LEASE	(7,139,392)
STATE TAX LAG	(143,482)
TOTAL	(5,019,083)

ARIZONA PUBLIC SERVICE COMPANY
CASH WORKING CAPITAL SUMMARY - LEAD LAG STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2005

LINE	DESCRIPTION	WORKING CAPITAL REQUIREMENT (SOURCE)
1	CASH REQUIRED FOR (PROVIDED BY) OPERATING EXPENSES	(34,391,952)
2	SPECIAL DEPOSITS AND WORKING FUNDS	234,271
3	NET CASH WORKING CAPITAL REQUIRED FOR (PROVIDED BY) OPERATIONS	(34,157,681)

ARIZONA PUBLIC SERVICE COMPANY
CASH WORKING CAPITAL REQUIRED FOR OPERATING EXPENSES - LEAD LAG STUDY
TWELVE MONTHS ENDED SEPTEMBER 30, 2005
REBUTTAL - REVISED

LINE	DESCRIPTION	AMOUNT	REVENUE LAG DAYS	EXPENSE LAG DAYS	NET LAG DAYS	CWC FACTOR	WORKING CAPITAL REQUIREMENT
		(1)	(2)	(3)	(4)	(5)	(6)
1	FUEL FOR ELECTRIC GENERATION:						
2	COAL	200,856,342	36.85231	32.36664	4.48567	0.01229	2,468,524
3	NATURAL GAS	237,557,927	36.85231	44.25857	-7.40626	-0.02029	(4,820,050)
4	FUEL OIL	1,077,082	36.85231	32.34060	4.51171	0.01236	13,313
5	NUCLEAR:						
6	AMORTIZATION	34,445,413	36.85231	0.00000	36.85231	0.10097	3,477,953
7	SPENT FUEL	7,336,099	36.85231	76.35359	-39.50128	-0.10822	(793,913)
8	TOTAL NUCLEAR FUEL	41,781,512					2,684,040
9							
10	TOTAL FUEL	481,272,863					345,827
11							
12	PURCHASED POWER	458,146,296	36.85231	38.15020	-1.29789	-0.00356	(1,631,001)
13	TRANSMISSION BY OTHERS	14,391,245	36.85231	33.69389	3.15842	0.00865	124,484
14	TOTAL PURCHASED POWER & TRANSMISSION	472,537,541					(1,506,517)
15							
16	TOTAL FUEL AND PURCHASED POWER	953,810,404					(1,160,690)
17							
18	OTHER OPERATIONS & MAINTENANCE:						
19	PAYROLL	240,714,447	36.85231	15.00192	21.85039	0.05986	14,409,167
20	INCENTIVE	8,653,091	36.85231	214.50000	-177.64769	-0.48671	(4,211,546)
21	PENSION AND OPEB	38,986,000	36.85231	77.71371	-40.86140	-0.11195	(4,364,483)
22	EMPLOYEE BENEFITS	26,995,515	36.85231	20.35895	16.49336	0.04519	1,219,927
23	PAYROLL TAXES	18,118,131	36.85231	21.78589	15.06642	0.04128	747,916
24	MATERIALS & SUPPLIES	53,466,114	36.85231	24.22000	12.63231	0.03461	1,850,462
25	FRANCHISE PAYMENTS	11,986,402	36.85231	52.83966	-15.98735	-0.04380	(525,004)
26	VEHICLE LEASE PAYMENTS	3,169,771	36.85231	7.43789	29.41442	0.08059	255,452
27	RENTS	6,776,038	36.85231	-33.48601	70.33832	0.19271	1,305,810
28	PALO VERDE LEASE	45,900,681	36.85231	103.99426	-67.14195	-0.18395	(8,443,430)
29	PALO VERDE S/L GAIN AMORT	(4,575,722)	36.85231	0.00000	36.85231	0.10097	(462,011)
30	INSURANCE	4,639,562	36.85231	0.00000	36.85231	0.10097	468,457
31	OTHER	119,131,971	36.85231	35.39000	1.46231	0.00401	477,719
32	TOTAL	573,962,000					2,728,436
33							
34	DEPRECIATION & AMORTIZATION	321,525,565	36.85231	0.00000	36.85231	0.10097	32,464,436
35	AMORT OF ELECTRIC PLT ACQ ADJ	0	36.85231	0.00000	36.85231	0.10097	0
36	AMORT OF PROP LOSSES & REG STUDY COSTS	(2,564,492)	36.85231	0.00000	36.85231	0.10097	(258,937)
37	TOTAL	318,961,073					32,205,499
38							
39	INCOME TAXES:						
40	CURRENT:						
41	FEDERAL	59,824,326	36.85231	58.95000	-22.09769	-0.06054	(3,621,765)
42	STATE	16,379,288	36.85231	62.05000	-25.19769	-0.06903	(1,130,662)
43	DEFERRED	77,758,889	36.85231	0.00000	36.85231	0.10097	7,851,315
44	TOTAL	153,962,503					3,098,888
45							
46	OTHER TAXES:						
47	PROPERTY TAXES	123,403,653	36.85231	211.94223	-175.08992	-0.47970	(59,196,732)
48	SALES TAXES	158,240,555	16.69615	40.21000	-23.51385	-0.06442	(10,193,857)
49	FRANCHISE TAXES	18,920,381	16.69615	52.83966	-36.14352	-0.09902	(1,873,496)
50	TOTAL OTHER TAXES	300,564,589					(71,264,085)
51							
52	TOTAL	2,301,260,569					(34,391,952)

SUMMARY OF ACCEPTED CHANGES	Revenue Lag Change Only	All Other	Total
REVENUE LAG	(427,493)	0	(427,493)
PURCHASED POWER	(354,716)	3,046,000	2,691,284
PV LEASE	(11,935)	(7,127,457)	(7,139,392)
STATE TAX LAG	(4,422)	(139,060)	(143,482)
Total	(798,566)	(4,220,517)	(5,019,083)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PALO VERDE UNIT 1 STEAM GENERATORS

Retire PV Unit 1 Steam Generators and LP Turbine Rotors.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ (36,684)
2.	Less: Accumulated Depreciation and Amortization	$ (36,684)
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ -
5.	Total Additions	$ -
6.	Total Rate Base	$ -

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: BARK BEETLE REGULATORY ASSET

Adjust regulatory asset balance for deferred taxes; updated projected costs through December 2006; and correction to original calculation.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ 2,793
5.	Total Additions	$ 1,038
6.	Total Rate Base	$ (1,755)

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Original Cost Rate Base as Shown on Schedule B-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: ALLOWANCE FOR WORKING CAPITAL

Net reduction to Cash Working Capital for Palo Verde Lease, Revenue Lag and Purchased Power.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	
5.	Total Additions	$ (5,019)
6.	Total Rate Base	$ (5,019)

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Adjusted Test Year Ended 09/30/2005
(Dollars in Thousands)

		Original Cost						RCND						
		Total Company			ACC			Total Company			ACC			
Line No.	Description	SFR B-1 Schedule as Filed on 1/31/06 (a)	Rebuttal Adjustments to B-1 (b)	Rebuttal Adjusted B-1 (c)	SFR B-1 Schedule as Filed on 1/31/06 (d)	Rebuttal Adjustments to B-1 (e)	Rebuttal Adjusted B-1 (f)	SFR B-1 Schedule as Filed on 1/31/06 (g)	Rebuttal Adjustments to B-1 (h)	Rebuttal Adjusted B-1 (i)	SFR B-1 Schedule as Filed on 1/31/06 (j)	Rebuttal Adjustments to B-1 (k)	Rebuttal Adjusted B-1 (l)	Line No.
1	Gross Utility Plant in Service	$10,893,882	$ (36,884)	$ 10,857,198	$9,296,308	$ (36,261)	$9,260,047	$17,842,146	$ (62,939)	$17,779,207	$15,219,192	$ (62,213)	$15,156,979	1
2	Less: Accumulated Depreciation	4,168,540	(36,684)	4,131,856	3,546,560	(36,261)	3,510,299	7,241,636	(62,939)	7,178,697	6,161,346	(62,213)	6,099,133	2
3	Net Utility Plant in Service	6,725,342	-	6,725,342	5,749,748	-	5,749,748	10,600,510	-	10,600,510	9,057,846	-	9,057,846	3
	Deductions:													
4	Deferred Taxes	1,205,461	303	1,205,764	1,064,449	447	1,064,896	1,205,444	303	1,205,747	1,064,432	447	1,064,879	4
5	Investment Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	5
6	Customer Advances for Construction	59,807	-	59,807	59,807	-	59,807	59,807	-	59,807	59,807	-	59,807	6
7	Customer Deposits	54,860	-	54,860	54,860	-	54,860	54,860	-	54,860	54,860	-	54,860	7
8	Pension Liability	72,920	-	72,920	68,699	-	68,699	72,920	-	72,920	68,699	-	68,699	8
9	Liability for Asset Retirement	263,457	-	263,457	260,419	-	260,419	263,457	-	263,457	260,419	-	260,419	9
10	Other Deferred Credits	111,791	6,376	118,167	109,485	6,007	115,492	111,791	6,376	118,167	109,485	6,007	115,492	10
11	Unamortized Gain-sale of Utility Plant	46,901	-	46,901	46,360	-	46,360	46,901	-	46,901	46,360	-	46,360	11
12	Regulatory Liabilities	168,048	-	168,048	160,744	-	160,744	168,048	-	168,048	160,744	-	160,744	12
13	Total Deductions	1,983,245	6,679	1,989,924	1,824,823	6,454	1,831,277	1,983,228	6,679	1,989,907	1,824,806	6,454	1,831,260	13
	Additions:													
14	Regulatory Assets	84,531	-	84,531	64,020	-	64,020	84,531	-	84,531	64,020	-	64,020	14
15	Miscellaneous Deferred Debits	42,522	1,038	43,560	39,464	1,038	40,502	42,522	1,038	43,560	39,464	1,038	40,502	15
16	Depreciation Fund - Decommissioning	290,537	-	290,537	285,855	-	285,855	290,537	-	290,537	285,855	-	285,855	16
17	Allowance for Working Capital	168,146	(5,019)	163,127	152,433	(4,344)	148,089	168,146	(5,019)	163,127	152,433	(4,344)	148,089	17
18	Total Additions	585,736	(3,981)	581,755	541,772	(3,306)	538,466	585,736	(3,981)	581,755	541,772	(3,306)	538,466	18
19	Total Rate Base	$ 5,327,833	$ (10,660)	$ 5,317,173	$4,466,697	$ (9,760)	$4,456,937	$ 9,203,018	$ (10,660)	$ 9,192,358	$ 7,774,812	$ (9,760)	$ 7,765,052	19

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(1) SFR Sch. B-2 Total as filed on Jan. 31, 2006 Test Year 9/30/2005		(2) REBUTTAL Long Term Disability (SFAS 112)		(3) REBUTTAL Bark Beetle Regulatory Asset	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service	$ 10,893,882	$ 9,296,308	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	4,168,540	3,546,560	-	-	-	-
3.	Net Utility Plant in Service	6,725,342	5,749,748	-	-	-	-
4.	Less: Total Deductions	1,983,245	1,824,823	3,886	3,661	2,793	2,793
5.	Total Additions	585,736	541,772	-	-	1,038	1,038
6.	Total Rate Base	$ 5,327,833	$ 4,466,697	$ (3,886)	$ (3,661)	$ (1,755)	$ (1,755)
				FROGGATT		ROCKENBERGER	

(1) Total Rate Base Adjustments from APS' Direct Testimony filed on Jan. 31, 2006. Please see SFR Schedule B-2, page 3, columns (M) and (N).

(2) Additional rate base pro forma to include deferred credits related to expenses for employees on long term disability.

(3) Adjust regulatory asset balance for deferred taxes; updated projected costs through December 2006; and correction to original calculation.

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(4) REBUTTAL Allowance for Working Capital Total Co. (G)	(4) REBUTTAL Allowance for Working Capital ACC (H)	(5) REBUTTAL Palo Verde Unit 1 Steam Generators Total Co. (I)	(5) REBUTTAL Palo Verde Unit 1 Steam Generators ACC (J)	(6) REBUTTAL Total Original Cost Rate Base Pro Forma Adjustments Total Co. (K)	(6) REBUTTAL Total Original Cost Rate Base Pro Forma Adjustments ACC (L)
1.	Gross Utility Plant in Service	$ -	$ -	$ (36,684)	$ (36,261)	$ (36,684)	$ (36,261)
2.	Less: Accumulated Depreciation & Amort.	-	-	(36,684)	(36,261)	(36,684)	(36,261)
3.	Net Utility Plant in Service	-	-	-	-	-	-
4.	Less: Total Deductions	-	-	-	-	6,679	6,454
5.	Total Additions	(5,019)	(4,344)	-	-	(3,981)	(3,306)
6.	Total Rate Base	$ (5,019)	$ (4,344)	$ -	$ -	$ (10,660)	$ (9,760)
		ROCKENBERGER		ROCKENBERGER			

(4) Net reduction to Cash Working Capital for Palo Verde Lease, Revenue Lag and Purchased Power.

(5) Retire Palo Verde Unit 1 Steam Generators and Low Pressure Turbine Rotors.

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(7) REBUTTAL Adjusted for Rebuttal at the end of Test Year 9/30/2005 Total Co. (M)	ACC (N)
1.	Gross Utility Plant in Service	$ 10,857,198	$ 9,260,047
2.	Less: Accumulated Depreciation & Amort.	4,131,856	3,510,299
3.	Net Utility Plant in Service	6,725,342	5,749,748
4.	Less: Total Deductions	1,989,924	1,831,277
5.	Total Additions	581,755	538,466
6.	Total Rate Base	$ 5,317,173	$ 4,456,937

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(1) SFR Sch. B-3 Total as filed on Jan. 31, 2006 Test Year 9/30/2005		(2) REBUTTAL Long Term Disability (SFAS 112)		(3) REBUTTAL Bark Beetle Regulatory Asset	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Gross Utility Plant in Service (a)	$ 17,842,146	$ 15,219,192	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort. (a)	7,241,636	6,161,346	-	-	-	-
3.	Net Utility Plant in Service (a)	10,600,510	9,057,846	-	-	-	-
4.	Less: Total Deductions	1,983,228	1,824,806	3,886	3,661	2,793	2,793
5.	Total Additions	585,736	541,772	-	-	1,038	1,038
6.	Total Rate Base	$ 9,203,018	$ 7,774,812	$ (3,886)	$ (3,661)	$ (1,755)	$ (1,755)
				FROGGATT		ROCKENBERGER	

(1) Total Rate Base Adjustments from APS' Direct Testimony filed on Jan. 31, 2006. Please see SFR Schedule B-3, page 3, columns (M) and (N).

(2) Additional rate base pro forma to include deferred credits related to expenses for employees on long term disability.

(3) Adjust regulatory asset balance for deferred taxes; updated projected costs through December 2006; and correction to original calculation.

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(4) REBUTTAL Allowance for Working Capital Total Co. (G)	(4) REBUTTAL Allowance for Working Capital ACC (H)	(5) REBUTTAL Palo Verde Unit 1 Steam Generators Total Co. (I)	(5) REBUTTAL Palo Verde Unit 1 Steam Generators ACC (J)	(6) REBUTTAL Total Original Cost Rate Base Pro Forma Adjustments Total Co. (K)	(6) REBUTTAL Total Original Cost Rate Base Pro Forma Adjustments ACC (L)
1.	Gross Utility Plant in Service (a)	$ -	$ -	$ (62,939)	$ (62,213)	$ (62,939)	$ (62,213)
2.	Less: Accumulated Depreciation & Amort. (a)	-	-	(62,939)	(62,213)	(62,939)	(62,213)
3.	Net Utility Plant in Service (a)	-	-	-	-	-	-
4.	Less: Total Deductions	-	-	-	-	6,679	6,454
5.	Total Additions	(5,019)	(4,344)	-	-	(3,981)	(3,306)
6.	Total Rate Base	$ (5,019)	$ (4,344)	$ -	$ -	$ (10,660)	$ (9,760)
		ROCKENBERGER		ROCKENBERGER			

(4) Net reduction to Cash Working Capital for Palo Verde Lease, Revenue Lag and Purchased Power.

(5) Retire Palo Verde Unit 1 Steam Generators and Low Pressure Turbine Rotors.

ARIZONA PUBLIC SERVICE COMPANY
RCND Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

Line No.	Description	(7) REBUTTAL Adjusted at the end of Test Year 9/30/2005 Total Co. (M)	ACC (N)
1.	Gross Utility Plant in Service (a)	$ 17,779,207	$ 15,156,979
2.	Less: Accumulated Depreciation & Amort. (a)	7,178,697	6,099,133
3.	Net Utility Plant in Service (a)	10,600,510	9,057,846
4.	Less: Total Deductions	1,989,907	1,831,260
5.	Total Additions	581,755	538,466
6.	Total Rate Base	$ 9,192,358	$ 7,765,052

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PALO VERDE UNIT 1 STEAM GENERATORS DEPRECIATION

Remove Test Year depreciation expense related to the old low pressure turbine rotors that were retired.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Depreciation and Amortization	$ (262)
4.	Total Pro Forma Adjustment to Expenses	$ (262)
5.	**OPERATING INCOME (before income tax)**	**$ 262**
6.	Interest Expense	-
7.	**Taxable Income**	**$ 262**
8.	Income Tax at 39.05%	102
9.	**OPERATING INCOME AFTER TAX**	**$ 160**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: BARK BEETLE

Update Test Year expense to reflect revised bark beetle remediation costs.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Operations Excluding Fuel Expenses	$ 110
4.	Total Pro Forma Adjustment to Expenses	$ 110
5.	**OPERATING INCOME (before income tax)**	**$ (110)**
6.	Income Tax at 39.05%	(43)
7.	**OPERATING INCOME AFTER TAX**	**$ (67)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: SPENT FUEL STORAGE

Adjustment to Test Year operations for current period spent nuclear fuel storage costs.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Fuel Expenses	$ (264)
3.	Other Operating Expenses	
4.	Operations Excluding Fuel Expenses	
5.	Maintenance	
6.	Total Pro Forma Adjustment to Expenses	$ (264)
7.	**OPERATING INCOME (before income tax)**	**$ 264**
8.	Interest Expense	
9.	**Taxable Income**	**$ 264**
10.	Income Tax at 39.05%	103
11.	**OPERATING INCOME AFTER TAX**	**$ 161**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PROPERTY TAXES

Adjustment to Test Year operations to remove the 2007 phase-in cost increase for new generation plant.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Other Taxes	$ (1,708)
4.	Total Pro Forma Adjustment to Expenses	$ (1,708)
5.	**OPERATING INCOME (before income tax)**	**$ 1,708**
6.	Income Tax at 39.05%	667
7.	**OPERATING INCOME AFTER TAX**	**$ 1,041**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: PENSION

Adjustment to Test Year operations to reflect actual 2006 pension expense.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses	$ -	
3.	Other Operating Expenses		
4.	Operations Excluding Fuel Expenses	2,249	
5.	Maintenance		
6.	Total Pro Forma Adjustment to Expenses		$ 2,249
7.	**OPERATING INCOME (before income tax)**		**$ (2,249)**
8.	Income Tax at 39.05%		(878)
9.	**OPERATING INCOME AFTER TAX**		**$ (1,371)**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: POST RETIREMENT MEDICAL BENEFITS

Adjustment to Test Year operations to reflect actual 2006 post retirement medical expenses.

Line No.	Description		Amount
1.	**EXPENSES:**		
2.	Fuel Expenses	$ -	
3.	Other Operating Expenses		
4.	Operations Excluding Fuel Expenses	(3,191)	
5.	Maintenance		
6.	Total Pro Forma Adjustment to Expenses		$ (3,191)
7.	**OPERATING INCOME (before income tax)**		**$ 3,191**
8.	Income Tax at 39.05%		1,246
9.	**OPERATING INCOME AFTER TAX**		**$ 1,945**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: ADVERTISING

Adjustment to Test Year operations to exclude advertising expenses related to Company branding.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ -
3.	Fuel and Purchased Power Expense	-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$ -
5.	**EXPENSES:**	
6.	Other Operating Expense	
7.	Operations Excluding Fuel Expense	(171)
8.	Maintenance	-
9.	Subtotal	(171)
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	(337)
13.	Other Taxes	-
14.	Total	(508)
15.	**OPERATING INCOME (before income tax)**	**$ 508**
16.	Interest Expense	-
17.	**Taxable Income**	**$ 508**
18.	Income Tax at 39.05%	198
19.	**OPERATING INCOME AFTER TAX**	**$ 310**

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2
Total Company
(Thousands of Dollars)

PRO FORMA ADJUSTMENT: Administrative and General

Remove out-of-period and other legal costs from administrative and general expense.

Line No.	Description	Amount
1.	**REVENUES:**	
2.	Operating Revenue	$ -
3.	Fuel and Purchased Power Expense	-
4.	Operating Revenues less Fuel and Purchased Power Expenses	$ -
5.	**EXPENSES:**	
6.	Other Operating Expense	
7.	Operations Excluding Fuel Expense	-
8.	Maintenance	-
9.	Subtotal	-
10.	Depreciation and Amortization	-
11.	Amortization of Gain	-
12.	Administrative and General	(8,520)
13.	Other Taxes	-
14.	Total	(8,520)
15.	**OPERATING INCOME (before income tax)**	**$ 8,520**
16.	Interest Expense	-
17.	**Taxable Income**	**$ 8,520**
18.	Income Tax at 39.05%	3,327
19.	**OPERATING INCOME AFTER TAX**	**$ 5,193**

Revenue Requirement for Additional Plant-in-Service

1.	Total Plant in Service 12/31/06 (contains estimated Jul-Dec)	$	11,369,664,724
2.	Total Plant in Service 9/30/05	$	10,797,607,202
3.	Increased Plant in Service	$	572,057,522
4.	Requested ROE		11.5%
5.	Projected 12/31/06 ROE		8.5%
6.	ROE Shortfall		3.0%
7.	Net Increased Plant In Service	$	572,057,522
8.	ROE Shortfall		3.0%
		$	17,161,726
9.	Equity percentage of capitalization structure		54.5%
		$	9,353,140
10.	Revenue Conversion Factor		1.6407
11.	Total Revenue Requirement	$	15,345,698
12.	ACC Jurisdictional Factor		87.84%
13.	**ACC Revenue Requirement**	**$**	**13,479,661**

REBUTTAL TESTIMONY OF CHRIS N. FROGGATT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

Table of Contents

I. INTRODUCTION 1

II. SUMMARY OF TESTIMONY 1

III. STAFF AND INTERVENOR RECOMMENDED ADJUSTMENTS 3

- A. Unregulated APS Marketing & Trading Activity 3
- B. Federal and State Income Tax 4
- C. Rate Base Offset for Long Term Disability (SFAS 112) 4
- D. Interest on Customer Deposits 5
- E. Generation Production Deduction 5
- F. Income Tax/Interest Synchronization 6
- G. Out-of-Period Tax Consulting Fees 7
- H. Investment Tax Credit Rate Base Reduction 9

IV. CONCLUSION 11

ATTACHMENTS

- Adjustment to Schedule C-1 ..... Attachment CNF-1RB
- Adjustment to Schedule C-2 ..... Attachment CNF-2RB
- Unregulated APS Marketing and Trading Activity ..... Attachment CNF-3RB
- Federal and State Income Tax ..... Attachment CNF-4RB
- Rate Base Offset For Long Term Disability (SFAS 112) ..... Attachment CNF-5RB
- Interest on Customer Deposits ..... Attachment CNF-6RB
- Generation Production Deduction ..... Attachment CNF-7RB
- Income Tax / Interest Synchronization ..... Attachment CNF-8RB
- Tax Consulting Fees ..... Attachment CNF-9RB

REBUTTAL TESTIMONY OF CHRIS N. FROGGATT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Chris N. Froggatt, and I am Vice President and Controller for Arizona Public Service Company ("APS" or "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed Direct Testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to address several adjustments to operating income proposed by Staff and RUCO witnesses. I will also address two proposed rate base adjustments. I will indicate where we are in agreement with those recommendations, and will discuss those that I do not believe are appropriate or accurate. In addition, I will present the Company's revised income statement, which incorporates the adjustments the Company has accepted as discussed herein.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. Staff and intervenors in this case have proposed both rate base and operating income adjustments to the Company's original request. In some cases, proposals are for reasonable revisions due to legislative changes, updated information that was not available at the time the Company filed its original request, or corrections for errors uncovered during the discovery process. Other adjustments that have been proposed are clearly inappropriate or inaccurate, and I discuss why these adjustments should either be revised or not accepted at all. Specifically, I discuss the following proposed operating income adjustments with which I agree:

- Staff and RUCO's Unregulated Marketing and Trading adjustment
- Staff's Income Tax adjustment

In addition, I agree with Staff and RUCO's rate base adjustment related to long term disability deferrals (SFAS 112).

The following proposed operating income adjustments are those with which I agree in principle, but portions of the calculations require corrections, which I discuss:

- RUCO's Interest on Customer Deposits adjustment
- Staff's Generation Production Deduction adjustment
- Staff and RUCO's Income Tax/Interest Synchronization adjustment
- RUCO's Out-of-Period Tax Consulting Fee adjustment

However, I do not agree with Staff's Investment Tax Credit rate base adjustment.

Additional Staff and intervenor operating income pro forma recommendations are addressed by APS witnesses Laura L. Rockenberger, Peter M. Ewen, and David J. Rumolo in their Rebuttal Testimony. Ms. Rockenberger will also address the remainder of the proposed adjustments to rate base.

Additionally, the Company's Adjustments to Schedule C-1, the revised income statement which incorporates all adjustments accepted or corrected by the Company, is attached to my testimony as Attachment CNF-1RB. I sponsor the Total Company calculations that are presented on page 1. Attachment CNF-2RB is the Company's Adjustments to Schedule C-2, which individually presents each adjustment, including those adjustments that other Company witnesses are discussing. Of these adjustments, I am sponsoring the Total Company column for those which I have listed above and discuss in my Rebuttal Testimony.

All jurisdictional allocations shown on the attached Adjustments to Schedule C-1 and C-2 have been calculated using the same factors that were used in APS' January 31, 2006 filing, and were addressed by Mr. Rumolo in his Direct Testimony.

The overall change in the Company's rate request, which includes these revisions, is addressed by APS witness Steven M. Wheeler in his Rebuttal Testimony.

III. STAFF AND INTERVENOR RECOMMENDED ADJUSTMENTS

A. Unregulated APS Marketing & Trading Activity

Q. DO YOU AGREE WITH AN ADJUSTMENT TO REMOVE UNREGULATED APS MARKETING AND TRADING ACTIVITY AS IS RECOMMENDED BY BOTH STAFF AND RUCO?

A. Yes, I do. During the discovery process, the Company became aware that it had inadvertently failed to exclude revenue and expenses associated with APS' unregulated marketing and trading activities. These activities relate to transactions that are not used to serve APS native load, and therefore should have been excluded in the Company's test year calculations. This adjustment is proposed in

Staff Schedules C-4 and C-5, sponsored by Staff witness Dittmer, and in the Direct Testimony of RUCO witness Diaz Cortez on page 24. This additional adjustment increases test year pre-tax operating income by $15.1 million, and is shown on Attachment CNF-3RB.

B. Federal and State Income Tax

Q. DID STAFF PROPOSE A REVISION TO THE FEDERAL AND STATE INCOME TAX PRO FORMA ADJUSTMENT?

A. Yes. As part of the discovery process, Staff and the Company agreed upon a "top down" cost-of-service income tax expense calculation. This calculation uses 2006 levels of various tax credits and other permanent tax items to estimate on-going income tax expense. This calculation is shown on Staff Schedule C-20, sponsored by Mr. Dittmer, and reduces test year income tax expense by $4.8 million. I agree with Staff's proposal and this adjustment is set forth on Attachment CNF-4RB.

C. Rate Base Offset for Long Term Disability (SFAS 112)

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATION OF STAFF AND RUCO TO ADJUST RATE BASE FOR LONG TERM DISABILITY DEFERRED CREDITS (SFAS 112)?

A. Yes. Mr. Dittmer presents Staff's proposed rate base adjustment on Staff Schedule B-1, and Ms. Diaz Cortez discusses RUCO's proposed adjustment on pages 7 and 8 of her Direct Testimony. Deferred credits related to expenses for employees on long-term disability were incorrectly excluded from rate base. The expenses are included in the test year and the related credit should likewise be included as a rate base offset. The calculation is shown on Attachment CNF-5RB and results in a rate base reduction of $3.9 million.

D. Interest on Customer Deposits

Q. WHAT IS THE OPERATING INCOME ADJUSTMENT PROPOSED BY RUCO WITNESS RIGSBY REGARDING INTEREST ON CUSTOMER DEPOSITS?

A. On RUCO Schedule WAR-1, Mr. Rigsby calculates an adjustment for interest on customer deposits of $2.5 million, which results in an increase of $976,000 over the Company's original proposal. RUCO recommends using the most recent interest rate (as determined in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access, paragraph 2.7.4) available prior to the filing deadline for direct testimony. In this case, the most recent rate is the 2006 rate of 4.38 percent, in contrast to the 2005 rate of 2.79 percent used by the Company in its January Filing.

Q. DO YOU AGREE WITH THIS ADJUSTMENT?

A. I agree with the principle of adjusting this interest rate to the most recently available rate. However, it appears that RUCO inadvertently utilized the March 31, 2006 deposit balance rather than the test year balance at September 30, 2005. Using the September 30, 2005 balance multiplied by the revised rate results in a total interest expense of $2.4 million. This revised calculation is shown on Attachment CNF-6RB and results in a pre-tax operating income decrease of $871,000 from the Company's January Filing calculation.

E. Generation Production Deduction

Q. DO YOU AGREE WITH STAFF'S ADJUSTMENT TO THE COMPANY'S ORIGINAL GENERATION PRODUCTION INCOME TAX DEDUCTION CALCULATION?

A. I agree in principle with the changes to the Generation Production Deduction calculation as discussed by Staff witness Dittmer on pages 126 through 128 of his

Direct Testimony. Staff presents a series of appropriate revisions to the Company's original calculation, based on the final Treasury Regulations pursuant to the American Jobs Creation Act, which were not available when the Company filed its direct testimony on this issue.

Q. DO YOU DISAGREE WITH A PORTION OF STAFF'S ADJUSTMENT?

A. Yes, I do. Staff calculates its deduction adjustment using its proposed weighted cost of common equity. As discussed by APS witness Donald Brandt in his Rebuttal Testimony, the Company does not agree with Staff's recommended weighted cost. Therefore, I have recalculated the deduction adjustment using Staff's proposed changes, but with the Company's recommended capital structure. This revised calculation results in a reduction in income tax of approximately $3.1 million, an additional $1.2 million reduction from the calculation included in the Company's January Filing pro forma adjustments. The Company's recalculated Generation Production Deduction is shown on Attachment CNF-7RB. Ultimately, this adjustment should reflect the cost of capital used by the Commission to establish rates in its final order.

F. Income Tax/Interest Synchronization

Q. PLEASE DESCRIBE THE PURPOSE OF AN INCOME TAX/INTEREST SYNCHRONIZATION PRO FORMA ADJUSTMENT.

A. The purpose of this adjustment is to align the cost of long-term debt and the capital structure, which was utilized as a part of the calculation of the Company's rate request, with the effect of pro forma adjustments made to the test year rate base. Therefore, when a rate base pro forma adjustment is revised (which would reflect a change in future capital requirements, possibly requiring a different cost or level of debt acquisition), this synchronization pro forma must be revised as

well to reflect any change in the Company's cost or level of debt related to that revision. Resultant income tax changes due to increases or decreases in debt are then included in operating income.

Q. DID STAFF AND RUCO PROPOSE CHANGES IN THE COMPANY'S ORIGINAL SYNCHRONIZATION PRO FORMA?

A. Yes. Staff's recommendation is proposed by Mr. Dittmer and presented on Schedule C-19. RUCO's adjustment is sponsored by Mr. Rigsby and is shown on Schedule WAR-3.

Q. DO YOU AGREE WITH THEIR ADJUSTMENTS?

A. I agree that it is appropriate to revise the synchronization adjustment as revisions to rate base and/or cost or level of debt are proposed. However, because the Company does not agree with all of the Staff and RUCO rate base adjustments, or changes to the Company's weighted cost of debt, I do not agree with their specific synchronization calculations.

Q. WHAT IS THE COMPANY'S PROPOSED ADJUSTMENT?

A. The Company's proposed synchronization adjustment calculation is presented on Attachment CNF-8RB. The calculation reflects rate base adjustments accepted or recalculated by the Company and results in a synchronization adjustment decrease of $263,000 in interest expense.

G. Out-of-Period Tax Consulting Fees

Q. ARE YOU IN AGREEMENT WITH RUCO'S PROPOSED ADJUSTMENT FOR OUT-OF-PERIOD TAX CONSULTING FEES?

A. Yes, I am. These consulting fees were incurred to prepare a claim made by APS to the IRS for certain Investment Tax Credits ("ITCs") that was ultimately

successful. This expense was incurred prior to the beginning of the test year, is not an on-going expense, and is appropriate to exclude from operating expense.

The adjustment proposed by RUCO does not include an additional expense of $1.5 million recorded in the test year. This additional expense, although recorded during the test year, is non-recurring and should also be removed from operating expense. This revision increases RUCO's adjustment from a $1.2 million reduction to operating expense (as discussed in Ms. Diaz Cortez's Direct Testimony at page 21) to a $2.8 million operating expense reduction, as shown on Attachment CNF-9RB.

Q. DID STAFF ADDRESS THIS SAME OUT-OF-PERIOD CONSULTING FEE?

A. Yes, Mr. Dittmer addresses this fee in Staff's Schedule C-12. Staff includes both portions of the fee in its calculation, but proposes that the expense reduction be split on a 50/50 basis between ratepayers and the Company as part of a larger proposal involving the ITCs themselves as a rate base reduction. I do not agree with the overall Staff proposal regarding these ITCs and the corresponding consulting fees. I believe both the fees and the tax credits are appropriately removed from regulated cost of service in their entirety.

Q. WHY DO YOU BELIEVE BOTH THE FEES AND THE TAX CREDITS ARE APPROPRIATELY REMOVED FROM REGULATED COST OF SERVICE AND RATE BASE?

A First, as I discuss above in full agreement with Staff and RUCO, both the fees and the related tax credits are non-recurring and clearly unrelated to the test year.

Second, as part of the 1994 settlement (Docket No. U-1345-94-120, Decision No. 58644), the Company was authorized to accelerate below the line amortization of all deferred ITC's in order to fully amortize those credits over a five year period beginning in 1995. Staff's proposed adjustment is not consistent with this treatment.

Lastly, I will address the rate base portion of Staff's proposal below.

H. Investment Tax Credit Rate Base Reduction

Q. PLEASE DISCUSS STAFF'S RATE BASE PROPOSAL REGARDING ITCs.

A. These ITCs are income tax credits, originally issued by the IRS in 1962 specifically for reinvestment purposes, which were realized by APS as a result of our recent claim requesting additional credits for a specific transition period after repeal of the ITCs in 1986 (as allowed by law). In Schedule B-3, Staff has proposed a 50/50 sharing of the ITCs.

Q. DO YOU AGREE WITH THIS PROPOSAL?

A. No. It is clear, based on discussions with outside legal counsel, that Staff's proposed treatment would constitute an IRS normalization violation.

Q. WHY DOES THIS TREATMENT CONSTITUTE A NORMALIZATION VIOLATION?

A. Of the additional ITCs allowed as a result of this claim, the majority (62%) relates to nuclear fuel. Under the ITCs regulations, a Company rate base offset (as proposed by Staff) requires a corresponding below-the-line amortization of the ITCs over time. The amortization period can vary, but in no event can it exceed the remaining useful life of the related asset. This fuel, being fully spent years

ago, has no remaining useful life. Therefore, under no circumstances can the related ITCs be treated as a rate base offset and amortized 15 years after the fact. This clearly constitutes a normalization violation.

In fact, there have been several recent (2005 - 2006) IRS rulings on this subject, in response to utilities that have sought to continue the amortization of existing ITCs balances despite the fact that the facilities to which the ITCs was related were transferred or sold. The IRS has consistently issued adverse rulings premised on the fact that the related facilities had no remaining useful life.

Q. THAT COVERS ONLY A PORTION OF THE ITC. WHAT ABOUT THE REMAINING PORTION?

A. The remainder of the additional ITCs (38%) relates to facilities that may have a remaining useful life. However, APS is in the unique situation of receiving the ITC 15 to 20 years into the useful life of the related assets (as our claim related to the tax years 1986-1990). It is likely that tax authorities would determine that any rate base offset allowed would be limited to what would have been the unamortized 2006 balance from the time the assets were placed in service. If the balance is required to be calculated in this manner, Staff's proposed treatment for this remaining portion would be a normalization violation as well. Determination of the treatment of these ITC's would have to be requested from the IRS in the form of a Private Letter Ruling.

Q. DO PENALTIES EXIST FOR NORMALIZATION VIOLATIONS?

A. Yes. Tax law regarding normalization violations for ITC's specifies that a violation results in a full disallowance of the entire ITC originally allowed for those years within the statue of limitations. The Company's statute of limitations

remains open back to the 1980's. This would be a significant liability for APS and, ultimately, its customers.

Therefore, for all these reasons discussed above, I do not support Staff's ITC proposal.

IV. CONCLUSION

Q. WHAT IS THE IMPACT OF ADDITIONAL ADJUSTMENTS ON THE COMPANY'S TEST YEAR OPERATING INCOME?

A. All Staff and intervenor recommended adjustments that the Company agrees with or has revised, including those addressed by other Company witnesses, are shown on Attachment CNF-2RB. These adjustments result in an Adjusted Total Company net income of $(51,137,000) for the test year ending September 30, 2005, as shown on Attachment CNF-1RB, page 1. This is an increase of $4,032,000 over the January Filing of Adjusted Total Company test year net income.

As I mentioned earlier, the overall change to the Company's rate request, which includes this adjusted test year net income, is presented and discussed by Mr. Wheeler in his Rebuttal Testimony.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

1885728.1

ARIZONA PUBLIC SERVICE COMPANY
Total Company
Adjusted Test Year Income Statement
Test Year 12 Months Ended 09/30/2005

(Dollars in Thousands)

Line No.	Description	Total Company: SFR Schedule C-1 as Filed on 1/31/06 (a)	Rebuttal Adjustments to C-1 (b)	Rebuttal Adjusted C-1 (c)
1	Electric Operating Revenues	$ 3,509,720	$ (836,652)	$ 2,673,068
2	Purchased power and fuel costs	2,174,283	(810,949)	1,363,334
3	Operating revenues less purchased power and fuel costs	1,335,437	(25,703)	1,309,734
4	Other operating expenses:			
5	Operation and maintenance	684,209	(20,565)	663,644
6	Depreciation and amortization	344,690	(262)	344,428
7	Income taxes	9,952	(7,200)	2,752
8	Other taxes	141,839	(1,708)	140,131
9	Total	1,180,690	(29,735)	1,150,955
10	Operating income	154,747	4,032	158,779
11	Other income (deductions):			
12	Income taxes	56,698		56,698
13	Allowance for equity funds used during construction	10,433		10,433
14	Regulatory disallowance	(143,217)		(143,217)
15	Other income	26,019		26,019
16	Other expense	(15,176)		(15,176)
17	Total	(65,243)	-	(65,243)
18	Income before income deductions	89,504	4,032	93,536
19	Interest deductions:			
20	Interest on long-term debt	141,301	-	141,301
21	Interest on short-term debt	6,285		6,285
22	Debt discount, premium and expense	4,344		4,344
23	AFUDC - debt	(7,257)		(7,257)
24	Total	144,673	-	144,673
25	Net Income	$ (55,169)	$ 4,032	$ (51,137)

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Income Statement
Test Year 12 Months Ended 9/30/2005

(Dollars in Thousands)

Line No.	Description	ACC Jurisdiction SFR Schedule C-1 as Filed on 1/31/06 (a)	Rebuttal Adjustments to C-1 (b)	Rebuttal Adjusted C-1 (c)
1	Electric operating revenues	$ 3,440,590	$ (823,174)	$ 2,617,416
2	Purchased power and fuel costs	2,129,741	(797,409)	1,332,332
3	Operating revenues less purchased power and fuel costs	1,310,849	(25,765)	1,285,084
4	Other operating expenses:			
5	Operation and maintenance	766,212	(20,209)	746,003
6	Depreciation and amortization	306,988	(259)	306,729
7	Income taxes	395	(7,116)	(6,721)
8	Payroll and Other taxes	121,350	(1,688)	119,662
9	Total	1,194,945	(29,272)	1,165,673
10	Operating income	$ 115,904	$ 3,507	$ 119,411

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(1) SFR Sch. C-2 Total as filed on Jan. 31, 2006 Income Statement Adjustments		(2) REBUTTAL Tax Consulting Fees		(3) REBUTTAL Unregulated APS Marketing and Trading Activity	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)	ACC (F)
1.	Electric Operating Revenues	$ 138,174	$ 137,135	$ -	$ -	$ (849,248)	$ (835,567)
2.	Purchased Power and Fuel Costs	351,718	350,695	-	-	(855,618)	(841,847)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(213,544)	(213,560)	-	-	6,370	6,280
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	65,716	63,234	(2,778)	(2,746)	(6,618)	(6,511)
5.	Maintenance	17,131	16,756	-	-	-	-
6.	Subtotal	82,847	79,990	(2,778)	(2,746)	(6,618)	(6,511)
7.	Depreciation and Amortization	25,806	23,504	-	-	-	-
8.	Amortization of Gain	(77)	(71)	-	-	-	-
9.	Administrative and General	27,400	24,958	-	-	(2,161)	(2,126)
10.	Other Taxes	16,867	16,719	-	-	-	-
11.	Total	152,843	145,100	(2,778)	(2,746)	(8,779)	(8,637)
12.	Operating Income Before Income Tax	(366,387)	(358,660)	2,778	2,746	15,149	14,917
13.	Interest Expense	(5,669)	(4,470)	-	-	-	-
14.	Taxable Income	(360,718)	(354,190)	2,778	2,746	15,149	14,917
15.	Current Income Tax Rate - 39.05%	(144,010)	(140,396)	1,085	1,072	5,916	5,825
16.	Operating Income (line 12 - line 15)	$ (222,377)	$ (218,264)	$ 1,693	$ 1,674	$ 9,233	$ 9,092
	WITNESS:			FROGGATT		FROGGATT	

(1) Total Income Statement Adjustments from APS' Direct Testimony filed on Jan. 31, 2006. Please see SFR Schedule C-2, page 11, Columns (KKK) and (LLL).

(2) Additional adjustment to operating expense to remove out-of-period and non-recurring tax consultant fees.

(3) Additional operating income pro forma to remove APS unregulated marketing and trading activities from operating expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(4) REBUTTAL Generation Production Deduction Total Co. (G)	ACC (H)	(5) REBUTTAL Interest on Customer Deposits Total Co. (I)	ACC (J)	(6) REBUTTAL Income Tax/Interest Synchronization Total Co. (K)	ACC (L)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs	-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	-	-	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	-	-	871	871	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	-	-	871	871	-	-
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	-	-	871	871	-	-
12.	Operating Income Before Income Tax	-	-	(871)	(871)	-	-
13.	Interest Expense	-	-	-	-	(263)	(240)
14.	Taxable Income	-	-	(871)	(871)	263	240
15.	Current Income Tax Rate - 39.05%	(1,227)	(1,213)	(340)	(340)	103	94
16.	Operating Income (line 12 - line 15)	$ 1,227	$ 1,213	$ (531)	$ (531)	$ (103)	$ (94)
	WITNESS:	FROGGATT		FROGGATT		FROGGATT	

(4) Adjustment to the Company's original pro forma to reflect the final Treasury Regulations pursuant to the American Jobs Creation Act.

(5) Adjustment to the Company's original pro forma to reflect the use of the 1/2/06 Treasury Interest rate and the deposit balance at 9/30/05.

(6) Additional adjustment to reflect interest expense related to certain proposed changes in rate base reflected in the Company's rebuttal testimony.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(7) REBUTTAL Federal and State Income Tax Total Co. (M)	ACC (N)	(8) REBUTTAL Administrative and General Total Co. (O)	ACC (P)	(9) REBUTTAL Property Taxes Total Co. (Q)	ACC (R)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs	-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	-	-	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	-	-	-	-	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	-	-	-	-	-	-
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	(8,520)	(8,422)	-	-
10.	Other Taxes	-	-	-	-	(1,708)	(1,688)
11.	Total	-	-	(8,520)	(8,422)	(1,708)	(1,688)
12.	Operating Income Before Income Tax	-	-	8,520	8,422	1,708	1,688
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	-	-	8,520	8,422	1,708	1,688
15.	Current Income Tax Rate - 39.05%	(4,838)	(4,588)	3,327	3,289	667	659
16.	Operating Income (line 12 - line 15)	$ 4,838	$ 4,588	$ 5,193	$ 5,133	$ 1,041	$ 1,029
	WITNESS:	FROGGATT		ROCKENBERGER		ROCKENBERGER	

(7) Additional adjustment to the Company's original cost-of-service income tax expense to reflect a top-down tax calculation including permanent tax items.

(8) Remove out-of-period and other legal costs from administrative and general expense.

(9) Adjustment to Test Year operations to remove the 2007 phase-in cost increase for new generation plant.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(10) REBUTTAL Advertising Total Co. (S)	(10) REBUTTAL Advertising ACC (T)	(11) REBUTTAL Bark Beetle Total Co. (U)	(11) REBUTTAL Bark Beetle ACC (V)	(12) REBUTTAL Pension Total Co. (W)	(12) REBUTTAL Pension ACC (X)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs	-	-	-	-	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	-	-	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	(171)	(167)	110	110	2,249	2,119
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	(171)	(167)	110	110	2,249	2,119
7.	Depreciation and Amortization	-	-	-	-	-	-
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	(337)	(312)	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	(508)	(479)	110	110	2,249	2,119
12.	Operating Income Before Income Tax	508	479	(110)	(110)	(2,249)	(2,119)
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	508	479	(110)	(110)	(2,249)	(2,119)
15.	Current Income Tax Rate - 39.05%	198	187	(43)	(43)	(878)	(827)
16.	Operating Income (line 12 - line 15)	$ 310	$ 292	$ (67)	$ (67)	$ (1,371)	$ (1,292)
	WITNESS:	ROCKENBERGER		ROCKENBERGER		ROCKENBERGER	

(10) Adjustment to Test Year operations to exclude advertising expenses related to Company branding.

(11) Update Test Year expense to reflect revised bark beetle remediation costs.

(12) Adjustment to Test Year operations to reflect actual 2006 pension expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(13) REBUTTAL Post Retirement Medical Benefits Total Co. (Y)	ACC (Z)	(14) REBUTTAL Spent Fuel Storage Total Co. (AA)	ACC (BB)	(15) REBUTTAL Palo Verde Unit 1 Steam Generators Replacement Depreciation Total Co. (CC)	ACC (DD)
1.	Electric Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power and Fuel Costs	-	-	(264)	(260)	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	-	-	264	260	-	-
	Other Operating Expenses:						
4.	Operations Excluding Fuel Expense	(3,191)	(3,006)	-	-	-	-
5.	Maintenance	-	-	-	-	-	-
6.	Subtotal	(3,191)	(3,006)	-	-	-	-
7.	Depreciation and Amortization	-	-	-	-	(262)	(259)
8.	Amortization of Gain	-	-	-	-	-	-
9.	Administrative and General	-	-	-	-	-	-
10.	Other Taxes	-	-	-	-	-	-
11.	Total	(3,191)	(3,006)	-	-	(262)	(259)
12.	Operating Income Before Income Tax	3,191	3,006	264	260	262	259
13.	Interest Expense	-	-	-	-	-	-
14.	Taxable Income	3,191	3,006	264	260	262	259
15.	Current Income Tax Rate - 39.05%	1,246	1,174	103	102	102	101
16.	Operating Income (line 12 - line 15)	$ 1,945	$ 1,832	$ 161	$ 158	$ 160	$ 158
	WITNESS:	ROCKENBERGER		ROCKENBERGER		ROCKENBERGER	

(13) Adjustment to Test Year operations to reflect actual 2006 post retirement medical expenses.

(14) Adjustment to Test Year operations for current period spent nuclear fuel storage costs.

(15) Remove Test Year depreciation expense related to the old low pressure turbine rotors that were retired.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(16) REBUTTAL Base Fuel and Purchased Power Including Off-System Sales Total Co. (EE)	ACC (FF)	(17) REBUTTAL Schedule 1 Total Co. (GG)	ACC (HH)
1.	Electric Operating Revenues	$ 12,596	$ 12,393	$ -	$ -
2.	Purchased Power and Fuel Costs	44,933	44,698	-	-
3.	Oper Rev Less Purch Pwr & Fuel Costs	(32,337)	(32,305)	-	-
	Other Operating Expenses:				
4.	Operations Excluding Fuel Expense	-	-	(19)	(19)
5.	Maintenance	-	-	-	-
6.	Subtotal	-	-	(19)	(19)
7.	Depreciation and Amortization	-	-	-	-
8.	Amortization of Gain	-	-	-	-
9.	Administrative and General	-	-	-	-
10.	Other Taxes	-	-	-	-
11.	Total	-	-	(19)	(19)
12.	Operating Income Before Income Tax	(32,337)	(32,305)	19	19
13.	Interest Expense	-	-	-	-
14.	Taxable Income	(32,337)	(32,305)	19	19
15.	Current Income Tax Rate - 39.05%	(12,628)	(12,615)	7	7
16.	Operating Income (line 12 - line 15)	$ (19,709)	$ (19,690)	$ 12	$ 12

WITNESS: EWEN RUMOLO

(16) Adjustment to the Company's original pro forma to include 2007 base fuel and purchased power expense and off-system revenues in cents/kWh at adjusted test year usage levels.

(17) Adjustment to the Company's original pro forma for Schedule 1 charges.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 9/30/2005
(Thousands of Dollars)

Line No.	Description	(18) REBUTTAL Total Rebuttal Pro Forma Income Statement Adjustments		(19) REBUTTAL Total Rebuttal Total Income Statement Adj.	
		Total Co. (II)	ACC (JJ)	Total Co. (KK)	ACC (LL)
1.	Electric Operating Revenues	$ (836,652)	$ (823,174)	$ (698,478)	$ (686,039)
2.	Purchased Power and Fuel Costs	(810,949)	(797,409)	(459,231)	(446,714)
3.	Oper Rev Less Purch Pwr & Fuel Costs	(25,703)	(25,765)	(239,247)	(239,325)
	Other Operating Expenses:				
4.	Operations Excluding Fuel Expense	(9,547)	(9,349)	56,169	53,885
5.	Maintenance	-	-	17,131	16,756
6.	Subtotal	(9,547)	(9,349)	73,300	70,641
7.	Depreciation and Amortization	(262)	(259)	25,544	23,245
8.	Amortization of Gain	-	-	(77)	(71)
9.	Administrative and General	(11,018)	(10,860)	16,382	14,098
10.	Other Taxes	(1,708)	(1,688)	15,159	15,031
11.	Total	(22,535)	(22,156)	130,308	122,944
12.	Operating Income Before Income Tax	(3,168)	(3,609)	(369,555)	(362,269)
13.	Interest Expense	(263)	(240)	(5,932)	(4,710)
14.	Taxable Income	(2,905)	(3,369)	(363,623)	(357,559)
15.	Current Income Tax Rate - 39.05%	(7,200)	(7,116)	(151,210)	(147,512)
16.	Operating Income (line 12 - line 15)	$ 4,032	$ 3,507	$ (218,345)	$ (214,757)

WITNESS:

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **APS UNREGULATED MARKETING AND TRADING ACTIVITY**
Additional operating income pro forma to remove APS unregulated marketing and trading activities from operating expense.

Line No.	Description	Amount
1.	**REVENUES:**	(849,248)
2.	**EXPENSES:**	
3.	Purchased Power and Fuel Expense	(855,618)
4.	**Operating Revenue Less Purchased Power and Fuel Expense**	6,370
5.	Other Operating Expenses	
6.	Operations Excluding Fuel Expense	(6,618)
7.	Administrative and General	$ (2,161)
8.	Total Other Operating Expense	(8,779)
9.	Total Pro Forma Adjustment	15,149
10.	**OPERATING INCOME (before income tax)**	**15,149**
11.	Income Tax at 39.05%	5,916
12.	**OPERATING INCOME AFTER TAX**	**$ 9,233**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **FEDERAL AND STATE INCOME TAX**
Additional adjustment to the Company's original cost-of-service income tax expense to reflect a top-down tax calculation including permanent tax items.

Line No.	Description	Amount
1.	OPERATING INCOME (before income tax)	
2.	Income Tax	(4,838)
3.	**OPERATING INCOME**	**4,838**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED RATE BASE
Total Company
(Thousands of Dollars)

ADJUSTMENT: **RATE BASE OFFSET FOR LONG TERM DISABILITY (SFAS 112)**
Additional adjustment to the Company's rate base to include deferred credits related to expenses for employees on long-term disability.

Line No.	Description	Amount
1.	Gross Utility Plant in Service	$ -
2.	Less: Accumulated Depreciation and Amortization	$ -
3.	Net Utility Plant in Service	$ -
4.	Less: Total Deductions	$ 3,886
5.	Total Additions	$ -
6.	**TOTAL RATE BASE**	**$ (3,886)**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **INTEREST ON CUSTOMER DEPOSITS**

Adjustment to the Company's original pro forma to reflect the use of the 1/2/06 Treasury Interest rate and the deposit balance at 9/30/05.

Line No.	Description			Amount
1.	**EXPENSES:**			
2.	Other Operating Expenses			
3.	Operations Excluding Fuel Expense			
4.	Balance of Customer Deposits at 9/30/05	$ 54,800		
5.	One year Treasury Constant Maturities Interest Rate as of 1/2/06	4.38%		
6.	Total Pro Forma Adjustment to Expenses			2,400
7.	OPERATING INCOME (before income tax)			(2,400)
8.	Company's original Interest on Customer Deposits pro forma		(1,529)	
9.	**ADJUSTMENT TO COMPANY'S ORIGINAL PRO FORMA**			**(871)**
10.	Income Tax at 39.05%			(340)
11.	**ADDITIONAL ADJUSTMENT TO OPERATING INCOME AFTER TAX**			**$ (531)**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: **GENERATION PRODUCTION DEDUCTION**
Adjustment to the Company's original pro forma to reflect the final Treasury Regulations pursuant to the American Jobs Creation Act.

Line No.	Description		Amount
1.	OPERATING INCOME (before income tax)		$ -
2.	Income Tax		(3,089)
3.	Company's original Generation Production Deduction pro forma	(1,862)	
4.	**ADJUSTMENT TO COMPANY'S ORIGINAL PRO FORMA**		(1,227)
5.	**ADDITIONAL ADJUSTMENT TO OPERATING INCOME AFTER TAX**		**$ 1,227**

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: INCOME TAX/INTEREST SYNCHRONIZATION
Additional adjustment to reflect interest expense related to certain proposed changes in rate base reflected in the Company's rebuttal testimony.

Line No.	Description	Amount
1.	OPERATING INCOME (before income tax)	$ -
2.	Interest Expense	(263)
	TAXABLE INCOME	263
5.	Income Tax at 39.05%	103
6.	OPERATING INCOME AFTER TAX	$ (103)

ARIZONA PUBLIC SERVICE COMPANY
ADJUSTMENTS TO THE COMPANY'S ORIGINALLY FILED OPERATING INCOME
Total Company
(Thousands of Dollars)

ADJUSTMENT: TAX CONSULTING FEES
Additional adjustment to operating expense to remove out-of-period and non-recurring tax consultant fees.

Line No.	Description	Amount
1.	**EXPENSES:**	
2.	Other Operating Expenses	
3.	Operations Excluding Fuel Expense	(2,778)
4.	Total Pro Forma Adjustment to Expenses	(2,778)
5.	**OPERATING INCOME (before income tax)**	2,778
6.	Income Tax at 39.05%	1,085
7.	**ADDITIONAL ADJUSTMENT TO OPERATING INCOME AFTER TAX**	**$ 1,693**

REBUTTAL TESTIMONY OF FRED BALLUFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

TABLE OF CONTENTS

I. INTRODUCTION 1

II. CASH WORKING CAPITAL: NON-CASH ITEMS 1

III. CASH WORKING CAPITAL: INTEREST EXPENSE AND COST OF CAPITAL .. 10

IV. CONCLUSION 11

REBUTTAL TESTIMONY OF FRED H. BALLUFF
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Fred H. Balluff. My address is 238 Elm Park Avenue, Elmhurst, Illinois 60126.

Q. ARE YOU THE SAME FRED H. BALLUFF WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ARE YOUR CREDENTIALS SET FORTH IN THAT TESTIMONY?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My purpose is to respond to the direct testimony of Staff witness James Dittmer and RUCO witness Marylee Diaz Cortez regarding the cash working capital requirements of APS. I have specific comments on the positions that Mr. Dittmer and Ms. Diaz Cortez took on items that they characterized as non-cash items and their positions on interest expense.

II. CASH WORKING CAPITAL: NON-CASH ITEMS

Q. DID STAFF OR RUCO IDENTIFY ANY ITEMS AS NON-CASH ITEMS?

A. Yes. They characterized depreciation and amortization of capital items as non-cash items. Additionally, Mr. Dittmer characterized deferred income tax expense and the amortization of prepaid insurance as non-cash items.

Q. DID STAFF OR RUCO MAKE ANY RECOMMENDATIONS CONCERNING THESE ITEMS?

A. Yes. They recommend eliminating the revenue lag applicable to the recovery of the items they characterized as non-cash items. Ms. Diaz Cortez also eliminated the revenue lag applicable to the recovery of deferred income tax expense, but provided no support for her elimination.

Q. HOW DOES YOUR TREATMENT OF DEPRECIATION, AMORTIZATION EXPENSE, AND DEFERRED INCOME TAXES DIFFER FROM THAT OF STAFF AND RUCO?

A. In its direct case filed on January 31, 2006, APS included depreciation and amortization expense, insurance expense and deferred income taxes in the calculation of cash working capital (Attachment FHB-1) with a zero expense lag and the revenue lag used for all other expenses. My support for this was provided in my Direct Testimony. Both Ms. Diaz Cortez and Mr. Dittmer indicate that non-cash items are properly excluded from cash working capital requirements.

I have acknowledged that these items are considered non-cash items <u>at the time they are expensed</u>. But that is not the issue. The issue deals with the timing of the recovery of depreciation expense in revenues. Both of these expenses are included in the determination of revenue requirements (cost of service). Thus, the recoveries of these expenses through the collection of revenues and more specifically, the lag in those recoveries represent a cash item.

As indicated beginning on page 9, line 14 through page 11, line 4 of my Direct Testimony, this method was used to recognize that these items are recorded (expensed) before such expenses are recovered from customers. When depreciation expense is recorded and deferred income tax charges are recorded, accumulated depreciation and

deferred income tax credits are recorded. These are reductions from rate base. At that time, the expenses have not been recovered from customers because of the revenue lag. Unless the revenue lag is included with a zero expense lag in the calculation of cash working capital, it is clear that APS will not earn a return on a significant portion of its unrecovered invested capital.

Depreciation expense represents a significant portion of operating expenses. As shown on FHB-1, depreciation expense alone was $321,525,565 and amortization of nuclear fuel was $34,445,413. The incorrect exclusion of depreciation and amortization expense prevents APS from earning a return on over $35 million of unrecovered invested capital.

Q. DID STAFF OR RUCO ADDRESS THE REVENUE LAG APPLICABLE TO THE RECOVERY OF DEPRECIATION EXPENSE AND DEFERRED TAXES?

A. Ms. Diaz Cortez does not deal with the issue of recovery of depreciation and deferred income taxes in her testimony. As for Mr. Dittmer's testimony, it only addresses the issue on page 40 of his Direct Testimony. He states:

> Furthermore, the rate base valuation date for both the accumulated depreciation reserve and accumulated deferred income tax reserve, adopted by Company and Staff, is September 30, 2005. Because this valuation date materially precedes the expected rate-effective date of this proceeding, APS will have fully collected accruals to these September 2005 reserve balances from ratepayers months, if not over a year, before any rate change is granted by the Commission.

Q. WHAT IS THE RELEVANCE OF STAFF'S STATEMENT ON DEPRECIATION AND DEFERRED INCOME TAXES?

A. There is none — Mr. Dittmer's statement is not relevant to the issue at hand. Of course the depreciation and deferred income taxes recorded by September 30, 2005 will be collected by October 2006. But that is true with <u>all</u> other expenses with a revenue lag. APS calculated a revenue lag of over 36 days, and it is that lag in recovery and not the

fact that costs are eventually recovered, which is relevant to cash working capital requirements. If his statement had any relevance, there would be no reason to do a lead/lag study.

Q. DID YOU CONSIDER THE OVERALL DETERMINATION OF REVENUE REQUIREMENTS IN THE CALCULATION OF CASH WORKING CAPITAL?

A. Yes. I believe it is important to keep in mind the relationship between rate base, operating expenses and the return on rate base in the determination of revenue requirements. APS used the traditional rate base/rate of return approach to determine its cost of providing service. Under this method, revenues equal the total of operation and maintenance expenses, depreciation, taxes including income taxes, and a return on rate base.

In the calculation of revenue requirements, pro forma adjustments to recorded data are made to reflect known and measurable changes and adjust for abnormal events. Rates are made for the future, not the past. In an ideal setting, rates that are set in a rate case will provide appropriate revenues for a number of future years. That does not mean that a year from now we will have the same items of uncollected accumulated depreciation and deferred income taxes that APS has included in its calculation of rate base as suggested by Mr. Dittmer. Clearly, at any point in time, depreciation expenses and deferred income tax expenses will be recorded before such expenses are recovered in the collection of revenues.

Q. COULD WE OMIT DEPRECIATION AND DEFERRED TAXES FROM THE CWC STUDY AND MAKE ADJUSTMENTS DIRECTLY TO THE ACCUMULATED DEPRECIATION AND DEFERRED TAX CREDITS INCLUDED IN RATE BASE.

A. Yes. It would have the same impact.

Q. DO YOU HAVE ANY OTHER COMMENTS CONCERNING STAFF'S TESTIMONY REGARDING PLANT OR DEPRECIATION?

A. Yes. On page 40, beginning on line 3 of his Direct Testimony, Mr. Dittmer indicates that "Certain payments for recently completed construction projects closed to plant in service or otherwise included in rate base would not have been fully paid for in cash as of September 30, 2005." On the same page, beginning on line 17, he indicates that the Company's proposal to include "...non-cash items in CWC fail to analyze or account for delayed cash outflows in payment of construction costs ..."

This testimony does not discuss the relevancy of this speculation about plant-in-service balances to the cash recovery of depreciation expense. And, furthermore, Mr. Dittmer does not offer any proof that a significant portion of plant (if any) has not been paid for at the time that plant is transferred to completed plant, let alone that it would have a significant effect on total plant-in-service.

Again, the issue that depreciation expense should be disallowed because it is a non-cash item is not supported. The issue is related to the recovery of depreciation expense. Moreover, most of the cash is expended during the construction of plant with the balance paid before such plant is reclassified to plant-in-service.

Q. DOES STAFF ADDRESS THE REDUCTION IN RATE BASE FOR DEFERRED INCOME TAXES?

A. Yes. Mr. Dittmer discusses the treatment of deferred income taxes as a reduction in rate base because it is cost free capital.

I discussed this issue on page 10 and 11 of my testimony. I believe we are in general agreement with Staff as to the purpose of the reduction in rate base by deferred income taxes. I indicated that, "Rate base is reduced by deferred income taxes payable to prevent investors from earning a return on investments made with funds provided by

consumers. However, the funds have not been provided by consumers until paid by consumers. That has to be recognized in the lead/lag study."

Q. HAS STAFF REFUTED THAT POSITION?

A. No.

Q. WHAT IS STAFF'S POSITION REGARDING DEFERRED INCOME TAXES?

A. On page 41, line 13, Mr. Dittmer states,

> Consequently, deferred income taxes should be excluded from the determination of the Company's cash working capital requirements, because there are no current period cash working capital requirements or outflows.

Q. IS STAFF'S POSITION REGARDING DEFERRED INCOME TAXES VALID?

A. No. Although the statement is true, the conclusion is clearly erroneous. There is no justification for excluding expenses from the calculation of cash working capital requirements simply because there are no current period cash working capital requirements.

Q. WHAT ARE THE IMPLICATIONS OF FOLLOWING STAFF'S RECOMMENDATION?

A. It would mean that expenses incurred in 2006 and paid in 2007 would not be included in the CWC calculation. For example, it would mean that utilities that pay property taxes in the year following the year that such taxes were accrued would exclude the expense lag in their calculation of cash working capital. If that makes sense, why not exclude the APS calculation of the expense lag with respect to Arizona property taxes. Assuming that it was logical to exclude property tax expense from the calculation of cash working capital because the entire payment was paid in the subsequent year, it would be logical to exclude the expense lag for Arizona property taxes from the calculation of cash

working capital. Indeed in this case the 50% of the property taxes for Arizona are due on November 1 and 50% are due by May 1 of the following calendar year. Additionally, very few expenses are paid for currently. Operation and maintenance expense are recorded on the accrual basis of accounting. That means expenses are recorded when incurred. A portion of all of the expenditures shown on FHB-1 that are paid for in cash are paid in a later month. At the end of fiscal year, a portion of these expenses are paid in another fiscal year. *See* the purpose of a lead/lag study on page 5 of my Direct Testimony.

Q. DO DEFERRED INCOME TAX LIABILITIES AFFECT CASH WHEN THEY ARE REDUCED?

A. There is no question that deferred income taxes are expected to be paid in cash at some future date. That is why deferred income tax credits are properly recorded as a liability. There is a difference, however, in the way cash payments affect deferred tax liabilities and the way cash payments affect most liabilities, and that difference can create confusion. Most liabilities are charged or reduced at the time of payment. That is not directly observed when the deferred taxes liabilities are reduced.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE CASH NATURE OF DEFERRED INCOME TAXES?

A. Yes. The following simple example is intended to explain the cash nature of deferred income taxes:

> Assume that a company sells a product that qualifies under the Internal Revenue Code as an installment sale. The sale price of $3,000 and related costs of $2,100 are recorded in the year of sale. The resulting profit of $900 is recognized in the year of sale for financial reporting purposes. If installments of $1,000 each are collected over the next three years, then one-third of the profit or $300 is recognized for income tax purposes in each of the years: 1, 2,

and 3. This deferral of income for income tax purposes creates what is called a timing difference.

A timing difference occurs when revenues or expenses are recognized in one period for financial reporting purposes but are reported in another period for income tax purposes. These differences originate in one period and reverse in one or more subsequent periods. In my example, at the end of the period in which the sale was made, the timing difference is $900. This represents the difference between the profit recognized for financial reporting purposes and the income reported for tax purposes in the year of sale. The deferred tax liability would be $225 (25% of $900). The contra entry would be to deferred tax expense.

For each year that an installment is collected, $300 will be recognized on the income tax return which reduces the timing difference. I have assumed an income tax rate of 25%.

Timing Difference-Year	1	2	3
Beginning of year	$900	$600	$300
Reversing in year	300	300	300
End of year	$600	$300	$0
Deferred tax at 25%			
Beginning balance	$225	$150	$75
Ending balance required	150	75	0
Change in balances	75	75	75

In each year, the profit of $300 increases taxable income and decreases the timing difference. Assuming only this timing difference, deferred income tax payables are

reduced by $75 in each of the three years. Deferred income tax expense would be negative by $75 each year. No cash payment is recorded directly to the deferred tax liability account. However, taxable income is increased in comparison to book income by $300 per year. This increases current tax payables and current tax expense by $75 per year. The charge to current tax expense is offset by the credit to deferred income tax expense. When payments are made to the Internal Revenue Service, cash is disbursed and the current income tax liability is reduced.

Q. ARE YOU AWARE OF OTHER JURISDICTIONS WHERE PUPLIC UTILITY COMMISSIONS ADOPTED AN APPROACH SIMILAR TO YOURS WITH RESPECT TO DEPRECIATION EXPENSES AND DEFERRED INCOME TAXES?

A. Yes. Recognizing the revenue lag with respect to depreciation and deferred income tax expenses is often a contested ratemaking issue, and the determinations made by public utility commissions on these issues are varied. Some examples of those states that have included "non-cash" items, such as depreciation and deferred income taxes by recognizing the revenue lag and using a zero expense lag, include South Carolina where the Public Service Commission found "non-cash" items <u>must</u> be included in a lead lag study to reflect the delay in the collection of these components of revenue; and Connecticut, where the Department of Public Utility Control agreed that non-cash expenses such as depreciation, amortization, and deferred income taxes create a working capital requirement. Additionally, the California Public Utilities Commission has adopted a Standard Practice (U-16-W) which includes both depreciation expense and deferred income taxes at zero lag days because of the reduction of rate base by accumulated depreciation and deferred income taxes.

Q. DO YOU HAVE AN OPINION AS TO WHY THERE IS INCONSISTENCY AMONG PUBLIC UTILITY COMMISSIONS REGARDING THE TREATMENT

OF NON-CASH ITEMS IN DETERMINING A UTILITY COMPANY'S CASH WORKING CAPITAL NEEDS?

A. I believe that the calculations involved can be difficult to understand. Non-cash items can be particularly difficult for non-accountants to understand. There may be too much of a focus on the fact that these items do not require a cash outlay when expensed rather than the effect that expensing these items has on rate base and overall recovery of these expenses in rates. Also the cash nature of deferred income taxes is also difficult for non-accountants to understand.

Q. DOES STAFF CLASSIFY INSURANCE EXPENSES AS A NON-CASH CHARGE?

A. Yes.

Q. DOES STAFF PROVIDE A REASON FOR DRAWING THIS CONCLUSION?

A. No. Mr. Dittmer classifies this expense as a non-cash charge but does not explain why he arrived at that conclusion.

Q. HOW DID RUCO ADDRESS THE INSURANCE EXPENSES?

A. RUCO did not make an adjustment to the APS calculation, apparently recognizing that the cash was paid in advance.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO SAY ABOUT CLASSIFYING INSURANCE EXPENSES?

A. Nothing, aside from noting that the APS position is supported in my Direct Testimony beginning on page 8, line 12.

III. <u>CASH WORKING CAPITAL: INTEREST EXPENSE AND COST OF CAPITAL</u>

Q. HOW DO STAFF AND RUCO TREAT INTEREST EXPENSE?

A. Both Mr. Dittmer and Ms. Diaz Cortez include a provision for interest expense in their calculations of cash working capital requirements. Mr. Dittmer acknowledges that interest costs are included in the weighted cost of capital that is applied to rate base.

Q. WHAT IS THE SIGNIFICANCE OF THEIR TREATMENT?

A. By including interest expense in his working capital calculations, Mr. Dittmer has treated interest expense in the same way as you would operating expenses without justification for doing so.

I believe that what Mr. Dittmer and Ms. Diaz Cortez have done is unfair to APS. They included the interest cost component in the calculation of a working capital as opposed to including the entire return on rate base. If it is appropriate to include the interest component of the return in the calculation of cash working capital, it is necessary to include the entire return on rate base (including the weighted cost of debt) in the calculation of working capital. The revenue lag would not be different for any component of the cost of providing service.

Q. ARE YOU RECOMMENDING THAT THE RETURN ON RATE BASE BE INCLDUDED IN THE CALCULATION OF CASH WORKING CAPITAL IN THIS CASE?

A. No. Although there is some argument for including the return on rate base in the working capital calculations, it is a significant expansion of what I consider to be embraced by a lead/lag study. As such, the return on rate base, including the interest component, is properly excluded from the working capital calculations.

IV. CONCLUSION

Q. ARE YOUR RECOMMENDATIONS CONCERNING THE TREATMENT OF DEPRECIATION AND AMORTIZATION, DEFERRED INCOME TAXES AND INTEREST EXPENSE CONSISTENT WITH PRIOR ARIZONA CORPORATION COMMISSION DECISIONS ON THESE ISSUES?

A. No.

Q. WHY DON'T YOU BELIEVE THAT IT IS NECESSARY TO FOLLOW PRIOR COMMISSION DECISIONS ON THESE ISSUES?

First, I believe that my positions are correct. For APS, the last litigated case was eighteen years ago. I believe that the Commission should revisit these issues and I am confident that the Commission will consider the evidence provided in this case and decisions rendered by other regulatory commissions. Moreover, the order issued in the last case, Decision No. 55931, did not discuss the relevant issues regarding these expenses. For example, the order states that:

> However, neither depreciation nor deferred taxes require the expenditure of cash at the time the expense is recorded and thereby charged to the customers. They are not "current" cash expenses. (Decision No. 55931 at page 67)

There is no discussion concerning the revenue lag associated with depreciation or deferred income taxes. As I stated earlier in my testimony, the issue deals with the timing of the recovery of these expenses. The Company's rate base at September 30, 2005 includes deductions for accumulated depreciation and deferred income taxes that were not fully recovered from customers at September 30 due to the revenue lag.

Additionally, Mr. Dittmer attached JRD-B to his testimony. This attachment contains excerpts for ten different decisions of the Arizona Corporation Commission. Some of these excerpts indicate that the Commission excluded depreciation and deferred taxes from CWC, but none of those excerpts indicate that the Commission even discussed the issue of recovery of these expenses due to the revenue lag. Also, none of the excerpts indicate that the Commission addressed the incorrectness of including one component of

the rate of return on rate base while excluding another component of the return on rate base.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

REBUTTAL TESTIMONY OF PATRICK DINKEL

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

Table of Contents

I. Introduction 1

II. Summary of Testimony 1

III. Renewables as a Hedge 2

IV. Wind Integration Cost Study 4

V. Demand Response 6

VI. Conclusion 8

REBUTTAL TESTIMONY OF PATRICK DINKEL
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Patrick Dinkel, 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU PROVIDE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes. I filed Direct Testimony in this docket on November 4, 2005 ("Initial Filing"), and also provided updated testimony on January 31, 2006 ("January Filing").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of Mr. David Berry of Western Resource Advocates and his position regarding the use of renewable energy as a hedge against high natural gas prices. In addition, I will be responding to the concerns raised by Ms. Amanda Ormond of Interwest Energy Alliance regarding wind integration costs. Finally, I will discuss APS' position related to the testimony of Staff and several Intervenors and their increased interest in Demand Response programs.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY IN THIS RATE CASE DOCKET.

A. My testimony will address the use of renewables as a hedge. Specifically, APS agrees that renewable energy should be a bigger percentage of APS' generation portfolio and that renewable energy will offset the need for generation from conventional resources. However, to date, APS is paying a premium for

renewable energy, and that premium must be given consideration. My testimony will also include a discussion of APS' pending Wind Integration Cost Study and the concerns raised by Interwest Energy Alliance. Finally, I will discuss APS' interest in exploring additional Demand Response offerings to provide effective supply side options for meeting our system needs.

III. RENEWABLES AS A HEDGE

Q. IN MR. BERRY'S TESTIMONY, HE INDICATES THAT APS SHOULD USE AN INCREASED AMOUNT OF RENEWABLE ENERGY AS A HEDGE AGAINST HIGH NATURAL GAS PRICES. DO YOU AGREE WITH HIS CONCLUSION?

A. I agree with his proposition that renewable energy should make up a larger percentage of APS' generation portfolio. APS has supported the increasing renewable energy requirements proposed in the draft Renewable Energy Standard ("RES").

Q. DO YOU BELIVE THAT THE RENEWABLE ENERGY PROCURED BY APS IS AN EFFECTIVE HEDGE AGAINST NATURAL GAS?

A. While renewable energy will offset some of the need for generation from natural gas, this displacement comes at a higher cost than natural gas, based on current prices. In general, there is a cost premium for any "hedge", and careful consideration of the cost is required. So, while renewable generation may be "effective" as a hedge due to its displacement of future gas needs, the critical questions are whether they are a *cost effective* hedge and whether the added costs are acceptable from the perspective of APS customers. Natural gas hedges can be secured at a relatively small cost over prevailing market prices, yet renewable energy is currently only available at a more expensive premium to the cost of conventional, gas-fired energy resources. Mr. Berry provides data that indicates that renewable energy can be procured at a small premium to, or possibly even

below, the cost of conventional resources. There have been some very recent projects in certain states where that has been true, but unfortunately APS has not been in that situation. APS has been acquiring resources in the market and is paying a significant premium compared to the cost of conventional energy resources utilizing natural gas.

Q. WHY IS APS NOT ACQUIRING RENEWABLE PROJECTS AT THE RELATIVELY LOW PRICES MR. BERRY IS CITING?

A. A number of factors affect the price of renewable generation, such as federal and state incentives, the price of equipment, and the quality of the natural resource (e.g., wind, geothermal steam, or biomass material). Arizona renewable resources are limited and can be lower quality than renewable energy resources available in some states. APS' choices are to procure out-of-state renewable resources in direct competition with other utilities, or to acquire the limited in-state resources at a higher cost.

Q. DOES THIS MEAN RENEWABLES ARE NOT AN EFFECTIVE ECONOMIC HEDGE AGAINST NATURAL GAS?

A. Not necessarily. It just means that the economics are not as obvious or compelling for APS as they may be for other utilities, and that global statements on the topic may prove inaccurate in the specific case of APS. Project specific analysis is required to adequately measure the economic value of each renewable project.

Q. DOES THE TYPE OF RENEWABLE TECHNOLOGY AFFECT ITS VALUE AS A HEDGE?

A. Yes. Renewable energy that displaces energy produced by natural gas generation will cause a reduction in gas volume purchases and thus will reduce the total exposure to natural gas price volatility. But, as Mr. Berry correctly points out in his testimony, wind energy is an intermittent source of power, which means that

the timing of when the energy is being produced is uncertain from hour to hour, day to day and variable over the course of the year. Moreover, the wind energy resources that might be most available to the Company generally are less available during the peak summer demand period when gas generation is most needed. This uncertainty means it may be difficult to schedule the gas purchases needed to counterbalance the renewable resource intermittency, possibly resulting in increased costs.

Q. MR. BERRY INDICATES THAT AN ADVANTAGE OF USING RENEWABLE ENERGY IS THAT RENEWABLE ENERGY PRICES ARE FIXED. DO YOU SEE THIS AS A BENEFIT?

A. Yes, it is a benefit. Renewable energy is generally either at a fixed price or a price with known escalators, which in either case removes price uncertainty from a certain percentage of APS' energy portfolio. However, it generally comes at a premium when compared to the expected price of energy from conventional resources. Our renewable purchases made under settlement agreement in Decision No. 67744 locked in a cost of renewable energy that was up to 125% above APS avoided cost. We can't ignore the premium we are paying for the benefit of a fixed price.

IV. WIND INTEGRATION COST STUDY

Q. MS. ORMOND RAISES CONCERNS ABOUT APS' METHODOLOGY FOR CALCULATING WIND INTEGRATION COSTS. DOES APS SHARE MS. ORMOND'S CONCERNS?

A. We believe it is in everyone's best interest that we continue to study the impact of the integration of renewable resources into our portfolio. For this reason, APS is in the final stages of discussion with Northern Arizona University for the coordination of a Wind Integration Cost Study.

Q. DESCRIBE THE APS WIND INTEGRATION COST STUDY.

A. The wind integration cost study is being designed to answer the question of what are the system impacts and costs associated with effectively integrating potential wind projects into APS' system. It will address the nuances of APS' system, and the known characteristics of probable wind projects that may be made available to APS. This study should establish a basis to start from, and as we gain experience with actual renewable resources we will have the ability to better predict and evaluate the costs and impacts of integrating specific renewable resource technologies into the system, particularly those which demonstrate intermittency like wind and solar. NAU will conduct the analysis with the direct involvement of industry experts, with the scope, technical process and results overseen by a Technical Advisory Committee. In addition, a Stakeholder Advisory Committee is being formed to provide review from a variety of stakeholders including other utilities and renewable energy advocates. A time frame is currently being evaluated, but APS expects the integration cost study to be complete in approximately 6 to 8 months.

Q. WHY IS A WIND INTEGRATION COST STUDY NECESSARY?

A. Our most recent experience is that APS has had limited availability to detailed wind data. Our recent experience is that very few bidders could provide detailed wind data, so getting multiple years of data on numerous projects, as one would require for an effective cost study, has been difficult if not impossible. To date, wind data is still very difficult to acquire because developers have limited site specific data and carefully guard what data they have. Industry knowledge is also limited and is to date, system and project specific. APS' system and Arizona's wind resources are unique and widely publicized studies based upon others'

projects and systems are not directly transferable to Arizona projects on APS' system. The wind in Texas isn't the same as the wind in Arizona. Also, APS relies heavily upon natural gas fired power plants for system regulation whereas other utilities may be able to provide regulation out of lower cost hydroelectric or coal-fired facilities. A Wind Integration Cost Study would incorporate input from industry professionals and establish a more credible method to determine the expected wind resource integration costs. In addition, APS will be gaining specific knowledge on wind integration costs once our two wind projects begin operation in early 2007.

V. DEMAND RESPONSE

Q. SEVERAL INTERVENORS EXPRESSED AN INTEREST IN DEMAND RESPONSE. DOES APS SUPPORT DEMAND RESPONSE?

A. Yes. APS is interested in Demand Response ("DR") and believes it may be able to provide effective supply-side options for meeting system needs, in addition to introducing greater elasticity in energy demand and use. To be effective, DR programs must adequately address reliability requirements and provide economics that are favorable compared to other supply-side options.

Q. DO YOU AGREE WITH STAFF AND RUCO THAT DEMAND RESPONSE OFFERINGS NEED TO BE EXPLORED?

A. Yes. There are a variety of demand response programs which differ in their implementation cost, benefits, infrastructure needs and complexity of administration. Price response in particular is very complex and requires a through assessment of infrastructure costs, customer acceptance and pricing mechanisms. One only needs to look to the myriad of demand response initiatives in California to realize large number of potential approaches. For that reason, a thorough study is necessary to determine which types of Demand Response

programs would be likely to produce the most cost effective benefits for the APS system and our customers. We will need to analyze the types of technologies (measures) to be considered, measure-by-measure benefit to cost, potential MW impacts, types of customers who would participate and their specific loads, likely customer responses and behavior, what it would take to get customers to participate, and the costs of infrastructure/equipment for such a program. The results of this analysis should be reviewed and commented on by interested parties, including the Arizona Corporation Commission ("ACC"), Residential Utility Consumer Group ("RUCO"), and industry participants. Staff has proposed that APS perform a feasibility study for demand response programs and a cost/benefit analysis within eight (8) months of the Decision and submit one or more demand response programs for ACC approval after the study is completed. Although APS is not opposed to conducting such a study, eight months is not a sufficient amount of time to complete a thorough study and develop appropriate demand response programs.

Q. RUCO HAS SUGGESTED THAT A TASK FORCE BE FORMED TO EXPLORE OPPORTUNITIES FOR LOAD SHAVING AND LOAD SHIFTING THROUGH DEMAND RESPONSE PROGRAMS. DO YOU AGREE?

A. The first course of action should be to conduct a study to determine which types of Demand Response programs are most beneficial to the APS system and our customers. APS is not opposed to a task force but believes the most effective and expeditious way to manage this first phase is for APS to conduct the study with open communication with interested parties. After the assessment is complete, the specifics of which programs are selected, the costs of the programs, and how certain programs are procured and managed can be discussed with interested parties and filed with the Commission for approval.

Q. IS THERE A FUNDING MECHANISM FOR COSTS THAT WOULD BE INCURRED TO STUDY AND DEVELOP DEMAND RESPONSE PROGRAMS?

A. Since Demand Response is included in Decision No. 67744 along with Demand Side Management programs, the DSM adjustor mechanism provides for such funding and, for now, is the appropriate mechanism. Demand Response programs funded through the DSM adjustor mechanism would be filed with the Commission for approval prior to implementation in a manner similar to the DSM programs.

VI. CONCLUSION

Q. AND DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

REBUTTAL TESTIMONY OF THOMAS J. CARLSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

TABLE OF CONTENTS

I. Introduction 1

II. Summary of Testimony 2

III. APS Hedging Program and Philosophy for Gas and Power Procurement 3

IV. Response to the Filed Testimony of Witnesses Antonuk and Hornby 11

V. Conclusion 17

REBUTTAL TESTIMONY OF THOMAS J. CARLSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Thomas J. Carlson. I am the Portfolio Manager for Arizona Public Service Company ("APS" or "Company") Regulated Marketing and Trading Division. In that role, I am responsible for procuring wholesale purchased power and natural gas for APS native load needs and also the marketing of surplus APS generation and natural gas.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree from the University of South Dakota in 1977. Prior to coming to APS, I worked in marketing and market research positions with the airline and motor transportation industries. I held a similar position when I joined APS in 1988. In 1992, I began working in the gas trading and fuel management area of the Company, rising to Director of Generation Fuel Procurement for APS in 2001 and to Portfolio Manager in 2004.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My testimony will briefly describe APS' natural gas and purchased power hedging philosophy and policies relating to the procurement of the natural gas and purchased power needed to serve our native load, and also discuss certain aspects of the Direct Testimony filed by Staff witness John Antonuk and RUCO witness J. Richard Hornby relating thereto.

II. SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Yes. APS incorporates extensive use of financial and physical contracts to minimize commodity price volatility when purchasing natural gas and purchased power to serve retail load. Since price stability is the goal of our system hedge program, financial risks associated with projected requirements of these commodities are systematically hedged at various levels starting approximately three years prior to delivery with standard energy products.

APS has hedged its financial commodity risk since the late 1990's in response to market price fluctuation, with the most recent revisions to the policy in June of 2005, when APS increased its hedge percentages in light of even greater price uncertainty. The measured approach utilized by the system hedge program helps APS customers largely avoid much of the turbulence of price volatility that can occur in the short-term commodity markets. Coupled with the practice of optimizing natural gas and purchased power to provide the lowest cost commodity to meet load, the current approach to hedging financial risk can provide APS customers with future price stability.

I have reviewed the filed testimony of Mr. Antonuk and Mr. Hornby with respect to their assessment of the APS hedging program. With respect to Mr. Antonuk, I concur with the majority of his findings and characterizations as they relate to APS' hedging program. As to Mr. Hornby's testimony, there are a number of statements in his testimony that I believe are incorrect. One such issue is his failure to acknowledge the inherent cost optimization processes found in the APS hedging plan. In addition, Mr. Hornby makes certain general

statements as to the propriety and effectiveness of the APS hedging policy with which I disagree, but on these issues I will defer to the testimony of APS witness Donald Brandt.

III. APS HEDGING PROGRAM AND PHILOSOPHY FOR GAS AND POWER PROCUREMENT

Q. WHAT IS A "HEDGE"?

A. As applied in our industry, a hedge is defined as "any technique designed to reduce or eliminate financial risk." Since commodity prices of natural gas and purchased power are extremely volatile (i.e. can change significantly from day to day), the use of a hedge can eliminate much (but not all) of the financial risk associated with price changes in these markets. From the perspective of APS, we hedge primarily with fixed price contracts, i.e. we fix the price of the commodity for a specific term in order to limit price risk during that term.

Q. HOW LONG HAS APS BEEN HEDGING ITS NATURAL GAS AND PURCHASED POWER NEEDS?

A. APS has hedged natural gas and purchased power requirements for native load customers in various respects since the late 1990's. The impetus for hedging these commodities originated in the increasing exposure to market prices arising from APS' retail load growth and a coincident increase in the volatility of prices in the energy market. The continuing development of organized and relatively liquid commodity markets, and subsequently financial equivalent contracts, has since made the implementation of hedging programs far more efficient and manageable.

Q. HOW WOULD YOU DESCRIBE APS' HEDGING "GOALS" AND HAVE THOSE GOALS BEEN ATTAINED THROUGH THE APS HEDGING PROGRAM?

A. As both Messrs. Antonuk and Hornby correctly state, price stability is the primary goal of the APS system hedge program. Price stability is, of course, a relative concept. In a consistently rising market, even hedged prices will also increase, albeit less quickly. The converse is true in a falling market. APS' system hedging philosophy is not one of trying to predict the direction of the market – as we have said in the past, that's what speculators do, and we do not speculate on behalf of our customers. Our hedging philosophy is mechanistic in its approach with minimal trader discretion as we seek to stabilize costs over time. This goal of price stability is achieved in the current system hedge program by virtue of specific target hedge levels, a requirement for strict compliance in meeting those hedge targets, and senior management oversight and direction of the hedging program.

APS' measured approach to hedging helps its customers largely avoid the turbulence that can occur in volatile short-term energy commodity markets. The peril of failing to properly hedge has severely impacted companies from any number of industries, from utilities to airlines. In our industry, an example of the benefits of a long-term hedge program can be seen in the California energy crisis of 2001 and 2002. Over-reliance on the spot markets for procurement of electricity and natural gas resulted in extreme price volatility. As a result of the implementation of a deregulation plan, the investor-owned utilities in California were restricted from entering into long-term contracts for energy. As spot energy prices increased due to any number of factors, including rising natural gas prices, transmission constraints and limited hydro production, those utilities were forced to buy power from the near-term market. Although they were highly exposed to this market turbulence, neither Pacific Gas & Electric nor Southern

California Edison had a rate mechanism to recover rising costs from their customers. This caused extreme financial distress for the utilities and provided no financial incentive for their customers to curb their consumption of an increasingly expensive commodity. The result was the very well documented "energy crisis" that dramatically impacted both the utilities and their customers.

By hedging purchased power and natural gas needs over a roughly three-year horizon using a systematic approach and well defined compliance deadlines, APS can mitigate the impact of volatile gas and power prices and wholesale capacity concerns for its customers.

Q. CAN YOU PLEASE DESCRIBE THE EVOLUTION OF THE APS HEDGE PROGRAM?

A. In the years prior to 2003, the volumes of natural gas and purchased power exposed to price volatility were considerably less than present volumes and, for the most part, the costs of those commodities were also significantly lower than current costs. As APS' exposure to the requisite volumes of natural gas and/or purchased power increased dramatically, the hedge program followed by APS in the fall of 2003 was restructured to require lower levels of discretion in hedge target levels. Specifically, in the fall of 2003, APS initiated a hedge program for total energy (natural gas and purchased power needs combined) that required near term (or "prompt calendar year") requirements to be 75% hedged prior for that particular year. In June of 2005, APS again modified its system hedge program to address growing concerns about still increasing market volatility and the related financial risks to APS customers. The revised hedge program was prepared in consultation with Risk Advisory, industry experts in the design and implementation of hedging policies and practices, and remains in effect today.

Mr. Antonuk's testimony correctly captures the basics of APS' system hedge program for total energy (again, natural gas and purchased power combined). In summary, APS' hedge program establishes the following requisite hedge levels:

- Remainder of 2006: 85% hedged;
- Calendar Year 2007: 85% hedged;
- Calendar Year 2008: approximately 55% hedged;
- Calendar Year 2009: approximately 35% hedged.

Subsequent calendar year hedge positions are automatically added to the system hedge program as current year positions roll off. For example, APS will begin hedging commodity risk exposure for the first quarter of calendar year 2010 later this year as calendar year 2006 rolls off the plan.

Q. HOW DOES APS ESTIMATE ITS NATIVE LOAD REQUIREMENTS AND THUS ITS REQUIRED HEDGE VOLUMES?

A. APS serves retail load requirements by sourcing power from its nuclear, coal, and natural gas generators, and by purchasing wholesale power in the marketplace under long term agreements, or by purchasing power in shorter term or real-time markets if it is more cost effective than self-generation.

Fuel used in the nuclear and coal-fired generators is purchased through long term contracts at prices that, although escalated over time in accordance with contractual formulae, allow those units to generally run as base load units. Since our retail load demand cannot be readily predicted on an hour by hour or day to day basis, the incremental or "swing" supply of energy needed to serve APS' hourly-varying load is sourced through our natural gas-fired generators, through market purchases of electricity, or through a combination of both.

In attempting to assess future native load energy needs, APS utilizes a computerized simulation model called Real Time Simulation ("RTSIM") to project the necessary level of incremental energy (gas-fired or purchased power, or both). In hedging for the APS system, we use this model to forecast incremental monthly energy needs over a time horizon of roughly three years, in order to establish our hedge requirements. Key inputs into the model include:

- Forecast of system load requirements.
- Forward price curves of natural gas and purchased power.
- Scheduled outages of APS generators.
- Heat rate efficiencies and capacities of APS generators.
- Operating constraints such as Reliability Must Run ("RMR") requirements, minimum run time, ramp rates, etc.

In assessing estimated needs, we are also aware that generators are going to have non-scheduled outages. Because these outages generally occur randomly, APS includes a planning reserve in the monthly supply/demand balance prior to calculating the monthly total energy hedge requirement.

Q. WHAT DOES APS DO TO ATTEMPT TO OPTIMIZE ITS HEDGE POSITIONS?

A. As I will describe in detail later in my testimony, a key area of misunderstanding in the testimony filed by Mr. Hornby involves the cost optimization processes inherent in the APS hedge program. Specifically, in order to allow our hedging program to respond to market price changes on our required hedge volumes, APS re-runs the RTSIM model weekly with updated forward prices for natural gas and purchased power. Under normal situations, the total energy requirements forecast for the forward three years change only minimally, but the least-cost volumetric mix between natural gas and purchased power can vary significantly.

As a result, the traders will "optimize" the hedge position to capture the least expensive incremental energy to serve load, as identified by the model, while adhering to the total energy hedge targets. By optimizing, term traders can:

- Adjust hedge levels of each specific commodity (purchased power versus natural gas).
- Modify receipt and/or delivery points by commodity in order to minimize costs and retain reliability.
- Investigate the economic value of financial/physical derivatives as opposed to outright financial/physical contracts in managing risk.

Notwithstanding such optimizations, the total energy hedge at any given time must remain at the target levels in accordance with the existing system hedge program.

Q. WHAT TYPES OF TOOLS AND/OR CONTRACTS DOES APS USE TO HEDGE ITS NATURAL GAS AND PURCHASED POWER NEEDS?

A. APS transacts in various markets and uses various hedge tools in managing price volatility and financial risk. The most common hedge tools include:

- Physical purchased power contracts delivered at Palo Verde, Four Corners, Mead, and other accessible delivery points.
- Physical purchased power call options to hedge financial capacity risk delivered at Palo Verde, Four Corners, and Mead.
- Financial natural gas futures contracts traded on the New York Mercantile Exchange ("NYMEX"). (The NYMEX financial contracts used to hedge natural gas are very liquid and allow for physical natural gas contracts purchases prior to the delivery month).
- Physical natural gas contracts for gas from the San Juan and Permian Basins.

To give some perspective on the scope of our program, at any one time APS has literally thousands of financial and physical contracts in place covering a roughly three year time horizon.

Q. HOW DOES APS THEN GO FORWARD AND TRANSITION CONTRACTS BOUGHT FOR HEDGES TO DELIVER POWER TO APS' CUSTOMERS?

A. As stated earlier, APS uses a number of mechanisms to hedge its needs. Some are called "physical" contracts (e.g. deliverable power) and others "financial" contracts (e.g. cash settled). The most common "financial contract" is a futures contract. Futures contracts used to hedge our financial risk must be converted to physical contracts in order to obtain the physical commodity to serve load. The most common example of this is the natural gas NYMEX futures contract, which APS uses extensively in hedging.

NYMEX futures contracts expire three business days prior to the first day of the next month. For example, the September 2006 NYMEX natural gas futures contract required as part of our hedging program, expired on August 29, 2006. APS will have then sold all futures contracts back to the market on or just before August 29, and simultaneously purchase a physical supply contract, with a natural gas producer or marketer through an electronic trading platform or via third party brokers, that allows APS to deliver that gas to one of our power plants. In other words, if APS had hedged the equivalent of 5 billion cubic feet (Bcf) of NYMEX natural gas futures for a particular month, APS will sell 5Bcf of futures contracts back to the NYMEX market, and purchase 5Bcf of physical supply through ICE (the Intercontinental Exchange – the most commonly used electronic trading platform in our markets). This activity normally occurs during

the last week of the month prior to delivery, but must occur prior to the expiration of the NYMEX contract.

Within the delivery month, APS will take appropriate short term positions in natural gas and/or purchased power in response to changes in market price or load requirements. These modifications include both the purchase and sale of natural gas and electricity as our native load requires. For example, if APS had expected to burn 100,000 mmbtu of natural gas in our generators on a given day, but because of cooler than normal temperatures, the expected load demand fell, APS will sell back to the market any excess natural gas purchased for that day. The same holds true for any excess purchased power. In the event the load is higher than projected, APS will purchase from the market any additional natural gas or electricity needed to serve that load in the most cost effective manner. Natural gas is normally purchased one day prior to delivery while electricity can be purchased either one day prior or hourly (real time) during the day of delivery.

Q. WHAT ARE SOME OF THE LIMITATIONS ON APS' ABILITY TO HEDGE?

A. Credit restrictions, market liquidity, and load uncertainty are the three primary factors that limit hedging.

- Credit restrictions: Can limit the number of counterparties and hedge tenor (both volume and length of transactions).
- Market liquidity: Reduced liquidity further out in time (2008 and beyond).
- Load uncertainty: Customer demand for electricity changes daily due mostly to weather.

- APS' Credit Score: The strength of APS' credit is critical in allowing APS to transact with favorably-rated counterparties, which in turn limits the amount of credit risk to APS customers.

IV. RESPONSE TO THE FILED TESTIMONY OF WITNESSES ANTONUK AND HORNBY

Q. HAVE YOU READ THE DIRECT TESTIMONY OF STAFF WITNESS JOHN ANTONUK?

A. Yes.

Q. CAN YOU PROVIDE YOUR REACTION TO MR. ANTONUK'S TESTIMONY?

A. As I stated initially, I agree with most of the discussion in Mr. Antonuk's filed testimony regarding APS' hedging program and the implementation of that program. I would also note that, based upon my own observations and numerous discussions with Mr. Antonuk and others from Liberty, I believe Liberty undertook a very thorough audit and review of not only our hedge program, but our trading and hedging practices and procedures.

Q. ARE THERE ANY AREAS WHERE YOU BELIEVE THERE MAY BE SOME FURTHER CLARIFICATION NEEDED REGARDING MR. ANTONUK'S TESTIMONY AND/OR THE LIBERTY AUDIT?

A. Yes. Initially, there are a handful of issues discussed in Mr. Antonuk's testimony that are addressed in the filed testimony of Mr. Brandt. On those issues, I will defer to Mr. Brandt. There are, however, three areas where after reading Mr. Antonuk's testimony, I believe it may be helpful to provide some further discussion and/or underlying factual background.

First, in his testimony, Mr. Antonuk raises the issue of future potential APS costs arising from changes in natural gas pipeline transportation costs. I agree with Mr. Antonuk's conclusion that there has been a substantial shift in the

natural gas transportation pricing structure for APS, with the unwinding (over APS' strenuous objections) by the Federal Energy Regulatory Commission of APS' full requirements agreement with the El Paso Natural Gas pipeline. APS has already begun the process of reviewing alternatives as to future natural gas pipeline transportation alternatives and their associated costs. In fact, APS has discussed many of these options touched upon on this issue by Mr. Antonuk with Staff, (e.g. as discussed below, APS is interested in the development of natural gas storage projects in Arizona, and has received pre-approval from the Commission to contract with Transwestern Pipeline Company, LLC if they indeed expand pipeline infrastructure into the Phoenix market). In any event, I agree with Mr. Antonuk's suggestion and the suggestion found in the Liberty Audit Report that we should meet annually with Staff to provide the results of our analysis of potential cost management options regarding future natural gas pipeline transportation requirements.

Second, both Mr. Antonuk and the Liberty Audit Report raise the issues of natural gas storage and liquefied natural gas ("LNG"). On the gas storage issue, the Liberty Audit Report discusses the need to develop high deliverability natural gas storage to accommodate the operation of combustion turbines. That is one of the reasons why APS remains active in encouraging and assisting in the development of natural gas storage projects that could benefit APS and other natural gas generators (users) in Arizona. APS has worked with a gas storage developer on developing the Red Lake Gas Storage site near Kingman, Arizona. The Red Lake site was a large salt dome structure capable of high gas deliverability ideally suited for power generators. The natural gas storage developer involved in the Red Lake project discontinued this business pursuit

about three years ago, and it is our understanding the storage site has now been sold for purposes of real estate development. In addition, APS has worked with two other gas storage developers over the past two years on developing underground natural gas storage near Eloy, Arizona, at a site commonly referred to as the Picacho site. While this site does not geologically possess the same large salt dome configuration found at Copper Eagle and Red Lake, it appears to have an adequate geological structure to store natural gas that could be used to enhance the overall reliability of supply in Arizona. In summary, APS has a strong interest in securing natural gas storage capacity if indeed a potentially viable geologic site is found and can be allowed to be developed and an appropriate business relationship can be consummated. APS will continue to work with developers to effectuate a mutually beneficial natural gas storage project.

In addition to enhancing the reliability of our natural gas supply through underground gas storage, APS continues to monitor the development of Liquefied Natural Gas ("LNG") at a location just south of Tijuana, Mexico called the Costa Azul LNG project. This facility, which is expected to come on line in 2008, will convert LNG to pipeline quality natural gas with a process called regasification and will be made available to Arizona and California markets immediately by virtue of interstate natural gas pipelines already in place in extreme northern Mexico and the southeast corner of California. APS believes the Yuma area can initially benefit from this new supply of natural gas by virtue of its proximity to the interstate pipeline already in place. Accordingly, again, we agree with Liberty and Mr. Antonuk that the development of LNG should be

monitored closely and may ultimately provide value to Arizona generators, including APS.

Third, the Liberty audit makes a brief reference/recommendation relating to audit procedures for the acceptance of gas supply offers. Based upon my discussions with Mr. Antonuk, I believe this issue relates to APS' level of internal oversight on purchases of our physical gas supply. Specifically, APS generally "rolls" out of its financial hedge position the week prior to the close of the NYMEX contract, during a time period referred to within the industry as "bid week". It is during bid week that buyers/sellers of physical natural gas normally go to the market in order to firm up the next month's physical gas requirements. During this "roll" process, as the physical APS gas trader buys supply in the market, the financial trader generally will sell the financial contracts in order to lock in the appropriate overall value for the supply. While many of those physical trades occur via an online computer system where market values are easily discerned, some occur during normal trading hours directly with gas producers and marketers via telephone solicitations. While existing controls already included the recording of telephone transactions for audit purposes and the review of gas purchase and sale prices by personnel independent of the trading function, APS, following Liberty's suggestion, has expanded the review process to compare its gas transaction prices to market prices through the use of prices captured each hour by an electronic trading platform. Transactions found to fall outside these market parameters are documented by the Compliance Manager and reviewed with the trader and myself and reported to the Energy Risk Management Committee ("ERMC"). In the event the trader has not transacted within the market parameters due to

generally acceptable circumstances (i.e. reliability or system emergencies), the trader will be subject to the terms for trading violations as provided for in the ERMC guidelines.

Q. ONE LAST ISSUE AS TO MR. ANTONUK'S TESTIMONY. HE SUGGESTS THAT THE COMMISSION INTRODUCE AN "INCENTIVE" FOR THE OPTIMIZATION BETWEEN NATURAL GAS AND PURCHASED POWER. DO YOU AGREE?

A. Mr. Antonuk recommends that the Commission introduce a sharing arrangement to provide an incentive for APS to "optimize" between natural gas and purchased power hedge positions. He appears to base this recommendation on his observation that during a period when APS' hedge target was fixed at 85%, the procurement costs were reduced as APS shifted its positions between natural gas and purchased power in response to market price movements. (Antonuk testimony, p 44.) Shifts in hedge positions between natural gas and purchased power are primarily responses to shifting energy need forecasts produced by our RTSIM model as it adjusts its least-cost forecast to changes in market prices (to a lesser degree, such shifts can also be the result of traders managing transaction costs and contract minimum size issues as they try to follow the RTSIM volumetric forecasts). In other words, it is likely that the cost savings that Mr. Antonuk ascribes to optimization in his testimony are due far more to shifts in APS' forecasts and/or specific commodity decisions derived from the RTSIM runs (as described in more detail below) than by adjustments made by the APS traders. Although we appreciate Mr. Antonuk's suggestion on this issue, my belief is that any attempt to optimize beyond the modeling we now employ could create an incentive to try to "outguess" the RTSIM model and approach which we have been able to successfully apply over the last several years.

Q. *HAVE YOU READ THE DIRECT TESTIMONY OF RUCO WITNESS J. RICHARD HORNBY?*

A. Yes.

Q. CAN YOU PROVIDE YOUR REACTION TO MR. HORNBY'S TESTIMONY?

A. I believe that Mr. Hornby's testimony included a number of statements which were not correct. One example relates to his reference that APS does not optimize under its hedging plan in the context of "minimizing" its overall costs. (Hornby testimony, p. 3)

Q. IN WHAT SENSE DOES MR. HORNBY'S TESTIMONY IGNORE APS' STEPS IN OPTIMIZING ITS HEDGING POSITION AND THE IMPACT THAT PROCESS HAS ON LOWERING COSTS?

A. In essence, Mr. Hornby's testimony fails to acknowledge the frequent and continuous re-optimization steps undertaken in conjunction with the hedge program. The primary objective of that re-optimization is cost minimization. As I previously discussed, APS purchases both natural gas and purchased power to hedge our native load requirements. In order to properly quantify the volumes of natural gas and/or purchased power required to meet native load, APS incorporates the aforementioned RTSIM model. The RTSIM model uses software to help determine the optimal commitment and dispatch of APS' generation fleet in light of heat rates, non-fuel O&M, start costs, ramp rates, and so forth, as well as fuel and power prices in wholesale markets. It then forecasts the anticipated requirements for fuel and purchased power. Forecast energy requirements are based on APS' forecast of jurisdictional loads, on the capabilities, operating costs, and maintenance schedules of APS' generation resources, and on forward market prices of natural gas and power.

Since APS can either burn natural gas in its own power generators, or source the wholesale market for available power, the model will take into account the forward cost of each commodity in order to "optimize" the least cost mix of natural gas and purchased power. The model is updated weekly with new forward prices, and traders then use this information to adjust natural gas/purchased power hedge positions in order to reduce the cost to serve retail load. At no time in this process is the overall hedge position compromised. Rather, the model simply provides a report of the most economic mix of natural gas and power for the term of the hedge positions, and the subsequent change in that mix will result in a net lower cost.

Q. ARE THERE ANY OTHER AREAS OF THE FILED TESTIMONY OF MR. HORNBY WITH WHICH YOU DISAGREE?

A. Yes, I disagree with a handful of other assertions in his testimony, including issues relating to the development and overview of APS' hedging philosophy and program, but I defer to Mr. Brandt on these issues.

V. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. APS incorporates extensive use of financial and physical contracts to minimize commodity price volatility when purchasing natural gas and purchased power to serve native load. Since price stability is the goal of our system hedge program, financial risks associated with projected requirements of these commodities are systematically hedged at various levels starting roughly three years prior to delivery with standard energy products. The measured approach utilized by the system hedge program helps APS customers avoid much of the price volatility that can occur in the short-term commodity markets. Coupled

with the practice of optimizing natural gas or purchased power to provide the necessary commodities to meet load, the current approach to hedging financial risk is providing APS customers future price stability. We appreciate that Mr. Antonuk and Liberty agree with the propriety and soundness of the APS program, and we shall implement their recommendations on our program going forward consistent with the steps outlined in my testimony.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

REBUTTAL TESTIMONY OF STEPHEN J. BISCHOFF

On Behalf of Arizona Public Service Company

Docket No. E-01345A-05-0816

September 15, 2006

Table of Contents

I. Introduction 1

II. Summary of Rebuttal Testimony 1

III. Bark Beetle Infestation Remediation Costs 2

IV. Reliability 5

V. Distributed Generation Workshop Activities 11

VI. Conclusion 13

Bark Beetle Work Activity & Expenses ..... Attachment SJB-1RB

REBUTTAL TESTIMONY OF STEPHEN J. BISCHOFF
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-05-0816)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Stephen J. Bischoff. My business address is 2121 West Cheryl Drive, Phoenix, Arizona 85021.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the testimony of various Commission Staff and intervenor witnesses related to expenditures and deferral of costs related to bark beetle remediation as well as concerns regarding electricity outages and reliability. My rebuttal testimony will also address concerns raised by William J. Murphy on behalf of the Arizona Cogeneration Association/Distributed Energy Association of Arizona ("DEAA") and Edward Smeloff on behalf of Solar Advocates that deal with distributed generation interconnection requirements.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony will explain why the level of reasonable and prudent bark beetle remediation costs has been modified from that discussed in my Direct Testimony. Specifically, the modifications were necessary to reflect the way such costs are recorded in the General Ledger by FERC account. In addition, costs and credits were inadvertently excluded in the original submission. The net result of

these modifications increases the previous level of deferred costs by less than three percent. In addition, I address concerns raised by Staff associated with reliability issues and discuss the status of projects implemented to deal with the reliability concerns. Finally, I describe APS' participation in the ongoing distributive generation workshops conducted by the Commission and my position that the concerns raised by Solar Advocates and DEAA regarding distributed generation interconnection requirements be dealt with through those workshops.

III. BARK BEETLE INFESTATION REMEDIATION

Q. STAFF CONSULTANT UTILITECH INC. IS RECOMMENDING A PARTIAL DISALLOWANCE OF BARK BEETLE REMEDIATION COSTS INCURRED BETWEEN JANUARY 1, 2005 AND MARCH 31, 2005, PRIOR TO THE EFFECTIVE DATE OF DECISION NO. 67744. DO YOU AGREE?

A. As explained in the testimony of Laura Rockenberger, it is APS' position that Decision No. 67744 authorized the recovery of Bark Beetle Remediation Costs from the years 2005 forward. Staff's proposed disallowance is based upon the timing of when costs were incurred and not a determination that the costs were imprudent or unreasonable.

Q. WHAT WERE THE TOTAL COSTS DEFERRED FROM JANUARY 2003 TO DATE, FOR BARK BEETLE INFESTATION REMEDIATION?

A. No bark beetle costs were deferred in the years 2003 and 2004. All distribution bark beetle costs for the years 2005 and 2006 were deferred pursuant to Decision No. 67744. Approximately, $6,283,000 was deferred for the year 2005, and $5,339,000 will be deferred for the year 2006. Deferrals for bark beetle expense were recorded once adjustments were made to ensure that expenses for distribution line vegetation management in 2005 and 2006 would equal the level of such expenses in the 2002 Test Year, as specified by Decision No. 67744.

Q. WHAT IS THE LEVEL OF DEFERRED EXPENSE THROUGH 2006 FOR BARK BEETLE REMEDIATION FOR THE YEARS 2005 AND 2006?

A. APS estimates it should recover approximately $11,622,000 for deferred bark beetle remediation costs from January 1, 2005 through January 1, 2007.

Q. IN YOUR WORK PAPER SJB_WP3, THERE IS A LINE ITEM ENTITLED, "TOTAL BARK BEETLE." DEFINE THE COSTS WHICH ARE INCLUDED IN THAT LINE ITEM.

A. The type of costs that are included in the subject line item reflect expenses paid to remove and/or clear dead or dying trees from proximity to our distribution lines on forested lands. These trees would otherwise represent a hazard to the reliability of the system and could result in forest fires if contact with the lines were made. These costs include payroll and benefits, transportation, material and supplies, employee expenses, outside services, and other types of expenses related to this work.

Q. IN YOUR WORK PAPER SJB_WP3, PLEASE EXPLAIN THE CHARGES ENTITLED "OTHER O&M" TO THE DISTRIBUTION AND TRANSMISSION LINES.

A. The charges identified as "Other O&M" are those charges, including payroll, materials and supplies, and other related costs that were charged for tree and brush control costs that were not charged to a specific work order identified as "bark beetle."

Q. HAVE YOU MODIFIED THE COSTS ASSOCIATED WITH BARK BEETLE INFESTATION FROM YOUR ORIGINAL TESTIMONY?

A. Yes.

Q. WHY WERE THE COSTS MODIFIED FROM THE ORIGINAL FILING?

A. Bark beetle costs have been modified from earlier testimony to reflect the way they are recorded in the General Ledger by FERC account. The costs as originally

presented separated transmission and distribution work by the primary functions of the departments performing the work. However, this did not address the issue of transmission department personnel occasionally doing work on the distribution system, or visa-versa. Since these groups charge their time to specific job numbers, they are correctly recorded in the General Ledger as Transmission or Distribution based on the job worked on, rather than by the department's primary function. Further, certain costs and credits were inadvertently excluded in the original submission.

Q. COULD YOU PLEASE EXPLAIN WHAT TYPES OF MODIFICATIONS WERE MADE?

A. Attachment SJB-2 to my direct testimony provided total distribution and transmission costs for the year 2004 in the amounts of $6,699,079 and $715,908 respectively. Upon modification of the 2004 costs described above, the distribution cost for 2004 were revised from $6,699,079 to $6,617,978. The cost per tree under the distribution category has also been revised from $74.17 to $73.27. In addition, modifications were made to the transmission cost from $715,908 to $785,606. The cost per tree under the transmission category has also been revised from $20.18 to $22.15. The combined per tree cost for transmission and distribution in 2004 decreased from $58.95 to $58.85.

Q. ARE THERE OTHER MODIFICATIONS TO ATTACHMENT SJB-2?

A. Yes. Attachment SJB-2 to my direct testimony calculated 2005 costs using actual data from January through November and projected costs for December of 2005. We have updated the 2005 costs to include actual costs incurred through December of 2005. By updating the 2005 costs, distribution costs increased from $5,644,232 to $6,282,819. Transmission costs increased from $872,079 to

$1,104,227. We have also included the actual January through July 2006 expenses for bark beetles and projected a year end 2006 figure. This update changed the year end 2006 projection from $5,644,232 to approximately $5,339,000 for distribution only. The corresponding costs per tree figures are also updated.

Q. BASED UPON THE ABOVE CHANGES, WERE OTHER MODIFICATIONS NECESSARY TO YOUR ORIGINAL FILING?

A. Yes. To support these modifications, I have attached (as Attachment SJB-1RB) a revised Attachment SJB-2 from my direct testimony and have provided revised versions of work papers SJB_WP3 and SJB_WP4.

Q. IS APS REVISING ITS REQUEST FOR RECOVERY OF BARK BEETLE COSTS IN THIS APPLICATION?

A. Only to the extent that the actual costs for December of 2005 and a revised projected year end 2006 have been modified. The above changes for the year 2004 will not effect APS' proposal because Decision No. 67744 only authorized recovery of reasonable and prudent costs beginning in 2005. APS witness Laura Rockenberger has revised the pro forma adjustment to the test year for the amortization of this increase.

IV. RELIABILITY

Q. STAFF'S ENGINEERING DEPARTMENT, IN ITS ASSESSMENT OF THE QUALITY OF SERVICE PROVIDED BY APS TO ITS CUSTOMERS, DETERMINED THAT THERE WAS NO REASON TO RECOMMEND CONSIDERATION OF QUALITY OF SERVICE MITIGATION MEASURES AS PART OF THE PENDING APS RATE CASE. IN IT'S QUALITY OF SERVICE ASSESSMENT AND USED AND USEFULL DETERMINATION, DID STAFF IDENTIFY SEVEN ITEMS ASSOCIATED WITH 2005 TEST YEAR CAPITAL IMPROVEMENTS THAT "MERIT SOME ATTENTION" AND WHAT STEPS HAS APS TAKEN TO RESOLVE THESE ISSUES?

A. Yes, Staff did identify the following seven items that merit some attention as follows:

1) "Chino Wells Substation is an old substation with old equipment serving water pumps for Chino Wells. The station service transformers are not in service and have been abandoned in place. The substation transformers are old and showed signs of old oil leaks and have older Type U bushings. The substation is scheduled for replacement or refurbishment in the next few years."[1]

Status: As noted, APS is currently in discussion with the City of Prescott regarding an expansion of the well field. At that time, the substation will be rebuilt to accommodate the increased demand. APS will continue to monitor the equipment in the substation to ensure reliable service. The station power transformers no longer in service have been removed.

2) "The Fairview generator and an emergency 69kV tie at Sulphur Springs Valley Electric Cooperative's ("SSVEC") McNeal Substation are of inadequate capacity to restore full service to all of the Southeast Division for an outage of the APS Adams to Mural 115 kV line. This service area has the potential of exhibiting quality of service concerns comparable to that of Nogales and Santa Cruz County. In fact, the Southeast Division is APS' poorest service performance division over the last five years. A second 69 kV tie is being sought with SSVEC."[2]

Status: The local generation and the emergency tie through SSVEC's McNeal substation is not currently adequate to restore full service to all customers in

[1] See Engineering Report: Staff's Quality of Service Assessment and Used and Useful Determination, dated August 18, 2006, pp 7-8

[2] *Id.*

APS' Cochise District. However, this limitation is abnormal and only temporary because it is caused by two defective transformers at Southwest Transmission Cooperative's (STC) Apache substation and is expected to be remedied by the end of the year. As designed, the emergency tie and local generation is adequate to supply the current load. Future plans include the addition of a transformer at the STC Apache substation and the noted tie between APS' future Palominas substation and SSVEC's proposed Miller substation, which should improve reliability significantly in the local area. Once completed, all Cochise District load will be able to be carried by the emergency ties at the McNeal and Miller substations without the need for local generation.

3) "A new transformer was constructed at Humbug in 2005 without an oil cache basin. The second unit already has asphalt curbing to assure containment of transformer oil spills. It is assumed that the construction activity may not have been completed or the cache basin may have simply been an oversight given the new focus of fire mitigation."[3]

Status: An oil retention basin will be completed for the second transformer by year end 2006, in compliance with our new standard.

4) "Laguna Feeder #1 was rebuilt in 2005 as an underbuild on a 69 kV line on steel poles. The telephone lines previously in joint use on the old wood pole still remain in service with the poles topped above the telephone line. The wood poles are leaning in such a manner as to likely pose a public safety concern for road

[3] *Id.*

crossings. This is not an APS problem, but is reflective of untimely relocation of joint use facilities on poles that are being removed and replaced."[4]

Status: APS has contacted the local telephone company in Yuma regarding the transfer of communication lines and removal of these poles. We have been informed the work will start in early September, 2006.

5) "One 69 kV steel pole just north of Laguna Substation was observed to have experienced a hit and run vehicular accident. The base of the steel pole was severely crushed. The pole appears to be structurally sound but obviously needs replacement."[5]

Status: APS replaced the subject pole. This incident had occurred just prior to the field visit.

6) "Paulden substation had a larger auger bit stored in an inappropriate location. It was placed in a position that could pose an obstacle for a vehicle's ingress to the site if occurring at night. Simply placing the auger bit adjacent to the substation fence would resolve this safety concern."[6]

Status: The auger bit has been removed from the yard.

7) "The San Luis Substation control house has had a roof leak. A black garbage bag was suspending above electronic equipment on the top of a control rack to protect the equipment until the leak was resolved. The roof leak needs to be repaired and the plastic garbage bag removed to enable proper equipment ventilation void of moisture and to avoid the bag becoming a

---

[4] *Id.*

[5] *Id.*

[6] *Id.*

loose impediment in the control house."[7]

Status: Repairs to the roof of the control house have been completed, and the protective cover removed.

Q. STAFF ALSO RAISED CONCERNS REGARDING THE QUALITY OF SERVICE IN APS' SOUTHEAST DIVISION FOR THOSE PORTIONS OF THE APS SYSTEM THAT PROVIDE SERVICE TO THE COMMUNITIES OF DOUGLAS AND BISBEE. WHAT STEPS HAS APS TAKEN TO IMPROVE SERVICE IN THESE AREAS?

A. APS agrees that reliability in the Southeast Division deserves attention and has made significant efforts to improve reliability. APS continues to patrol underperforming feeders and has performed a substantial amount of maintenance to feeders in the Division.

In 2004, APS began to route and construct a new 69kV transmission line to energize a new substation being located in the Palominas area. At the same time, the main portion of the distribution feeder is being reconstructed on the same poles and will improve reliability of the feeder when completed. This work was scheduled to be performed in four phases, over four years. The new Palominas 69/12kV substation will be placed in service by 6/1/2008. APS recently completed the rebuilding of a portion of the line along Highway 92 that was planned for 2006.

In addition, as part of an agreement between APS, Sulphur Springs Valley Electric Cooperative (SSVEC), and Southwest Transmission Cooperative (STC), APS, SSVEC and STC are performing additions and improvements that will allow for a second emergency tie between APS' Palominas substation and SSVEC's Miller substation. Upon completion in 2009, APS will be able to carry

[7] *Id.*

the entire APS load in the region through use of the two emergency ties without the need for the local generation at our Fairview plant.

Q. STAFF ALSO FINDS THAT THE YEAR 2005 WAS STATISTICALLY NOT A GOOD YEAR FOR APS REGARDING SUSTAINED SERVICE INTERRUPTIONS TO CUSTOMERS. PLEASE EXPLAIN THE CAUSES ASSOCIATED WITH INCREASED OUTAGES IN THE YEAR 2005.

A. As noted in the Staff report, Quality of Service complaints did rise in 2005 compared to 2003 and 2004. However, 2005 was a much more challenging year with respect to weather related outages.

When significant or unusual weather events are removed from the computation, as described below, there is no significant difference in outage rates from 2003 through 2005. Specifically, IEEE 1366-2001, IEEE Guide for Electric Power Distribution Reliability Indices, Section 4.5, Major Event Day Classification, and Annex B, Major Events Definition Development, provide a method to "better reveal trends in daily operation that would be hidden by the large statistical effect of major events." The purpose of determining Major Event Days is to allow major events to be studied separately from daily operation. The following reliability data is the result of removing the Major Event Data.

	SAIFI[8]	SAIDI[9] (minutes)	CAIDI[10] (minutes)
2003	1.23	101	82
2004	1.05	82	78
2005	1.15	105	91

The Major Event Days that were excluded were January 4 and 5 (a significant

[8] SAIFI or System Average Interruption Frequency Index is defined as the total number of customers interrupted divided by the total customer base.

[9] SAIDI or System Average Interruption Duration Index is defined as the total outage duration time seen by customers divided by the total customer base.

[10] CAIDI or Customer Average Interruption Duration Index is defined as the total outage duration time seen by customers divided by the total number of customers experiencing an outage.

winter storm affecting nearly 100,000 customers in northern Arizona), July 17 (a major monsoon in the Metro Phoenix area affecting nearly 130,000 customers), July 23 (a Metro Phoenix monsoon affecting over 20,000 customers), and August 2 (a Metro Phoenix monsoon affecting nearly 30,000 customers). Absent the Major Event days, the statistic difference in performance is not significant.

Further, APS maintains its own quality of service measure called "Clear-Weather SAIFI," which is calculated per IEEE 1366 methods for SAIFI with the exception that weather related causes are excluded. APS uses this indicator to gauge the effectiveness of our maintenance programs through removal of the variability of weather. The "Clear-Weather" reliability data is as follows:

	SAIFI	SAIDI (minutes)	CAIDI (minutes)
2003	0.99	64	64
2004	0.82	57	70
2005	0.84	69	82

APS tracks annual performance for all reliability metrics. The difference in performance is not statistically significant as the annual SAIFI, SAIDI, and CAIDI results are within one standard deviation (as calculated between 1995 and 2005). The general trend has been an improving one, and the results fall within our expected bandwidth of performance.

V. DISTRIBUTED GENERATION WORKSHOP ACTIVITIES

Q. DID YOU PARTICIPATE IN THE COMMISSION GENERIC INVESTIGATION OF DISTRIBUTED GENERATION AND INTERCONNNECTION ("DGI") (DOCKET NO. E-00000A-99-0431)?

A. Yes. I represented APS as a panelist for the DGI Workshop hosted by the Commission on June 28, 1999, and later as a member of both the Access, Metering, and Dispatch Committee and the Commission's DGI Advisory Committee. In addition, I am currently representing APS as a participant in the

ongoing distributive generation workshops ordered by the Commission in ACC Decision No. 67744 (APS Rate Case Settlement) which began in July of 2005.

Q. PLEASE DESCRIBE THE CURRENT ACTIVITIES OF THE COMMISSION ON DISTRIBUTED GENERATION PURSUANT TO ACC DECISION NO. 67744?

A. ACC Decision No. 67744 directed the parties to conduct Workshops on distributed generation which begins by evaluating the following three recommendations made by DEAA:

- utilizing Texas interconnection standards or as an alternative California 21 as a basis for Arizona Standards;
- using Salt River Project's rate E-32 as a basis for a new experimental partial requirements tariff; and
- developing a distributed generation program

The workshops began in July of 2005 and began developing a statewide set of distributed generation interconnection standards. Several workshops were held over the next nine months and the parties a comprehensive set of statewide interconnection standards with agreement on all but 11 issues. Position papers were filed on these 11 issues and the Commission Staff will be coming up with a staff recommended set of statewide standards.

Q. ACCORDING TO THE DIRECT TESTIMONY OF WILLIAM MURPHY ON BEHALF OF DEAA, HE SUGGESTS THAT THE COMMISSION SHOULD HOLD A HEARING TO DECIDE INTERCONNECTION RULES. DO YOU AGREE?

A. I don't believe a hearing is necessary in that we have been working through the collaborative group to develop statewide distributed generation interconnection standards that is under review by Staff. All parties have worked very hard to develop a statewide standard and in the process, have had the opportunity to raise and discuss areas of interest and concerns. Resolution of the remaining 11 issues

should continue to occur through the process Staff is following.

Q. SOLAR ADVOCATES HAS IDENTIFIED ELEMENTS THAT THEY WOULD LIKE TO BE INCLUDED IN A NET METERING POLICY. WHAT IS YOUR OPINION ON THOSE CRITERIA?

A. If any of the criteria include interconnection requirements, resolution of those requirements will occur through the above-mentioned workshop collaborative.

VI. CONCLUSION

Q. AND DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes it does.

ARIZONA PUBLIC SERVICE COMPANY
BARK BEETLE WORKSHEET
WORK ACTIVITY AND EXPENSES
(2003 - 2006)
(Revised Attachment SJB-2)

DISTRIBUTION

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	50,181	90,321	54,749	24,689	
Total Cost	$2,345,584	$6,617,978	$6,282,819	$2,926,307	$5,016,526
Cost / Tree	$46.74	$73.27	$114.76	$118.53	

TRANSMISSION

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	221	35,473	6,701	3,127	
Total Cost	$34,227	$785,606	$1,104,227	$491,986	$843,405
Cost / Tree	$154.87	$22.15	$164.79	$157.33	

TOTAL T&D

YEAR	2003	2004	2005	2006 Jan. - July	2006 Projected Y.E.
Trees Worked	50,402	125,794	61,450	27,816	
Total Cost	$2,379,811	$7,403,584	$7,387,046	$3,418,293	$5,859,931
Cost / Tree	$47.22	$58.85	$120.21	$122.89	